HARTENERGY

# 2016 Unconventional Yearbook

## The Top Five U.S. Regions

*The Drive to Capital Efficiencies and Bigger Wells*

Gulf Coast

Northeast

Midcon

Western

Permian

Oil and Gas Investor

E&P

MIDSTREAM Business

# 2016 Unconventional Yearbook

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## 2016 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 2016 Unconventional Yearbook presents the most important facts and figures on the top five U.S. resource plays. This sixth in an annual series of yearbooks provides an overview of current activity with snapshots of the regional plays, profiles of key players, a review of technology, a look at midstream activity, as well as economic analysis and data. Like the playbooks, this yearbook includes a full-color map. To learn more, visit ***ugcenter.com/subscribe***.

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(*Photo by Tom Fox, courtesy of* Oil and Gas Investor)

# Waiting for a Second Wind

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

*The decade-long run of unconventional success in the U.S. pauses for the rest of the world to catch up.*

The "shale gale" gently breezed over the Fort Worth Basin for some 25 years before gusting out in all directions. The land rushes were not far behind, bringing potential success and stirring up history's dust in sleepy towns across the nation. Then came the march of man and iron necessary to drill, frack and repeat.

With company flags planted firmly in the source rock that fed many a conventional oil and gas play back in the day, the multivaried complexities of being "unconventional" began to unfurl. Recipes scrawled out not in cookbooks but log books detailed how to best coax oil and gas from the tightly bound nanoscale pores. In the span of 10 years, the ingenuity and the dogged persistence of the U.S. petroleum industry lifted the nation from importer to exporter status, from being just a player in the global petroleum market to its swing producer.

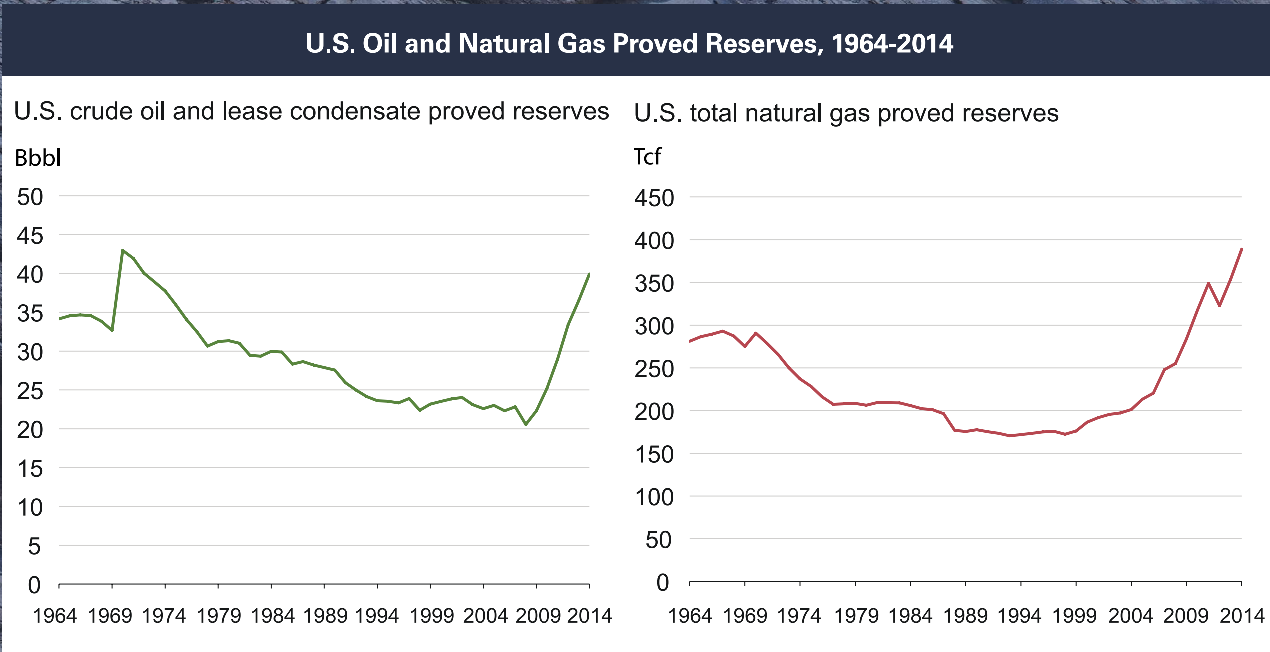
In November 2015, the U.S. Energy Information Administration (EIA) announced that oil and natural gas reserves reached record highs. In 2014, U.S. crude oil and lease condensate proved reserves increased to 39.9 Bbbl, an increase of 3.4 Bbbl from 2013, the EIA reported. This marks the sixth straight year that proved reserves of crude oil and lease condensate have increased, and exceeded 39 Bbbl for the first time since 1972. Texas added 2.1 Bbbl of crude and condensate proved reserves, located mostly within the Permian Basin and Eagle Ford Shale plays. North Dakota added 0.4 Bbbl of crude and condensate proved reserves mostly from the Bakken Shale play, the EIA stated.

On the natural gas side of the coin, proved reserves increased 34.8 Tcf to 388.8 Tcf in 2014. This increase boosts the national total of proved natural gas reserves to a record-high level for the second consecutive year, according to the EIA report. Proved reserves additions of natural gas were highest in Pennsylvania, where operators added a net 10.4 Tcf of natural gas proved reserves in the state's portion of the Marcellus Shale play, according to the EIA. In 2014, West Virginia surpassed Wyoming and Colorado to become the fourth-largest state for natural gas proved reserves (behind Texas, Pennsylvania and Oklahoma). Proved natural gas reserves in Ohio more than doubled as a result of development of the Utica Shale play, and Idaho in 2014 reported proved natural gas reserves for the first time, according to the EIA.

And as quickly as the gale gusted, the winds shifted in 2015, prompting course changes. Revisions in yearly budgets delivered cost cuts close to the bone as operators dug in to weather a storm that has shown an unexpected longevity. According to the EIA, sustained low prices for oil and natural gas are anticipated to reduce the reserves. The administration found that lower prices have curtailed drilling and made recovery economics more challenging. Although resource estimates are not necessarily reduced by lower prices, the calculation of proved reserves is sensitive to price, it said in the report.

The EIA forecasted in October 2015 that U.S. shale production was expected to fall by more

The setting summer sun reflects off one of six Carrizo Oil and Gas Co.'s pumpjacks on a pad outside of Cotulla, Texas, in La Salle County.




*(Source: U.S. Energy Information Administration, Form EIA-23L, Annual Survey of Domestic Oil and Gas Reserves, 1977-2014, American Petroleum Institute, 1964-76)*

than 93 Mbbl/d to 5.12 MMbbl/d, according to its monthly drilling productivity report. It is the largest monthly cut forecast since data were available in 2007. Natural gas production in the major shale plays was expected to fall 294 MMcf/d to 44.9 Bcf/d in November from October 2015, the EIA forecasted. It would be the biggest decline since March 2014, according to EIA data.

Increased demand will help bring balance to the market. Global oil demand will grow by the most in six years in 2016 while non-OPEC supply stalls, Reuters reported.

Total world supply is expected to rise to 95.98 MMbbl/d in 2016, according to the EIA's Short Term Energy Outlook. Demand is expected to rise 270 Mbbl/d to 95.2 MMbbl/d, up 0.3% from September 2015's forecast due in part to an outlook for stronger demand growth from China, Reuters reported.

In this fifth issue of Hart Energy's Unconventional Yearbook, we chronicle the last year of activity in five major regions where unconventionals are in play and offer insights into what 2016 could mean for operators. The pages that follow include extensive regional reports detailing the upstream and midstream activities in the Northeastern, Midcontinent, Gulf Coast, Permian and Western shale plays.

In addition, updates on the top key players in the upstream and midstream markets are provided. In-depth reporting on the techniques and technologies seeing success in the drilling, completing and producing arenas are covered as well. The yearbook wraps up with expert analysis on the key trends for the year ahead as provided by Stratas Advisors.

James Wicklund, managing director and senior oilfield services analyst for Credit Suisse, said it best in his remarks to attendees of Hart Energy's 2016 Offshore Executive Conference: Gulf of Mexico.

"We [the U.S.] are the swing producer now, and that means if the world is oversupplied, we take the hit," he said. "If the world is undersupplied, we rev up the U.S. shale machine to provide the balance."

It is probably safe to say that operators across the U.S. are waiting for that day to come when they can stand on the gas pedal and get busy balancing. ■

(Photo by Glenn Kulbako, courtesy of Oil and Gas Investor)

# Gas Mountain

By **Nissa Darbonne**, Editor-at-Large

*Appalachian gas producers kept piling on in 2015, bringing 60-plus-MMcf/d deep-Utica tests online and further refining their existing Marcellus harvesting techniques. Here's what 2015 produced and the outlook for 2016.*

In two news releases within 35 minutes one morning in mid-October 2015, there was further evidence that the U.S. Northeast energy-short profile had changed. Antero Resources Corp. reported it had signed a 10-year contract with Japan's Chubu US Gas Trading LLC to deliver 70 MMcf/d to the Freeport LNG liquefaction facility that is under construction on the Texas Gulf Coast with a late-2018 or early-2019 start date.

Traditionally, the Gulf Coast had been the Northeast's greatest source of natural gas in addition to LNG that was imported from abroad. Over the life of Antero's contract, the delivered gas will total 256 Bcf.

Roughly a half-hour later, Entergy Corp. announced it is closing its Massachusetts nuclear power-generation plant, citing, among its reasons, an inability to compete with low-priced shale gas from the Utica and Marcellus plays in Ohio, Pennsylvania and West Virginia.

These are in 180-degree contrast to the 1970s natural gas shortages in the Northeast that resulted in school and other facility closings some winters and the Three Mile Island crises that produced increased concern about the safety of nuclear plants. A Pennsylvania newspaper reported in mid-October 2015, "In the last five years, Marcellus Shale drillers have gone from producing 25% of Pennsylvania's natural gas to 20% of America's natural gas."

Bloomberg reported in mid-September that wholesale electricity prices for New York City averaged $40.99 a MWh in the prior 11 weeks, heading toward setting the lowest third-quarter average since before 2006. "Cheap (natural) gas has subdued power prices even as the East Coast experienced waves of unusually hot weather in the second half of the summer [2015]," it reported.

And more gas is to come, according to Jeff Ventura, chairman, president and CEO of Range Resources Corp., which made the commercial, horizontal, Marcellus discovery, Gulla 9, in 2007 and began working on the play in 2004, using modern fracturing.

"Yes, the Appalachian Basin has seen many changes in the last decade," he told Hart Energy in late October 2015. "Coal used to be the dominant fuel source for power generation in the U.S.; this summer [2015], for a first time in history, natural gas usage surpassed coal. A couple of decades ago, about 10% of U.S. power generation was with natural gas as feedstock and coal was about 65%; today, natural gas is about 30% and coal is in the 30% range."

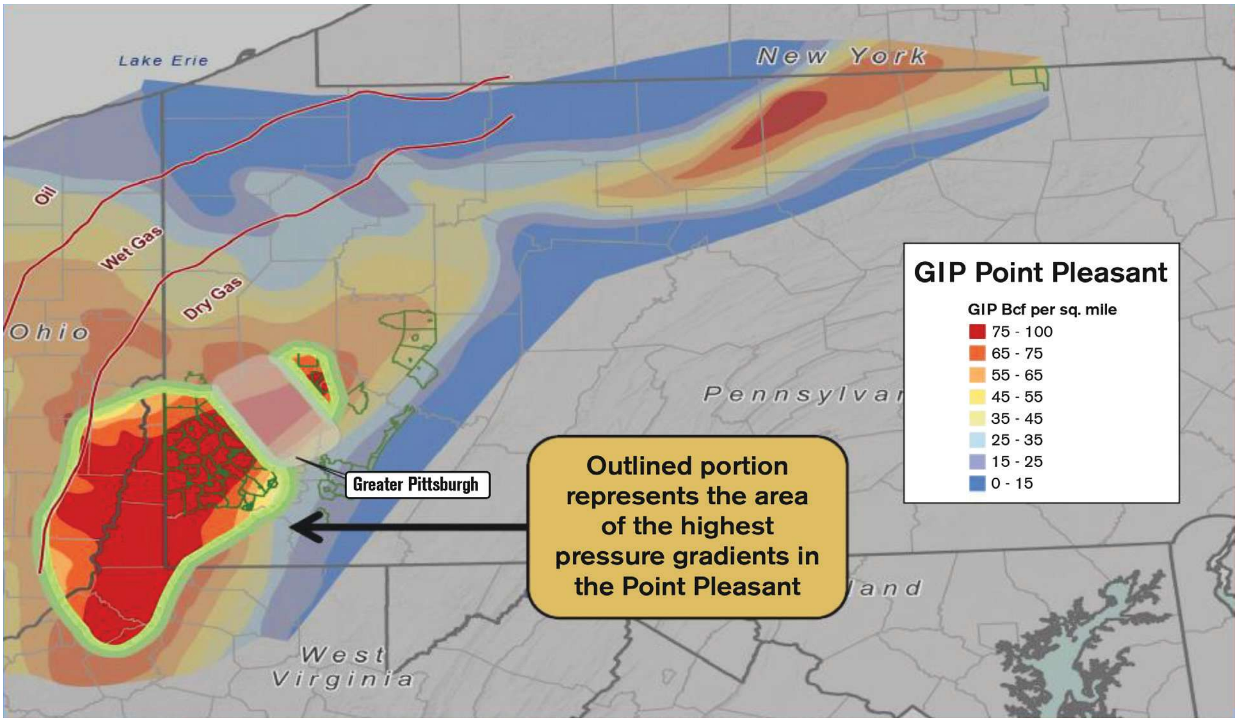
Alone, Range produced some 635 MMcf/d from Appalachia in third-quarter 2015, net of its 1 Bcfe/d from the basin, including liquids. Like Antero has now, it has contracts to supply gas to Gulf Coast LNG-export facilities that are underway. Range cannot reveal to whom it has committed the gas supply, but there are three contracts, totaling 200 MMcf/d.

Cheniere Energy Inc. expects its first liquefaction train—the first in U.S. history—will fill a first tanker in January 2016 at Sabine Pass, La. In April 2008, Cheniere's Sabine Pass facility had received its first *delivery* of LNG as the regasification terminal had been built in expectations of a shortage of North American gas supply.

Another LNG-liquefaction-for-export project is underway at Cove Point, Md., which is also a former import facility. Ventura said, "We're open to contracts with that as well."

Ensign 160 drilled West Branch Pad O for Seneca Resources in McKean County, Pa., in 2015.

Gas in Place: Point Pleasant




*(Source: Range Resources, Tudor Pickering Holt & Co.)*

### Appalachian supply

How much can Appalachian producers deliver locally and to ports? Jefferies LLC Securities analyst Jonathan Wolff estimated in October 2015 that U.S. Northeast dry gas supply would exit 2015 at 21.2 Bcf/d. Of this, 13.1 Bcf was expected from Pennsylvania's Marcellus; 3.3 from West Virginia; 4.1 from Ohio's Utica; and the rest, from legacy gas fields. The figure is about a third of total U.S. dry gas production, which he estimated would be 72.4 Bcf/d at year-end 2015.

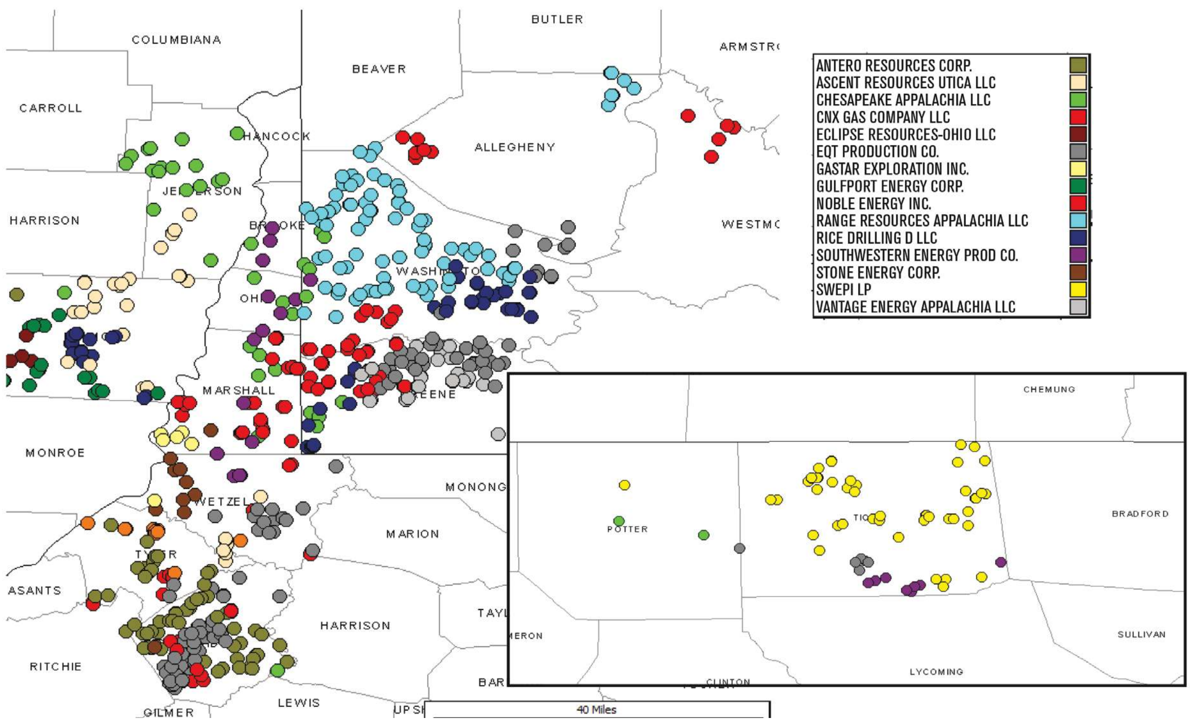
Is demand stepping up to supply? Pearce Hammond, a securities analyst with Simmons & Co. International Inc., reported that an additional 15.8 Bcf/d of demand is expected between now and into 2020. The figure was reduced from his 2014 forecast of 19.9 Bcf/d. "Why the 4.1 Bcf/d reduction between forecasts? Some of the difference is due to new projects/sources of demand, which have already started up [in 2015] year to date," Hammond reported.

Some of this is 1.5 Bcf/d from greater exports to Mexico. Also, additional demand has been from power generation driven by coal-plant retirements. "[Daily] gas demand for power generation is up more than 3 Bcf [in 2015] due not only to coal-plant retirements but also to coal-to-gas switching," he wrote.

According to U.S. Energy Information Administration data on gas in working storage in early November 2015, the U.S. was oversupplied by 3.9 Tcf. Backing out what was in storage at the end of the 2014-15 winter drawdown, in the 217 days between March 27 and Oct. 30, the U.S. was oversupplied by some 11.4 Bcf/d.

And Appalachian operators—collectively contributing the greatest growth in U.S. gas supply—were continuing to improve well results and cost. In the 12-year-old Marcellus play that matriculated nine years ago, Southwestern Energy Co. increased production 60% higher in 2015 than the type curve it used to buy into the West Virginia and southwestern Pennsylvania Marcellus in late 2014 with $5 billion.

**Core Dry Gas Utica Operators**




*(Source: Drillinginfo, Tudor Pickering Holt & Co., company filings)*

Seaport Global Securities (SGS) analysts reported that the well-performance improvement is the result of 260-ft spacing of stages and more than 65% more sand—i.e., between 2,000 lb and 3,000 lb per lateral foot—than the previous owner, Chesapeake Energy Corp., was deploying.

New offset wells' EURs improved 54% to an average of 2.1 Bcf/1,000 ft of completed lateral. On one pad, Southwestern drilled more than 86,000 lateral feet and completed the wells with more than 200 MMlb of sand. Drilling and completion cost was about $1,000 per lateral foot. One rig drilling for Southwestern had already made some 133,000 ft of hole for it, involving 11 wells, SGS added.

### Deep-Utica dry gas

In the Barnett Shale play in early 2006, a 10-MMcf, first-24-hour well completed by EOG Resources Inc. in Johnson County was considered a "screamer." In the deep-Utica play that has developed in southwestern Pennsylvania and West Virginia, EQT Corp. reported in July 2015 that its Scotts Run 591340 came on with 72.9 MMcf/d in Greene County, Pa. This was from a treated lateral of just some 3,200 ft. Flowing casing pressure was 8,641 psi; pore pressure gradient, 0.95.

SGS reported in October 2015 that the well "continues to produce at a high, consistent rate and with elevated pressures...The well has stayed flat at 30 MMcfe/d through 60 days and has exhibited extremely high casing pressures." EQT was expecting in fourth-quarter 2015 that the well's production will begin to decline in March 2016. SGS noted that, by then, "it will have produced approximately 7.4 Bcf."

The well followed the first deep-Utica test, Claysville Sportsman's 11H, in Pennsylvania. Drilled by Range, it came on in late 2014 with 59 MMcfe/d in Washington County, home of the Marcellus discovery, and has a 5,420-ft lateral at 11,700 ft true vertical depth (TVD). Pressure was 0.88 psi/ft. After

**Range Marcellus—2015 Well Economics Summary**

| | SW Super-rich | SW Wet | SW Dry | NE Dry |
|---|---|---|---|---|
| EUR | 12.9 Bcfe<br>1,169 Mbbls & 5.9 Bcf | 17.6 Bcfe<br>1,501 Mbbls & 8.6 Bcf | 17.1 Bcf | 15.2 Bcf |
| EUR/1,000 ft. lateral | 2.40 Bcfe | 2.95 Bcfe | 2.52 Bcf | 2.67 Bcf |
| EUR/stage | 477 Mmcfe | 586 Mmcfe | 504 Mmcf | 542 Mmcf |
| Well Cost | $5.9 MM | $5.9 MM | $6.0 MM | $4.9 MM |
| Cost/1,000 ft. lateral | $1,099 K | $991 K | $883 K | $865 K |
| Stages | 27 | 30 | 34 | 28 |
| Lateral Length | 5,367 ft. | 5,955 ft. | 6,798 ft. | 5,663 ft. |
| IRR – Strip (as of 6/30/2015) | 26% | 28% | 60% | 64% |
| IRR – $4.00 | 33% | 38% | 101% | 140% |

**The different Marcellus areas provide optionality and a balanced approach to developing acreage and growing overall Marcellus production**

*(Source: Range Resources)*

the test, Range tightened the choke, restraining the well to 20 MMcfe/d.

"As of the last update, the well was still producing at this rate," Jefferies' Wolff noted in October 2015. Later in fourth-quarter 2015, Range revealed that the well's EUR is 15 Bcf—or 2.8 Bcf per 1,000 ft of lateral.

The company also announced results from its second deep-Utica test, Claysville Sportsman's 9H. It has a 5,228-ft lateral that was completed with 32 stages. It was choked immediately to 13 MMcf/d to manage pressure; a first-24-hour test was not conducted.

Popping back over to Greene County, Rice Energy Inc. reported its John Briggs 50U encountered casing pressure of 10,254 psi, which, SGS wrote, "we think makes it the highest-pressured dry gas Utica well encountered to date." The well is at 12,820 ft TVD with a 5,800-ft lateral completed with 41 frack stages.

Consol Energy Inc.'s Gaut 41 in Westmoreland County was landed at 13,400 ft and IPed 61 MMcf/d; casing pressure was 9,921 psi. It had a 5,800-ft lateral with 30 stages at 200 ft apart and 500,000 lb of proppant per stage—about 32% of this 100-mesh, 40% 40/80 ceramic and 28% 30/50 ceramic. Wolff reported, "This well was drilled some 35 miles east of any other Utica wells and, with further testing in the area, could expand the productive area of the Utica farther east."

The 2015 tests of the Pennsylvania Utica, which is at the greatest depth compared with some 8,000 ft to 9,000 ft in Ohio, are insight into "the deeper and more overpressured areas in eastern Pennsylvania," he added.

Consol's second Utica dry gas well, Switz 6D, had a 24-hour rate of 44.7 MMcf/d with pressure of 6,835 psi in Monroe County, Ohio. Consol raised its type curve for the area to 2.4 Bcf per 1,000 ft of lateral from an initial estimate of 2.2 Bcf.

## Deeper costs

There is a cost at this depth, however. The Rice well's cost was $27 million. Consol's Pennsylvania well cost $27 million. The EQT well cost $30 million. The latter included EQT having to change out, mid-drill, to a higher-powered rig to take on the reservoir pressure and finish the job, Wolff reported. Because these were tests or "initial science" wells, they "have obviously been more expensive," he added.

Without disclosing Range's spend, Ventura said it also invested in a great deal of science in it—and industry's—first Utica test. The cost is "because we're starting over," he said.

"An advantage is our Utica wells are on existing Marcellus pads; we can utilize some of the roads, infrastructure [and] personnel. But, when you start in a new horizon, you have to put some science into it. The question, ultimately, is 'What will the cost be to drill and complete these wells, what will the EUR per 1,000 ft be and what will be the shape of the curve?' That will dictate economics."

Range and EQT both expect their subsequent wells will cost about $12 million. EQT reported that it may run a 10- to 15-well deep-Utica program

in 2016. "Management notes that it feels very comfortable with the geology of the play; delineation is not an issue," SGS' analysts reported. "However, high well costs are the current limiting factor."

Some of what's motivating deep-Utica exploration is a new-production reweighting from less wet gas to more dry gas. "You look at where oil and gas prices are today," Ventura said. "There has been a shift from wet to dry. Dry gas wells today are better for us than wet."

Of Range's third-quarter 2015 Appalachian net production of 1 Bcfe/d, 64% was gas; the balance, 51,967 bbl of NGL and 8,676 bbl of condensate.

"Looking back a couple of years, it was the other way around," Ventura said. "If you look forward a couple of years, it depends on where oil and gas prices go. But we have the opportunity to drill in any one of those three regimes, the dry, wet and super-rich, as well as in those other (reservoir) horizons."

While expensive on a per-lateral-foot basis, the deep-Utica wells in southwestern Pennsylvania are powerful, SunTrust Analyst Robinson Humphrey's (STRH) Securities Analyst Neal Dingmann noted. "Unlike the typical oil or natural gas well that declines some 75% in the first nine to 12 months, many [of these] wells continue to show minimal decline in the early months, given the active choke program used by most operators in the region in conjunction with the high pressure reported by many wells."

### Pressure, drainage

With pressure of some 10,000 psi, the wells' decline is only some 100 psi a month. "Our channel check indicates that many [of these] wells—excluding some early wells that were pulled too hard—continue to show relatively flat production and likely could continue to do so until natural line pressure is reached 12 to 18 months after first production," Dingmann reported.

"The flat early rates give many…much higher accumulated production than wells in nearly any other part of the U.S."

In addition to decline rate, Tudor, Pickering, Holt & Co. (TPH). analysts were awaiting data on what may be the wells' drainage area and the Utica's gas in place in the area. "Most wells highlighted in company releases have been in 'virgin' reservoir with no offsetting wells, preventing us from getting an accurate view of development-drilling (potential)," they reported.

Subsequently, Range released its EUR for the first deep-Utica well: 15 Bcfe or 2.8 Bcfe per 1,000 ft of lateral. Its average EUR per 1,000 ft of lateral in the Marcellus, meanwhile, is 2.52 Bcfe in the southwestern, dry window; 2.95 in the wet window; 2.4 in the super-rich; and 2.67 in the northeastern dry. Jefferies' Wolff called the deep-Utica EUR "modest" and also believed more wells and time were needed.

"It's too early to make broad generalizations about recoveries of typical 'deep' Utica wells," he wrote. "But, clearly, at first glance, the capital pro-

## Future Role

**The Burket play is expected to further expand Marcellus/Utica potential.**

Another emerging Appalachian play is the Upper Devonian Burket-Geneseo that stretches over the Marcellus, separated by Tully limestone, from West Virginia into northeastern Pennsylvania. Consulting geologist Gregory Wrightstone told DUG East attendees in mid-2015 that it may contain nearly 87 Tcf in recoverable potential, according to an *Oil and Gas Investor* report.

"To date, the industry has completed 85 horizontal wells in the Burket. Previously, operators drilled about 100 uneconomic vertical wells. Most wells are concentrated in Washington and Greene counties in the southwestern corner of Pennsylvania and in Wetzel County, W. Va.," *Investor* reported.

Producers currently landing laterals into the rock include EQT, with 60 Burket wells, and Consol Energy Inc., Rex Energy Corp. and Royal Dutch Shell Plc. "The significance of the Burket is not the resource size; rather, it is the role the Burket will play in expanding the potential of the world-class Marcellus/ Utica natural gas province. The implications are not so much about what happens in 2016; rather, they are about how the Burket will extend and expand the Appalachian gas play over a couple of decades," *Investor* reported. ■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**Core Dry Gas Utica Prospectivity and Reserves**

| State | County | Prospective Sections (Sq mile) | TPHe Bcf / Section | TPHe Recoverable / Section (60% rf) | TPHe Recoverable Resource Potential (Bcf) | TPHe Locations @ 7.5k' laterals (5-7 Wells/Section) |
|---|---|---|---|---|---|---|
| OH | Belmont | 217 | 125 | 75 | 16,238 | 866 |
| OH | Jefferson | 165 | 125 | 75 | 12,338 | 658 |
| PA | Allegheny | NA* | 125 | 75 | NA* | NA* |
| PA | Greene | 174 | 125 | 75 | 13,013 | 694 |
| PA | Potter | 54 | 125 | 75 | 4,050 | 216 |
| PA | Tioga | 171 | 125 | 75 | 12,788 | 682 |
| PA | Washington | 517 | 125 | 75 | 38,738 | 2,066 |
| PA | Westmoreland | 104 | 125 | 75 | 7,763 | 414 |
| WV | Brooke | 69 | 125 | 75 | 5,175 | 276 |
| WV | Doddridge | 32 | 125 | 75 | 2,400 | 128 |
| WV | Ohio | 109 | 125 | 75 | 8,175 | 436 |
| WV | Marshall | 312 | 125 | 75 | 23,400 | 1,248 |
| WV | Tyler | 131 | 125 | 75 | 9,788 | 522 |
| WV | Wetzel | 343 | 125 | 75 | 25,725 | 1,372 |
| **Total / Average** | | **2,400** | **125** | **75** | **180,000** | **9,600** |

*(Source: Range Resources, Tudor Pickering Holt & Co.)*

ductivity looks inferior to the 'core' Marcellus, which has less than half the completed well cost (i.e, $6 million vs. estimates that Range's second deep-Utica test cost some $13 million) and slightly more per-well resource, which is some 17.1 Bcfe per well."

But, he added, "Range does have a history of giving conservative early EURs and [later] raising recovery rates on development improvements."

TPH estimated in October 2015 that deep-Utica drillers may get drilling and completions down to between $1,500 and $2,000 per lateral foot. Rice's in the shallower Utica in Ohio in one year of drilling has declined from $3,300 to $1,500 per lateral foot. But "the West Virginia and Pennsylvania side of the play is deeper with higher pressure, which should keep well costs higher on a relative basis," the TPH analysts reported.

As for gas in place, it's "difficult to nail down," they added. Range estimates it is between 75 Bcf and 100 Bcf/sq mile. If there is contribution from the overlying Utica in these wells, which are actually landed in tight, but more frackable, Point Pleasant, it could be between 100 Bcf and 150 Bcf/sq mile, TPH estimated.

"Based on discussions with companies and reserve auditors, it appears the best wells on core acreage in the Marcellus [in comparison] are approaching recovery factors of 60%. It's hard to pin down what the Utica performance will ultimately look like, but we are currently assuming recovery rates may reach similar levels...."

## Stacked pay

Ventura said Range held off on testing the deep Utica in its leasehold in part to hold its acreage by Marcellus production, which is at some 6,000 ft to 6,500 ft in Washington County. There, the Marcellus, Utica and Devonian are stacked and the Marcellus' pressure gradient is about 0.7 psi.

The Utica there is at about 11,200 ft TVD; pressure is roughly 0.9. In Greene County, where EQT and Rice are drilling, it's even deeper and with yet-higher pressure.

"The Marcellus was our original target," Ventura said. "We hold all-depth rights with our Marcellus drilling. And our Marcellus wells are really pretty spectacular. The EUR per 1,000 ft of lateral ranges from 2.5 to 3 Bcfe."

The drilling and completion cost for this EUR is between $880,000 and $1.1 million per 1,000 ft of lateral. "When you marry the cost and the EUR per 1,000 ft, those are pretty stout numbers. The Utica will have to compete with that," he said.

"And it may or may not. Time will tell. We're excited about what the Utica can be and we have a big position right underneath us. It's all about capital efficiency and

# Marketing Ethane

Years in the making, the first shipments of Marcellus ethane are heading to Europe.

With great NGL supply from the wet gas Marcellus and Utica windows, there is a need to find markets. Range Resources Corp. recognized this in early 2007, after testing the Marcellus for three years with verticals and three horizontals and before bringing on its first commercial horizontal.

It immediately went to work on finding a buyer of the ethane, resulting in shipments to a Canadian petrochemicals manufacturer via pipe beginning in 2013 and the first ethane shipments to Europe, which were expected by year-end 2015.

The latter required construction of ships, dubbed "Dragon ships" by the ethane's buyer, petchem manufacturer Ineos, under a 15-year contract. A newbuild pipeline, Mariner East 1, will deliver a daily rate of 20,000 bbl of ethane for Range to an existing port terminal, Marcus Hook, in Philadelphia. Range has 50% of the pipe's capacity. At press time, operator Sunoco Logistics was querying Appalachian-producer interest in contracting capacity on an expansion of a second line, Mariner East 2.

Range also plans to deliver ethane to the Gulf Coast via ATEX.

Jeff Ventura, Range chairman, president and CEO, said, "We will be the first company to export ethane to Europe." In addition, Range's marketing group tied the ethane contracts to dry gas, naphtha and other indices rather than to Mont Belvieu. "That will be a nice uplift for us."

Range also will deliver a daily rate of 20,000 bbl of propane to Marcus Hook via Mariner East I, selling it into the local market or exporting it. "That's a strategic advantage for us," he said.

Also, some 10% of Range's NGL production is condensate. At press time, it was upgrading its transportation scheme and, during third-quarter 2015, became the first Appalachian producer to offer condensate for export to markets abroad.

As for dry gas, producers are continuing to seek access to myriad means of getting their excess production to markets outside the U.S. Northeast as well. Tudor, Pickering, Holt & Co. Securities Analyst Matt Portillo reported that midstream relief is due in 2016.

"With several southwestern Pennsylvania Marcellus and Utica long-haul pipelines—some 4.5 Bcf/d to 5 Bcf/d—set to" come online by early 2017, but daily-production growth from the plays slowing to between some 2 Bcf and 2.5 Bcf, Portillo expected Tetco M2 and M3 and Dominion DTI differentials "significantly tightening [in 2016]."

As for NGL, "generally, the Northeast market will remain challenged until Mariner East 2 is operational in 2017, taking some 275,000 bbl/d. However, specific operators are set to benefit sooner," he said.

Specifically, that is Range, which owns 50% of Mariner East 1 capacity, which is 70,000 bbl/d. Range also owns 80% access to a 1-MMbbl propane-storage cavern at Marcus Hook.

For dry gas, however, Portillo reported, "Looking ahead, we continue to believe demand growth will exceed supply growth in the coming years, but [2015 and 2016] may remain relatively challenged.

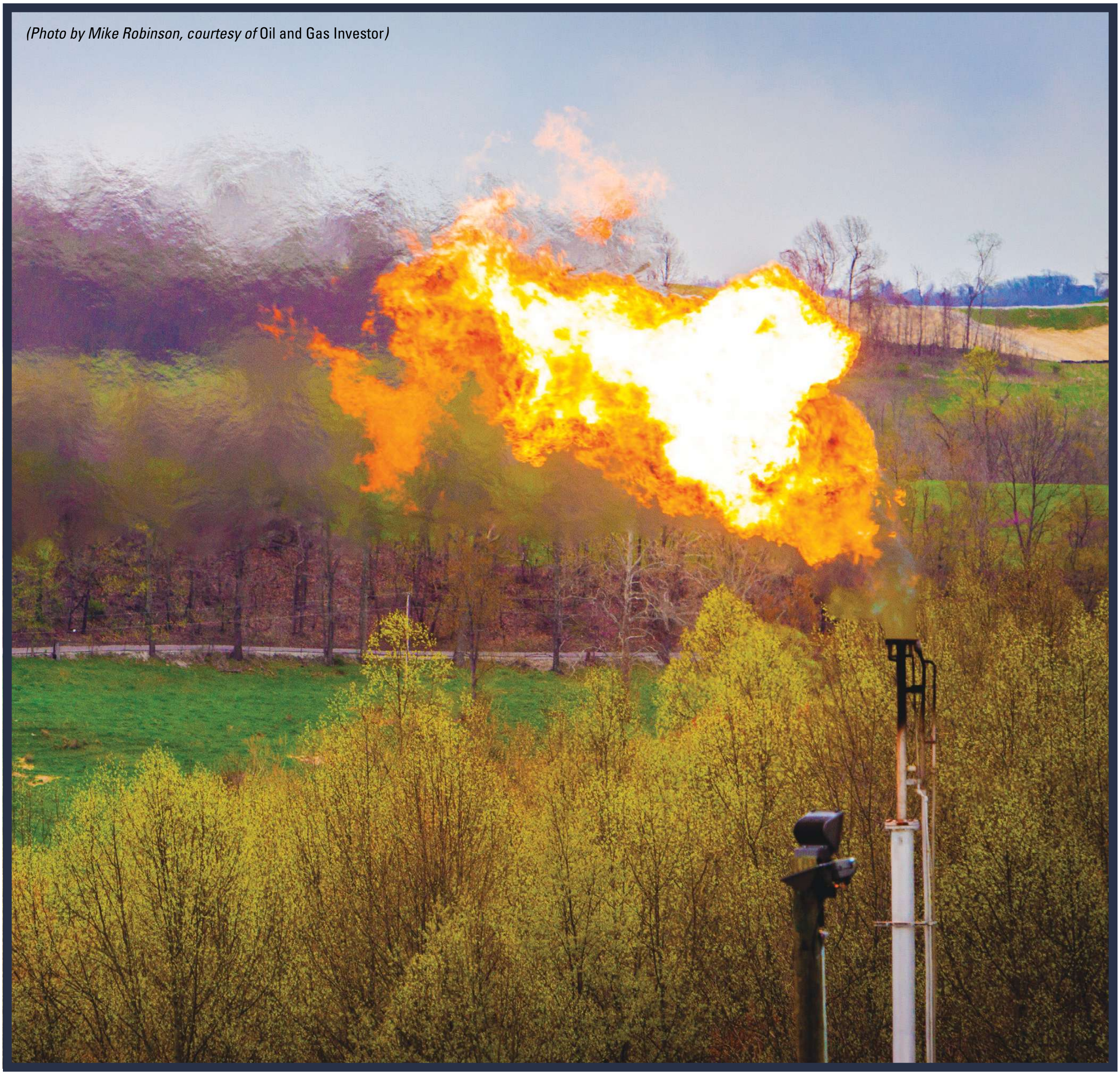
SunTrust Robinson Humphrey Securities analyst Neal Dingmann reported that, while the Henry hub price for natural gas was depressed, U.S. Northeast prices "continue to be much more challenging." The prices at Leidy, Dominion, Tetco M2 and Tetco M3 "remain among some of the worst in the U.S." At the time, they were between $0.90 and $1.03.

Bob Brackett, an analyst with Bernstein Securities, reported that Cabot Oil & Gas Corp. "has some of the best gas assets in the country, but their pricing suffers as takeaway capacity is limited in the northeastern Marcellus." He referred in October 2015 to his April 2015 report. In that, he wrote, "If an E&P producer was to be granted a wish, it would ask for Susquehanna County—the heart of the northeastern Marcellus and focus of Cabot's acreage.

"The equivalent of nearly 3 million barrels of oil rapidly flows out of $7 million wells that can be laid down several hundreds of feet apart in fairly continuous acreage." But the exit routes are full, "effectively trapping low-cost growth." The Constitution and Atlantic Sunrise pipelines are expected to help, he added.

Seaport Global Securities analysts reported that ongoing uncertainty of Constitution's in-service date—as a result in permitting delays by the state of New York—has held Cabot's production growth back. If construction begins this month, it might be operating before year-end 2016. Atlantic Sunrise is expected to start in third-quarter 2017.

Also underway is a Mountain Valley pipeline from West Virginia to Pittsylvania County, Va., connecting 2 Bcf/d to existing infrastructure that directs supply to the U.S. Southeast. Construction is expected to begin by year-end 2016. ■



(Photo by Mike Robinson, courtesy of Oil and Gas Investor)

Gas is flared at the Hays central gathering facility.

returns. We know what the Marcellus is. The question is 'What will the Utica be?' But, being that it is a complementary operating position, it is upside for us if it is better than the Marcellus."

Dave Porges, EQT chairman, president and CEO, said in the company's third-quarter 2015 call in late October, "A year ago, it would have been hard to imagine a more prolific play than the Marcellus...However, if the deep Utica works, it is likely to be larger than the Marcellus over time." EQT is focusing its current budget on Marcellus and Utica in the plays' center and suspending work in non-core areas, such as central Pennsylvania.

Regarding the deep-Utica wells, Porges said, according to a transcript by Seeking Alpha, "There have been fewer than 10 wells drilled and completed in the deep Utica around our acreage, so it is still too early to be confident that the play will be economic, but the early results are certainly encouraging."

### Deep-Utica displacement

If the Utica works, the returns could be better than from wells in the core Marcellus window. But how would high-test Utica wells affect natural gas supply, therefore prices? Lower-return gas across North America will be deferred by producers "possibly for many years," Porges said.

"So, while those of us…who have a significant position in the core of the deep Utica will be the winners, if you will, the cannibalization of other opportunities will affect everyone, including those of us who will net/net be much better off if the deep-Utica play does work economically."

Irene Haas, an analyst for Wunderlich Securities Inc., titled a report, "More Low-cost Dry Gas Coming Out of the Utica? A Scary Scenario." She wrote, "With crude/liquids prices plummeting, Appalachia producers are looking for better returns from dry gas wells. As a result, more resources and drilling money [are being] poured into the Utica dry gas trend."

Tests have been "stunning," she added. With more data points, "if we connect the dots, the Utica dry gas belt could be huge, rivaling the Marcellus."

On a restricted choke, EQT's Scotts Run well was producing 30 MMcf/d. If EQT's and others' deep-Utica wells at 13,000 ft with 5,400-ft laterals cost between $12.5- and $14 million and have EURs of between 13.9 Bcfe and 18.8 Bcfe, "a Utica dry gas well could generate a more than 20% return at $2 gas," she estimated. This happened to be what the November 2015 contract for gas delivery to Henry Hub was at the time.

Tim Dugan, Consol COO of E&P, also suggested deep-Utica gas could displace other gas supply. Consol's first well, Gaut 41, in Pennsylvania that IPed 61.4 MMcf/d in July 2015 still had pressure of about 9,000 psi in October; flow was restricted to about 20 MMcf/d.

"High reservoir pressure, high reservoir deliverability and large reservoir extents make us all very excited about the potential of the Utica in this area," Dugan said in Consol's earnings call, according to a Seeking Alpha transcript.

"…If the Utica truly does [continue to perform]…logic indicates that Utica development will displace other, higher-cost developments and not be additive," he concluded.

Haas reported that smaller producers may be forced to operate elsewhere, without the balance sheet to support drilling $12 million wells. For example, Gastar Exploration Inc., which has had success in the Marcellus and Utica, is looking to sell its roughly 11,000-net-acre Appalachian position to invest in the Midcontinent's oily Woodford/Meramec (Stack) and Hunton plays instead.

David Tameron, an analyst for Wells Fargo Securities LLC, reported that the dry gas Utica play is good, on a micro basis, and bad on a macro basis. Well results have great potential for the producers, "but what does this mean for the broader picture of Utica dry gas production?…It's not been easy to find a bull on natural gas lately."

In late October 2015, the November contract for gas delivered to Henry Hub slipped below $2 per MMBtu, a prompt-month number last seen in the spring of 2012. In the Northeast, the New York City Gate (Tetco M3) price was below $1 earlier in the month.

"However, with IP rates and EURs continuing to impress in the dry gas Utica," Tameron wrote, "it's hard to argue against not drilling these wells even at $2 MMBtu gas."

Ventura said that, of Range's 1.6 million acres of Appalachian leasehold, about 900,000 are in the dry window and about 700,000 in the wet window. "You get the advantage of drilling up and down the stratigraphic column—dry, wet or super-rich." In addition, some 400,000 acres are in the stacked-pay region of southwestern Pennsylvania, holding Marcellus, Utica and Upper Devonian.

"We kind of view it as a portfolio within a portfolio. Plus, that stacked pay happens to be in what is the best infrastructure in the basin and where a lot of it is getting built. It's a blessing in that regard as well," Ventura said.

The company's focus will continue to be on the Marcellus. "In the short run, the best returns are going to be from the Marcellus because there is up to 10 years of history and thousands of wells that have de-risked it," he said.

Yet technology continues to improve. "We won't have drilled all of our inventory yet. As the next waves of technology continue to come through, we will continue to increase recovery." ■


Genie GT

# Proximity Oil

By **Nissa Darbonne**, Editor-at-Large

*Producers continue to push the needle to the right in Oklahoma with new oil pay from the vast basin with a 20th-century approach.*

How about an oil play *at* Cushing? Newfield Exploration Co., which secretly leased for two years just west of the Nymex-priced hub, was delivering more than 70,000 bbl/d to it from a new play, dubbed "STACK," and from another, southwest of Oklahoma City.

"There is an infrastructure advantage (to STACK) here. You can put it in a truck and get it to Cushing before breakfast," Brandon Mikael, an analyst for Wood Mackenzie at the time and now an investment banker, told upstream mergers and acquisitions (M&A) professionals in Houston. "Everybody talks about $10 differentials in North Dakota." From Oklahoma City, however, "I can drive to Cushing during lunch."

In early 2015, as West Texas Intermediate (WTI) delivered to Cushing slid below $50, the continuing potential of the Midcontinent's newest plays became evident in two headline-making events—both generated by Newfield.

The STACK-play founder, which also has a large position in the Bakken, reported on Feb. 24, 2015, a $1.2 billion capex budget for that year with 70% of that devoted to its Oklahoma leasehold, including to another new play—the Goddard Shale member of the Springer group of sands within the "SCOOP" south of STACK.

Two days later, when WTI was $50 or half the year-before price, the company announced it was going to offer 18 million shares—the first U.S. E&P to tap the appetite of public-equity markets for interest in a Lower 48 oil producer. Other E&Ps had not dared, except for an overnight deal by an Appalachian gas producer whose stock price continued to tumble during the year to about $2 in November 2015.

How would the Newfield offering go? And with an oily Oklahoma story rather than a gassy Marcellus story?

Quite well, actually. Before day's end, it sold an upsized 22 million shares and, within a few days later, those wanting more took the 3.3-million-share overallotment too. Despite the dilution, the price grew during 2015 to $40 in November—just $4 shy of its 2014 high and up from a pre-dilution low of as little as $22.

This is in contrast to producers in other oil basins whose share price was halved or more during 2015. Even EOG Resources Inc., a favorite among E&P investors, had managed to post, roughly, at least no change in its share price. Newfield's, however, was up some 80%.

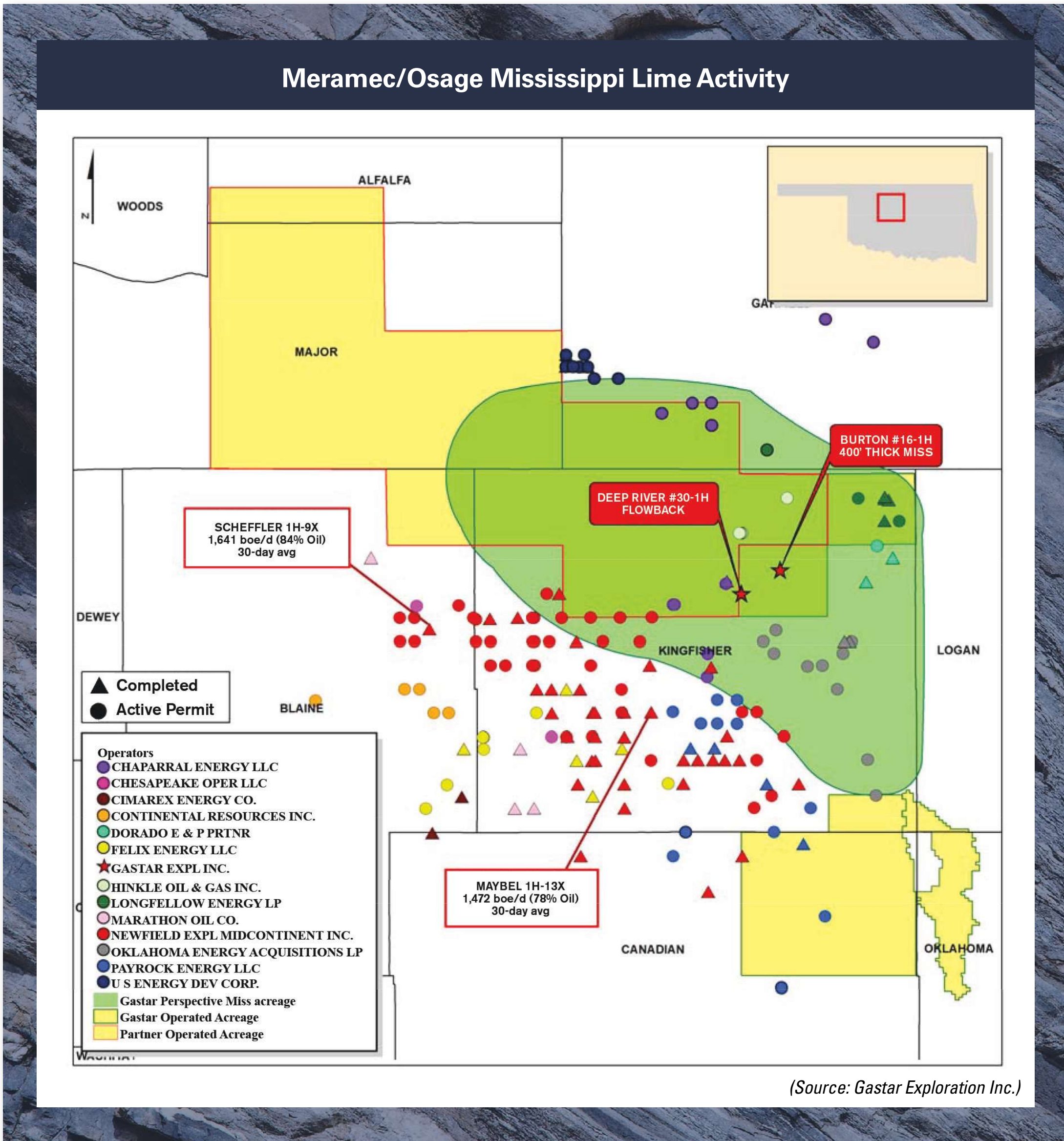
"We're fortunate that we're still seeing returns of between 35% and 40% from STACK, even at $45 oil, so the 2016 program will be really focused on holding the acreage," Steve Campbell, Newfield vice president, investor relations, told Hart Energy.

## A rising star

The STACK play—an acronym for Sooner Trend (oil field), Anadarko (Basin), Canadian and Kingfisher (counties)—primarily targets Meramec and the underlying Woodford. It has become so popular that Gastar Exploration Inc. put its Marcellus and Utica gas portfolio up for sale in fourth-quarter 2015 to fund a STACK expansion. The $43.3 million purchase involves 15,700 net acres in Kingfisher and Garfield counties and 11,000 net nonproducing acres in Blaine and Major counties.

After closing, Gastar will hold 62,300 net acres prospective for Meramec and 48,900 net for Wood-

Newfield Exploration Co.'s Laura 1H-17x well is in Kingfisher County, Okla., near Okarche.



(Source: Gastar Exploration Inc.)

ford. The company expected the leasehold also will be prospective for horizontal pay from Pennsylvanian-age Oswego overlying Mississippian-age Meramec and also for Mississippian-age Osage underlying Meramec and overlying Silurian Devonian-age Woodford and Hunton.

Seaport Global Securities LLC analyst Mike Kelly reported that Gastar paid roughly $1,900 per undeveloped acre for the stacked-pay, Oklahoma expansion. "We think this is a very attractive entry price for added STACK exposure; we have recently heard of M&A bids well north of $10,000 an acre," Kelly wrote.

He expected Gastar may devote 100% of its 2016 capex budget to the position, "given strong, offset Meramec wells—with Newfield the biggest read-through." A first Gastar test, Deep River 30-1H, was underway. Kelly estimated that, "if the Meramec's trajectory continues to trend positively and acreage values hit $15,000 per [acre]," the play could more than quadruple what was Gastar's net asset value in fourth-quarter 2015.

## Finding STACK

Lee Boothby, Newfield chairman, president and CEO, said in an *Oil and Gas Investor* article that delineation of the Meramec and Woodford in STACK wasn't challenging. "There was a lot of well control we used to identify the target areas," Boothby said. The Sooner Trend discovery was in 1945 and more than 13,000 wells had been drilled in Oklahoma by the turn of the century to at least as deep as the Hunton, which appears throughout the state.

Woodford is the source rock for Meramec production on the eastern flank of the Anadarko Basin. "Some intervals may be self-sourcing, but the dominant source is the Woodford," Boothby said.

By submitting core, Newfield won from the Oklahoma Geological Survey a designation of its Meramec target as a shale within a series of Mississippian carbonates. "Despite all the well control," Boothby said, "there weren't many geoscientists expecting to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encounter the Meramec as having a shale interval. Most people thought it was a carbonate."

The reason for the previous designation was that, north and south of STACK, the Meramec group includes the Mississippian Lime play. South of STACK, Meramec is known as Sycamore—again a limestone. "The facies do change but, in our acreage block, it's a shale," Boothby said.

The finding was important in how the target could be produced, Boothby added. To date, the state has allowed two-section laterals only in shale plays.

From this and other new drilling in the state, Oklahoma's production soared to 384,000 bbl/d in March 2015 from a modern low of 153,000 in January 2010, according to Energy Information Administration data. With rig cuts, the number slipped to 325,000 in August 2015.

### Stacking

Continental Resources Inc. joined the STACK headlines in 2015, announcing a 136,400-net-acre position, 60% HBP by legacy wells. Its first STACK well, Ludwig 1-22-15XH, had a 9,711-ft lateral in Meramec in Blaine County and came on with 2,076 boe/d, 76% oil. Pressure was 2,100 psi on a 34/64-in. choke; gravity, 44; and 1,460 Btu gas.

In November 2015, the company reported a second and third two-section-lateral Meramec test: Ladd 1-8-5XH and Marks 1-9-4XH northwest of Ludwig and also in Blaine County. Ladd tested at an IP rate of 2,181 boe/d, 79% oil; Marks, 994 boe/d, 73% oil.

As for Ludwig, Continental updated the performance: Its ultimate, 24-hour peak rate was 2,782 boe/d, 76% oil. It added that, in Blaine, Dewey and Custer counties, west of Newfield's Canadian- and Kingfisher County fairway, STACK reservoirs are thicker and overpressured.

Tudor, Pickering, Holt & Co. analysts replied that Continental's STACK potential "definitely improves our view" of how the company can meet or top its Bakken play. But it's early in this westward expansion. After an earnings call, they wrote, "Simply put, the Continental conference call was a STACK attack, as analysts honed in on management's bullish tone around the resource."

Dan Katzenberg, analyst with R.W. Baird & Co., quipped that he was "waiting to see how 2016 stacks up." Zeroing in, as well, on what is possible west of what Newfield targeted, he wrote, "Upcoming step-out wells should provide a better understanding and will be closely scrutinized, though management's tone was very optimistic." But, if it works out, it could be even more prolific, he wrote, "given its overpressured reservoir."

Wunderlich Securities Inc. analyst Jason Wrangler was piqued by the idea of Continental using the Bakken—it was piling up uncompleted wells there in 2015, projecting some 115 by year-end—

## SoHot

Unit Corp. announced the SoHot play in 2014 that targets the Marchand and Medrano sandstone members at about 3,300 ft in the Pennsylvanian-age Hoxbar on the western edge in Grady County. "SoHot" is derived from the "southern Oklahoma, Hoxbar oil trend."

In fourth-quarter 2015, Unit had one rig drilling SoHot. Of its three Marchand wells in 2015 through September, the 30-day IP averaged 1,345 boe/d, 79% oil and 11% NGL. From its nine new Medrano wells, the 30-day IP averaged 7.0 MMcfe/d, 8% oil and 21% NGL.

Production from its play averaged 6,574 boe/d with 31% of this oil and 25% NGL. The company reported that, going forward, it will drill the oily Marchand, primarily, as the wells were indicating "higher returns under current commodity pricing."

In Medrano, unit's Rosey 2H came on with 7.6 MMcfe/d in a 30-day IP and its Hiram 1-13H came on with 9.5 MMcfe/d. Unit had 14 wells completed by October 2015; the average 30-day IP was 7.3 MMcfe/d. The EUR was looking like 4.9 Bcfe, 28% liquids, per well at a cost of $4.4 million apiece for a 27% rate of return at strip at the time.

In the Marchand sand, its Schenk 18H had a 30-day IP of 700 boe/d. Of its six wells in the zone, the 30-day IPs averaged 1,511 boe/d. EUR was estimated as 480 MMboe, 91% liquids, with well costs of $5.2 million for a rate of return of more than 100% at strip. ■

to develop its Oklahoma potential, making its uncompleted wells a type of oil bank "that we feel could be tapped quickly" when oil prices improve. Oklahoma is "the next act for CLR," he concluded.

Also a large Midcontinent producer, Cimarex Energy Co. reported in fourth-quarter 2015 that it completed its first 10,000-ft-lateral well, Clayton 1HX, in the Meramec for a 30-day IP of 16 MMcfe/d, 15% oil and 28% NGL. As for its 11 one-section laterals in Meramec, these had 30-day IPs averaging 9.3 MMcfe/d, 29% oil and 24% NGL.

Also with STACK prospects is Devon Energy Corp., which began developing the gassy Woodford play in Cana Field west of STACK and north of SCOOP in 2007 and is a 50% partner with Cimarex in some of its position. It has 4,000 risked locations in the Anadarko Basin in 340,000 net acres, averaging a well per 85 acres for some 15 years of inventory at the 2014 pace, which was 271 wells, according to a Bernstein Research analysis.

The Meramec is prospective in some 75,000 of its net acres as of November 2015, holding 500 derisked locations. Two initial appraisal wells in 2015 in southeast Blaine County and northwest Canadian County produced 30-day IPs averaging 1,500 boe/d.

Five appraisal wells completed in third-quarter 2015 had 30-day rates of 1,430 boe/d, 37% light oil. Drilling and completions for one-section laterals averaged $7 million. It was increasing drilling in the formation to five rigs, including two that had been drilling Cana-Woodford for it in the area. In a spacing pilot, it planned five laterals in the upper Meramec, 1,150 ft apart. In another pilot, it planned one in the upper Meramec and one in the lower Meramec, 660 ft apart.

Todd Moehlenbrock, Devon vice president, Anadarko Basin business unit, said in an *Oil and Gas Investor* article that the Meramec isn't greenfield for Devon; it's gravy. "We do have the infrastructure. We have a team…We can easily scale up and that makes it even more attractive," he said.

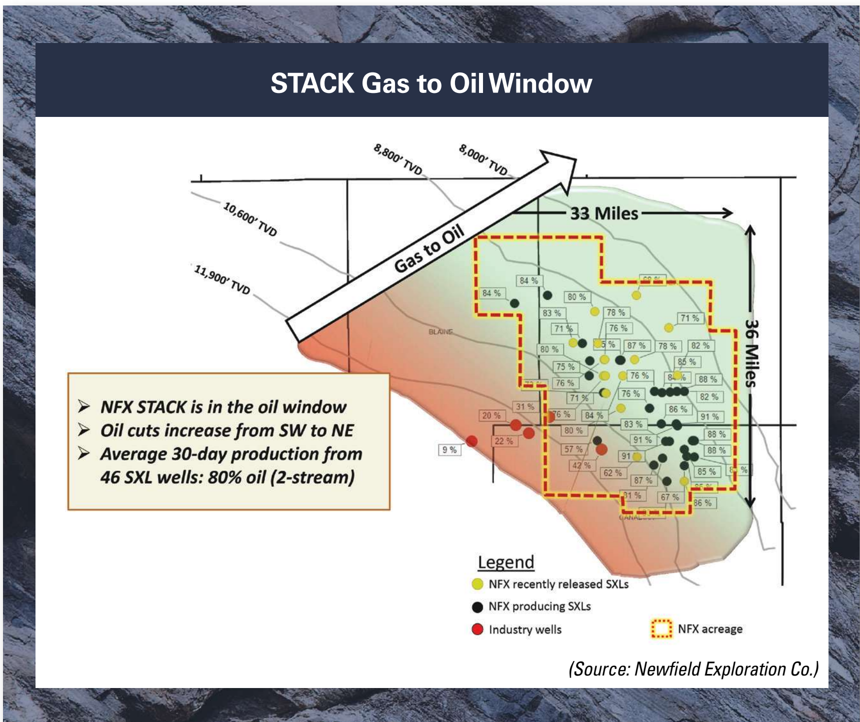
### SCOOP-Woodford, SCOOP-Springer

Continental's SCOOP play is further along in understanding than STACK. Southwest of Oklahoma City, the name is an acronym for South-Central Oklahoma oil province. Continental holds 460,000 net in SCOOP for Woodford pay. Of the Woodford wells, its Kellner 1-19H in the condensate window had IP rates of 16.9 MMcfe/d; in the oil window, its Dungan 1-31-30XH showed IP rates of 1,754 boe/d.

Density testing in the condensate fairway put 10 wells in its Poteet unit, 10 in Honeycutt and eight in Vanarkel. Density testing in the oil window had eight wells in its Good Martin unit and seven in its May unit.

In Poteet, the 10 wells—five in the upper Woodford and five lower—had combined peak production of 147 MMcf and 3,250 bbl/d. After six months online, they were producing some 10 MMcfe/d apiece on average, normalized for 7,500-ft laterals; the laterals ranged from 4,552 ft to 10,110 ft. Spacing between the holes was 513 ft.

But, adding another scoop to its plate, Continental delivered another play in 2014: SCOOP-Springer. Its Springer potential within its SCOOP leasehold is some 210,000 net acres. Its Chester 1-32H well had IP rates of 1,733 boe/d from a 4,999-ft lateral. The Celesta 1-5-32XH well, with a 7,199-ft lateral, showed IP rates of 1,199 boe/d.



(Source: Newfield Exploration Co.)

In second-half 2015, the company was testing four-well density in its Jeanna and Hartley units. In Jeanna, with spacing averaging 1,320 ft between the four wells, they had combined peak production of 3,852 boe/d. After more than 80 days online, the laterals, averaging 4,664 ft, were producing more than 800 boe/d apiece. The overall Springer type curve was revised to 940,000 boe.

Continental didn't plan any more Springer wells through year-end 2015, however, as the zone was being delineated and HBP by its SCOOP-Woodford drilling. It reported it was "preserving the asset for a higher oil price."

Continental's target within the Springer group is Goddard Shale, a self-sourcing reservoir. The Springer fairway is a northwest/southeast swath in the middle of the SCOOP fairway. Beginning at about 11,000 ft, Springer sits between 1,000 ft and 1,500 ft above Woodford, which is as deep as 15,000 ft in the SCOOP area. Jack Stark, Continental president and COO, said in an *Oil and Gas Investor* article, "When you're drilling a Woodford well, you get a free look at the Springer on your way down."

Continental estimated its combo Woodford/Springer holds almost as much net, unrisked resource potential as does its Bakken and Three Forks leasehold: more than 4 Bboe. "And it's still growing," Stark added. Springer itself "competes head to head with the Bakken and we have excellent wells in the Bakken."

A secondary target within the Springer group may be the Boatwright sandstone. WoodMac's Mikael said, "What I think is going on is that you're seeing [operators] land [the laterals] in the top part of the Goddard and completing up a bit into the Boatwright on top of it. But the Boatwright could be a new target (on its own)."

Marathon Oil Corp., which was pulling away from conventional exploration to focus on U.S. resource plays, completed a first SCOOP-Woodford pad—a five-well pilot at its Smith unit with 106-acre spacing in western Garvin County. In the company's SCOOP-Woodford leasehold, it estimated it had 1,770 gross (450 net) locations, 70% delineated. For Springer, it held 31,000 net acres and planned three wells before year-end 2015.

Its SCOOP one-section-lateral condensate wells had 30-day IPs of 1,080 boe/d and cost $8.3 million for an EUR of 1.7 MMboe; extended-laterals, 1,615 boe/d and $11.5 million for 3.1 MMboe.

## Canyon Lime

Apache Corp. was testing the Pennsylvanian-age Canyon Lime Formation in the Texas Panhandle. Its Quanah 95-1H confirmed "a distinct upper interval in the Canyon Lime," it reported in November 2015. The well's 30-day rate averaged 1,662 boe/d and, after 74 days online, was still producing nearly 1,000 boe/d. Cumulative production in that timeframe was 91,000 boe.

The play is in Texas' legendary Panhandle Field, which has produced more than 1.4 Bbbl of oil and 8.1 Tcf of gas beginning in 1910. At between 7,500 ft and 9,500 ft, the pay in the Canyon Wash is between 100 ft and 580 ft thick, according to an Apache report.

Porosity is 6% to 10%. Total organic carbon is between 2% and 6%. Liquids yield is roughly 1,000 bbl per 1MMcfg.

Tim Sullivan, Apache senior vice president, operations, said in an analyst call in November 2015 that Quanah was made in the upper portion of Canyon Lime. "It's the only well that we've got in that landing zone," he said, according to a SeekingAlpha transcript. "So, it is a standalone well, but it's just a function of getting the spacing right. We have not been curtailing production or anything. It's just a shallower decline and we're excited about that zone."

Apache's leasehold is in Oldham and Potter counties. In Potter County, its Canyon Lime discovery, Bivins East 41-1H was out of zone in some 75% of the 5,500-ft lateral but had a 30-day IP of 787 boe/d. First-seven-month oil production was 54,286 bbl.

Its Bivins East 94-1H well had a 30-day IP of 1,718 boe/d from 4,500 ft of lateral. The first-six-month oil production was 80,087 bbl. ■

Apache Corp., which has a large position in the Granite Wash in far western Oklahoma, was working on the SCOOP-Woodford as well. In Grady County, its Truman 28-6-6 #1H well had a 30-day IP of 1,949 boe/d. Its Monty 1-12 1XH well was scheduled to be completed in November 2015.

### SCOOP to STACK

Newfield is also in SCOOP. Its Woodford there is between 225 ft and 350 ft thick with porosity of between 3% and 10%. In the wet gas window, lateral lengths averaging 7,340 ft had gross 90-day rates averaging 1,448 boe/d, 26% oil. In the oil window, laterals averaging 9,415 ft had 90-day rates of 1,053 boe/d, 51% oil. Among them, Newfield's first super-extended-lateral Springer well averaged 1,340 boe/d, 85% oil, during its first 30 days online.

"SCOOP is further along in its (play) maturity and understanding," Campbell said. Most of its leasehold there is HBP. Both STACK and SCOOP target the Woodford. Are the mechanics different southwest of Oklahoma City than northwest? Yes, Campbell said. "In SCOOP, you transition very quickly from wet gas into black oil. That occurs in about a 30-mile area as you move west to east."

In STACK, at least in Newfield's position, it's virtually all black oil. In exploring the 700-ft dual-pay section, Newfield took four whole cores from the top of the 275- to 475-ft-thick Meramec to the bottom of the 75- to 300-ft-thick Woodford. Where the Meramec is thickest, pay may be possible from both the upper and lower reservoir. Porosity in STACK-Meramec ranges from 3% to 6%; STACK-Woodford, 3% to 7%.

Drilling days in 2011 when exploration commenced averaged 51; in 2015, a STACK well was drilled in 12 days. "And that's spud-to-rig release," Campbell said. "We've really been able to target how we drill the wells, how we land the wells, how we position the heel and toe and identify areas that drill quicker but also lend themselves to better completions."

While drilling to HBP its STACK position, Newfield also has been able to sample a large portion of

## To Cushing

**New Oklahoma oil production is looking to get to Cushing via central gathering facilities.**

Currently, Newfield Exploration Co. is trucking its STACK oil to Cushing for about $2 per barrel. Recent agreements will allow 100% of it to be piped to Cushing, beginning this year.

The company's SCOOP and STACK gas was going to Conway and Mont Belvieu. Meanwhile, its SCOOP condensate is mostly used as a blend stock for heavier Midcontinent crudes, Steve Campbell, Newfield vice president, investor relations, told Hart Energy.

Tall Oak Midstream LLC planned gas-gathering and gas-processing for STACK, involving 40,000 net acres in Kingfisher and Blaine counties at its newbuild Chisholm cryogenic facility. The first train was online with initial capacity of 100 MMcf/d. A second train will add 200 MMcf/d capacity and is expected online in third-quarter 2016. The plant could eventually process 700 MMcf/d.

More than 100 miles of existing gathering lines were supplemented with an additional 100 miles and two additional compressor stations.

For STACK's oil takeaway, Tall Oak planned a truck-unloading facility at Okarche, Okla., connecting the production to Cushing and expected to bring it online by year-end 2015. The anchor producer is privately held Felix Energy LLC. The facility was expected to include 40,000 bbl of oil-storage capacity. Ultimately, Tall Oak planned more than 200 miles of gathering and 150,000 bbl of storage.

Blueknight Energy Partners LP was querying producer interest in firm capacity in November 2015 in a pipeline for Oklahoma's condensate. Its plan is to convert part of an existing system to take SCOOP and STACK condensate to Cushing. It reported, "The system initially will be designed to move a single, comingled condensate-grade crude oil. However, with sufficient customer demand, a second grade of condensate could also be transported." ■

its leasehold, which is some 1,500 sq miles. "It's a massive area. We think about 90% of our acreage has now been production-delineated." Along the southern and western borders, outside Newfield's position, explorers have encountered wet gas.

In addition to a better understanding of the reservoirs in time, drilling and completion improvements in 2015 were sourced from overall North American reductions in demand for oilfield services. "That is certainly a portion of it," Campbell said. "We've been able to pick and choose the rigs we want as well as the crews. We have the best iron and the best crews working in that play today.

"We're high-grading locations as well as rigs and personnel." But, as Newfield's well cost has declined from $12 million to less than $7.5 million, a great deal is due to in-house efficiencies as well "that will be sustainable even when service costs turn."

As for fracturing equipment and crews, Campbell was on a job in the field in late summer 2015. "There was a brand-new frack spread out there. The paint was still new. We're getting that throughout the field."

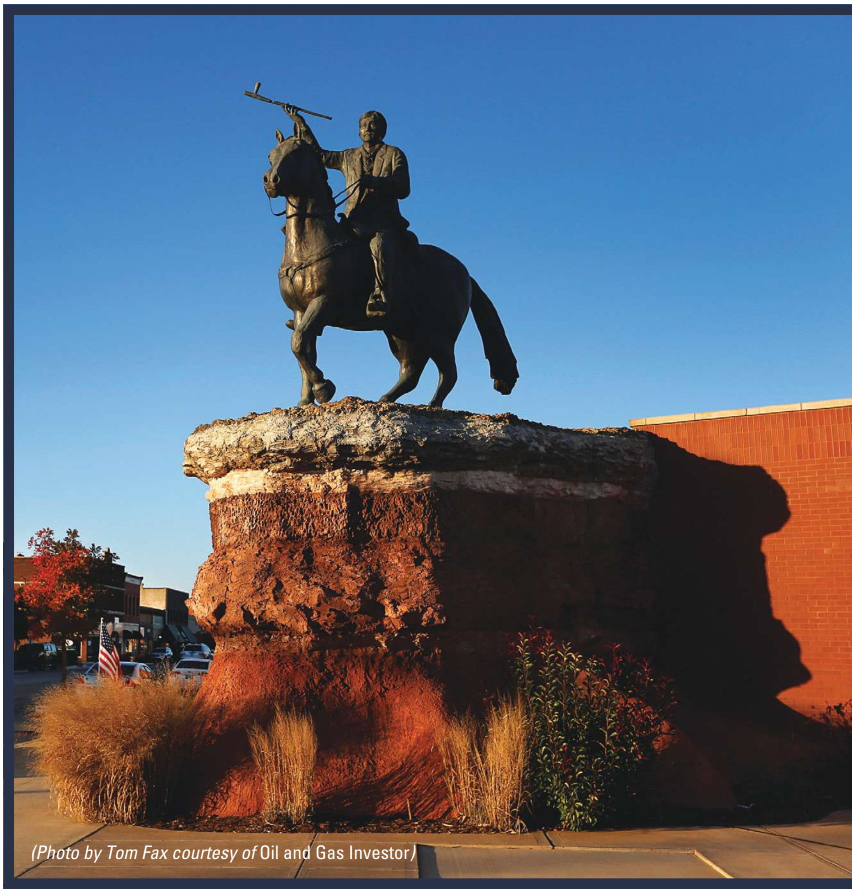
## Clusters

Findings include the spacing of clusters. "We've gone to tighter cluster-spacing between the frack stages," Campbell said. "Imagine a 10,000-ft lateral. We're putting the frack stage every 350 ft to 400 ft and we're putting our cluster spacing as tight as 50 ft."

In addition, Newfield has changed up what it is pumping. "Our proppant had been between 800 lb and 1,000 lb a foot. We're now pumping close to 1,500 lb a foot in the Meramec and around 1,200 lb a foot in the Woodford. Some jobs around us are going to as much as 2,000 lb per foot."

In fall 2015, proppant was, on average, 80% of the October 2014 peak price, according to a Cowen & Co. analysis of U.S. Bureau of Labor Statistics data. "Yes," Campbell said. "It's less expensive and everything you want to try is available. You don't have any shortages."

The results have been promising, but Newfield is giving the wells more time. "The biggest game changer has been the cluster spacing—tightening up the spacing. The next generation will be sampling the wells that have more proppant pumped."


*(Photo by Tom Fax courtesy of* Oil and Gas Investor*)*

A large statue of Jesse Chisholm on horseback is mounted in downtown Kingfisher, Okla. Chisholm is most famous because of the namesake cattle trail that passed through town.

Newfield also is testing the use of diverters. "The diverters should allow tighter clusters and more clusters per stage. We're testing diverters and diverting agents. It's very early. We're probably in the second inning on completions and probably in the eighth inning on the drilling.

"On drilling, we've gone to 12 days. You can't go to zero, so we're getting close to the maximum that can be achieved in drilling efficiencies. On completions, however, we're still early on getting the most-optimal EUR."

Currently, it is making six per section, "so we think we fully understand the spacing," Campbell said. Two rigs work side by side, each drilling three. Once all are drilled, the six wells are completed simultaneously—i.e., zipper fracks. "It will be 2017 when we get to that stage in STACK," he said.

Again, "the lion's share" of Newfield's 2016 capex spend will go to the Anadarko Basin. "We're at more than 70,000 boe/d now. It will continue to grow at a large clip in 2016." ■

(Photo by Tom Fox, courtesy of Oil and Gas Investor)

# They're Staggering

By **Nissa Darbonne,** Editor-at-Large

*Eagle Ford operators are increasing lateral lengths, stages, clusters, proppant and more—and in more locations too via stacking and staggering.*

In the fall of 2015, half of the top 10 oil-producing counties in Texas were in the Eagle Ford; the other half were in the Midland and Delaware basins, according to Texas Railroad Commission data. Among the state's top 10 condensate producers, seven Eagle Ford counties ranked.

Thus, adding more leasehold in the Eagle Ford remained a challenge for operators, even at $40-something West Texas Intermediate. Tudor, Pickering, Holt & Co. analysts had lunch in early November 2015 with Jay Ottoson, president and CEO of SM Energy Co., which operates in the Eagle Ford, Bakken and Permian. "Increasing that inventory depth remains an ongoing challenge," they reported, "particularly in light of strong asset pricing in SM's core areas...."

But, SM was creating more inventory from its existing position instead, via down-spacing, infill drilling and upper and lower-upper Eagle Ford tests, involving nine trials and 76 wells altogether, in its 144,000 net operated acres. One test is a 14-well down-spacing to 450 ft from 625 ft in its East Area in western Webb County; early indications were that the higher-density wells were working, it reported in fall 2015.

Meanwhile, a five-well test of laterals in both the upper and lower Eagle Ford with 312-ft plan-view spacing in a dry gas area was suggesting the upper Eagle Ford works farther south in its leasehold where it is up to 350 ft thick.

In its North Area in northwestern Webb County, the company completed 11 wells in upper, lower-upper and lower Eagle Ford in a stacked-and-staggered manner—a "W" shape. (The pilot was planned as 12 wells, but one had a casing problem and wasn't completed.) Results were expected early this year.

Overall, SM's Eagle Ford production averaged 134,500 boe/d during third-quarter 2015, up 31% from a year earlier and despite an 11% decline in nonoperated production from the second quarter. Completion costs were down 54% to less than $400 per lateral foot from 2014; drilling costs were down 28% to $250 per lateral foot.

Also in the play, Noble Energy Inc. was making wells indicating EUR of 600 boe per lateral foot. The international operator took in Rosetta Resources Inc. in July 2015, adding the E&P's 50,000 net acres in the Eagle Ford. Two new lower-Eagle Ford wells—Gates 05D 14-20 and Gates 05D 10-20—were placed 950 ft apart with 20-ft cluster spacing and some 2,000 lb of proppant per lateral foot in its Gates Ranch area in northwestern Webb County. Each had a roughly 7,100-ft lateral. The estimated 600 boe per lateral foot suggested EUR of more than 4 MMboe apiece.

The 10-20 well had a 30-day IP of 4,885 boe/d. The 14-20 was still in early flowback in November 2015, but it "is probably the best well ever completed on the acreage," Gary Willingham, executive vice president, operations, told investors, according to a Seeking Alpha transcript.

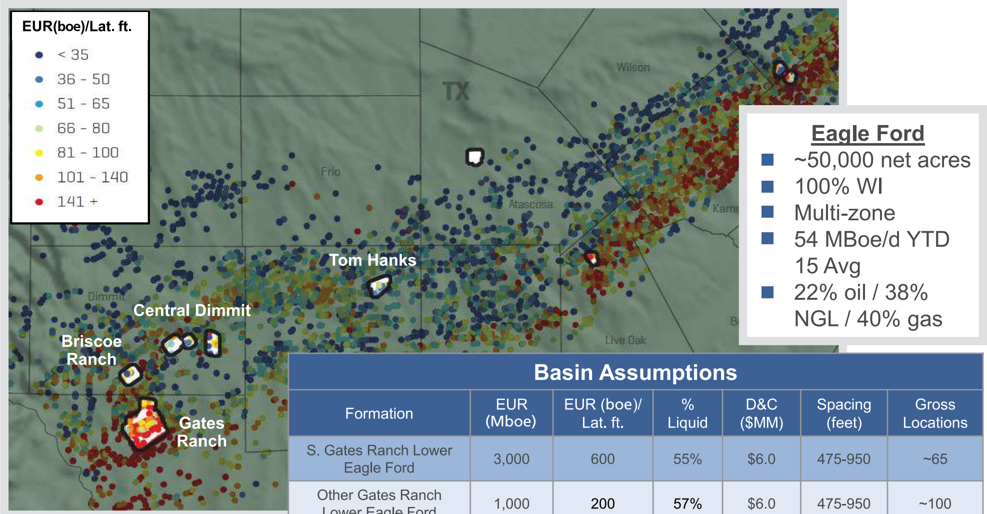
Noble expected to exit 2015 with 35 Eagle Ford wells uncompleted and one rig drilling. Including the two Gates wells, it drilled seven in third-quarter 2015, brought five online and averaged more than 35,000 boe/d from the play. Spud to release was eight days per one section of lateral, down 30% from the spring.

Light from a gas flare reflected off six Carrizo Oil and Gas Co. pumpjacks producing side by side in July 2015 on the Pena 30 pad outside of Cotulla, Texas.

## Horned Frog

Meanwhile, Lonestar Resources Ltd.'s star was rising. Seaport Global Securities LLC (SGS) analyst

## A Premier Acreage Position in the Eagle Ford




**Basin Assumptions**

| Formation | EUR (Mboe) | EUR (boe)/ Lat. ft. | % Liquid | D&C ($MM) | Spacing (feet) | Gross Locations |
|---|---|---|---|---|---|---|
| S. Gates Ranch Lower Eagle Ford | 3,000 | 600 | 55% | $6.0 | 475-950 | ~65 |
| Other Gates Ranch Lower Eagle Ford | 1,000 | 200 | 57% | $6.0 | 475-950 | ~100 |
| Other Lower Eagle Ford | 400 | 80 | 68% | $5.4 | 475-950 | ~75 |
| Upper Eagle Ford | 500+ | 100+ | 58% | $5.4 | 475-950 | ~400 |

Note: Locations expected to be economic at strip pricing. Drilling and completion (D&C) cost based on 5,000' lateral and includes flowlines. EUR's are threestream.

*(Image courtesy of Noble Energy Inc. and ITG Investment Research)*

Mike Kelly titled his report on the E&P's results "Heisman Hopeful Horned Frog." The Fort Worth-based Eagle Ford operator's stock price grew some 50% within a few weeks in fall 2015. On its board is Texas Christian University graduate John Pinkerton, the retired chairman of Range Resources Corp. who led the company's entry into the Barnett play and its discovery of the Marcellus.

In planning its Horned Frog wells in southwestern La Salle County, Lonestar "studied 107 offset completions, operated by six different companies, to come up with its own D&C [drilling and completions] recipe," Kelly wrote. It took up better geosteering and had been "able to keep 99% of laterals in its target zone." It increased sand to 1,557 lb/ft, up 52% from the neighborhood average; managed the choke to emphasize condensate recovery; and made laterals averaging 8,200 ft.

"Net/net, Lonestar's homework paid off," Kelly wrote. The wells' 30-day IPs averaged 1,377 boe/d. Kelly calculated that the production per lateral foot put the wells among the best of the 107 offsets—"and 133% higher on an absolute basis."

The wells' total depth of some 18,500 ft was reached in 11.5 days. They cost $6.1 million each "and management believes it has line of sight to sub-$6 million" wells, Kelly reported.

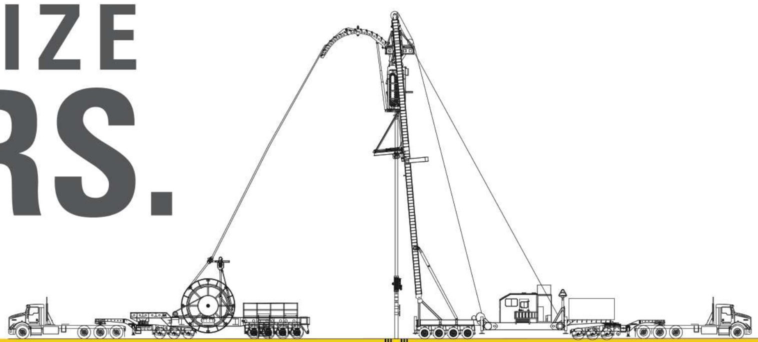
At Lonestar's Burns Ranch area in northern La Salle, it analyzed 113 offsets. Its three initial wells were each flowing 390 boe/d after 180 days on a 22/64 choke. Average cumulative production per well in its first five months was 110,000 boe—again among the best in the neighborhood, Kelly wrote.

At its Beall Ranch leasehold in Dimmit County, "production rates here have not been eye-popping," he added in another report. The laterals are some 3,000 ft, "but management currently pegs IRRs [internal rate of returns] at approximately 42%, driven by low well costs" of some $3.3 million for 11,500 ft of total depth.

Three new wells, Beall Ranch #26H, #27H and #28H, were completed with tighter spacing and an average of 1,654 lb of proppant per lateral foot, Lonestar reported. They came on with an average of 419 boe/d, 79% oil, on an 18/64 choke. After 105 days online, they were averaging 365 boe/d. The production was 43% more oil per perforated foot than three 2014 offsets, Lonestar added.

### A 13,000-footer

Chesapeake Energy Corp.'s 108,000 boe/d from the Eagle Ford contributed the 3% net gain in third-quarter 2015 in companywide production to 667,000 boe/d. Wells were costing $5.3 million each



with lateral lengths averaging 6,000 ft and stages averaging 21, compared with the 2014 average of $5.9 million, 5,850 ft and 18 stages. Of the 112 gross wells the company brought online in the quarter, 30 are in the Eagle Ford.

Chesapeake made its Rogers E-1H well in northeastern Dimmit County with 12,488 ft of lateral and its Faith San Pedro F-4H well in southwestern Dimmit with 13,151 ft. From the former, the peak 24-hour rate was 1,479 bbl of oil and from the latter, 1,067 bbl. They cost $7.8 million each.

These extra-long-lateral wells join Chesapeake's 10,000-footers in the Midcontinent and Haynesville. "We're making a strategic bet as a company to drill longer laterals in every single play," Jason Pigott, executive vice president, Southern Division operations, told Hart Energy.

Chesapeake had 19 Eagle Ford wells drilled with laterals of more than 9,000 ft in early November 2015. As for the more than 12,000-footers, these cost $7.1 million and $7.4 million, according to a Chesapeake report. Pigott said that, in short, the longer laterals were exposing 100% more reservoir than a 6,500-ft-lateral for 47% more cost—drilled and completed.

"Think about the cost of not repeating that vertical section of the well," Pigott said. "A 13,000-ft-lateral well is the same as drilling two 6,500-ft laterals. The cost for us per boe goes down from $11 to $7. At an oil price of $40 or $50, we're creating an up to 10% price uplift."

It can be rough riding down 9,000 ft and out 13,000 ft, though. "It's not easy," Pigott said. "The curves have to be very smooth or you get into a torque-drag issue. We've had to upgrade the pumps on all of our rigs, so they have sufficient pressure to move the mud."

Also, Chesapeake is using dissolving plugs in lieu of coiled tubing (CT) that can't reach the toe to drill out traditional plugs. "The dissolvables have eliminated coiled tubing in a lot of our wells. We estimate a $200,000-a-well savings by using this technology."

CT is usually no longer than 20,000 ft. "There is one company that has coil long enough to make it all the way out. The key is you have to have really smooth curves. If you get a bunch of ups and downs, those cause friction pressure. It doesn't allow your coil to get out as far as you need it to. It's required a lot from our engineering teams to design these wells," Pigott said.

Regarding combining sections to allow 13,000-ft laterals, a great deal of Chesapeake's leasehold is large ranches. Also, it is working with other landowners on production-sharing wells. "A lot of landowners are realizing that, when prices are tight like this, it's the only way to drill economic wells," he said.

### Completions

On the completions side, Chesapeake's cost declined by about $850,000 per well or 25% from 2014. The company was testing tighter cluster spacing and more sand, finding improved well performance from both.

## Haynesville

Chesapeake Energy Corp.'s first three 10,000-footers in the Haynesville were in production-test in fourth quarter 2015. The company reported in November that its northwestern Louisiana wells' 2015 average cost was $7.7 million for 5,000-ft laterals and 14 frack stages vs. $8.4 million in 2014.

Chesapeake had six rigs drilling in the play approaching year-end 2015. Its gross production declined 5% from second-quarter 2015 to 1.03 Bcf/d. Its share of this was 636 MMcf/d.

Tudor, Pickering, Holt & Co. (TPH) analysts reported that the Haynesville was "attempting to regain its shine in the Utica's cloud. While we've seen little interest in the Haynesville, given the Utica…, the basin's gas potential should not to be forgotten."

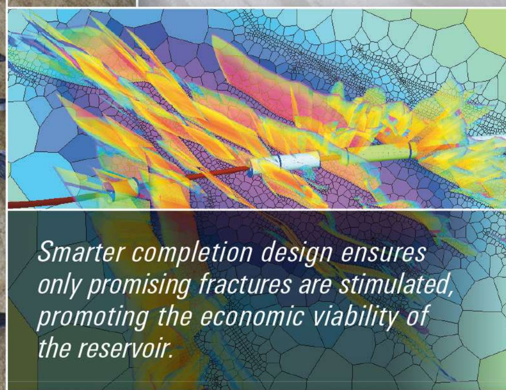
Laterals were growing to 1.5 sections and proppant to between 2,000 lb and 3,000 lb per lateral foot. Chokes were also tighter, resulting in 14-day IPs of more than 20 MMcfe/d.

"The result of these operational changes has been a material uplift in initial performance and better economics vs. traditional wells," TPH reported. ■

# BroadBand Sequence

FRACTURING SERVICE


BroadBand Sequence service stimulates more clusters (blue) than conventional stimulation techniques.


Smarter completion design ensures only promising fractures are stimulated, promoting the economic viability of the reservoir.

## BroadBand Sequence service boosts production more than 50% for Apache Corporation.

In the Anadarko basin, Apache Corporation encountered unforeseen operational issues that resulted in a poorly cemented lateral. Because BroadBand Sequence* fracturing service can enhance lateral coverage in any completion type, Schlumberger deployed the service to improve fracture distribution. Using temporary, dissolvable composite pills, BroadBand Sequence service sequentially isolated and stimulated each zone. As a result, Apache achieved an increase in normalized oil production of more than 50%, with a 28% reduction in completion time compared with conventional plug-and-perf treatments.

Find out more at
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Schlumberger

## To Mexico

**Gulf Coast gas producers and shippers are gearing up for new demand from Mexico.**

More than 3 Bcf/d of gas-pipeline interconnects to Mexico are expected to begin coming online soon, most of them connecting at the border just south of the Eagle Ford play. Chesapeake Energy Corp. operates there as well as in the Barnett, Haynesville, Oklahoma, Marcellus and Utica.

Might it dial up drilling in its gassy window of the Eagle Ford to supply Mexico or will the gas come from elsewhere? "It's something we're looking at. Right now, oil is still the prize out there," said Jason Pigott, executive vice president, Southern Division operations at Chesapeake.

"We have a lot of gas across the country, and our marketing guys can get gas from the Barnett into this pipeline or they can get it from the Haynesville. It gets back to where the most productive gas assets are."

Oneok Partners LP received a permit for its Roadrunner gas-pipeline project that is a 50:50 joint venture with Fermaca Infrastructure BV to get gas from San Elizario, Texas, to San Isidro, Mexico. The 200-mile, 30-in. pipeline is expected to export 570 MMcf/d.

NextEra Energy Partners LP bought NET Midstream in October 2015 for $2.1 billion. Its 120-mile, 42-in. NET Mexico pipeline, with capacity of 2.3 Bcf/d, has a 2.1-Bcf/d, 20-year, ship-or-pay contract with Pemex Gas, sending Eagle Ford gas to Mexico.

Another NET pipeline is connected from La Salle County to the Agua Dulce Hub in Nueces County, thus Mexico. The anchor shipper is Anadarko Petroleum Corp. ■

"What we're looking at now is 'Does that incremental gain in productivity justify the incremental cost?' It's tied to the commodity price," Pigott said. "Some of these things could get you a higher initial rate. Well, if prices are high, that pays for itself over 90 days, but, in a lower price environment, it might not be justified."

Its one-section-lateral Jea Unit XIV LAS S 4H East Four Corners underwent an enhanced design, producing a 24-hour rate of 1,311 bbl. It cost $4.8 million.

Tighter spacing and more sand are being tried separately. "Sometimes in the Eagle Ford, if I drill a three-well pad and did the same completion in all three wells, we could get three separate results. We try one major variable at a time.

"We've done some wells all with higher sand and some with tighter perf clusters. We're also testing how many perf clusters we treat at one time. There are three different techniques."

The cost of frack sand was 20% less in fall 2015 than a year earlier, according to a Cowen and Co. analysis. "Testing more sand right now is a really inexpensive test," Pigott said. "Increasing the perf-cluster spacing is more expensive; if I cut the spacing in half, I have twice as many stages.

"Proppant volume is the cheaper option to test right now. Tighter perf clusters and treating fewer clusters at a time are more expensive."

Chesapeake usually spaces stages 40 ft to 60 ft apart; the tests are of 15 ft to 20 ft. Sand is usually 1,700 lb/ft. "Our max test was 2,200 lb/ft," he said.

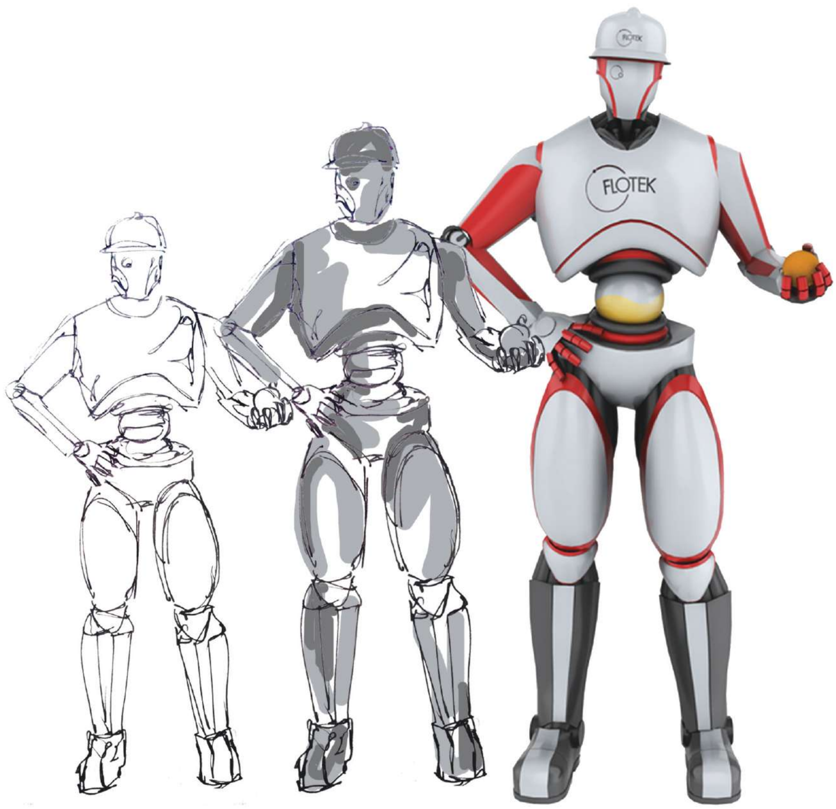
As high-graded rig crews became consistently available in 2015, Chesapeake got its Eagle Ford drilling speed in September to 1,231 ft/d from 1,000 ft/d a year earlier. "In drilling, we talk about nonproductive time; we think about the same thing on the completions side. Completions are where we've seen our costs drop the most dramatically.

"We want to do more stages per day. If we can eliminate five minutes or 5 hours of downtime from every single well, when we have 4,000 wells to drill in the Eagle Ford, it is very material."

As for additional, stacked laterals, Chesapeake is watching others' results in the upper Eagle Ford. "Our acreage is largely HBP, so we're happy to let them prove that up for us," Pigott said. As for the Austin Chalk, "we're not in that trough area. That's where a lot of those stacked reservoirs are."

Drillers also have tested the hit-or-miss Buda. "When we look at the Buda, the pockets are in the tens

# The CREATION of a TECHNOLOGY

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of millions of barrels of oil and they have good returns and pay out real fast. But our Eagle Ford and Mid-continent areas have billions of barrels, so we're really focused on the larger-scale, repeatable opportunities."

## A lesson for all

Pioneer Natural Resources Co. brought 36 Eagle Fords online in third-quarter 2015, in which it averaged 43,000 boe/d, 40% condensate, in Karnes and DeWitt counties with 21 in the upper Eagle Ford and 15 in the lower. The output was about a quarter of companywide production.

But Scott Sheffield, chairman and CEO, told a Houston audience in mid-November 2015 that the Permian Basin, where it has an estimated 10 Bboe of net recoverable resource potential, is, increasingly, its focus.

"I wouldn't be surprised if in five years the Eagle Ford is not a part of this company," Sheffield said, according to a Reuters report. In its 36-slide investor presentation in early November 2015, the Eagle Ford was the focus of one; the Permian Basin, eight.

The company's production from the play was down 7% from spring 2015. About 2,000 boe/d of that was due to ethane rejection. But there was a problem too.

"Production for third-quarter 2015 was negatively impacted by well-performance issues," Pioneer reported, "resulting from well completion-design changes, primarily reduced fluid-level concentrations, that were made early in 2015 to reduce costs."

SGS' analysts visited with Pioneer in late October 2015 after Pioneer's Eagle Ford joint-venture partner, Reliance Industries Ltd., released its quarterly results, indicating a decline in its share of production from the play. Some 50 to 60 of Pioneer's 2015 Eagle Ford wells, representing some 65% of those spud, utilized "diversion agents and less completion fluid," the analysts reported.

"Since the wells were initially choked," they wrote, "the poor performance did not show immediately

and Pioneer continued to complete wells with this technique over several months before noticing steeper-than-normal declines with more production history."

Pioneer tried this in its Permian wells in early 2015 as well, according to SGS, "but did not choke the wells; therefore the underperformance was readily apparent and Pioneer quickly stopped using the method" there.

Pioneer told investors in November 2015 that it had returned to its previous recipe. It also planned to test more proppant, tighter cluster spacing and more stages.

### 'W,' but not exactly

Meanwhile, EOG Resources Inc. continued to cite the Eagle Ford, where it has 561,000 net acres and 5,500 locations left to drill, as its highest-return play. The inventory is 13 years' worth; the resource potential, 3.2 Bboe. That's compared with 2.35 Bboe and 4,900 locations it estimates in its stacked-pay Delaware Basin leasehold and 1.2 Bboe and 1,540 locations in the Williston Basin.

Nearly all of its 2015 Eagle Ford wells were high-density—stacked and staggered—in the lower Eagle Ford and took its HBP in the play to 91%. Billy Helms, executive vice president, E&P, told investors in early November 2015 that, while EOG is using the "W" pattern in staggering its wells, it isn't using an arbitrary distance between them. Rather, the spacing "is determined by certain characteristics of the rock," he said, according to a Seeking Alpha transcript.

"We started this targeting work by analyzing 60 unique well characteristics from hundreds of recently drilled Eagle Ford wells," Helms said. "From these 60, we identified 12 characteristics that are present in our best wells. By incorporating these data into our 3-D seismic and petrophysical data, we determined that the lower Eagle Ford may have two sweet-spot intervals."

In an example provided in EOG's slides, the rock quality along the lateral length was most uniformly best in two intervals in the lower half—rather than also in the upper half—of the lower Eagle Ford. "The laterals in our W-pattern test are geosteered to very specific areas that meet specific criteria," he said. "These targets can be as narrow as 20 ft."

The IPs were not yet provided, but "we're very encouraged with the early results," he added.

Meanwhile, in Gonzales County, the company's Phoenix Unit #4H and Phoenix #5H wells came on with IPs averaging 3,815 bbl of oil and 415 bbl of NGL. In McMullen County, its Naylor Jones Unit 26 #1H and Naylor Jones #2H wells had IP rates that averaged 2,650 bbl of oil and 150 bbl of NGL.

### Eaglebine

Anadarko Petroleum Corp., which made a rejected and withdrawn bid for Apache Corp. in the fall of 2015, reported 83,000 boe/d from the Eagle Ford in the third quarter, down 8% from the spring and had 40 wells waiting on completion in the fall. Companywide, drilled-but-uncompleted wells totaled 200 by late October 2015.

It reported new average drilling costs of $81/ft. In the Eaglebine play west of the Eagle Ford, the average cost was a new low of $124/ft, down 30% from 2014, and it increased average lateral length by more than 20%.

Apache reported that its third-quarter 2015 Eagle Ford production declined 6% to 13,203 boe/d due to a reduced rig count and field trials that slowed completions. The trials were focused in its Area A at the intersection of Burleson, Brazos and Grimes counties east of the San Marcos Arch.

The eight wells the company brought online during the quarter had 30-day rates that averaged 1,545 boe/d, which it cited as typical for the area. The wells had true vertical depth of between 10,415 ft and 11,441 ft and laterals of between 6,322 ft and 8,057 ft. Liquids from each ranged from 79% to 85%. The 30-day IPs were between 1,250 boe/d and 1,846 boe/d.

In the far-eastern Eaglebine and Woodbine play in San Jacinto, Trinity and Walker counties, EOG was selling its leasehold in mid-October 2015, involving some 66,820 net acres and prospective also for Buda, Georgetown, Glen Rose and Dexter.

Also, Lonestar was beginning tests of its Wildcat project in Brazos County. It reported that the position is offset by about 3,000 ft easterly by another operator's Rae #3H well, which had a 30-day IP of 1,587 boe/d from a 5,527-ft lateral. A second well, Rae #4H, had a peak rate of 1,520 boe/d from a 5,494-footer.

Some 3,300 ft northeast, an operator made the 6,841-footer Walker Family #1H well for a 30-day rate of 1,897 boe/d and the identical-length Walker Family #3H well for 1,973 boe/d. ■

(Photo by Tom Fox, courtesy of Oil and Gas Investor)

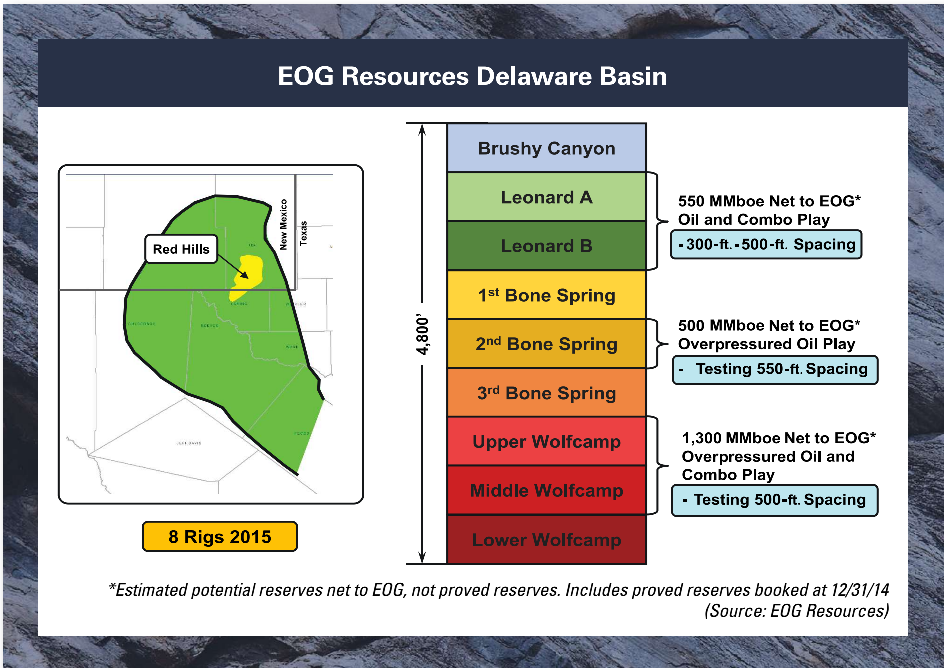
# Texas Like 1931

By **Nissa Darbonne**, Editor-at-Large

*The East Texas oil boom of the 20th century spawned Texas' dominance in world oil supply and pricing until the early 1970s. Well, it's back.*

Texas onshore oil production that declined at year-end 2009 to just shy of 1.1 MMbbl/d from the unchoked 1970s was making 3.6 MMbbl/d in the spring of 2015. The rate, coupled with that of growing supply across the U.S., brought domestic production to 9.6 MMbbl/d in April 2015, a rate not seen since May of 1972, according to Energy Information Administration data.

Texas' increased daily production alone—some additional 2.5 MMbbl—provided 60% of the 4.15 MMbbl of growth in daily U.S. output between year-end 2009 and spring 2015.




EOG Resources Inc. delivered another big number in November 2015, as it often does. The company increased its estimate of its Delaware Basin net resource potential by some 1 Bboe to 2.35 Bboe, derived from adding 500 MMboe of estimated potential from Wolfcamp and Second Bone Spring each. It increased its estimate of its inventory from 2,700 net wells to 4,900, with 1,250 of these additional net locations landing in Bone Spring.

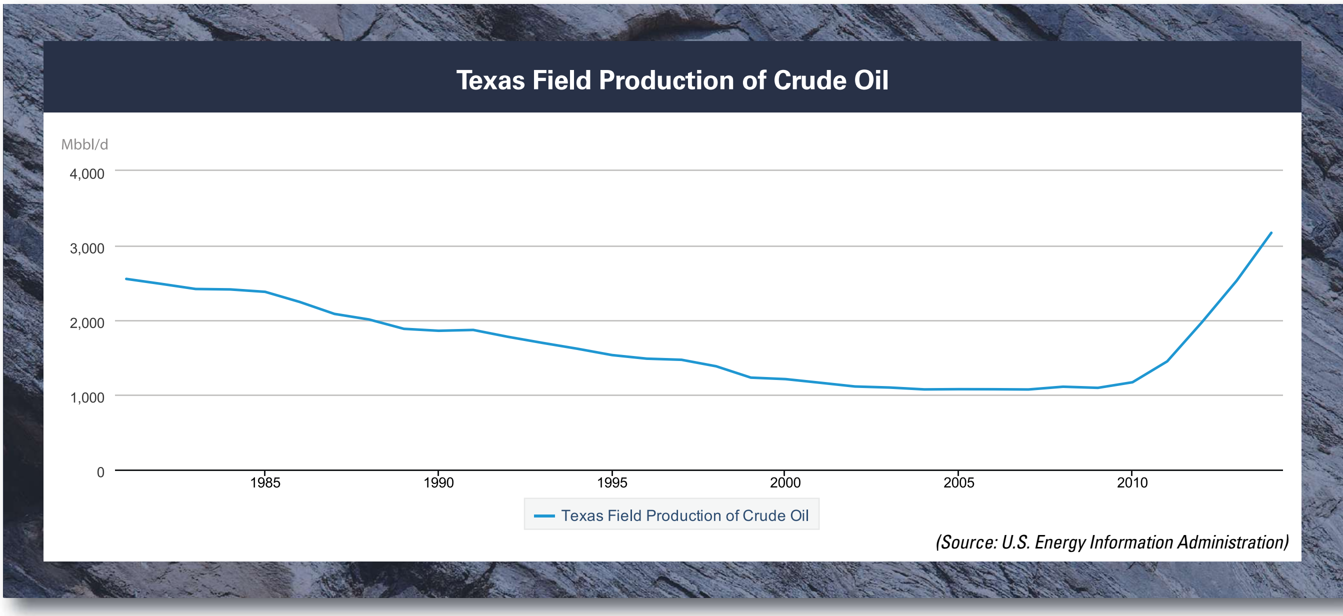
Another sign of good times? EOG bought 26,000 net acres in Loving County, Texas, and Lea County, N.M., for $368 million, or about $14,000 per net acre. In terms of production and using pre-shale-potential math on acquisitions, the acreage's 750 boe/d represented a deal value of $491,000 per flowing barrel of oil equivelent.

Well-wise, EOG claimed another new record for Wolfcamp in the Delaware Basin. Its one-section-lateral Thor 21 #702H in Lea County IPed 3,335 bbl of oil and 4,465 boe. Nearby, its Thor 21 #701H IPed 3,175 bbl and 4,270 boe. The 30-day rates were 3,490 bbl/d of oil and 2,800 boe/d. The wells' average gas IP—3.9 MMcf/d—would alone have been a good gas well in 2000.

Tudor, Pickering, Holt & Co. (TPH) analysts replied, "Holy Wolfcamp, Batman! Confidence continues to grow in the productivity and resource potential of the Wolfcamp in an area where the industry is just starting to delineate."

Two other EOG one-section laterals, Brown Bear 36 State #702H and #703H, had IPs of 3,725 boe (83%

Cimarex Energy Co.'s Delaware Basin drilling operations take place in Culberson County, Texas.




*(Source: U.S. Energy Information Administration)*

oil) and 3,905 boe (77% oil) and 30-day rates of 2,035 bbl of oil and 2,405 boe/d. The TPH analysts called the Lea County wells' IPs "massive." Their math put them at 600 boe/d for 30 days per 1,000 ft of lateral, "which is more than double our type curve."

Two one-section-lateral Second Bone Spring wells, Neptune 10 State Com #501H and #502H, also in Lea County, IPed at 2,865 bbl of oil and 2,430 boe. A four-well Leonard Shale pad, Hawk 35 Federal, produced IPs between 1,130 bbl and 1,985 bbl of oil and averaged 1,615 bbl of oil.

Simmons & Co. International Inc. analyst Pearce Hammond wrote that EOG's Delaware resource potential appeared to be the second best in its portfolio, behind the Eagle Ford with 3.2 Bboe and exceeding its Bakken and other positions. "The resource increase was due to the long-awaited Second Bone Spring reveal combined with more well data," Hammond reported.

Some was also the result of adding in potential from its 26,000 net acres of acquisitions. He added, "The Delaware Basin disclosure should assuage any investor anxiety over what's next for EOG after the Eagle Ford."

EOG's return at $50 oil is more than 40% in Delaware Wolfcamp (156,000 net acres), Second Bone Spring (109,000 net acres) and Leonard (91,000 net acres); Eagle Ford (561,000 net acres); and core Bakken (120,000 net acres). In its Midland Basin Wolfcamp and noncore Bakken leasehold, the return is less than 10%, according to EOG.

Billy Helms, EOG executive vice president, E&P, told investors in November 2015, according to a Seeking Alpha transcript, that in the Delaware Basin, "we're earlier in the ability to get into a good development program there" vs. in the Eagle Ford, which EOG has been developing since 2009. The Delaware "is a highly complex basin," he said. "The geology changes quite a bit … There are multiple targets [and] multiple formations."

He concluded that EOG is probably in the third inning of understanding the Delaware's horizontal potential "as opposed to the sixth or seventh inning" in the Eagle Ford.

As for the record-setting Thor 2 well, which had only a one-section lateral, Helms said that completion and landing "are making a huge difference, regardless of lateral length." Lateral placement in each formation is "a big part of why the productivity on these [EOG] wells is increasing every quarter."

While the 26,000 net acres EOG picked up were at some $14,000 per acre, the TPH analysts declared that Delaware acreage is still "cheap," based on what the leases appear to be able to produce. "Not to paint too broad of a brush here," they wrote, "but in each case we see full development value exceeding $30,000 per acre given our view on resource delineation and cost reductions.

"Ultimately, we believe it is likely that the Delaware M&A [merger and acquisition] market may follow a path similar to the Midland, where assets that originally traded at $10,000 [per acre] to $20,000 per acre now go for $30,000 [per acre] to $35,000 [per acre] in many instances as the commercial horizontal potential in the basin was proved up."

### Matador, Delaware

With just three rigs drilling for it in the Delaware, Matador Resources Co. increased production 10% in third-quarter 2015 from its 2014 rate. JPMorgan analyst Gabriel Daoud reported, "Capital efficiency continues to improve, with Permian well costs trending lower on the back of faster spud-to-TD [total depth] times across both the Bone Spring; the most recent well cost some $4 million—vs. the $4.5 [million] to $5 million budgeted—and Wolfcamp at $5.8 [million] to $6.5 million at Rustler Breaks."

In a step-out test of Wolfcamp A, Matador's Scott Walker State 36-22S-27E RB #204H IPed at only 504 boe/d "but does confirm prospectivity of the step-out area," Daoud wrote. Second Bone Spring wells at Matador's nonoperated Arrowhead area "impressed, and management indicated oily Wolfcamp, among other targets, are likely prospective in the area as well," he added. "The focus will remain on stacked lateral concepts in 2016 to optimize spacing and resource development."

Matador combined its Delaware position with that of legendary Delaware operator Heyco Energy Group Inc. in the spring of 2015, adding 18,200 net acres in Lea and Eddy counties. Daoud deemed Matador "one of the most Delaware Basin-levered operators." It held 90,000 net acres, up from about 8,000 net in 2012.

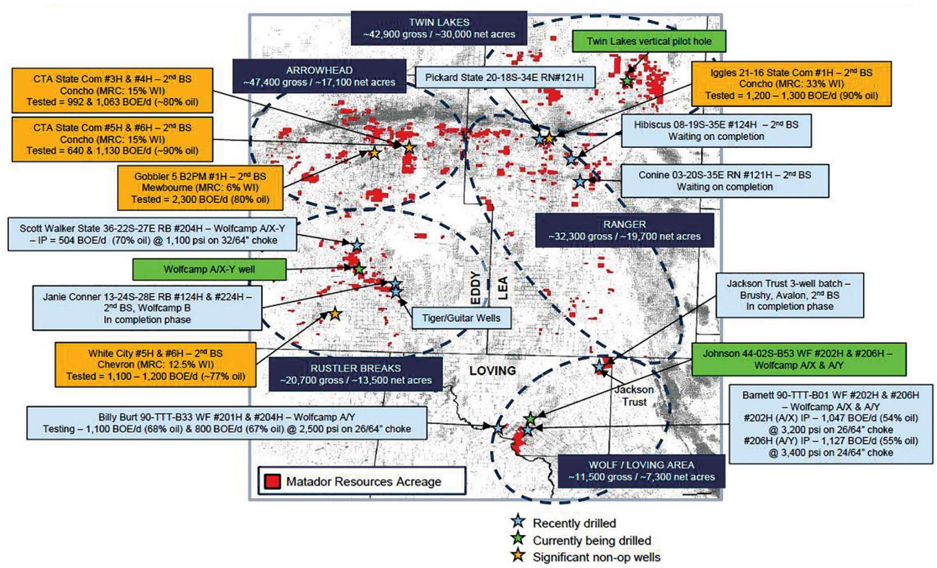
"Significant stacked pay exists across the entire position, with a 4,000-ft hydrocarbon column, providing [prospects] that could last decades," Daoud estimated. Bone Spring in Matador's Ranger and Rustler Breaks areas has mostly been de-risked as well as some Wolfcamp intervals in Rustler Breaks and Wolf/Loving.

Irene Haas, an analyst with Wunderlich Securities Inc., titled her Matador report, "Delaware Basin: Where the Action Is." Its work to date in the basin "is just the tip of the iceberg and … 2016 will be a banner year for transforming prospects into discoveries and discoveries into developments."

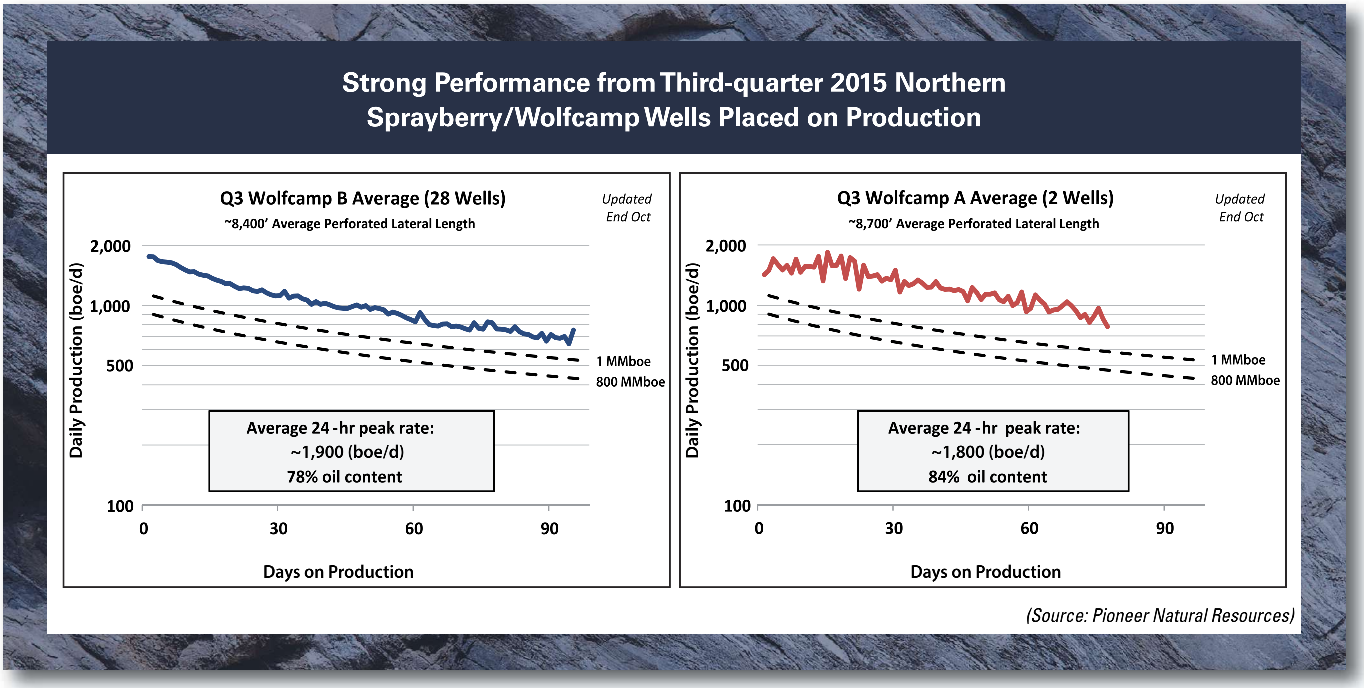
Matador has 87,600 net acres in the play with three rigs: One was drilling two Wolfcamp A laterals from a Loving County pad; the second, Wolfcamp A in Eddy County; and the third, a vertical pilot Wolfcamp D test in northern Lea County, which it was planning to drill with laterals.

Haas added that Matador's nonoperated Arrowhead area is intriguing. "This is an oily region, and we believe that there are multiple horizons in addition to the Second Bone Spring sand."

**Permian Basin Acreage Position and Recent Test Results**




*(Source: Matador Resources Co.)*




Thirty-three horizontal wells were placed on production during third-quarter 2015. The majority were Wolfcamp B and Wolfcamp A wells.

She concluded, "The Delaware Basin is truly a 'Candy Land' for oil and gas explorers."

## Pioneer, Midland Basin

Pioneer Natural Resources Co.'s Permian Basin position, in which it holds 800,000 gross and mostly contiguous acres, pushed aside its behemoth Eagle Ford asset in commentary in early November. Scott Sheffield, chairman and CEO, said in a conference in mid-November that the Permian is "the only place to grow oil long-term in this country," Reuters reported. "I wouldn't be surprised if, in five years, the Eagle Ford is not a part of this company."

Almost all HBP by legacy vertical-well production, Pioneer's Permian leasehold is 600,000 gross for Sprayberry/Wolfcamp in the northern portion of the basin and 200,000 gross in the south. It estimates it contains more than 10 Bboe of net recoverable resource potential.

Companywide production grew 7% in third-quarter 2015 to 211,000 boe/d, 52% oil. In the Spraberry/Wolfcamp horizontal program alone, daily production grew by 15,000 boe (67% oil), or 13%. It was expecting to exit 2015 with some 25% more Permian Basin production than its year-end 2014 rate. Drilling and completion costs were 25% less than the year-before period; by year-end 2015, the company expected that to be 30%.

Meanwhile, it put a three-lateral pad online in 135 days with each well drilled in 25 days, down from 37 at year-end 2014. "The improvement has been driven in large part by rigs drilling one interval consistently and utilizing a modified three-string casing design," it reported. Its quickest wells from rig release to rig release have been in 17 days in the northern area and 13 in the south.

Of the 33 horizontals it put online in third-quarter 2015 in the northern position, which is primarily in Midland and Martin counties, 28 wells landed in Wolfcamp B and two in A appeared to have a type curve that may produce a 15% better EUR than the 1 MMboe average of all of its A and B wells post-2012. Average first-24-hour rates from the new wells were some 1,900 boe, 78% oil.

With 17 of the B wells and the two A wells, Pioneer dialed up stages, clusters per stage, fluid volumes and proppant. It also continued to experiment with dissolvable plugs. Two wells were landed in Wolfcamp D and had a 24-hour IP of some 1,600 boe; a lower Spraberry well had not yet IPed.

Joey Hall, Pioneer executive vice president, Permian operations, told Hart Energy, "I would characterize this past year as exceptional." In mid-2014, "all of my meetings were about ramping up." Then,

they were "about ramping down, then back to a period of where we're in a measured ramp-up."

Laying down rigs did "give us the opportunity to catch our breath from the days of $100 oil and allowed us to focus in on a particular execution plan and work on our efficiencies and completion recipes." What the year has produced is a "robust plan for the future," he said.

As for the mechanics of the Midland Basin's stacked reservoirs, he said, "we continue to discover things. Anybody who tells you they've figured out the reservoir with 100% certainty just isn't where they should be with it. We're learning new things all the time. When you have stacked plays like we do, you're not only learning about the reservoir you're targeting, but you're learning about how they interact with the reservoirs above and below them.

"The day you think you've cracked the code on your reservoir will be the day you flatten out on your learning. I think we're still in the early days of understanding."

Pioneer is targeting lower Spraberry and Wolfcamp A, B and D, primarily. Wolfcamp C is "different for different operators," he said. In some areas, it's very thin. "People haven't had a lot of luck exploiting the C. It doesn't work for some for different reasons, but it is a lower priority for almost everyone."

Pioneer is currently focused on Wolfcamp B in particular. "We continue to dabble in Wolfcamp A and lower Spraberry. We're focused right now on B because we know the most about it; it allowed us to be as efficient as we possibly could.

"But we continue to drill in those other intervals and, going forward, it allows us to take the lessons learned from the B and apply them to the other areas. Wolfcamp A and the lower Spraberry are definitely prolific as well."

### Fewer rigs, more growth

Pioneer continued to expect in November 2015 annual production growth of 15% or more in 2016 through 2018—and with fewer rigs than the 28 it planned in 2014 as a result of efficiency gains and higher EUR. The company added eight rigs in the northern Spraberry/Wolfcamp during third-quarter 2015 and in November had 14 drilling the northern play and four drilling the southern play.

Lateral lengths are 7,500 ft to 10,000 ft since most of its acreage is contiguous. It estimates two-section B laterals have net present value (NPV) of some $8 million at $60 oil and $3.25 gas less differentials, while one-section laterals have an NPV of $2.3 million. And they're paying out in 18 months rather than 36.

The company's two-section laterals cost between $8 million and $8.5 million. It expected the cost in the northern area to decline to $7.5 million in early 2016.

Overall, it was expecting to exit 2015 with 110 new horizontals in the northern area, with 75% in B and the balance in A, D and Spraberry. Among those spudded in 2015, about 120 were on two- and three-well pads in the northern area, 80% landed in the B.

Southern-area wells, which are in a joint venture with Sinochem and are primarily in Upton County, were suggesting EURs of 900,000 boe and costing about as much as northern-area wells. Most of the 85 it estimated would be put on production in 2015 by year-end were landed in B.

Hall said reduced oilfield service costs have resulted in lower well costs, but the increased availability of rigs and crews also have led to efficiency gains. Pioneer added four rigs in third-quarter that had been stacked.

"Traditionally, when you do something like that, you have an expectation that the rig will start off at a slower pace than the rigs that have been working," he said. During third-quarter 2015, however, "we put a stacked rig out in the field and its first well out of the gate was a record for us."

Based on previous drilling, Pioneer had its well design in place. "That is a huge help, but the fact that these companies can staff these rigs with their best people and their best crews right out of the gate—plus people are hungry to perform—undoubtedly allows us to perform at a higher level. There's no doubt that we've definitely benefited from the fact that we have some of the best people out there working on our rigs."

What was the record that was set? Well, Hall said, Pioneer analyzes these by different areas and different zones. "We have such a huge position that what is a record in one area might not be a record in another. But, to put it in perspective, we have

some areas where spud to bump of plug is 11 days, another where it is 15 and another, 21 days. All of those are new records. It depends on which areas you're drilling in."

In addition to adjusting for the nature of different areas and, possibly, multiple targets in each, Pioneer is adjusting variables in increased water and sand volumes, reduced cluster spacing and more stages. "Each area is different, so we're experimenting with all of these variables in all of these areas to the extent that it's practical."

For water, Pioneer spent some $130 million in 2015 on building a distribution system and planned another $130 million for 2016. The project includes a line for 100,000 bbl/d of effluent from Odessa, Texas. It also was pursuing an agreement with the city of Midland, Texas.

As for water volume, Pioneer is testing the limit of what is the least amount that can be used. "The conventional wisdom was that, as long as you could deliver your proppant, you would get the well performance you expected," Hall said. "But our experience has been that the water volume matters as much or more than the sand volume. We get a reservoir open and the next question is 'How much proppant does it take to keep it open?'

"You may even see us, at some point in time, experiment with higher water volumes but less sand. The real trick is to not test too many variables at a time because you'll never know which one was the contributor to either the betterment of the well or the degradation of the well."

With pad wells in particular, from spud to "any meaningful data, it may be six months before you can make a judgment call on if it did or didn't work," he said.

Pioneer is using only brown sand in its Midland Basin wells, where the Wolfcamp is at about 9,000 ft. The Eagle Ford is at more than 12,000 ft. "When we started off [in the Eagle Ford], it was all ceramic. We started using some white sand and then only white and no ceramic, and we even experimented with brown sand," said Hall, who was previously Pioneer's senior vice president, South Texas operations.

Brad Handler, an analyst with Jefferies LLC, reported in November 2015 that the use of brown sand is on the rise as "economics take precedence over science." Pioneer is expanding its mine at Brady, Texas, to produce 2.1 MMtons/year, nearly triple the current capacity. Permian Frac Sand LLC has turned on the lights at its 750,000-ton/year mine at Voca, Texas, Handler reported.

"We have heard numerous references to Permian/Eagle Ford operators warming up to brown sand—and other lower-grade frack sands—given the significant delivered-cost advantage," he added. Northern white is primarily sourced from the northern Midwest.

"We believe that logistics are now more than 70% of delivered Northern white sand cost vs. some 60% at the end of 2014." He added that brown sand is more easily crushed than Northern white "but is often sufficient for lower-pressure wells."

Titling his report "Proppantpalooza," Cohen and Co. analyst Marc Bianchi estimated that Permian Basin proppant use averaged 6.2 MMlb per well in 2014. They estimated this grew in 2015 to 7.8 MMlb and will grow to 9 MMlb in 2016. Also, across all unconventional plays, operators' use of a sand-plus-resin recipe was on the rise again during third-quarter 2015.

## Midland and Delaware, Apache

Apache Corp. was prepared for and planned "to take full advantage of a potentially lower-for-longer commodity cycle," John Christmann, president and CEO, told investors in early November 2015.

Of the 28 rigs it had drilling for it worldwide in third-quarter 2015, 10 were in the Permian Basin. The company drilled 37 wells and completed 65 in the quarter, up from 53 in the prior quarter. Production was mostly unchanged at 170,000 boe/d, 55% oil.

Among the wells, 17 were drilled and 22 were completed in Bone Spring and Wolfcamp in the Delaware Basin, with five in the Waha area in northeastern Reeves County and 17 in the Pecos Bend area in western Loving County, where Apache is focusing on the third Bone Spring. Its Condor 210H and Condor 212H were posting better performances than type curve in early November 2015. Their 30-day IPs were some 1,460 boe/d each.

Meanwhile, Condor 209H and Condor 211H in a new third Bone Spring area had 30-day IPs of 724 boe/d and 960 boe/d, respectively. All 22 of Apache's Delaware wells were completed during the 92-day period with just one frack crew, and drilling and completions averaged less than $5 million per well.

In the Midland Basin, Apache completed 25 wells in Wolfcamp and Spraberry, primarily in the Wildfire area of Midland County and the Powell-Miller area of northern Reagan County and also in its Azalea in Glasscock and Barnhart in Irion. In Midland County it was awaiting results from its one-section June Tippett 17 #1HM, #2HM and #3HM tests of both 900-ft and 1,500-ft intervals of Wolfcamp B. And a three-well test of the lower Spraberry was underway.

In the Powell-Miller area three middle Wolfcamp horizontals came on with 30-day IPs of 819 boe/d. A fourth, CC 4132B, had a one-day rate of 1,623 boe. In its first test of the Azalea area, Schrock W.M. Deep 34 #1HU, #2HM, #4HU and #5HM in the middle and upper Wolfcamp underwent varied completions. Apache reported that on a per-lateral-foot basis, all four outperformed expectations, averaging a 30-day rate of 626 boe/d. Midland Basin completion costs were $2.7 million, down 44% from the beginning of 2015.

On the Central Basin Platform/Northwest Shelf, Apache had two rigs targeting Yeso with horizontals in its Cedar Lake area in Eddy County. Hummingbird #1H came on with a 30-day IP of 816 boe/d and Hummingbird #2H with 722 boe/d from laterals averaging 4,340 ft. Drilling and completion costs were only $2.6 million, down from $5.1 million in 2014.

### Delaware, Anadarko

In mid-November 2015, Anadarko Petroleum Corp. reported that it had made a "modest" all-stock bid for Apache that was rejected and withdrawn. Al Walker, chairman, president and CEO, said at an investment conference at the same time that the company was interested in adding acreage in basins where it also owned infrastructure, such as the DJ and Permian.

Seaport Global Securities LLC (SGS) analysts reported that Anadarko's Delaware position "continues to gain ground" on its successful DJ Basin portfolio as EUR is approaching 1 MMboe "across Anadarko's entire [Delaware] position." Also, well costs have declined to less than $6 million for pad wells.

"Activity here remains focused on holding acreage and delineation—testing the various benches


**With takeaway catching up to oil production, gas processing is gaining more recognition.**

Matador Resources Co. sold its Loving County midstream assets for $143 million, a price Wunderlich Securities Inc. analyst Irene Haas deemed "impressive." The processing plant "attracted 23 interested parties." For its Rustler Breaks area, Matador was planning a larger plant, she added. The plant was expected to be completed in third-quarter 2015.

Pioneer Natural Resources Co. increased its daily gas and NGL production by 5,000 boe in third-quarter 2015 by upgrading field compression and line looping. Also contributing was West Texas Gas Inc.'s new Sale Ranch processing plant, it reported.

With a 30% interest in the Sale Ranch system and 27% interest in Targa Resources' West Texas gas processing system, Pioneer spent $70 million in 2015, including in Buffalo for Targa's new 200-MMcf/d plant in Martin County. It expected to spend some $50 million on completing Buffalo in 2016.

Pioneer added, "No new plants are expected to be required after the Buffalo plant is completed until there is a significant increase in the Midland Basin rig count." Also, like many other Permian Basin producers, it reported that it was rejecting ethane.

Joey Hall, Pioneer executive vice president, Permian operations, told Hart Energy, "Infrastructure was definitely a concern [before 2015]. It still remains on our radar. We're very focused on having a long-term view on infrastructure and takeaway capacity because, if you don't pay attention to it, it can catch up with you." ■

Small spring flowers start to emerge in the landscape of Eddy County, N.M., near the Texas border in the Delaware Basin.

(Photo by Tom Fox, courtesy of Oil and Gas Investor)

with different completion techniques—as full development mode likely won't occur until returns are truly competitive with the (DJ) Wattenberg, which has the benefit of mineral rights, and commodity prices stabilize," SGS reported.

They estimated Delaware returns of more than 35% at $60 West Texas Intermediate, $3 Henry Hub and $3.3 million well costs, drilled and completed, "while Wattenberg returns are estimated at more than 50%."

Anadarko's position is 250,000 net acres in Loving, Winkler, Ward and Reeves counties. TPH analyst Matt Portillo reported that the company's "inventory depth could more than double over the next two years." Well costs had fallen to some $6.25 million each, and new wells looked like their EUR was "trending closer to 1 MMboe."

TPH's research team dove into the Delaware Basin in mid-November 2015, finding that it "still has the highest potential for further cost reductions of any of the major oil basins." Operators may knock 10 more days off their drill time. In the prior 12 months, days declined from some 50 to about 20 "while avoiding 'problem' wells, which plagued 2014 programs," TPH said.

One-section laterals were about $7 million each, down from an average of about $12 million in 2014, they added. With further reduction in completion costs and with drilling more pads, well costs could decline to almost $6 million. In addition, more operators may, like Cimarex Energy Co. in Culberson County, make longer laterals. Cimarex's joint development agreement with Chevron Corp. created a contiguous position.

A 1.5-section lateral may add only $1.25 million to $1.5 million to the drilling and completion cost, they estimated. "Extrapolating cost savings and longer lateral development would lower breakeven economics to [between] $30 and $35 per barrel in the core oil window" vs. roughly $40 in late 2015.

In the southern Delaware, "the combination of higher proppant loading, tighter cluster spacing and shorter stage spacing has translated to a step change in productivity," they added. Per 1,000 ft of Wolfcamp lateral, 30-day IPs had improved to about 250 boe/d and EURs to between 175,000 boe and 200,000 boe. "This compares to core Midland Wolfcamp development IP 30-day rates of [between] 120 [boe/d] and 190 boe/d per 1,000 ft of lateral and EURs of between 100,000 [boe] and 150,000 [boe] per 1,000 ft."

In the northern Delaware, EOG's news in southern Lea County, producing some 600 boe/d per 1,000 ft in "eye-popping" 30-day rates "is more than two times our type curve and competitive with any rate we've seen across the Permian," TPH reported. In addition, in the Bone Spring Devon Energy Corp.'s 30-day IP of 1,000 boe/d is a 10% increase in the type curve.

### RSP et al.

Wholly focused on the Permian, RSP Permian Inc.'s production grew 114% to 24,000 boe/d, 75% oil, in third-quarter 2015 from the year-before quarter and 21% from second-quarter 2015. It made 11 operated horizontals in third-quarter 2015, with five in the lower Spraberry, two in Wolfcamp A and four in Wolfcamp B.

At its Spanish Trail area in northwest Midland County, it made four Wolfcamps with laterals of more than 11,000 ft each and fracked with 53 stages on average. The 24-hour IPs averaged more than 1,750 boe/d.

Overall in the quarter, the company raised first-year estimated production for Middle Spraberry by 35% to 156,000 boe, Lower Spraberry by 16% to 177,000 boe and Wolfcamp A by 16% to 173,000 boe. As for EUR per 7,500-ft lateral, it raised this 10% to 715,000 boe for Middle Spraberry, 16% to 830,000 boe for Lower Spraberry and 12% to 800,000 boe for Wolfcamp A.

RSP increased its EUR for Middle Spraberry (up 10% to 715,000 boe), Lower Spraberry (up 16% to 830,000 boe) and Wolfcamp A (up 12% to 800,000 boe), and first-year cumulative production is expected to be 35%, 16% higher, respectively.

Simmons analyst Brian Gamble reported, "While we knew the RSP type curves were conservative ... affirmation of higher rates from a conservative operator is a positive." SGS reported that in RSP's 500-ft Lower Spraberry spacing tests in Andrews and Midland counties, more than 90 days of production data suggest the wells will have an EUR better than 830,000 boe.

In Wolfcamp D in northeastern Culberson County in the Delaware Basin, Cimarex Energy Co. was drilling Wolfcamp A, C and D. In D, 13 two-section laterals had 30-day IPs of 2,308 boe/d, 25% oil and 29% NGL, and 63% more one-year cumulative production—more than 550,000 boe—than a 5,000-ft lateral. For 2016, it was planning to infill its Tim Tam development with five 10,000-ft laterals in Wolfcamp D at 107-acre spacing.

Fully focused on the Permian Basin, Diamondback Energy Inc. reported that its 7,500-ft laterals were costing between $5.5 million and $5.8 million. In the company's focus area, its and others' wells had de-risked Wolfcamp A and Middle Spraberry.

One Wolfcamp A, Trailand A Unit 3906WA, was made with a 7,297-ft lateral and 33 frack stages where Diamondback also had Middle Spraberry and Wolfcamp B laterals. Its 30-day peak IP was 1,034 boe/d, 90% oil, with a 7,500-ft lateral. The EUR was considered to be between 750,000 boe and 850,000 boe. The Lower Spraberry and Wolfcamp B wells appeared to have EURs of 990,000 boe and 638,000 boe, respectively.

A Middle Spraberry well drilled during third-quarter 2015, ST W 705MS, was made with a 7,503-ft lateral and 32 stages. Its 30-day IP rate was 851 boe/d, 91% oil.

The cost of its 1.5-section laterals was between $5.5 million and $5.8 million. It had begun to drill in Glasscock County acreage it acquired and was about to begin drilling in Howard County. "We expect results for both areas [in early 2016]," Travis Stice, Diamondback president and CEO, told investors.

The three-well pad in Glasscock County targeted lower Spraberry and Wolfcamp A and B and was to be completed by year-end 2015. Another Glasscock pad was targeting A and B. The three-well Howard pad will target the same formations. In southwest Martin County it was drilling a four-well pad for Middle and Lower Spraberry and Wolfcamp A and B.

Devon reported it had another quarter of strong production results from its stacked-pay position in the Delaware Basin, where net production increased to 61,000 boe/d in third-quarter 2015, up 32% from a year earlier. It raised its type curve for Bone Spring and reported that the Leonard Shale "delivers excellent results."

In the Delaware, its production averaged 61,000 boe/d, 34% oil. In the Midland Basin, it drilled two new wells and production averaged 48,000 boe/d, 48% oil.

### Leonard Shale, Midland

Meanwhile, QEP Resources Inc. brought online in third-quarter 2015 "what we believe to be one of the first Leonard Shale wells" in the Midland Basin, SGS reported. QEP's well is in western Martin County. "Management noted that the well was flowing back strong but has not reached its peak 24-hour rate yet." If successful, Leonard could be another target zone, SGS concluded.

Meanwhile, Chris Stevens, an analyst with KeyBanc Capital Markets Inc., reported that the Leonard there "underwhelms" with 600 boe/d during flowback "that corroborates our belief that the Leonard/Clearfork most likely needs higher commodity prices to be economically viable." He added, "This likely places the Leonard at the bottom of the pecking order in terms of returns, consistent with results in the Clearfork announced by other operators."

Leonard overlies Spraberry and "is either a part of the Clearfork or lies directly beneath it," Stevens wrote. Its organic content is similar to the Spraberry, but it has slightly more porosity and permeability. The 600 boe/d during flowback "would be about 50% lower than other zones for which QEP has provided rates unless the rate on this Leonard well continues to increase."

He added that some interesting Permian Basin wells that were being drilled in fourth-quarter 2014 were Muddy Waters State 30 20H for Endurance Resources Holdings LLC in western Reeves County 12 miles south of Carrizo Oil & Gas Inc. leasehold and near Energen Corp. and ConocoPhillips Co., where results "have been subpar and gassy to date. It is a slight step-out ... so it will be interesting to see results from another operator in this area," he said.

Also, Stevens was looking for news of Parsley Energy Inc.'s Trees State 16 1H in the Delaware Basin in Pecos County. The well is the first horizontal Parley spuds in Delaware. Northwest of it, Anadarko had just spudded Walking O C3-28 in Reeves County and, just west, Apache spudded Evergreen 1 1H Wolfcamp. Also, Carrizo had spudded its third well in the Delaware Basin, Fortress State Unit 1H in Culberson County.

Spudded in March 2015 but not yet reported was U.S. Energy Development Corp.'s Admiral William Halsey Jr. 1HA in Culberson County. The well is 13 miles west of Carrizo in the Delaware. If successful, it "would extend the play westward," Stevens wrote.

Pioneer's Hall met nearly a dozen oilfield service providers in Houston in late September 2015. "We tend to focus with our vendors on reducing costs," he said. But many are making advanced technologies affordable to resource players.

"There is only a certain amount of costs you can cut. At some point in time, you just can't get your cost structure any lower, so they're looking at innovation to deliver better, faster wells. Some of the technologies that are evolving are very promising."

In an interview earlier in 2015, "I was asked what I thought the breakeven price of oil is. I said, 'I have no idea, but I know my job is to make it lower,'" he said. He told Hart Energy this past fall, "As we continue to gain in efficiency, get our service costs down, do better completions and increase EUR, the breakeven price is evolving. We're already having good returns at levels we didn't think were possible. I'm not sure what the limit is, but right now our plan is to continue to grow."

He is certain U.S. producers will answer global price competition by thriving. "The U.S. industry has a tremendous track record of figuring out how to make money in stressed environments. I'm very optimistic in our ability to push through this." ■

(Photo courtesy of Hess Corp.)

# All Pumped Up

By **Nissa Darbonne**, Editor-at-Large

*Dear OPEC: Super-sized fracks with more sand, the use of biodiverters and greater well density are making more Rockies oil.*

With 36% as many rigs drilling in North Dakota in November 2015 from a year earlier, the state's oil production remained relentless, weighing in at 97% of the all-time high that was set at year-end 2014. This was while wells waiting on completion were adding up too, totaling just shy of 1,000, compared with about 600 a year earlier.

Gains in efficiency, technology and understanding of the Bakken and Three Forks were made further obvious by the rig count, which was roughly 70 or about as many as in November 2009. At the time, drilling and completing had virtually ceased as producers had not yet fully picked themselves up from the 2008 financial markets crisis and oil-price collapse.

One of the Williston Basin's leading oil producers, Whiting Petroleum Corp., reported in fall 2015 that its production from the basin was 130,895 boe/d. The Bakken and Three Forks were 82% of companywide production. In contrast, third-quarter 2014 output was less than 128,000 boe/d, when adding in that of Kodiak Oil & Gas Corp., which Whiting acquired in December 2014.

And it was continuing to test bigger fracks, completing 34 operated wells with some 5.2 MMlb of sand each. In spring 2015, it had averaged 3.5 MMlb per each of 54 wells. The third-quarter 2015 wells that had been online for at least 30 days averaged 1,102 boe/d, up 44% from the prior-quarter wells' 30-day average. Meanwhile, the new wells cost $6.6 million each, down from $8 million in 2014.

In yet-bigger fracks, one of its P Johnson wells in a two-well pad in its Cassandra area had a first-24-hr IP of 5,062 boe/d; the other, 5,386 boe/d. The rates were the highest yet for the area. Each was pumped with 7 MMlb of sand and cost about $6.9 million.

Whiting's overall Williston Basin EUR for its 2015 wells was 700,000 boe each. At $50 oil and averaging $6.5 million each, it was estimating payout in 2.6 years.

Seaport Global Securities LLC (SGS) analysts reported that, "undoubtedly," the enhanced completions are a highlight. "Management hinted at a 'significant' upward revision of its 700,000-boe type curve [that is] likely to come sooner rather than later," they added.

Meanwhile, Hess Corp. reported strong Williston Basin results, despite a reduced rig count, concentrating its work in the "core of the core." It planned four rigs in the Bakken in 2016, down from 8.5 in 2015 and 17 in 2014. SGS estimated that, with Hess' wells' strong production rates, just four rigs "could even hold (its) volumes flat for the next several years."

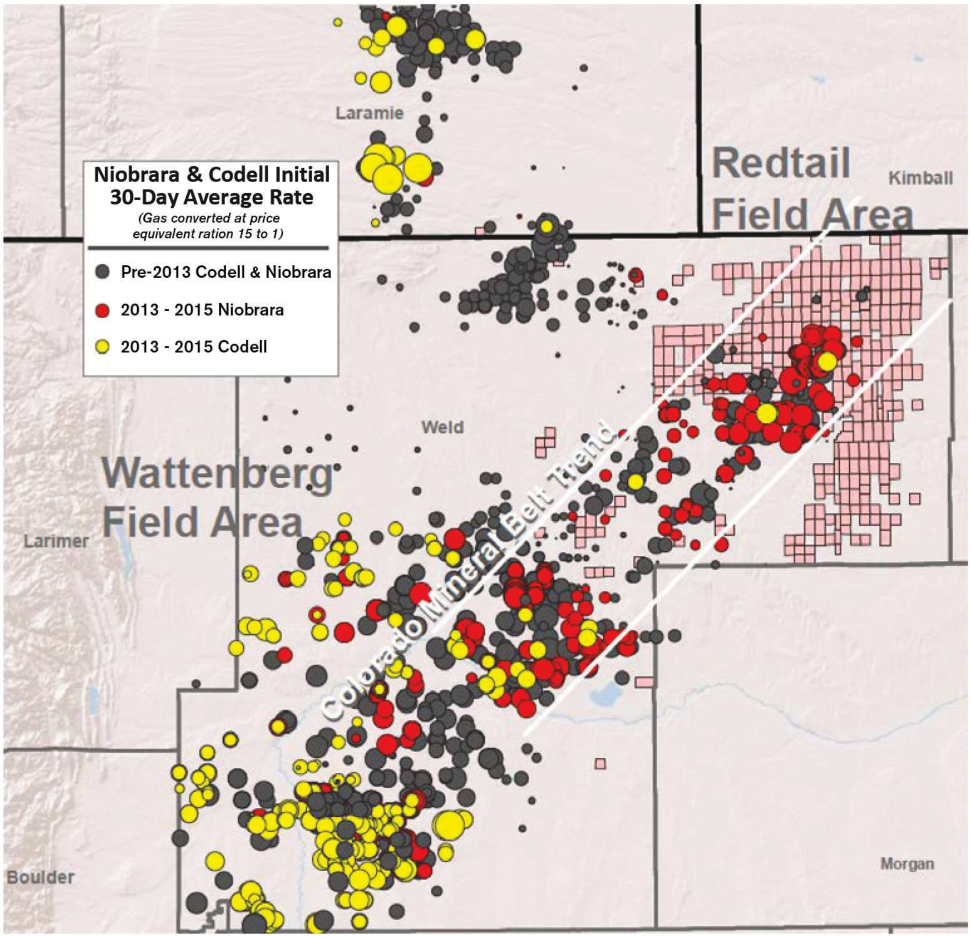
Of Hess' 51 Three Forks wells that were brought online in 2015, 20 had been producing for more than 90 days "with encouraging results," SGS added. In 50-stage, sliding-sleeve pilots, 18 of the 36 planned were online and outperforming a 35-stage design. "However, management intends to collect further history to fully weigh incremental costs vs. benefits."

Drilling and completions for Hess' operated wells was $5.3 million, down 26% from third-quarter 2014. Its net production from the play grew 31% in third-quarter 2015 year-over-year to 113,000 boe/d.

QEP Resources Inc. was making 54,000 boe/d in the Williston Basin, up 17% from a year earlier. In its South Antelope area in northwest McKenzie County, a Three Forks II bench test had made more

Despite moving to four rigs in the Bakken in 2016, Hess expects to hold production relatively flat through the combination of efficiency gains and increased gas capture.

**Redtail Development Program: Economic Sweet Spot**




*(Source: IHS and internal Whiting database as of 12/31/2014)*

Whiting has assembled 147,472 gross acres in its Redtail prospect in the northeastern portion of the DJ Basin. Redtail production averaged 16,575 boe/d in third-quarter 2015.

than 200,000 boe in its first 180 days online. Three others in the four-well test "are exhibiting a similar production profile," QEP added.

The company's 32 wells that were completed with between 9.5 MMlb and 10 MMlb of proppant in 48 to 51 stages had first-six-month production of some 180,000 boe each—50% more than 60 wells that were completed with 3 MMlb to 4 MMlb in 30 to 35 stages.

Meanwhile, WPX Energy Inc. had two rigs drilling for it in the Bakken and one in its horizontal Gallup oil play in northwestern New Mexico, which it ramped up to 10,400 bbl/d from 3,900 in 2014. The company reported in November 2015 that it planned to continue to test larger stimulations, including in the Bakken, where it made 18,900 bbl/d in third-quarter 2015.

Three two-section wells in the Mandaree area were each completed with 100% sand and 45 stages. In two, 10 MMlb were used in each; in the third, 6 million. The 10 MMlb wells' IP rates were between 2,100 and 2,300 bbl/d at roughly 3,400 psi. The third well came on with 1,650 bbl/d at 3,350 psi.

The results are better than WPX's 750,000-boe type-curve expectations, it reported. In early November 2015, the three wells were making 3,900 bbl/d, combined, at about 2,000 psi.

At Oasis Petroleum Inc., Tommy Nusz, chairman and CEO, reported the cost of 100% ceramic, slickwater completions had further declined to $7.4 million a well. Pre-2015, "base" fracks were plug-and-perf (PNP) in 36 stages with 4 MMlb of proppant, 60% ceramic and 60,000 bbl of frack fluid. Its new high-volume-proppant wells use 9 MMlb of sand, 50 stages and 150,000 bbl. Its new slickwater wells use 4 MMlb of ceramic, 36 stages and 220,000 bbl. The company expected 80% of its 2016 wells would be completed with the high-intensity design.

Taylor Reid, president and COO, told investors in November 2015, according to a Seeking Alpha transcript, that three all-sand tests were completed in its Indian Hills area in the deepest part of the Williston Basin.

"These wells are in early flowback," he said, "but, if their results are the same as we have seen in Montana, where production with and without ceramic is very similar, then we will apply this technique more broadly in the core [in North Dakota]," Reid said.

SGS reported, "Faster cycle times on wells completed with the latest and greatest completion enhancements on Oasis' best acreage should translate into more production per dollar of capex spent and lower breakeven costs."

Reid said, "The benefit would be an additional savings of $500,000 per well."

### Bakken DUCs

North Dakota delivered relief to operators in October 2015, giving them an extra year to complete their wells, with exception if the mineral-rights owner objects.

Continental Resources Inc. reported in November 2015 that it had 123 operated wells waiting on completion, up from 95 in June. It expected to exit 2015 with 115 wells drilled but uncompleted (DUC).

The company posted 4% less production, to 147,719 boe/d, from the basin in third-quarter 2015 vs. the prior quarter. Tudor, Pickering, Holt & Co. analysts responded, "Continental is a large Bakken producer whose production is firmly in decline. We think investors should care on a macro-level, as Bakken production has to date been resilient."

Jason Wrangler, an analyst with Wunderlich Securities Inc., wrote that the DUCs could be viewed as "a big bank of oil that Continental can utilize at the right time." The E&P sold its oil hedges in 2014, so it is fully exposed to the spot price. "These uncompleted wells provide a bank of oil for Continental that we feel could be tapped quickly, and for less incremental cost, and allow it to take advantage of price improvements, especially given that it is unhedged," Wrangler wrote.

A small-cap E&P, Arsenal Energy Inc., reported in November 2015 that six new Bakken/Three Forks wells it participated in in North Dakota were supposed to be online in August, but weren't completed by the operator. "The operator has now advised Arsenal that the wells should be on production in February 2016," it added.

QEP reported that 19 of its operated wells were waiting on completion. Also, 24 nonoperated wells were DUCs as well. Oasis had 87 operated DUCs. SM Energy Co. was actively not completing all of its wells. It had 47 DUCs at the end of September 2015. Marathon Oil Corp., meanwhile, released its frack crew in the Bakken. SGS reported, "So we expect DUCs to build throughout the winter."

Hess brought 48 wells online in third-quarter 2015 and 185 during the first nine months. Greg Hill, president and COO, told *Oil and Gas Investor* earlier in

## Oxy's Exit

Noncore Bakken acreage was going for $1,670 per acre and that isn't a typo. Simmons & Co. International Inc. analyst Guy Baber did the math in mid-October 2015 of Occidental Petroleum Corp.'s (OXY) planned exit of its 300,000-acre Williston Basin position for an estimated $500 million to deploy the proceeds in its Permian leasehold. The Williston leasehold is in southwestern Dunn County, northeastern Billings and northern Stark.

Baber wrote, "Oxy's view of its Williston Basin position has deteriorated since upping its stake in the play in December 2010. The asset can't compete for capital with a high-quality and improving Permian position." He added that, prior to Oxy's 2014 spin-off of its California E&P assets as California Resources Corp., "California was even receiving capital ahead of the Bakken."

Later word of the Oxy exit put an estimate of the deal value at some $600 million or $2,000 an acre. Seaport Global Securities LLC analysts reported, "Management believes that acreage in North Dakota, whether it's tier one, two or three, cannot compete with its Permian position."

Baber wrote that rumors in late 2014 were that Oxy wanted $3 billion for the position, which "seemed to be an aggressive assumption at the time." He estimated Oxy had been holding out for $1 billion into last summer. West Texas Intermediate began declining again, however. That and other reasons, including improving results in the Permian, "likely resulted in the willingness for management to move forward with the deal at a discounted price." ■

2015 that Hess didn't plan to accumulate DUCs in the Bakken—or elsewhere. "That's purely a cash-flow-management kind of strategy. But you've already got half of the well's cost sunk...You're much better off just completing it and getting it onto production."

He added, however, that it might make sense for an operator who isn't in "the core of the core" of the Bakken/Three Forks to wait until oil prices improve. "On an unconventional well like in the Bakken, 70% of the NPV [net present valve] is generated in the first three years," he said.

Whiting doesn't carry many DUCs, either. "Our philosophy is we want to drill and complete wells that make money at $40 to $50 oil," Eric Hagen, Whiting vice president, investor relations, told Hart Energy. "We don't like to base our results on whether prices are going to go up in the future.

"We don't see $30 oil unless there is a global recession. If that's the case, we would take some further measures on our capital program. But in the current range, we have a solid plan. We're earning good returns and we have a good, long-term-growth profile intact."

### Plug-less Bakken

Whiting has more than 13,000 locations in the Bakken and Niobrara. SGS Senior E&P analyst Mike Kelly reported, after meeting with Whiting in October 2015, that, among these, more than 50% are economic at $50 oil.

"With a significantly improved Bakken asset base post the Kodiak merger—it's simply better acreage—and with restricting drilling activity to its top prospects—rig count was slashed from 24 to eight rigs (six in the Bakken and two in Niobrara)—we think Whiting will prove to be one of the better capital-efficiency turnaround stories heading into 2016," he wrote.

Whiting's more intense fracks and use of diverter agents "continue to prove that last year's average rates can easily be surpassed," he added. In its Pronghorn-sand development, "for example, enhanced completions...are tracking 50% higher vs. its offset, standard completions on 120-day rates." Also 60-day rates were 50% higher at its Walleye area and 40% higher at Polar.

Whiting was experimenting with faster, plug-less, coiled-tubing (CT) fracks in 2014 and early 2015. One of these wells, Waldock-Federal 14-4-3XH in Mountrail County, was completed with 93 stages along its roughly 9,000-ft lateral. By October 2015, it had cumulative production of 208,006 bbl in 457 days online. September 2015 production was 310 bbl/d.

In a trial in Tarpon Field, its Flatland Federal 11-4TFH well in the first Three Forks bench, produced 398,000 bbl of oil in its first nine months. Brought back on in September 2015, after connecting production to a central processing facility, it produced 12,391 bbl in 11 days, according to the most recent well data the state had disclosed.

Its Flatland Federal 11-4HR well in the Bakken produced 293,000 bbl in its first eight months online. In 11 days in September 2015, it produced 7,346 bbl. From the second Three Forks bench,

## Pinedale

Tudor, Pickering, Holt & Co. (TPH) securities analysts reported in early November 2015, "Down but not out: Pinedale appears to be a sustainable source of near-term gas supply." Ultra Petroleum Corp.'s wells were costing some $2.85 million each and were "likely headed lower as higher-cost rig contracts roll, though it appears operational efficiency gains are slowing," TPH forecasted. New completions are resulting in a more than 30% increase in production.

Seaport Global Securities LLC analysts reported that QEP Resources Inc.'s new Pinedale completions with 100-mesh sand and slick water "are having a meaningful impact on first-year rates." The 99 wells with this type of completions have had cumulative production of 33% more on average.

TPH estimated Pinedale wells are profitable at less than $2.50/Mcf. But they were expecting differentials to widen in 2015 as more Appalachian gas begins to reach markets. ■

Flatland Federal 11-4TFHU produced 254,000 bbl in its first eight months online. In September 2015, it produced 3,907 bbl in seven days.

The Bakken well was completed with a cemented liner and CT in 94 stages. The Three Forks 1 well was fracked with cemented liner and CT in 104 stages; the Three Forks 2 well, with PNP and five frack clusters per 30 stages, for 150 frack points.

The wells' first-year production was remarkable; but, possibly, this wasn't due only to the completion method but also to their location, Whiting's Hagen said. "Identifying the sweet spots in the basin is a big part of having a rock lab.

"As Jim [Volker, Whiting chairman, president and CEO] puts it, the rock lab, where we analyze core, is a key advantage we have in understanding the rock properties. We think we have a better grasp of original oil in place than other operators in the basin and that's because of our ability to look at the rock on a molecular scale.

"We know where the highest OOIP [original oil in place] is in the basin and where the rock is going to be easier to break. Combine that with our focus on optimizing completion technology and you get results like the Flatland wells."

## Bakken, with plug

The plug-less, CT fracks were successful, "but we're really not using it anymore because we found a lower-cost way to achieve the same effect," he said. Instead, Whiting is using more perf clusters per stage and, then, biodiverter agents to isolate the clusters. "We want to have more entry points along the wellbore. With the coiled tubing, we achieved 90 to 100 entry points. But coiled tubing is more mechanically complex; it's a sliding-sleeve type of system."

With PNP coupled with a biodiverter, "we're getting the same effect for a lower cost and more operational efficiency. When you reduce the mechanical complexity of something, it makes it more reliable. In some cases, we're doing 35 stages with four to five perf clusters per stage, so we're getting more entry points—140 to 175—along the wellbore," he said.

As for proppant, Whiting reported that it is using 7 MMlb per well in its Polar area, in addition to Cassandra. Cumulative production is up 40% in the first 60 days with multiple perf clusters and larger sand volumes.

"The prior operator used 100% ceramic," Hagen said. The Bakken and Three Forks at Polar are at about 10,000 ft. "That's why they were using ceramic. Through our analysis, though, we thought, 'You don't need that much ceramic,'" he said.

Whiting is primarily using white sand and, in some cases, up to 50% 100 mesh, which is cheaper. "We do tail in with a small amount of ceramic, but you don't need to pump that much," Hagen said. "You can keep the rock propped with sand, which is less expensive."

Wells had cost some $9 million there in 2014; in fall 2015, they cost under $7 million, partially due to cost deflation. "And we're getting a 40% increase in productivity," he said.

At its shallower, Pronghorn-sand development southwest of the Bakken and Three Forks plays at basin center, Whiting was using between 5 MMlb and 5.5 MMlb of sand per well. The first 120-day rate from these wells was 50% more than those completed with less sand.

As for using new techniques, such as biodiverter agents, Hagen said this is the result of Volker's visit with major service providers. "Jim said, 'We're one of the top two producers in the Bakken. We want to keep a material number of rigs working here and we want to not just lower costs but increase efficiencies.'

"It's an example of how working with your service provider in a cooperative way can decrease your threshold price in a play. We think we're making good returns, in some cases at as low as $30 oil but certainly in the $40 to $50 range on a time-discounted basis.

"Innovation doesn't have to be wholly high tech. In some areas, you begin with a more complex approach, like coiled-tubing fracks. But, in some cases, you can find a simpler solution, which has been more perf clusters, more sand and using chemical agents to isolate the clusters," he said.

## Redtail, Niobrara

Whiting is producing well-received results from the Niobrara in its Redtail development in Weld County, Colo. Its geoscientists mapped the reservoir, finding an oil-rich window with some natural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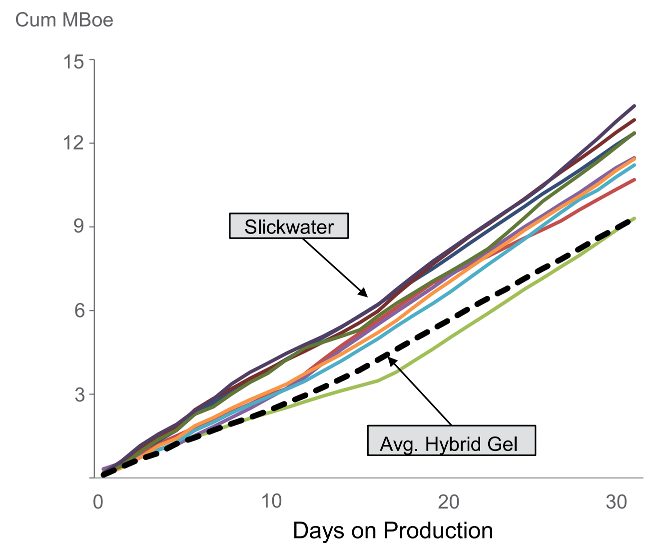
DJ Basin Slickwater Completion Results




*Note: All 13 wells included approximately 4,700 ft. lateral length each.*

*(Image courtesy of Noble Energy Inc.)*

Recent Wells Ranch test indicates more than 20% production uplift vs. comparable hybrid completions.

fracturing. "In terms of economics, they're some of the best wells, if not the best, being drilled in the [Denver-Julesburg] basin because they have a much higher oil ratio than, say, wells in Wattenberg Field," Hagen said.

The Whiting wells make 80% oil; wells in Wattenberg, about a third. "We're talking not NGL but true light sweet," Hagen said. The gas-oil ratio (GOR) is 1.5 Mcf/bbl of oil and 62 bbl of NGL per 1 MMcf.

OOIP is estimated to be greater than in the Bakken at 93 MMbbl per 960-acre unit from Niobrara A (22 MMboe), B (47 MMboe) and C (13 MMboe) and the Codell/Fort Hays (11 MMboe). "The Bakken is about a third of that in OOIP. So the Niobrara has a huge amount of potential."

Experimentation continues with completions in Redtail. "In the Bakken, we're maybe in the fifth inning in terms of completion technology. In Redtail, we may be in the second or third inning. We don't have as much well data there," he said.

In the Bakken, Whiting estimates it is now getting up to 20% recovery of OOIP; in the Niobrara, possibly 15%. Based on a 28-well unit landing in all four Redtail zones, 10% recovery would net 333,000 boe per well; 15% recovery, 499,000 boe; 20% recovery, 665,000 boe.

"We think that, as you start to apply better completion technology, you may get to 20% there as well. So the Niobrara has more upside, in that sense, than the Bakken, given that it isn't as mature a play," he said.

Whiting holds 1.5 million gross (118,000 net) acres in Redtail Field and made 16,575 boe/d from the leasehold in third-quarter 2015 or about 10% of companywide production, which includes the Bakken. In terms of lease expiration, Whiting isn't under any pressure to drill, Hagen said, as it can retain its Niobrara leasehold with extensions for some $10 million for the next few years. So, it is placing wells in high-graded acreage.

At Redtail, the company estimates it has some 5,800 potential drilling locations with a mix of 640-acre and 960-acre units. The 2015 average drilling and completion cost per well was $4.5 million.

### Slick water vs. hybrid gel, Niobrara

Noble Energy Inc. made 116,000 boe/d in the DJ Basin in third-quarter 2015, up 13% from a year earlier. Of the output, 50% was oil and condensate; 17%, NGL; 33%, gas. Of this, some 25,000 boe/d was from legacy, vertical wells; the balance, 91,000 boe/d, from Noble's horizontals.

Approaching year-end 2015, the company had three rigs drilling, down from four in the third quarter, and had two full-time frack crews in the basin. Its four rigs in third-quarter 2015 drilled 39 wells for it with laterals averaging more than 7,300 ft. Spud-to-release averaged 5.7 days for one-section wells—down from 6.1 in second-quarter 2015. They cost $3.5 million in its Wells Ranch area and $3.9 million in East Pony. In the former, production was 15% more than in the second quarter; in the latter, 20%.

"Refined completion techniques continue to enhance overall productivity," Noble reported. In Wells Ranch, it completed nine wells with slick water and four with hybrid gel. "Cumulative production from the slickwater completions is outperforming the hybrid-gel wells by more than 20% on average after 30 days."

Also, based on a one-section lateral length, they cost about $400,000 less. Noble added that it is seeing similar improvement with slick water in its East Pony fracks as well.

Anadarko Petroleum Corp. spent $354 million in the Rockies in third-quarter 2015—more than double what it spent in the Gulf of Mexico and 150% more than it spent outside the U.S. The other big-money winner was its Appalachian Basin division with $395 million.

The company's daily Rockies production in third-quarter 2015 was 103,000 bbl of oil, 57,000 bbl of NGL and 1.1 Bcf of gas for a total of 342,000 boe/d, down 6% from a year earlier. Of this, 220,000 boe/d was from the Wattenberg, which received $282 million or 80% of the Rockies capex budget; the balance was primarily on the Greater Natural Buttes, Powder River Basin, Wamsutter and elsewhere in the region.

Anadarko was deferring completions in the Wattenberg, Delaware Basin and Eagle Ford, with DUCs totaling 200 at the end of third-quarter 2015; it was projecting either 225 by year-end 2015 or 175. "The cost improvements achieved year to date, including a more than 30% reduction in completion costs, have enhanced the well returns in these assets and provides the opportunity to add completion crews to improve production flexibility into 2016," the company reported.

Anadarko's drill time in the Wattenberg was down to 4.7 days from an average of 10.5 during 2014. Its cost per foot was averaging $73, down from $142. It had eight rigs drilling in the Rockies, down from nine in spring 2015; five that were still drilling were working for it in the Wattenberg in November 2015. The eight third-quarter 2015 rigs made 140 wells, with 105 of these in Wattenberg. In the year-earlier quarter, its 14 Rockies rigs drilled 122 wells.

## Small-cap heavyweight

A small-cap Wattenberg operator, Synergy Resources Corp. has built a 90,000-net-acre leasehold, "all without stressing its balance sheet," Irene Haas, an analyst with Wunderlich Securities Inc., reported. She titled the work "Gearing Up to be a Heavyweight in the Wattenberg."

The company had one rig drilling and a capex plan of some $120 million in 2015. Its four-well Best Way pad was being completed with mid-length

## Line Pressure

**Operators are managing gas infrastructure to improve capture.**

Bill Barrett Corp.'s differentials for its Rockies oil and gas were improving as DJ Basin and Uinta Basin infrastructure have expanded, it reported. It forecasted in fall 2015 $7.72 less than the Nymex price for West Texas Intermediate and $0.50 less than the Northwest Pipeline spot.

Noble Energy Inc. planned to IPO its Wattenberg Field midstream assets, in which it had invested some $600 million into 2015, and planned to dedicate some 300,000 acres to the entity in its Wells Ranch, East Pony, Mustang, Greeley Crescent and Bronco areas.

The company reported that its gas-processing capacity, upon the startup of the Lucerne-2 plant, grew to more than 800 MMcf/d. "Accordingly, line pressures in the northern part of the field, particularly in and around the company's Wells Ranch area, have been reduced by up to 100 psi," Noble added. A low-pressure line-loop system, DCP Grand Parkway, was expected by year-end.

The reduced line pressure increased Noble's legacy, vertical production in the basin 25% to 25,000 boe/d, noted Irene Haas, an analyst with Wunderlich Securities Inc. Meanwhile, the Grand Parkway project "should help improve infrastructure reliability in the basin," she added.

Seaport Global Securities LLC analyst Mike Kelly reported that the reduced pressure was helpful to PDC Energy Inc. as well. "Management now states that the current midstream situation is in 'good shape,'" he added.

Anadarko Petroleum Corp.'s expansion of its Lancaster cryogenic plant doubled capacity to 600 MMcf/d. Also, its centralized oil-stabilization facility was expected to come online before year-end 2015. "This facility will increase oil recoveries, enhance efficiencies of tank batteries, lower operating expenses and improve environmental performance," the company reported. ■

laterals in Niobrara A, B and C and Codell. It also had regular-lateral-length wells drilled or underway in its eight-well Wind pad in Niobrara A and C and Codell. All three pads were expected to come online by year-end 2015.

"...With line pressure decreasing and infrastructure expanding, we expect Wattenberg producers to operate at higher efficiency and this, along with shorter drill time, could result in significant improvement in costs," Haas concluded.

Synergy plans some 34 horizontals in 2016, mostly in its higher GOR area and half or more having mid- or extended-reach laterals. Some of its regular-reach wells had been the result of areas in which it didn't hold contiguous sections.

Its mid-reach laterals in Wattenberg of some 7,500 ft cost between \$3.5 million and \$4 million, down from \$4.7 million to \$5.1 million, SunTrust Robinson Humphreys analyst Neal Dingmann reported. Its extended-reach laterals were costing between \$4.5 million and \$5 million, down from \$5.7 million to \$6.1 million.

The company was deploying biodiverters in its completions as well. Dingmann was watching in fourth-quarter 2015 for how Synergy's Niobrara A wells would compare with those it's made in B and C. "Later in 2016, we expect sufficient data for the company to quantify long-lateral productivity," he wrote, as well as how a test, Greenhorn, in its undeveloped northeastern extension, would work out.

Meanwhile, Whiting's plan for 2016 is for capex of \$1 billion, which is the same as the discretionary cash flow it expects to earn at \$50 West Texas Intermediate. Its spend would roughly maintain its 2015 production level.

Hagen said of its and other producers' uptake in 2015 of enhanced completions, "You see that with independents. By nature, we are institutionally willing to allow people to take some risks. We encourage our engineers to go out there and test new things. We want to be measured in how they do it, but we certainly want them to try."

He added, "R&D is not a discretionary thing. You have to be doing that. So, if we're going to do a pilot test now, maybe it won't be as many wells as when oil was \$100, but we're still going to do it." ■

## Gas Capture

**North Dakota has loosened its gas-capture deadline. Meanwhile, Bakken oil is looking north.**

North Dakota postponed a deadline in fall 2015 on when producers must capture 85% of their associated gas production. Compliance had been required by Jan. 1, 2015; that was pushed to Nov. 1, 2015.

In addition, the state approved allowing producers to trade credits for capturing gas that exceeded the target. Reuters reported that Exxon Mobil Corp., via its XTO Energy unit, had the most temporary exemptions. "[Department of Mineral Resources director Lynn] Helms said he hopes the credit system prods XTO…and others to 'get some credits in the bank.'"

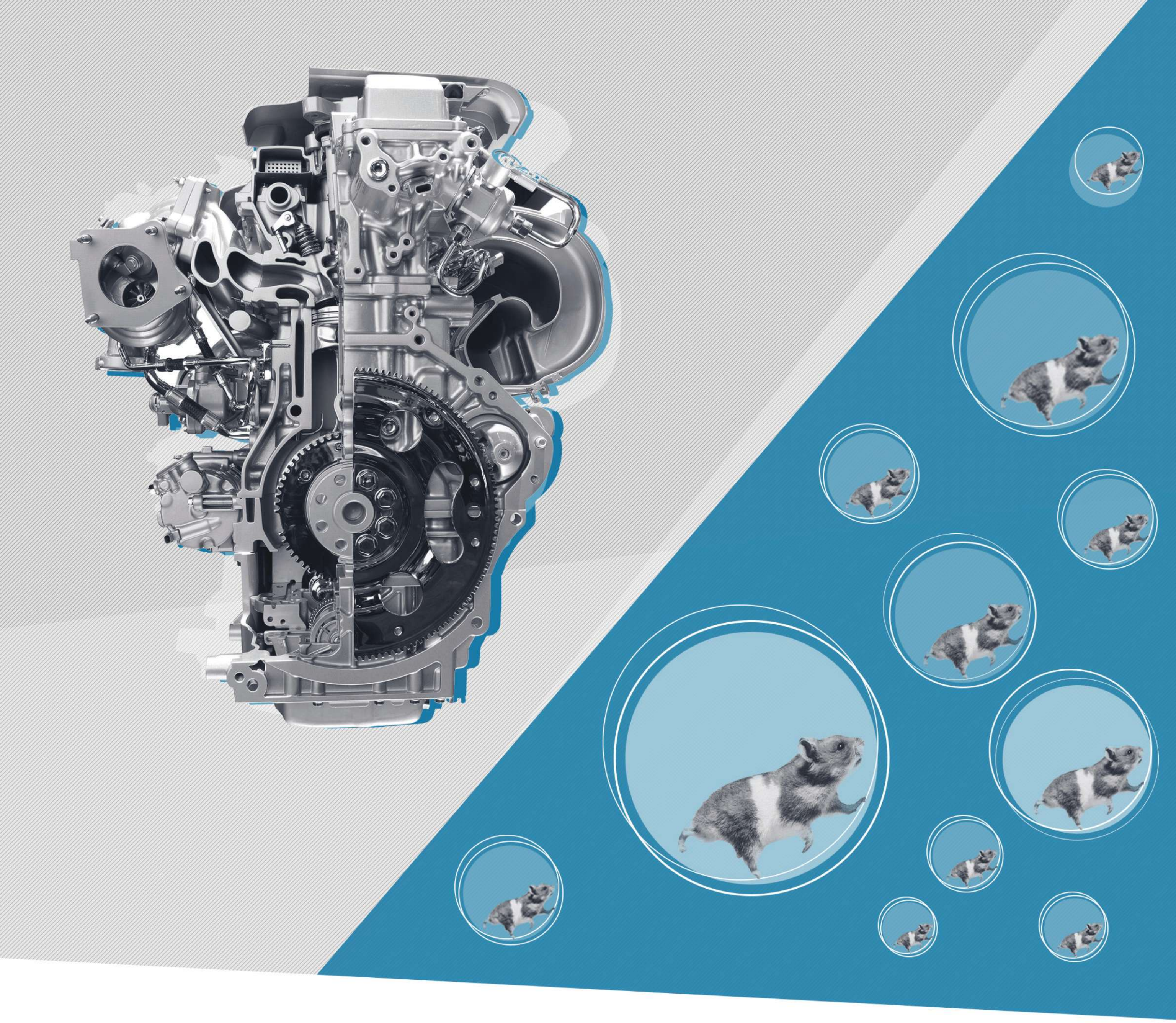
Oneok Partners LP reported that it gathered more than 685 MMcf/d in the Williston Basin, up some 25% from 2014. Also, its Bakken NGL Pipeline reached 111,000 bbl/d, up some 106%, as a result of new connections in the Rockies.

Meanwhile, its Lonesome Creek gas-processing plant with 200 MMcf/d of capacity and three additional compressor stations were expected online by year-end 2015.

Terry Spencer, Oneok Partners president and CEO, said in a company report, "Additionally, we've connected more than 720 new wells through the third quarter 2015, and we expect to connect approximately 825 wells by the end of 2015."

As for crude oil, President Obama rejected TransCanada Corp.'s permit request for Keystone XL, which some Bakken producers aimed to plug into to get production to the Gulf Coast in lieu of rail.

Meanwhile, however, TransCanada continued to work on its Upland Pipeline project, which would take Bakken production north into Canada, connecting to its Energy East project, which would take the oil to the East Coast. ■

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(Photo courtesy of Liberty Oilfield Services)

# Playmakers Pick Favorites

By **Veronica Bucio**, Associate Editor

*Operators have seen the competition, and it is among their assets.*

*Editor's note: Data are current as of Nov. 1, 2015.*

As commodity prices linger at low levels, operators are taking a hard look at their inventories, gambling on which to spend on and which to put aside to make the best use of their capital. And getting an even closer look are the drilling and completion efficiencies that close the gap between profit and loss in even the best of the plays.

While it may sound like more of the same for the cyclical oil and gas industry, in 2015, it was anything but business as usual.

The deck in this particular section of the 2015 Unconventional Yearbook, which was published in January, read: "Get in early, get in big and create a resource factory. That's the key to success in resource plays."

Barring a handful of exceptions, that's not the recipe for success most operators followed in 2015. In 2014, for each operator, the competition was still against other operators and still about acquiring assets that would move them into better shale plays. In 2015, the competition was internal for the most part. It's among the assets each operator has in hand, and it's about picking and playing favorites among them. The casualties of this competition are underperforming assets where development and drilling have been curtailed—or divested entirely.

Jeff Ventura of Range Resources summed up that mindset for his company, which is betting on returns in the Marcellus, in a third-quarter 2015 news release. "We are continuing to work on potential noncore asset sales for areas in our portfolio that cannot compete against the Marcellus for capital," he said.

For many operators, choosing shale plays in which to invest shrinking capital seems almost to be a consensus: The Permian, Eagle Ford, Bakken and Marcellus are popular for good and obvious reasons.

However, there are some surprises among the 25 most active companies in the top U.S. resource plays listed below. Snapshots of their positions in the plays, including their favorites, and plans for the future are offered.

## Anadarko Petroleum Corp.

- **Multibasin leader**
- **Unconventional pioneer**

Anadarko stretches its nonconventional activity from Pennsylvania in Appalachia through the Rockies and deep into South Texas.

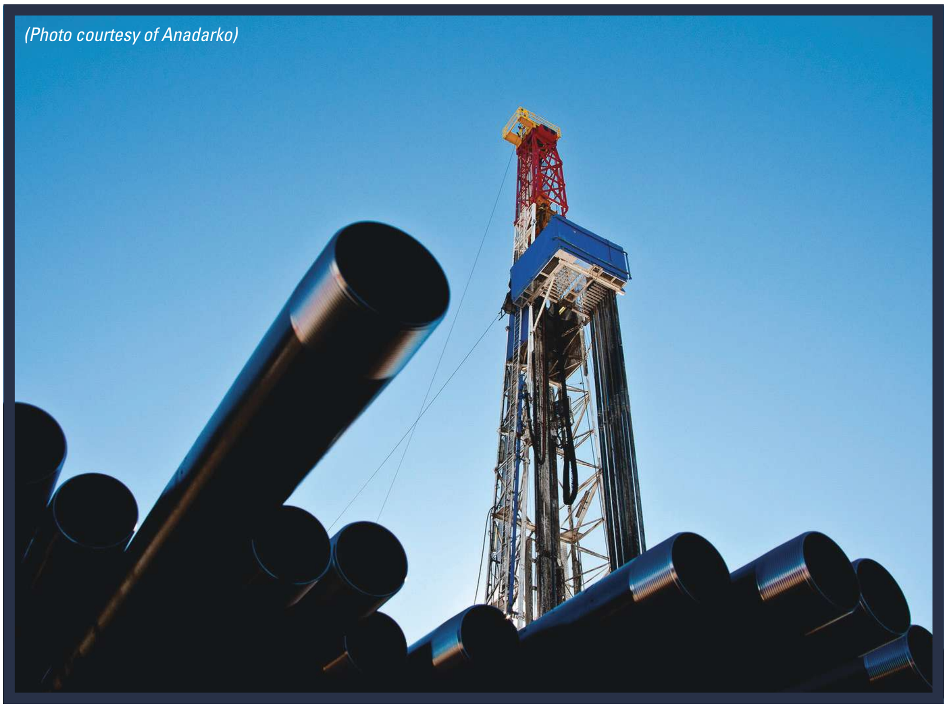
Operationally, to enhance value in the lower commodity-price environment, the company intentionally deferred completions in 2015.

### MARCELLUS SHALE

The company claims 773,000 gross (260,000 net) acres in the Marcellus play. Anadarko likes the play because the "Marcellus Shale is among the largest natural gas opportunities in the U.S. and is estimated to hold the second-largest deposit of natural gas in the world. This tremendous resource has the potential to supply the U.S. with clean-burning energy for more than 100 years," according to a 2015 company fact sheet.

The company's gas-prone operated properties lie in Centre, Clinton and Lycoming counties in northcentral Pennsylvania. Anadarko also has non-operated holdings in Porter, Sullivan and Tioga counties in Pennsylvania.

At the peak of the hydraulic fracturing activity, service companies were operating 24 hours a day like this Liberty Oilfield Services crew in the DJ Basin. In an effort to reduce costs, many service companies now only work during the day.



(Photo courtesy of Anadarko)

## NIOBRARA SHALE

Anadarko directed its primary Niobrara activity to the giant Wattenberg Field in the Denver Basin of Colorado.

In the company's third-quarter 2015 results news release, Anadarko said it had increased sales volumes by 14% vs. third-quarter 2014. In its operations report, the company said field net sales volumes decreased about 12,000 boe/d, or 5%, compared with second-quarter 2015 to an average of about 220,000 boe/d. The decrease was attributed to the decision to defer 120 completions year-to-date as a result of reducing completion crews.

At that time, Anadarko operated an average of six rigs and drilled 105 wells in the Wattenberg Field.

The company's holdings in the field offered between 1 Bboe and 1.5 Bboe in net resources with an upside of more than 500 MMboe from downsizing.

Its Niobrara play, combined with the adjacent Codell Formation, covers some 350,000 net acres.

The company averaged a record $73 per foot drilling cost during third-quarter 2015, which was attributed to continued wellbore design optimization and efficiency gains.

In the Niobrara, Anadarko averaged a record $73 per foot drilling cost during third-quarter 2015.

As of November 2015, Anadarko's net sales volumes averaged about 396 MMcf/d during the third quarter and were impacted by voluntary curtailments.

## PARKMAN SHALE

The company is the largest private landholder in Wyoming, thanks to a railroad land grant that runs along most of the southern boundary of the state. It's also an active driller and producer in the state, but its shale work is moving more slowly than some of the more popular shale plays.

A major part of the company's holdings are wrapped up in coalbed methane wells in the Powder River Basin.

In the Greater Natural Buttes, the company operated one rig and drilled 16 wells in third-quarter 2015, and natural gas sales volumes averaged 290 MMcf/d. During the time period, Anadarko reduced drilling costs by 15% and completion costs by 22% year-to-date.

In Laramie County, Wyo., the company participated in seven nonoperated well completions in the emerging liquids-rich play during third-quarter 2015, and in the Powder River Basin, it initiated a three-well oil exploration program targeting the Turner Formation.

## WOLFCAMP SHALE

The Wolfcamp Shale play has drawn extensive industry attention, and Anadarko has chosen the West Texas Delaware Basin segment of that play for its focus, seeing the region as an opportunity for future oil growth.

It holds 600,000 gross (245,000 net) acres in the play, where Anadarko's net sales volumes for third-quarter 2015 averaged more than 34,000 boe/d, an increase of 23% from the same time in 2014. The area also offers the company stacked pay potential, including the Bone Spring and other zones.

Anadarko averaged seven operated rigs, spud 22 wells and brought 11 wells online during third-quarter 2015.

It also drilled and completed its first well in the Second Bone Spring during third-quarter 2015, which tested in excess of 1,000 bbl/d of oil.

The company has reduced drilling costs to about $7.5 million per well, it said in October 2015, and it expects to achieve further reductions of $1.5 million to $2 million per well with a future move to fieldwide pad drilling.

During third-quarter 2015, Anadarko also acquired about 3,000 acres of leasehold on the border of Reeves and Loving counties in Texas.

### EAGLE FORD SHALE

The Eagle Ford Shale is a bright spot in the operating portfolios of several of the most aggressive and profitable companies in the business, and Anadarko is no exception.

It holds 388,000 gross (185,000 net) acres in the play, which it calls "among the most capital-efficient shale plays in Anadarko's U.S. onshore portfolio."

It drilled more than 1,000 wells, spudding 34 wells using three operated rigs in third-quarter 2015.

As the company learns from its wells, it is drilling longer laterals at lower costs and has the infrastructure to back up its ambitious drilling program. The company achieved a record low average cost per foot of $81, while averaging a record lateral length of more than 8,800 ft during third-quarter 2015.

Anadarko's net sales volumes averaged 83,000 boe/d during the quarter, an 8% decrease from the previous quarter, primarily due to the decision to defer 40 completions in 2015. Oil volumes averaged more than 32,000 bbl/d of oil, a 13% year-over-year increase.

Anadarko also holds Eagle Ford properties in East Texas, where it combines production with the Woodbine Formation, which the industry calls the Eaglebine play.

During third-quarter 2015, the company's net sales volume averaged 3,000 boe/d during third-quarter 2015 with the addition of five new wells, an increase of 7% compared to the same quarter in 2014.

Anadarko also reduced the average drilling cost per foot by nearly 10% to a record low of $124 per foot from second-quarter 2015, while increasing the average lateral length by more than 20%. Since 2014, drilling cost per foot has improved about 30%.

## Antero Resources Corp.

- **Most active operator in the Appalachia**
- **Utica production adds to bottom line**

Antero bills itself as the most active operator in drilling with the largest core-liquids-rich position.

### MARCELLUS SHALE

Antero has 418,000 net acres in the southwestern core of the Marcellus in southwestern Pennsylvania and northern West Virginia.

The company planned to operate an average of nine rigs during 2015, according to its 2014 annual report. As of third-quarter 2015, it was operating six drilling rigs, including one intermediate rig, in West Virginia, and completed and placed online six horizontal wells.

The average lateral length for the six wells was about 10,300 ft, and the average stage length was about 200 ft. Overall, the company has 419 horizontal wells completed and online.

The net production of Antero's Marcellus wells was 1,140 MMcfe/d in third-quarter 2015, including 33,000 bbl/d of liquids, according to a November 2015 company overview.

Antero projects 3,191 future drilling locations in the region, of which 2,302—or 72%—are processable rich gas.

The average Antero Marcellus well had a gross EUR of 15.3 Bcfe in 2014, and it projected 19.2 Bcfe in its 2015 budget.

Notably, during third-quarter 2015, the company's operational improvements resulted in an average budgeted cost of $1.14 million per 1,000 ft of lateral, representing a 16% improvement over 2014 well costs. About 50% of the well cost savings are from service cost reductions and the other half from operational efficiencies, the company said.

### UTICA SHALE

For Antero, 2014 marked the first year the Utica Shale significantly contributed to the company's total production, according to its 2014 annual report. Forty-one wells were turned to sales that year, achieving an average production rate of 134 MMcfe/d, including almost 7,000 bbl/d of liquids.

This represented a 433% increase over average 2013 production. In addition, acquisitions and base leasing brought its total core position in the southern part of the play to 148,000 net acres with 1,024 future drilling locations.

During 2015, Antero planned to operate an average of five rigs in the Utica, and as of November 2015, it was operating four rigs and three completion crews. In third-quarter 2015, it had 93 operated horizontal wells completed and online in its core areas, with a net production of 366 MMcfe/d, including 19,250 bbl/d of liquids.

The average lateral length for the 25 horizontal wells completed and placed online in third-quarter 2015 was about 8,100 ft, and the average stage length was about 180 ft.

During third-quarter 2015, Antero also placed online four wells on the Loraditch pad, the driest, most downdip Ohio Utica drilling completed by the company to date, Antero reported in November 2015.

Also, Antero reached total depth and cased its first West Virginia Utica well in Tyler County in third-quarter 2015. The company had 12 completions planned for the fourth quarter.

Antero has 226,000 net acres of exposure to the Utica dry gas play, and it spudded its first dry gas Utica well in third-quarter 2015.

## Apache Corp.

- **One of largest operators in the Permian**
- **U.S. and Canada assets push growth**

Apache cultivates profitable operations from Egypt to the North Sea, and some of its strongest assets lie in unconventional resources in the U.S. and Canada.

### HORN RIVER, MONTNEY AND DUVERNAY SHALES

While Apache currently holds 4.4 million gross acres across the provinces of British Columbia, Alberta and Saskatchewan, most of which is held in production, the company decided to divest about 328,400 net acres in the Ojay, Noel and Wapiti areas in April 2014. The company retained 100% of its working interest in horizons below the Cretaceous in the Wapiti area, including rights to the liquids-rich Montney and other deeper horizons. And, in second-quarter 2015, Apache completed the sale of its 50% interest in the Kitimat LNG projects and related upstream acreage in the Horn River and Liard natural gas basins of British Columbia.

The company is primarily focused on advancing its programs in the liquids-rich Duvernay and Montney plays, where it holds about 177,000 and 146,000 net acres, respectively.

In third-quarter 2015, production averaged 66,239 boe/d, down 4% from second-quarter 2015.

In September 2015, the company completed the final horizontal well on its seven-well Duvernay pad. The wells went online in October at an average peak test rate of 2,188 boe/d.

Apache plans to run up to two rigs in the Duvernay and one in the Montney in the upcoming drilling season.

### GRANITE WASH, CLEVELAND AND WOODFORD FORMATIONS

Apache's Midcontinent (formerly known as Central) region takes in the stacked pays in the Texas Panhandle and western Oklahoma, including the Granite Wash, Marmaton, Cottage Grove and Cleveland, where the company has more than 3,800 producing wells.

In December 2014, Apache sold noncore assets in the Anadarko Basin, including about 115,000 net acres in Wheeler County, Texas, and western Oklahoma, for about $730 million.

In the Midcontinent, third-quarter 2015 production averaged 56,535 boe/d, down 8% from the previous quarter due to natural declines and reduced activity levels, according to Apache's quarterly supplement.

During third-quarter 2015, Apache averaged two rigs in the Midcontinent, where it primarily targeted the Woodford/ South Central Oklahoma Oil Province and Marmaton plays. The company brought online two notable wells, one each in the Marmaton and Woodford plays. The Apache 21-11-21 targeting the Marmaton produced at an average 30-day rate of 1,686 boe/d, and the Truman 28-6-6 #1H targeting the Woodford produced an average 30-day rate of 1,949 boe/d.

### WOLFCAMP SHALE

Apache is one of the most active drillers in the Permian, where it has more than 3.2 million gross (1.7 million net) acres across the Permian Basin and had more than 14,500 producing wells in 155 fields at year-end 2014. Production growth was driven by Wolfcamp wells in the Barnhart area and in the Southern Midland Basin, the Bone Springs in the Delaware Basin and Yeso drilling on the Northwest shelf.

Production in the Permian Basin averaged 170 Mboe/d, consisting of 55% oil, for third-quarter 2015, only 1% lower than second-quarter 2015. Apache averaged 10 operated drilling rigs overall for the period. Also, 37 gross operated wells reached total depth and 65 wells were completed, up from 53 well completions in second-quarter 2015.

An average of three rigs were active in Apache's Midland focus areas in Midland, Upton, Reagan and Glasscock counties in third-quarter 2015. The company completed 25 wells during the quarter and directed its drilling activity primarily to Wolfcamp and Spraberry targets in the Wildfire area of Midland County and in the Powell Miller area of northern Reagan County.

Completion costs in the Barnhart area, where 17 wells remained to be completed as of November 2015, have dropped 44% to about $2.7 million due to a combination of price decreases and significant design changes.

In the Delaware Basin, Apache averaged four rigs and targeted the Bone Spring and Wolfcamp formations in the Pecos Bend and Waha areas during third-quarter 2015. The company completed 22 wells using only one frack crew, and completed wells costs continue to decline significantly, averaging below $5 million in November 2015.

### EAGLE FORD SHALE

Apache added to its Eagle Ford holdings in 2014, acquiring more than $600 million of acreage, realizing about 1.2 million gross acres in Texas and Louisiana. As it did in 2014, the company has continued to delineate the Eagle Ford in 2015, primarily in Brazos and Burleson counties.

Apache drilled or participated in drilling 77 wells in 2014, and in third-quarter 2015, production averaged 13,203 boe/d, down 6% from the second quarter of the same year. Per Apache's quarterly supplement, this was a result of natural field declines and ongoing field trials that intentionally slowed completions, the company said on its website.

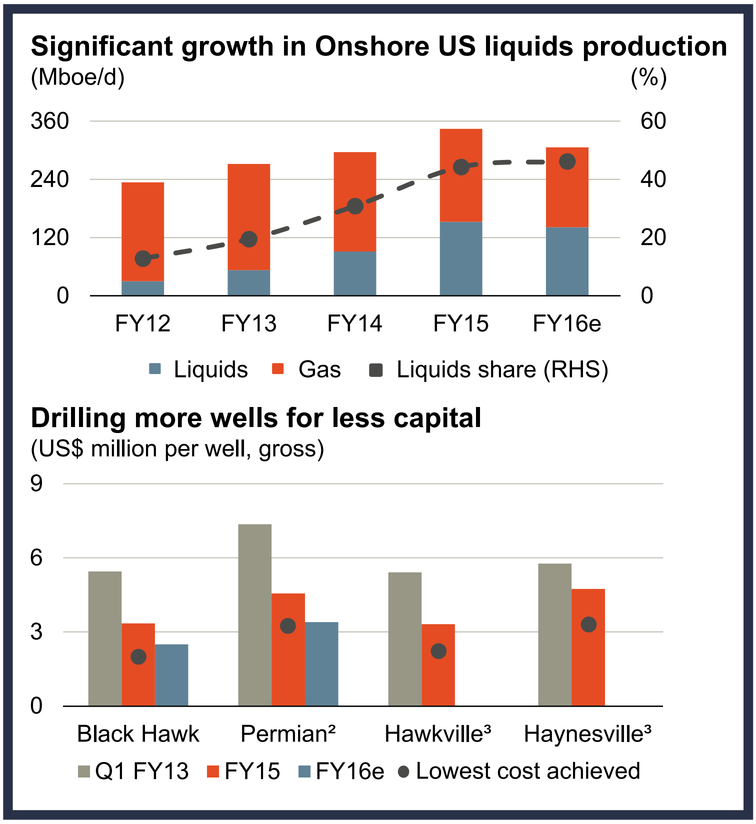
In Area A, Apache brought online eight wells during third-quarter 2015, with an average 30-day production rate of 1,545 boe/d.

During the remainder of 2015, Apache was scheduled to run one rig and finish the year with about 13 drilled but uncompleted wells in backlog.

## BHP Billiton Ltd.

- **Concentrating on liquids shales**
- **Eagle Ford and Permian are priorities**

Like other companies, BHP Billiton Ltd., a subsidiary BHP Petroleum, is backing down on its gassy shales, deferring development in those areas, and taking care to maximize value from its liquids assets.




BHP Billiton is driving continuous improvement onshore U.S. *(Data courtesy of BHP Billiton Ltd.)*

It expects overall shale petroleum production to decrease by 7% in 2016 to 237 MMboe while continuing to reduce drilling costs.

## FAYETTEVILLE SHALE

The Australian company's Fayetteville production operation, which is focused on gas, is located in northcentral Arkansas and consists of 0.4 million net acres. It holds an interest in about 4,950 gross wells and about 1,070 net wells, acting as a joint-venture (JV) operator for about 20% of its gross wells.

In 2015, the company's expenditure was the same as it was for 2014, $0.2 billion, resulting in 45 net development wells completed. Average production during 2015 was 379 MMcf/d.

BHP expects a decline in production in the lower-margin Fayetteville fields for 2016, as it continues to defer development for longer-term value.

## HAYNESVILLE SHALE

BHP's Haynesville production operation, which is focused on gas, is located primarily in northern Louisiana and consists of 0.2 million net acres. The company holds interest in about 1,045 gross wells and about 395 net wells, acting as a JV operator for about 37% of its gross wells.

In 2015, the company's capex was $0.3 billion, which was less than the $0.4 billion capex in 2014, resulting in 45 net development wells completed. The average production during 2015 was 446 MMcf/d gas.

At year-end 2015, there were no operated rigs in Haynesville, while year-end 2014 had three.

Also in 2015, BHP sold its interest in its north Louisiana conventional operations for $135 million to focus on its core assets in the region.

Like the Fayetteville, BHP expects a decline in production in the lower-margin Haynesville fields for 2016, as it continues to defer development for longer-term value.

## WOLFCAMP SHALE

BHP's production operation in the Permian consists of 0.2 million net acres and is primarily located in the western Texas county of Reeves, producing oil, gas and NGL.

The company's ownership interests range from 14% to 100%, and as of June 2015, it held an interest in about 81 gross wells and about 75 net wells, acting as JV operator for about 93% of its gross wells.

During 2015, the company's capex was $0.7 billion, an increase from 2014's $0.5 billion, resulting in 25 net development wells completed. In 2015, the operated rig count was three for the year, and average production was 30 MMcf/d gas, 10 Mbbl/d oil and condensate, and 4 Mbbl/d NGL.

Also in 2015, BHP sold its interest in its upstream Pecos Shale operation in the Permian for $75 million to concentrate on its core assets.

## EAGLE FORD SHALE

The Eagle Ford Shale in South Texas sits high atop the priority list among BHP's shale plays in the U.S.

The company's production operation is located primarily in the southern Texas counties of DeWitt, Karnes, McMullen and LaSalle, and it produces oil, condensate, gas and NGL from two fields: Black Hawk and Hawkville.

BHP's 2015 capex in the Eagle Ford, $2.1 billion, was $1 billion less than it was in 2014, and it was primarily related to drilling and completion activities, resulting in 188 net development wells, according to its 2015 annual report. The 2015 operated rig count was seven.

For 2016, BHP expects to reduce drilling costs to $2.5 million per well in the Black Hawk Field.

The Black Hawk acreage comprises 0.1 million net acres, and BHP's ownership interests range from 5% to 100%, with a majority of its interest (50% share) held with Devon Energy.

As of June 2015, the company held an interest in about 772 gross wells and about 427 net wells, acting as a JV operator for about 15% of its gross wells.

The average production in Black Hawk for 2015 was 130 MMcf/d gas, 82 Mbbl/d oil and condensate, and 24 Mbbl/d NGL.

BHP's Hawkville acreage comprises 0.2 million net acres, and its ownership interests range from 9% to 100%. As of June 2015, it held an interest in about 494 gross wells and about 409 net wells, acting as a JV operator for about 84% of its gross wells.

The average production in Hawkville for 2015 was 168 MMcf/d gas, 15 Mbbl/d oil and condensate, and 17 Mbbl/d NGL.

Like the Fayetteville and Haynesville, BHP expects a decline in production in the lower-margin, gassy Hawkville for 2016, as it continues to defer development for longer-term value.

## Cabot Oil & Gas Corp.

- **Appalachian veteran**
- **Eagle Ford growth company**

Cabot remains committed to its strategy in the Marcellus and Eagle Ford shales and foresees an overall production growth of 10% to 18% in 2015, despite a reduction in capital spending of 50% over 2014.

### MARCELLUS SHALE

Cabot calls its Marcellus operations the "cornerstone asset of its portfolio," a position the play has held since the company started drilling horizontal wells in northeastern Pennsylvania in 2008.

Cabot has about 200,000 net acres in the dry gas window of the Marcellus, primarily in Susquehanna County, Pa., with more than 3,000 locations. Its properties in the shale accounted for 89% of Cabot's proved reserves and 90% of its total net production as of year-end 2014.

Cabot planned to drill about 80 net wells in the Marcellus during 2015, with about 60% of the company's capital program allocated to the region.

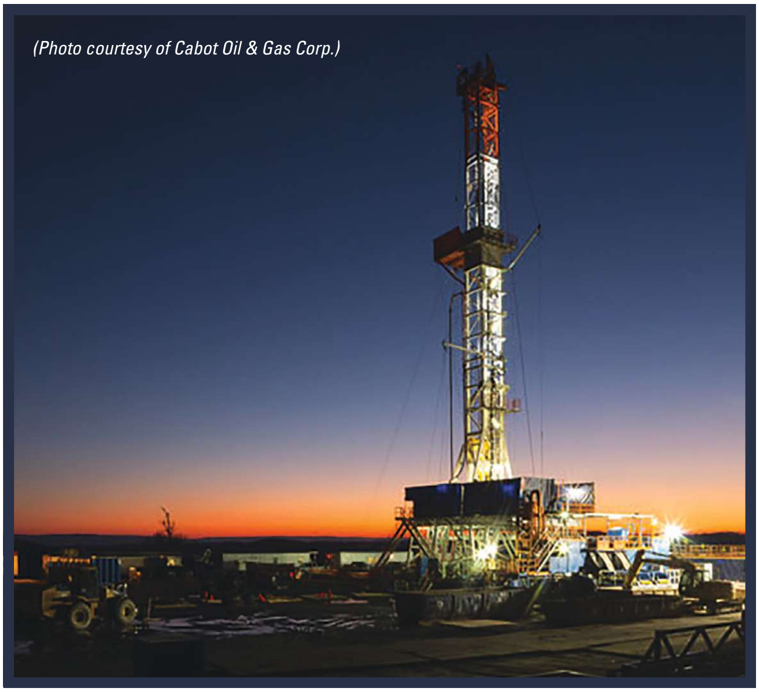
As of November 2015, Cabot had three rigs in the Marcellus and expected to reduce the number of rigs to two by year-end 2015, according to an investor presentation.

In its third-quarter 2015 report, Cabot provided a fourth-quarter net production guidance of 1,475 MMcf/d to 1,600 MMcf/d for natural gas, as it continues to curtail a portion of its Marcellus production, and 14,000 bbl/d to 15,500 bbl/d for liquids.

Based on cost reductions, improved operating efficiencies and longer planned lateral lengths, Cabot's best-in-class Marcellus assets generate about 70% internal rate of return at a realized price of $2 per MMBtu.

Cabot expects its drilling activity in the Marcellus to decrease to about 50 net wells in 2016, a decision that is based on lower anticipated natural gas prices throughout Appalachia, the company reported. Cabot anticipates completing about 90 wells in 2016, as well.

Cabot calls its Marcellus operations the "cornerstone asset of its portfolio."


(Photo courtesy of Cabot Oil & Gas Corp.)

### EAGLE FORD SHALE

Cabot's drilling activity in the Eagle Ford is focused on its 89,000 net acres and more than 1,300 locations, primarily located in Atascosa and Frio counties, Texas, with about 40,000 net acres of its position added in 2015 through a combination of bolt-on acquisitions and grassroots leasing efforts, according to the company's website.

Cabot is operating three rigs in the Eagle Ford and planned to decrease to one rig by year-end 2015 in response to lower commodity prices.

The company planned to drill about 50 net wells in 2015, with about 40 net wells completed and with 40% of the company's capital allocated to the region. It anticipated between 20 and 25 wells in backlog by year-end 2015.

Cabot's best-in-class Eagle Ford assets generate about 40% internal rate of return at $55 per barrel West Texas Intermediate price.

The company projected a 51% to 55% net liquids production growth in the Eagle Ford for 2015.

For 2016, Cabot expects to drill about 10 net wells in the Eagle Ford and complete 25 net wells, while the average net liquids production is expected to be flat to fourth-quarter 2015 levels.

## Chesapeake Energy Corp.

- **New record lateral length, cycle time in Utica**
- **Larger completions in Eagle Ford**

Chesapeake's focus on cost efficiencies continues to generate reductions in production expenses.

The company is voluntarily curtailing production in some areas in 2015.

### MARCELLUS SHALE

Chesapeake has 230,000 net acres and more than 750 locations in the Marcellus, where net production averaged about 809 MMcf/d (1.77 gross operated Bcf/d) during third-quarter 2015, a decrease of 1% over the previous quarter.

The company has been cutting production in the area since first-quarter 2015, primarily due to weak in-basin gas prices, according to its third-quarter 2015 report. The company expected to maintain curtailments for the remainder of 2015.

Average completed well costs, as of November 2015, were $6.4 million, with an average completed lateral length of 6,800 ft and 29 frack stages, compared to the full-year 2014 average completed well cost of $7.5 million, with an average completed lateral length of 6,000 ft and 27 frack stages.

Third-quarter 2015 well results included two tests of the Upper Marcellus Formation located in Bradford County, Pa., which had completed lateral lengths of 5,600 ft and 4,800 ft, respectively, and reached peak 24-hour production rates of about 19,000 Mcf/d and 17,000 Mcf/d, respectively. The company believes that these successful completions could provide more than 1,000 potential new drilling locations.

Operated rig count in the Marcellus averaged one rig in third-quarter 2015, and the company anticipated maintaining that count through year-end 2015.

### UTICA SHALE

Chesapeake has about 835,000 net acres and more than 500 drilled locations in the Utica, where the company's net production averaged about 106 Mboe/d (183 gross operated Mboe/d) during third-quarter 2015, a decrease of 15% over the previous quarter, as the company voluntarily curtailed about 20 net Mboe/d during the quarter as a result of weak product pricing.

Average completed well costs as of November 2015 were $7.7 million, with an average completed lateral length of 7,900 ft and 40 frack stages, compared to the full-year 2014 average completed well cost of $7.2 million, with an average completed lateral length of 6,200 ft and 29 frack stages.

Notably, during third-quarter 2015, Chesapeake drilled a new record lateral length in the Utica of 12,976 ft. Also, the average cycle time for Utica wells drilled in the third quarter was 9.9 days, with a record cycle time of 6.8 days.

The operated rig count in the Utica averaged two rigs in third-quarter 2015, and the company anticipated maintaining two operated rigs through year-end 2015.

### NIOBRARA SHALE

Chesapeake, one of the largest operators in the Powder River Basin, has 388,000 net acres and 150 drilled locations in the Niobrara, where net produc-


YOU CAN MEET YOUR TARGETS.
OR BE ONE.

tion averaged about 21 Mboe/d (31 gross operated Mboe/d) during third-quarter 2015, an increase of 5% over the previous quarter.

Average completed well costs, as of November 2015, were $10.6 million, with an average completed lateral length of 5,900 ft and 22 frack stages, compared to the full-year 2014 average completed well cost of $10.6 million, with an average completed lateral length of 5,400 ft and 20 frack stages.

Well results for third-quarter 2015 include the Barton 32-34-67 USA A 1H, which was placed on production in October with a completed lateral length of 9,500 ft and reached a peak 24-hour production rate of 1,500 boe/d (85% black oil).

Operated rig count in the Powder River Basin averaged one rig in third-quarter 2015, and the company released all operated rigs in the area through year-end 2015.

**Notably, during third-quarter 2015, Chesapeake drilled a new record lateral length in the Utica of 12,976 ft.**

## MIDCONTINENT FORMATIONS

Chesapeake's two prime plays in the Anadarko Basin are the Mississippi Lime and the Granite Wash in the company's home state of Oklahoma, where the company holds 2 million net acres and 1,500 drilled locations.

Net production in the Mississippi Lime averaged about 31 Mboe/d (74 gross operated Mboe/d) during third-quarter 2015, a decrease of 1% over the previous quarter.

Average completed well costs as of November 2015 were $2.8 million, with an average completed lateral length of 4,500 ft and nine frack stages, compared to the full-year 2014 average completed well cost of $3 million, with an average completed lateral length of 4,450 ft and nine frack stages.

During third-quarter 2015, Chesapeake drilled a record lateral length of 9,395 ft in the JJJ 23-25-11 1H well, and it also drilled its first multilateral well in the Mississippi Lime.

The company placed 13 wells on production during third-quarter 2015, compared to 44 wells in third-quarter 2014.

Operated rig count in the Mississippi Lime averaged three rigs during third-quarter 2015, and the company released all operated rigs in the area through year-end 2015.

In the Oklahoma STACK, Chesapeake drilled its first two wells targeting the Meramec Formation in third-quarter 2015 and was in the process of drilling a third well.

The company expected to keep one operated rig in the STACK area through year-end 2015.

## HAYNESVILLE SHALE

Chesapeake has 387,000 net acres and 800 drilled locations in Louisiana's Haynesville, where net production averaged about 636 MMcf/d (1.03 gross operated Bcf/d) during third-quarter 2015, a decrease of 5% over the previous quarter.

Average completed well costs, as of November 2015, were $7.7 million, with an average completed lateral length of 5,000 ft and 14 frack stages, compared to the full-year 2014 average completed well cost of $8.4 million, with an average completed lateral length of 4,900 ft and 14 frack stages.

Chesapeake placed seven wells on production during third-quarter 2015, compared to 14 wells in the same quarter in 2014.

Operated rig count in the Haynesville averaged six rigs in third-quarter 2015, and the company expected to maintain six operated rigs through year-end 2015.

## EAGLE FORD SHALE

Chesapeake's largest investment area is the Eagle Ford in South Texas, where it has 449,000 net acres and 1,100 drilled locations.

Net production in the Eagle Ford averaged about 108,000 boe/d (234 gross operated Mboe/d) during third-quarter 2015, an increase of 3% over the previous quarter.

Average completed well costs, as of November 2015, were $5.3 million, with an average completed lateral length of 6,000 ft and 21 frack stages, compared to the full-year 2014 average completed well cost of $5.9 million, with an average completed lateral length of 5,850 ft and 18 frack stages.

In 2015, Chesapeake focused on realizing efficiencies with longer laterals and larger completions in the Eagle Ford. Third-quarter 2015 well results included the Rogers E-1H and Faith San Pedro F-4H wells, which had completed lateral lengths of 12,488 ft and 13,151 ft, respectively, and reached peak 24-hour production rates of 1,479 bbl/d and 1,067 bbl/d of oil, respectively. These two long-lateral wells had an average field estimated completed well cost of $7.8 million each.

The JEA Unit XIV LAS S 4H East Four Corners well also was completed in third-quarter 2015 using an enhanced design on a 4,611-ft completed lateral and reached a peak 24-hour rate of 1,311 bbl/d of oil. The field estimated completed well cost of this well was $4.8 million.

Chesapeake placed 30 wells on production during third-quarter 2015, compared to 89 wells in the same quarter in 2014.

The company's operated rig count in the Eagle Ford averaged three rigs in third-quarter 2015, and the company expected to maintain three operated rigs through year-end 2015.

## Chevron

- **Top producer in San Joaquin Basin**
- **Permian is a bright spot**

Chevron has some of the biggest positions and impressive production numbers in the shale plays it operates in, but even for a supermajor, 2015 was a tough year.

The company's U.S. upstream operations incurred a loss of $603 million in third-quarter 2015 compared to earnings of $929 million at the same time in 2014.

### PERMIAN BASIN

Chevron is the largest net acreage leaseholder and one of the largest producers in the Permian Basin of West Texas and southeastern New Mexico, where operations date back to 1926.

As of 2015, total net production has surpassed 5 Bboe.

The company has about 500,000 net acres in the Midland Basin, and in 2014, drilled 176 company-operated wells, and eight rigs on company-operated wells were active at year-end. The company also participated in 206 nonoperated wells during 2014, with 11 rigs active at year-end.

Chevron is the largest acreage holder in the Delaware Basin, with about 1 million net acres.

In 2014, the company drilled 29 company-operated wells, and three rigs were active at year-end on company-operated wells. It also took part in 139 nonoperated wells in 2014, with eight rigs active at year-end.

Chevron saw about 20% to 50% cost reductions for major well spend categories in the company's 2015 horizontal drilling program in the Permian, according to an investor presentation in September 2015.

In 2015, footage per day increased more than 15%, frack stages per day increased by 20% and recovery estimates increased by 30%.

In addition, Chevron saw about 3,000 prospective well locations across five benches lower than $50 per barrel West Texas Intermediate breakeven.

### MARCELLUS SHALE

Chevron is a significant leaseholder in the Marcellus and Utica shales, primarily located in southwestern Pennsylvania, eastern Ohio and the West Virginia panhandle as well as in the Antrim Shale and Collingwood/Utica Shale in Michigan.

In 2014, the company's net production in these areas averaged 269 MMcf/d of natural gas, and capital spending during 2014 was focused on the Marcellus.

Chevron has 718,000 net acres in the Marcellus, and 85 development wells were drilled during 2014. The company had four drilling rigs in operation at year-end 2014.

### UTICA SHALE

In the Utica, Chevron has about 364,000 net acres, and six exploratory wells were drilled in 2014 to acquire data necessary for potential future development.

In Michigan, the company holds about 458,000 net acres in the Antrim Shale and Collingwood/Utica Shale formations. Production comes from about 2,800 wells in the Antrim.

### SAN JOAQUIN BASIN

At 177,000 bbl/d in 2014, Chevron is California's largest producer in net oil equivalent. The majority of the company's operated leases are part of three major crude oil fields in the San Joaquin Valley—Kern River, Midway Sunset and Cymric—although Chevron also operates and holds interests in San Ardo, Coalinga and Lost Hills fields.

Net production in 2014 averaged 163,000 bbl/d of crude oil, 66 MMcf/d of natural gas and 3,000 bbl/d of NGL.

Chevron drilled 779 new wells in 2014, and it planned to drill 520 more new wells in 2015.

Heavy oil makes up about 86% of the crude oil production in the San Joaquin, so the company uses steam injection to make oil flow more easily, which, coupled with its drilling program has reversed the decline rate on company-operated properties from 7% in 2010 to essentially flat in 2014, according to the company's website.

Chevron also holds a nonoperated working interest of about 23% in four producing zones at the Elk Hills Field. Net production averaged 8,000 bbl/d of crude oil, 43 MMcf/d of natural gas and 3,000 bbl/d of NGL in 2014.



## Cimarex Energy Co.

- **First 10,000-ft lateral in Meramec Formation**
- **Delineation in Wolfamp underway**

Cimarex started operations in the Midcontinent and, even though it spread its operations into the Permian Basin, still sticks to its origins.

### WOODFORD SHALE

The Cana Woodford in western Oklahoma gives Cimarex its main area of operations. It drilled its first horizontal well there in 2007 and started a multiwell drilling program five years later.

Activity in the Midcontinent region in third-quarter 2015 was focused in the Cana area, where 52 gross (10 net) wells were completed and brought on production. By the end of the third quarter, 53 gross (22 net) wells were waiting on completion.

Production from the Cana area averaged 32.16 MMcfe/d, representing 33% of total company production in third-quarter 2015, while total Midcontinent production averaged 405.3 MMcfe/d.

In the Meramec Formation, Cimarex completed its first 10,000-foot lateral. The Clayton 1HX had an average 30-day IP peak rate of 16 MMcfe/d (57% gas, 28% NGL and 15% oil). In addition, the company has 11 5,000-ft Meramec wells on production that have an average 30-day IP gross peak rate of 9.3 MMcfe/d (47% gas, 29% oil and 24% NGL).

### WOLFCAMP SHALE

Cimarex's production from the Permian region, where it has strong land positions with multiple horizontal drilling opportunities in the Wolfcamp, Avalon and Cisco/Canyon Shale, averaged 562.4 MMcfe/d in third-quarter 2015, a 38% increase over the same quarter in 2014.

Quarterly oil volumes increased 24% year-over-year to 42,367 bbl/d and accounted for 45% of the region's total production for third-quarter 2015.

The company completed and brought on production four gross (four net) wells in the region during third-quarter 2015. At the end of September

2015, there were seven gross (five net) wells waiting on completion in the Delaware Basin.

Cimarex is in the process of delineating the Wolfcamp Shale, with first development planned for 2016. The company had 13 long-lateral Wolfcamp D wells producing in Culberson County, Texas, in third-quarter 2015, up from two from the previous quarter. The 10,000-ft laterals had an average 30-day IP gross peak rate of 2,308 boe/d (46% gas, 29% NGL and 25% oil).

## Concho Resources Inc.

- **Commitment to horizontal drilling**
- **Delaware Basin production up 60%**

Concho Resources Inc. planned to spend about 90% of its capital budget in 2015 on drilling and completion activities on horizontal drilling opportunities.

### WOLFCAMP SHALE

Concho has property positions and operations in both the Delaware and Midland basins, where it has 635,000 and 330,000 gross areas, respectively.

At year-end 2014, the company had estimated proved reserves in the Delaware Basin of 243.8 MMboe, representing 38.3% of its total proved reserves and 42.8% of its PV-10.

In 2015, the company planned to spend $1.3 billion, or 72%, of its drilling and completions capital budget on its Delaware Basin assets, with 100% of its wells to be drilled horizontally, according to its 2014 annual report.

Production from horizontal wells in the Delaware Basin was 88.5 Mboe/d in third-quarter 2015, up 60% over the same quarter in 2014 and 8% over second-quarter 2015.

Concho drilled 45 wells, including 27 wells targeting the Bone Spring Sands, 11 wells targeting the Wolfcamp Shale and seven wells targeting the Avalon Shale.

Concho added 51 new horizontal wells in the northern Delaware Basin with at least 30 days of production as of the end of third-quarter 2015. The average peak 30-day and 24-hr rates for these wells were 966 boe/d (72% oil) and 1,471 boe/d, respectively. The average lateral length for these 51 wells reached a record for the company in the northern Delaware Basin at 5,158 ft, including 10 long-lateral wells averaging 8,782 ft.

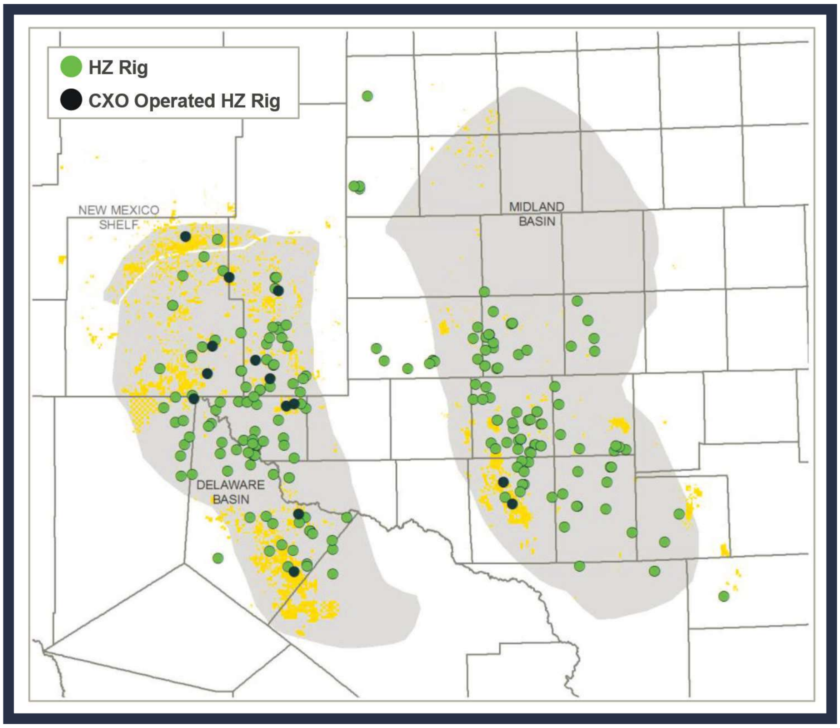
Concho added 10 new horizontal wells in the southern Delaware Basin with at least 30 days of production as of the end of third-quarter 2015. The average peak 30-day and 24-hr rates for these wells were 1,188 boe/d (76% oil) and 1,537 boe/d, respectively. The average lateral length for these wells was 5,991 ft, up about 7% year-over-year, while drilling days are down 20% year-over-year to an average of about 30 days per well.

As of November 2015, the company had 10 horizontal rigs in the Delaware Basin, with eight horizontal rigs in the northern Delaware Basin and two horizontal rigs in the southern Delaware Basin.

At year-end 2014, the company had estimated proved reserves of 145.4 MMboe in the Midland Basin, accounting for 22.8% of the company's total proved reserves and 19.3% of its PV-10 value.

In 2015, Concho planned to spend about $300 million, or 17%, of its drilling and completions capital budget in the Midland Basin, expecting

Concho has an intense focus on the Permian Basin, according to a September 2015 investor presentation. *(Image courtesy of Concho Resources Inc.)*



At right: ConocoPhillips holds 220,000 net acres, primarily in DeWitt, Karnes and Live Oak counties in Texas.

that about 39% of the wells in the region would be drilled horizontally.

As of November 2015, the company had eight new wells in the Midland Basin with at least 30 days of production. The average peak 30-day and 24-hr rates for these wells were 967 boe/d (81% oil) and 1,300 boe/d, respectively, from an average lateral length of 6,705 ft.

The company had two horizontal rigs in the Midland Basin in third-quarter 2015.

### NEW MEXICO SHELF

At year-end 2014, Concho had estimated proved reserves in the New Mexico Shelf, where it has 160,000 gross acres, of 247.8 MMboe, which represents a 38.9% of its total proved reserves and 37.9% of its PV-10.

In 2015, Concho planned to spend about $200 million, or 11%, of its drilling and completions capital budget on its New Mexico Shelf assets, expecting 52% of the wells to be drilled horizontally.

In third-quarter 2015, the company added 13 new horizontal wells with at least 30 days of production. The average peak 30-day and 24-hr rates for these wells were 294 boe/d (84% oil) and 389 boe/d, respectively.

Concho had one horizontal rig on the shelf as of November 2015.

## ConocoPhillips Co.

- **North to south shale interests**
- **Bakken and Eagle Ford sweet spots**

From gas supplies for LNG to high liquids content, ConocoPhillips paces its drilling.

### BAKKEN SHALE

The Bakken, along with the Eagle Ford, are the brightest spots in ConocoPhillips' shale inventory. It controls some 620,000 net acres, which includes about 430,000 net mineral acres and about 190,000 net leasehold acres.

In 2014, net production in the Bakken averaged 50 Mboe/d, and there were 400 operated wells online at year-end.

The company has a net resource of 0.6 Bboe in the region and is developing its assets at 160-acre combined spacing, according to an investor overview in November 2015.

(Photo courtesy of ConocoPhillips)

At year-end 2014, ConocoPhillips had more than 400 operated wells online, and it had an average of five operated rigs in the Bakken in 2015.

### WOLFCAMP SHALE

ConocoPhillips has property positions in the Delaware and Midland basins, holding about 1.1 million net acres.

In 2014, it drilled 166 wells in numerous plays, and net production was 58 Mboe/d.

In 2015, the company planned to have development drilling focus on the Central Basin Platform and Delaware Basin.

ConocoPhillips estimated about 100 million net acres of stacked play opportunity and 1 Bboe net resource, according to an investor overview.

An average of two rigs operated in the region in 2015.

### EAGLE FORD SHALE

The company holds 220,000 net acres, primarily in DeWitt, Karnes and Live Oak counties in Texas.

At year-end 2014, ConocoPhillips had more than 800 wells online, and net production averaged 155 Mboe/d.

In 2015, the company planned a continuation of full-field development in the Eagle Ford, with

the majority of its program there to be drilled on multiwell pads at 80-acre high/low spacing.

ConocoPhillips also planned to further develop more than 3,000 identified drilling locations and about 2.5 Bboe of resources.

In 2015, the company was testing triple stack development potential and had an average of seven rigs operating.

## Continental Resources Inc.

- **Drilling costs down in Bakken**
- **SCOOP production is up**

Continental Resources dipped its investment resources in several shale plays, but its favorites are the Bakken/Three Forks and the South Central Oklahoma Oil Province (SCOOP).

The company's drilling and completion costs for most operated wells have declined on average about 25% since year-end 2014, due to lower service costs and operational efficiency gains.

### BAKKEN SHALE

Continental Resources Inc. is the largest acreage holder in the Bakken/Three Forks play with 1.1 million net acres, most of it in North Dakota and some in Montana.

Continental's Bakken production averaged 135,609 boe/d in third-quarter 2015, an increase of 12% compared with third-quarter 2014 and a decrease of 4% compared with second-quarter 2015. The company completed 35 net (160 gross) operated and nonoperated Middle Bakken and Three Forks wells during third-quarter 2015.

As of November 2015, Continental had 123 gross operated wells drilled and waiting on first production in the Bakken, compared to 95 at the end of second-quarter 2015. This reflects the deferral of completion activities that started in third-quarter 2015 and completed wells that have not yet begun production. The company expected to decrease this total to about 115 gross operated wells drilled and waiting on first production by year-end 2015.

In addition, as of third-quarter 2015, Continental was operating eight rigs in the Bakken and had no completion crews active.

As of November 2015, the estimated drilling and completion cost in the Bakken had decreased to $7 million per operated well, compared with $9.6 million per operated well at year-end 2014. The company set multiple new Continental performance records in third-quarter 2015. For example, the company reduced average drilling time for spud-to-total-depth by 15%, compared to the average in first-quarter 2015.

Additionally, the new lateral drilling records also were set in third-quarter 2015, with the most recent drilled being a 9,495-ft lateral in 2.4 days.

### WOODFORD AND SPRINGER FORMATIONS

Continental Resources has Woodford properties in the Arkoma and Anadarko basins in Oklahoma and in the SCOOP play. The company has 315,675 net acres of land in the Anadarko Basin Woodford, which makes it one of the largest acreage holders in that play. That includes the SCOOP, but the company also has other pay zones in southcentral Oklahoma, including the Springer.

In third-quarter 2015, total SCOOP net production averaged 69,136 boe/d, an increase of 11% sequentially compared with second-quarter 2015 and 90% compared with third-quarter 2014. SCOOP production represented 30% of Continental's total production in third-quarter 2015, compared with 20% of company production for the same quarter in 2014.

During third-quarter 2015, the company completed 11 net (34 gross) operated and nonoperated wells, while operating an average of eight rigs in the SCOOP.

As of November 2015, Continental had 28 gross operated wells drilled and waiting on first production in SCOOP Woodford and Springer, compared to 22 at the end of second-quarter 2015, reflecting the deferral of completion activities that started in third-quarter 2015. The company expected this total to increase to about 35 gross operated wells drilled and waiting on first production by year-end 2015.

Continental had 15 rigs operating in Oklahoma and recently added two completion crews in the state, as of November 2015.

As with the Bakken, the company also continued to set new Continental records in third-quarter 2015, demonstrating the future potential for efficiency gains throughout the SCOOP and STACK plays.

## Devon Energy Corp.

- **Year-round drilling in Parkman Sand**
- **Cana-Woodford completions have begun**

Devon has played a pioneering role in the shale revolution since its acquisition of Mitchell Energy's Barnett Shale assets in North Texas in 2002. Devon has expanded its activity, working to make oil and gas volumes from shale formations more accessible with ongoing technical innovation and increasingly effective use of IT.

### PARKMAN SAND

The star of Devon's Powder River Basin properties in Wyoming is the Parkman Sand, although its wells also target the Turner and Frontier formations. The most significant production growth in the Rockies in 2015 has come from the Powder River Basin development activity, which is delivering some of the best rates of return in Devon's portfolio, according to its third-quarter 2015 operations report.

Oil production from the company's Rockies units, including the Wind River Basin, increased 61% in third-quarter 2015 over 2014. Devon attributes the strong results to the company's Powder River development program and the ramp-up of its Big Sand Draw $CO_2$ Project in the Wind River Basin.

Devon also saw lower operating costs in the Rockies, noting lease operating expenses declined 15% in third-quarter 2015 compared to the same quarter in 2014.

Third-quarter 2015 drilling activity was highlighted by four development wells in the company's Parkman focus area, where 30-day IP rates averaged about 1,300 boe/d, of which more than 90% was light oil.

Devon also achieved drilling efficiencies with its two rig lines in the Powder River Basin. During the six months ending in November 2015, extended-reach lateral drilling times improved by 11% to a low of 17 days in third-quarter 2015. The company also achieved a record-setting spud-to-rig release of just 14.5 days. As a result of productivity gains and further cost reductions across the supply chain, the company was targeting well costs of $7 million per well in the Parkman by year-end 2015.

The company believes future operational efficiencies also will be aided by a recent agreement Devon entered into with the Bureau of Land Management in 2015 that allows year-round drilling in its Parkman focus area.

**PERMIAN BASIN Q2 STATS**

| | Q2 2015 | Q2 2014 |
|---|---|---|
| Production: | | |
| Oil (MBOD) | 67 | 55 |
| NGL (MBLD) | 21 | 18 |
| Gas (MMCFD) | 152 | 134 |
| MBOED | 113 | 95 |
| E&P Capital (in millions): | $377 | |
| Operated Rigs (at 6/30/15): | 14 | |

*(Data courtesy of Devon Energy Corp.)*

### CANA-WOODFORD SHALE AND MERAMEC

Devon claims the largest land position in the Cana Woodford with more than half of the best acreage in the play. The Oklahoma-based company has about 280,000 net acres in Cana, which is part of the Anadarko Basin. Devon has about 3,200 gross producing wells in the basin that produced about 83 Mboe/d in third-quarter 2015, with 44% liquids.

In third-quarter 2015, net production averaged 83,000 boe/d, with nine rigs running.

In the Cana-Woodford Field, the company began completion operations with three frack crews at the beginning of third-quarter 2015, and in September, it tied in its first 14 operated wells from the Gordon Row.

As of November 2015, Devon was running three operated rigs in the Cana Woodford, and over the year, drilling times improved by about 42% to a record low of less than 24 days in third-quarter 2015.

Notably, the Cana-Woodford play was the most significant contributor to production in the Anadarko Basin, averaging 64,000 boe/d in third-quarter 2015, representing an 8% growth rate compared to second-quarter 2015 and exceeded the top end of guidance by 2,000 boe/d.

Devon expects to run as many as six rigs in the fourth quarter and bring online all the wells from its 7-section Gordon row, which is expected to drive a year-end exit rate in excess of 70,000 boe/d.

In addition, the company also is appraising the Meramec Formation, which sits directly above the Woodford Shale.

During third-quarter 2015, the company participated in seven Meramec wells, with five having at least 30 days of production history. Initial 30-day rates from these five appraisal wells averaged 1,430 boe/d, of which 37% was light oil. Since mid-2014, drilling times also have improved by 35% to an average spud-to-rig release of 23 days in third-quarter 2015.

**Devon claims the largest land position in the Cana Woodford with more than half of the best acreage in the play.**

Because of delineation in the region, Devon has identified 75,000 net acres in the oil and condensate windows of the Meramec and de-risked 500 locations, a 25% increase from a previous estimate.

Devon was scheduled to accelerate Meramec drilling by increasing activity to five rigs for the remainder of 2015, including reallocation of two operated Cana-Woodford rigs to the play.

### BARNETT SHALE

Devon holds the largest acreage position in the Barnett Shale play, with about 600,000 net acres and about 5,300 gross wells that produced 176 Mboe/d with 26% liquids in third-quarter 2015.

Devon's Barnett Shale operating costs totaled $1.25 per Mcfe in third-quarter 2015, as year-to-date operating costs declined by about $20 million compared to the same period in 2014.

Given the current commodity price environment, the company's operations are focused on enhancing existing well performance with an active refracturing program, artificial lift initiatives and line pressure reduction projects.

Devon restimulated 16 vertical wells during third-quarter 2015, with an average per-well production uplift of 725 Mcf/d. These results exceeded the company's type curve by nearly 50% and increased per-well production by about 700%.

The cost of vertical refracks has recently declined to as low as $270,000 per well, more than 30% below peak costs in 2014.

The company also is testing horizontal refracks.

### WOLFCAMP SHALE

Devon controls Wolfcamp Shale assets in the Delaware and Midland basins, both of which are part of the Permian Basin of West Texas and southeast New Mexico. Devon has 900,000 net acres in the Permian with about 7,800 gross wells that produced 105 Mboe/d (78% liquids) in third-quarter 2015.

In the Delaware Basin, net production averaged 61,000 boe/d in third-quarter 2015, a 32% increase compared to third-quarter 2014, and production in 2015 remains on track to once again deliver full-year growth of about 50%. Light oil reached nearly 70% of total Delaware Basin production.

The Delaware Basin production growth has been driven by outstanding well performance across the Bone Spring play, which in third-quarter 2015 had an average cumulative production per well over the first 60 days that increased about 40% compared to 2014.

The company brought online 12 new Bone Spring Basin wells during third-quarter 2015, and as a result of strong results from the Second Bone Spring interval, it raised Bone Spring Basin type curve expectations for its 2015 program. IPs for wells brought online in fourth-quarter 2015 were expected to be more than 10% higher than the previous estimate.

Devon also is appraising the Leonard Shale, which sits just above the Bone Spring Formation at a depth of 9,000 ft.

The company began production on three Leonard Shale wells in third-quarter 2015, and 30-day IP rates from these wells averaged 1,200 boe/d (74% was light oil).

Overall, Devon projected fourth-quarter 2015production in the Delaware Basin to exceed

**Permian Program: Key Modeling Statistics**

| | Glasscock | | Howard A | Martin | | Midland/Upton | | |
|---|---|---|---|---|---|---|---|---|
| | Wolfcamp A | Wolfcamp B | Wolfcamp A | Lower Spraberry | Wolfcamp B | Wolfcamp A | Wolfcamp B | Wolfcamp C |
| Gross Inventory (#) | 430 | 230 | 405 | 210 | 250 | 545 | 390 | 400 |
| Gross HZ 2015 Wells (#) | 12 | 4 | 14 | 10 | 2 | 4 | 18 | 1 |
| WI % | 85 | 85 | 90 | 96 | 96 | 89 | 89 | 89 |
| IP30 (bbls/d) | 950 | 700 | 875 | 900 | 800 | 775 | 900 | 725 |
| EUR/Well (MBOE) | 970 | 700 | 880 | 875 | 790 | 800 | 875 | 700 |
| $D_i$ (decline factor)* | 84% | 84% | 84% | 82% | 84% | 84% | 84% | 84% |
| b-factor* | 1.4 | 1.4 | 1.4 | 1.2 | 1.4 | 1.4 | 1.4 | 1.4 |
| Average Lateral Length (ft.) | 7,500 | 7,500 | 8,000 | 7,000 | 7,000 | 6,000 | 6,000 | 6,000 |
| D&C Well Cost $MM | 6.3 | 6.4 | 6.4 | 6.9 | 7.3 | 6.2 | 6.4 | 6.5 |

*(Data courtesy of Encana Corp.)*

65,000 boe/d, a projected increase of more than 40% from fourth-quarter 2014.

### EAGLE FORD SHALE

DeWitt and Lavaca counties in South Texas host Devon's 72,000 net acres of Eagle Ford properties. The company has de-risked the DeWitt County properties and found encouraging wells in Lavaca County, its least mature acreage from a drilling standpoint, according to Devon's website.

The company had about 900 gross wells and a production of 113 Mboe/d (77% liquids) in third-quarter 2015, which exceeded guidance by 13,000 boe/d representing a 43% increase in production compared to third-quarter 2014.

Devon added 53 Lower Eagle Ford wells to production in third-quarter 2015 with 30-day rates averaging an all-time quarterly high of 2,300 boe/d, exceeding the company's IP expectations by about 40%.

Devon also realized efficiencies with its drilling and completion operations in DeWitt County. Since 2014, drilling times have improved by about 40% to an average of 15 days per well, with leading wells reaching target depth in as few as eight days. And since 2014, the company has improved frack stage times by up to 65% and reduced equipment move times by 20%.

In fourth-quarter 2015, Devon was scheduled to run five rigs and two completion crews in the Eagle Ford, which is expected to result in roughly flat net production with third-quarter 2015.

## Encana Corp.

- **Focusing on four core assets**
- **Eagle Ford shines on all fronts**

After completing about $18 billion in acquisitions and divestitures activity in 2014, Encana placed about 80% of its 2015 capital program on its four most strategic growth assets: the Permian Basin, Eagle Ford, Montney and Duvernay.

### WOLFCAMP SHALE

Encana entered the Permian Basin in September 2014 with its purchase of Athlon Energy, acquiring 140,000 net acres, for $7.1 billion.

The company's 2015 horizontal program focused on the Wolfcamp A, B, C and Lower Spraberry, and it ran as many as six horizontal and seven vertical rigs during the year.

As of November 2015, Encana had drilled 52 horizontal and 90 vertical wells for the year and expected to drill 16 horizontal and 20 verticals in the fourth quarter.

In fourth-quarter 2015, the company expected to produce 50 Mboe/d, with 63% oil/field condensate, 20% NGL and 17% natural gas.

Encana had drilling and completion costs down $2 million per well since the acquisition in 2014. The drilling and completion costs of $6.4 million per well in third-quarter 2015 were down 9% from the previous quarter.

### EAGLE FORD SHALE

Encana also bought 43,200 net acres of land, largely in the Karnes Trough, in the core of the Eagle Ford play from Freeport-McMoRan for $3.1 billion in May 2014.

The company had two to three rigs operating during 2015 and drilled 51 horizontal wells as of November 2015. Encana expected to drill 14 horizontal wells and produce 57 Mboe/d, with 73% oil/field condensate, 12% NGL and 15% natural gas in fourth-quarter 2015.

Since acquiring the acreage in 2014, Encana has seen a 26% increase in production, a 33% decline in drilling and completion costs, a 55% increase in well inventory, an increase in average IP30 from up to 1,000 boe/d to up to 1,800 boe/d, and a 30% to 60% type curve improvement, according to a corporate presentation in November 2015.

The company had an average drilling and completion cost of $5.4 million per well in third-quarter 2015, which beat the $5.6 million well cost target for the second quarter. In addition, completion days dropped 42% to 3.5 days.

The third-quarter 2015 production of 54 Mboe/d was up 18% since the second quarter and included the successful ramp-up of the Patton Trust South facility.

### DUVERNAY SHALE

Encana sees huge potential growth in the Duvernay, where it has 335,000 net acres capable of producing about 50,000 boe/d.

The company had three to four rigs operating during 2015 and drilled nine horizontal wells as of November 2015. Encana expected to drill five horizontal wells and produce 17 Mboe/d, with 52% oil/field condensate, 3% NGL and 46% natural gas in fourth-quarter 2015.

Encana is driving down costs in the Duvernay. Since 2013, wells are drilled 41% faster, and the company has seen savings of about $3 million per well.

Since 2013, wells are completed 40% faster, saving about $7 million per well.

The company saw third-quarter 2015 production of 9.3 Mboe/d, an increase of 59% since the second quarter.

### MONTNEY SHALE

Encana sees 25-plus years of low-cost drilling inventory in the 590,000 net acres of land it has in the most proven region of the Montney fairway.

The company had one to two rigs operating during 2015 and had drilled 14 horizontal wells as of November 2015. Encana expected to drill two horizontal wells and produce 146 Mboe/d, with 3% oil/field condensate, 13% NGL and 84% natural gas in fourth-quarter 2015.

In the Mid-Montney, where Encana has 130 wells in inventory, four new condensate wells were completed in Tower in third-quarter 2015.

By year-end 2018, Encana is expecting 50,000 bbl/d of liquids in the Montney, where there are more than 1,500 oil and condensate wells in inventory.

## EOG Resources Inc.

- **Biggest producer in the Eagle Ford**
- **Expanded acreage in Delaware**

EOG Resources makes money by moving into plays early, gathering prime land, identifying more production on existing land and generating new plays internally. That philosophy has put it in plays all over the U.S., and the company added 26,000 net acres in the Delaware Basin, including 750 boe/d for $368 million, in third-quarter 2015.

The company planned to focus on the Eagle Ford, Bakken and Delaware Basin and produce flat year-after-year production in 2015, as well as strategically defer completions.

### EAGLE FORD SHALE

EOG is the largest acreage holder and oil producer in the Eagle Ford, with about 561,000 net acres in the region (91% of which is HBP) and 5,500 remaining locations. At year-end 2014, the company had produced in excess of 1 Bbbl of crude oil and condensate and completed 534 net wells. Year-end 2014 net production was about 203,000 Mbbl/d of crude oil and condensate.

In 2015, the company expected to complete about 345 net wells. As of third-quarter 2015, EOG had an average of 15 rigs operating and had completed about 300 net wells.


EOG planned to focus on the Eagle Ford, Bakken and Delaware Basin and produce flat year-after-year production in 2015, as well as strategically defer completions. *(Data courtesy of EOG Resources Inc.)*

The company was using multiwell pad development to improve capital efficiency in 88% of its third-quarter 2015 completions.

In 2015, EOG expanded high-density completions to about 95% of its wells.

## WOLFCAMP SHALE

After acquiring 26,000 net acres, including 750 boe/d net production in the Delaware Basin for $368 million, the company has 256,000 net acres in the region. EOG also has an estimated 4,900 drilling locations, 260 drilling years and a resource potential of 2,350 MMboe in the Delaware, according to its third-quarter 2015 report.

In 2014, EOG completed 62 net wells in the Permian Basin, where it has 420,000 net acres overall, to develop its liquids-rich Leonard, Wolfcamp and Second Bone Spring Sand plays.

The company controls some 234,000 net acres of land in the Delaware Basin Wolfcamp play where it has a drilling site inventory of more than 75 years at the 2014 rate of 14 net wells.

In third-quarter 2015, EOG had 2,050 net drilling locations in the Wolfcamp Shale and planned about 35 net well completions for the year. The company's Wolfcamp wells had 4,500-ft average lateral lengths with about 700-ft spacing.

In the Second Bone Spring Sand, the company had 109,000 net acres prospective and 1,250 net drilling locations and had completed about 35 net wells, with an average 850-ft spacing, as of third-quarter 2015.

In the Leonard Shale, where the company had 91,000 net acres, more than 1,600 net drilling locations and an estimated reserve potential of 550 MMboe net, EOG had completed about 10 wells net by the end of third-quarter 2015.

## BAKKEN SHALE AND PARKMAN

EOG controls about 120,000 net acres of land in the core area of the Bakken/Three Forks Shale play and Antelope extension of the play.

For 2014, net average production for the entire Rockies was about 35 net wells, primarily in the Williston Basin Bakken and, to a lesser extent, in the Powder River Basin, according to the company's 2014 annual report.

EOG has 590 net remaining locations in the Bakken core, an estimated 14 years of drilling and a resource potential of 360 MMboe net.

In third-quarter 2015, the company had two rigs operating in the Bakken/Three Forks core and had completed about 25 net wells for the year compared to 59 net wells in 2014.

In the Powder River Basin, the company has 63,000 net acres, including 30,000 acres in the Parkman zone, and has 275 remaining locations, 13 years of drilling and a resource potential of 190 MMboe.

## Exxon Mobil Corp./XTO Energy Co.

- **3.8 million acres in Texas**
- **Still acquiring in Permian**

XTO has established strong positions in some of the best shale plays in North America, and they're still acquiring land in attractive areas, particularly the Midland Basin.

### MARCELLUS SHALE/PENNSYLVANIA

The company controls about 576,000 acres of land in southeastern, central and northwestern Pennsylvania, although the company does not single out how much of that is in the Marcellus Shale. That property produces 240 MMcf/d, and the company is running one rig for development.

### UTICA SHALE

XTO has about 81,000 acres in two counties in eastern Ohio that produce 40 MMcf/d on one to three rigs.

### BAKKEN SHALE

Both North Dakota and Montana contribute Bakken and Three Forks properties to XTO. The company leases about 534,000 acres in the play in Colorado that produces 85 bbl/d of oil on zero to one rig. In North Dakota, the company has about 515,000 acres that produce 77 Mbbl/d on five to 14 rigs. In Montana, XTO has about 272,000 acres and produces 6 Mbbl/d on zero to one rig.

### NIOBRARA SHALE

By XTO's estimate, the Piceance Basin in Colorado, where it holds about 534,000 acres in three separate counties across the state, contains trillions of cubic feet of gas.

About 85 bbl/d of oil is being produced with zero to one rig.

### FAYETTEVILLE SHALE

The company is running only one rig on its about 792,000 acres in 15 counties in the Fayetteville Shale in Arkansas. It produces 434 Mcf/d of gas.

### HAYNESVILLE SHALE

Although XTO doesn't break out the Haynesville Shale properties, it holds about 675,000 acres of leases in an area that includes Haynesville and the Bossier-Cotton Valley production in East Texas and Louisiana. It's running zero to one rig on its properties in 13 counties and produced about 3 Mbbl/d.

### BARNETT, EAGLE FORD AND PERMIAN SHALES

XTO does not single out its total 3.8 million acres in Texas among the three shale plays on its website. However, since January 2014, it has executed five agreements in the Permian's Midland Basin that increased its position to more than 135,000 acres.

About 60 Mbb/d is being produced with 20 to 22 rigs in 78 counties across Texas.

## Hess Corp.

- **A two-play specialist**
- **Reductions in the works**

Hess effectively opened the Williston Basin with the first commercial production, and it drilled the first well to the Bakken Shale on the Bakken Farm in North Dakota.

It's using lessons from its Bakken experience to develop properties in the Utica Shale, despite the fact that it planned to strategically reduce spending in the Bakken and Utica in 2015.

### BAKKEN SHALE

Hess discovered oil in North Dakota in 1951 and holds some 605,000 net acres in the Bakken play, including more than 534,000 acres in the core area.

In 2015, the Bakken Shale was a growth asset for Hess, which had 113,000 boe/d oil and gas


(Photo courtesy of Hess Corp.)

production in the region in third-quarter 2015, an increase of about 31% from 86,000 boe/d in third-quarter 2014.

For 2015, the company planned to reduce spending in the Bakken to $1.8 billion, compared with $2.2 billion in 2014, and planned to operate an average of 9.5 rigs and bring about 210 new operated wells online, compared with 17 rigs and 238 operated wells brought online in 2014.

Since then, spending has been reduced to $1.7 billion with a forecast of 8.5 rigs average for 2015. Hess brought 48 operated wells on production in third-quarter 2015, bringing the year-to-date total to 185 wells and planned to bring 219 wells on by year-end 2015.

Drilling and completion costs per operated well averaged $5.3 million in third-quarter 2015, down 26% from the same quarter in 2014. During third-quarter 2015, the company operated seven rigs.

For fourth-quarter 2015, the Hess Bakken production guidance is between 100,000 boe/d and 105,000 boe/d.

In 2016, Hess expects to operate four rigs in the region and preliminary 2016 Bakken production is projected to be 95,000 boe/d to 105,000 boe/d.

### UTICA SHALE

Hess has some 90,000 acres in the Utica play in Ohio, mostly in Jefferson, Belmont, Harrison and Guernsey counties and a portion of the acreage is part of a 50:50 joint venture (JV) with CONSOL Energy. Hess is focused on the core play of the wet gas window.

Hess has some 90,000 acres in the Utica play in Ohio.

The company planned to spend about $240 million in the Utica in 2015, compared with $458 million in 2014. The company's JV currently has one rig in operation and is forecasting to bring 25 to 30 wells online, compared with four rigs and 39 wells in 2014.

In third-quarter 2015, on the company's JV acreage, five wells were drilled, and net production averaged 28,000 boe/d, compared with 11,000 boe/d in the same quarter in 2014.

Also in third-quarter 2015, Hess completed the sale of an additional 13,000 dry gas exploration acreages for the sale price of about $120 million, including a note of $37 million.

## Marathon Oil Corp.

- **Strong performers in the Bakken**
- **First well spud in Springer**

Marathon's unconventional resources grew by 520 MMboe from year-end 2012 to September 2014 with 3 Bboe in proved and probable resources on the books.

The company dedicated 70% of its 2015 capital spending on its three core plays: the Eagle Ford, Bakken and Oklahoma resource basins.

### EAGLE FORD SHALE

The Eagle Ford offers Marathon a 1-Bboe potential resource. By year-end 2013, it had 211,000 net acres in the popular shale. The company called the Eagle Ford the "premier U.S. resource play." It is concentrating its development work in Atascosa, DeWitt, Gonzales and Karnes counties.

In third-quarter 2015, the company's production in the Eagle Ford averaged 128,000 net boe/d, a decrease from 135,000 boe/d in second-quarter 2015 but a 9% increase above third-quarter 2014. The production decrease between second-quarter and third-quarter 2015 was principally blamed on the timing of wells to sales weighted late in the quarter.

Also during third-quarter 2015, Marathon brought 57 wells to sales, of which 11 were Austin

At right: Newfield has about 92,000 net acres in North Dakota and Montana, of which about 40,000 net acres are being developed in the Bakken and Three Forks plays of North Dakota.

Chalk, six upper Eagle Ford and 40 lower Eagle Ford, compared to 52 wells to sales in the previous quarter.

In third-quarter 2015, 30-day IP rates from the six upper Eagle Ford wells ranged from 1,050 net boe/d to 1,480 net boe/d (57% to 76% liquids), with wells drilled at an average rate of 2,000 ft/d, an 11% improvement over the previous quarter. With this improvement, the time to drill an Eagle Ford well spud-to-total depth dropped to 10 days.

### BAKKEN SHALE

Marathon's 290,000 net acres lie in North Dakota and eastern Montana, and production for the region in third-quarter 2015 averaged 61,000 net boe/d, a 9% increase above the same quarter in 2014. Volumes were flat to second-quarter 2015, with five wells brought to sales, all in East Myrmidon, down from 22 in the second quarter.

Production was driven by continued strong performance from the Doll pad wells in West Myrmidon, which went online in late June 2015.

### WOODFORD SHALE

Overall, Marathon's Oklahoma resource basins offer it 1.5 Bboe in total resource and 1.1 Bboe in 2P resource. That includes the STACK, Cana Woodford, South Central Oklahoma Oil Province (SCOOP) and Granite Wash.

The company's Oklahoma production averaged 23,000 net boe/d during third-quarter 2015, a decrease from 24,000 net boe/d in the second quarter but an increase of 21% over the same quarter in 2014.

Marathon brought online seven company-operated SCOOP wells, of which one was an extended-reach lateral, and two company-operated STACK Meramec wells during third-quarter 2015.

The company-operated Smith infill pilot wells also were brought online with 24-hour IP rates averaging 1,060 net boe/d (60% liquids) on 107-acre spacing.

Marathon also spud its first operated Springer well during third-quarter 2015 and is in the process of completing it.

(Photo courtesy of Newfield Exploration Co.)

## Newfield Exploration Co.

- **Concentrating on the Anadarko Basin**
- **Drilling cut in the Uinta, Eagle Ford**

Newfield has been in business since 1988, and its growth strategy, like many other companies, is still evolving. For now, the company's focus is on the Midcontinent, Rockies and Texas.

Newfield decided to curtail operations in some areas for 2015 to concentrate its focus on its most productive area, the Anadarko Basin, where 70% of its 2015 capital budget was allocated.

### WOODFORD SHALE

Newfield has about 400,000 net acres covering key positions in the liquids-rich South Central Oklahoma Oil Province (SCOOP), STACK and Springer plays in the Anadarko Basin and in the dry gas Arkoma Basin Woodford.

The company has about 85,000 net acres located in the SCOOP, and more than 210,000 net acres located in STACK, and the new Springer Shale is located in the SCOOP fairway.

Together, the SCOOP and STACK hold more than 700 ft of saturated oil interval. To date, Newfield has drilled about 140 wells in the Anadarko Basin.

The company planned to invest about $820 million on concentrated development drilling in the SCOOP, STACK and Springer Shale in 2015, and expected to operate 10 drilling rigs throughou the year.

At year-end 2014, Newfield's net production from the Anadarko Basin was about 54,000 boe/d (27% oil and 34% NGL). As of Nov. 24, 2015, it is more than 70,000 boe/d.

Newfield was a founder of the Arkoma Woodford Shale development and currently has 146,000 net acres in this play. The area represents about 18% of the company's domestic proved reserves. At year-end 2014, net production was 18,000 boe/d (99% dry gas).

For fourth-quarter 2015, the company is expected to increase its average net production in the Anadarko Basin to about 74,000 boe/d, up from its previous forecast of 71,000 boe/d.

### UINTA BASIN

Operations are concentrated in the Uinta Basin of Utah and Williston Basin of North Dakota, where Newfield is assessing and developing about 300,000 net acres.

The company's largest asset in the Rocky Mountains is the Greater Monument Butte (GMBU) field area, located in the Uinta Basin, where it owns interest in about 225,000 net acres. The company has drilled about 1,900 wells in the unit with more than 1,500 productive oil wells since 2004. The GMBU is the largest federal unit in the lower 48 states.

Newfield also has horizontal plays in the Central Basin, including the Uteland Butte and Wasatch formations.

The company temporarily suspended drilling operations in the Uinta Basin in early 2015 because of lower crude oil prices.

### WILLISTON BASIN

Newfield has about 92,000 net acres in North Dakota and Montana, of which about 40,000 net acres are being developed in the Bakken and Three Forks plays of North Dakota.

Net production at year-end 2014 was about 20,000 boe/d, with 74% oil and 10% NGL.

The company planned to run a single-rig program in the Williston Basin in 2015.

### EAGLE FORD SHALE

Newfield has 25,000 net acres under development in the Eagle Ford Shale play, located in Dimmit and Atascosa counties.

At year-end 2014, net production in the Maverick Basin was about 11,000 boe/d, with 52% oil and 24% NGL.

Drilling in the Eagle Ford was suspended in 2015 to allow for an increased investment to the Anadarko Basin.

## Noble Energy Inc.

- **Buys into the Eagle Ford, Permian**
- **First Utica well completed**

Noble doubled its shale reach in 2015 when it purchased Rosetta Resources in July, acquiring 1,800 gross horizontal locations that provide 1 Bboe net unrisked potential in the Eagle Ford and Permian Basin.

### MARCELLUS SHALE

Noble has more than 350,000 net acres in the leading U.S. natural gas play, and its production volumes in third-quarter 2015 averaged a record 493 MMcfe/d, which represents a more than 50% increase over the same quarter in 2014. Natural gas represented 81% of third-quarter 2015 volumes, with the remaining 19% being condensate and NGL.

During third-quarter 2015, the company began production on 16 operated wells having an average lateral length of nearly 8,000 ft, while reducing its current operated and nonoperated drilling activity to zero rigs.

Included in the wells brought online was the six-well RHL-4 pad located in the Majorsville area. Three of the wells were completed with reduced stage and cluster spacing, and all of the wells are laterally spaced 500 ft apart. After 30 days online, the RHL-4 pad, which averaged more than 2,200 lb

Noble has more than 350,000 net acres in the leading U.S. natural gas play, and its production volumes in third-quarter 2015 averaged a record 493 MMcfe/d. *(Map courtesy of Noble Energy)*

of proppant per lateral foot, was producing more than 60 MMcfe/d.

Noble also completed the company's first Utica well, the MND-6H, with a lateral length of 9,090 ft. The well, located in Marshall County, W.Va., was expected to begin production in fourth-quarter 2015.

Meanwhile, joint-venture partner CONSOL Energy began production on 12 dry gas wells.

Noble estimated it would end 2015 with about 80 wells drilled but uncompleted (including both the wet and dry gas areas).

### NIOBRARA SHALE

Noble holds more than 400,000 net acres in the Denver-Julesburg (DJ) Basin in northern Colorado, which contains the company's largest U.S. offshore field at Wattenberg.

**Noble doubled its shale reach in 2015 when it purchased Rosetta Resources in July, acquiring 1,800 gross horizontal locations.**

In the DJ Basin, sales volumes averaged a record 116 Mboe/d in third-quarter 2015, up 13% vs. third-quarter 2014. Liquids made up 67% of total DJ Basin volumes (50% crude oil and condensate and 17% NGL), and 33% was natural gas. Total liquid volumes of 78 Mbbl/d for third-quarter 2015 was a record for Noble.

The company operated four drilling rigs in the DJ Basin for the majority of third-quarter 2015, and Noble is currently operating three drilling rigs and two full-time completion crews in the region.

The company drilled 39 wells at an average lateral length of more than 7,300 ft, and the average spud-to-rig release time for a standard lateral length well (4,500 lateral ft) decreased to 5.7 days.

Noble began production on 58 wells (equivalent to 70 standard lateral length wells) in third-quarter 2015 in Wells Ranch and East Pony. Wells Ranch volumes in the third quarter were up more than 15%, and East Pony volumes were up more than 20% vs. second-quarter 2015.

Noble estimated it would end 2015 with about 40 wells drilled but uncompleted.

### EAGLE FORD SHALE

Noble has about 50,000 net acres in primarily Dimmit and Webb counties in Texas. Production averaged 54 Mboe/d in third-quarter 2015, with 22% oil, 38% NGL and 40% gas.

The company drilled seven operated wells to total depth in the Lower Eagle Ford wells in the third quarter, and spud-to-rig release times have been reduced to about eight days for a 5,000-ft lateral, down about 30% from prior 2015 activity.

Noble began production on five operated Lower Eagle Ford wells, and the two most recent wells represent Noble Energy's initial designed and executed completions. These wells were drilled with 950-ft effective lateral spacing and were completed with 20-ft cluster spacing and about 2,000 lb of proppant per lateral foot. Each of the two wells, normalized to a 5,000-ft lateral length, is outperforming the 3 MMboe EUR type curve for the area.

Noble estimated it would end 2015 with about 35 wells drilled but uncompleted and one rig operating in the Eagle Ford.

### DELAWARE BASIN

Noble has more than 45,000 net acres in the Delaware Basin and 9,000 acres in the Midland Basin in West Texas.

Net production in the Delaware Basin in third-quarter 2015 was 9 Mboe/d, with 71% oil, 12% NGL and 17% gas.

The company drilled one Wolfcamp A well in the Delaware Basin in third-quarter 2015 that had a lateral length of about 5,000 ft and was drilled in about 10 days less time than prior activity on these assets.

Noble estimated it would end 2015 with about 15 wells drilled but uncompleted and one rig operating in the Delaware. Initial completions are expected in early 2016.

## Occidental Petroleum Corp.

- **Concentrating on Wolfcamp**
- **Operating unit, well costs down**

Occidental sees its best chances for a high-growth future in the Permian Basin, where it is the largest operator and oil producer.

(Photo courtesy of Pioneer Natural Resources)

### WOLFCAMP SHALE

Occidental has almost about 5 million gross acres in its core asset—the Permian. With 12,000 operated gross oil and gas wells, the company accounts for 13% of the oil produced in the region.

The company spent more than $2.8 billion of its capital in 2014 in the Permian, and it planned to spend $2.2 billion in the region in 2015.

Occidental manages its Permian Basin operations through two business units: Permian Resources, which includes growth-oriented unconventional opportunities in New Mexico and West Texas, and Permian EOR, which uses EOR techniques such as $CO_2$ floods and waterfloods to boost oil production.

The company's 2014 Permian production of 222,000 boe/d represented nearly 38% of its total worldwide production.

Occidental's Permian Resources increased production throughout 2014, achieving 42% year-over-year growth in oil production in the fourth quarter, and it expects to increase this by more than 30% in 2015.

As of third-quarter 2015, Permian Resources' average production grew by 22,000 bbl/d to 204,000 bbl/d.

Permian Resources produced 75,000 boe/d in 2014 and is expected to increase production to 100,000 boe/d on average in 2015.

In 2014, Permian Resources drilled 167 horizontal wells and expects to drill the same number in 2015. Production in 2014 came from about 13,000 gross wells, of which 61% were operated by other producers.

Meanwhile, Wolfcamp well costs in the Delaware Basin are down more than 40% in third-quarter 2015, and the company's Permian Resources' unit operating costs are down 18% from the same quarter in 2014.

## Pioneer Natural Resources Co.

- **All horizontal in the Spraberry/Wolfcamp**
- **Production flat in the Eagle Ford**

Pioneer has put a lot of hard work into every play it has chosen. Lately, it has chosen to swing its focus back toward the Permian Basin and makes no secret on its website as to why: a potential of more than 75 Bboe in the Spraberry/Wolfcamp shales, which ranks it among the largest U.S. oil fields and the second-largest oil field in the world.

In 2015, the company shut down its vertical drilling program in the Spraberry/Wolfcamp and committed exclusively to horizontal drilling.

### WOLFCAMP SHALE

Pioneer is the largest acreage holder in the Spraberry/Wolfcamp, with about 600,000 gross acres in the northern portion of the play and about 200,000 gross acres in the southern Wolfcamp joint-venture (JV) area with Sinochem.

The company believes it has greater than 10 Bboe of net recoverable resource potential, allowing for decades of drilling horizontal wells with lateral lengths ranging from 7,500 ft to 10,000 ft, resulting in improved capital efficiency.

In third-quarter 2015, in the northern Spraberry/Wolfcamp, Pioneer placed 33 horizontal wells on production, and early production from 30 wells targeting the Wolfcamp B (28 wells) and Wolfcamp A (two wells) intervals are on average tracking more than 15% above a 1-MMboe EUR type curve. These wells delivered an average 24-hour peak production rate of about 1,900 boe/d, with 78% oil content.

In 2015, Pioneer shut down its vertical drilling program in the Spraberry/Wolfcamp and committed exclusively to horizontal drilling.

As of November 2015, Pioneer was operating 14 horizontal rigs in the northern Spraberry/Wolfcamp, of which eight had been added since July 2015.

The cost to drill and complete a horizontal well in third-quarter 2015 was about $8 million to $8.5 million, assuming average lateral lengths of about 9,000 ft, a 25% cost reduction compared to 2014.

Pioneer's best drilling times to date have been 16 days in the northern area and 13 days in the JV area.

The company expects its well costs in the northern Spraberry/Wolfcamp to decrease to $7.5 million to $8 million per well by early 2016.

Pioneer expected to place about 110 new horizontal wells on production in the northern Spraberry/Wolfcamp during 2015. Of these, 75% would be Wolfcamp B interval wells and the remainder would be split between Wolfcamp A, Wolfcamp D and Lower Spraberry Shale interval wells. Seventy-six wells were placed on production during the first nine months of 2015.

**As of November 2015, Pioneer was operating 14 horizontal rigs in the northern Spraberry/Wolfcamp, of which eight had been added since July 2015.**

In the southern Wolfcamp JV area, Pioneer continued to operate four horizontal rigs as of November 2015.

Well performance in the southern Wolfcamp JV area in third-quarter 2015 reflects EURs averaging about 900 Mboe, with internal rate of returns averaging 45% at current strip commodity prices. The current cost to drill and complete a horizontal well is about $7.5 million to $8 million, assuming average lateral lengths of about 9,000 ft and a 25% cost reduction compared to 2014. Costs are expected to be reduced by more than 30% by early 2016 as additional cost reductions and efficiency gains are achieved.

The JV drilling program is experiencing similar spud-to-PoP time reductions and efficiency gains as in the northern Spraberry/Wolfcamp.

The company expects its well costs in the southern Wolfcamp JV area to decrease to $7 million to $7.5 million per well by early 2016.

In the southern Wolfcamp JV area, Pioneer expected to place about 85 horizontal wells on production during 2015. Of these, 75% would be Wolfcamp B interval wells. The remainder would be split between Wolfcamp A and Wolfcamp D interval wells. Seventy-seven wells were placed on production during the first nine months of 2015.

The total Spraberry/Wolfcamp production grew 15 Mboe/d in third-quarter 2015 to 134 Mboe/d, or 13%, compared to the second quarter. Oil production in third-quarter 2015 grew 10,000 bbl/d compared to the second quarter and represented 65% of total third-quarter production in this asset.

A total of 52 horizontal wells were placed on production during the third quarter. Horizontal production was 75 Mboe/d, and vertical production was 59 Mboe/d, reflecting the first time that horizontal production has surpassed vertical production.

The company was scheduled to place about 40 horizontal wells on production in fourth-quarter 2015, a reduction of 12 wells from the third quarter. Even with this reduction, Spraberry/Wolfcamp production was forecasted to grow by 25% to 26% in 2015 compared to the 22% to 24% previously forecasted due to strong year-to-date horizontal production performance.

## EAGLE FORD SHALE

In the liquids-rich area of the Eagle Ford Shale play in South Texas, where it has 215,000 gross acres mostly in Karnes and DeWitt counties, Pioneer's horizontal rig count was reduced from nine rigs in 2014 to six rigs in early 2015.

The company placed 36 wells on production in the Eagle Ford Shale during third-quarter 2015, of which 21 wells were in Upper targets and 15 wells were in Lower targets.

Pioneer's third-quarter 2015 production from the Eagle Ford Shale averaged 43 Mboe/d, of which 40% was condensate.

Pioneer placed 85 wells on production during the first nine months of 2015 and was scheduled to place about 100 wells on production for full-year 2015.

As of November 2015, Eagle Ford Shale production was forecasted to average 45 Mboe/d in 2015, essentially flat compared to 2014.

Eagle Ford properties produced 47 Mboe/d during second-quarter 2014, and the play has an estimated 131 MMboe in proved reserves, a resource potential of 450 MMboe and 1,400 undrilled locations.

## Range Resources Corp.

- **Focused almost entirely on the Marcellus**
- **Production flat in the Midcontinent**

Range has its sights set on the largest natural gas field in the U.S., and it's directing 95% of its 2015 capital budget toward the Marcellus.

### MARCELLUS SHALE

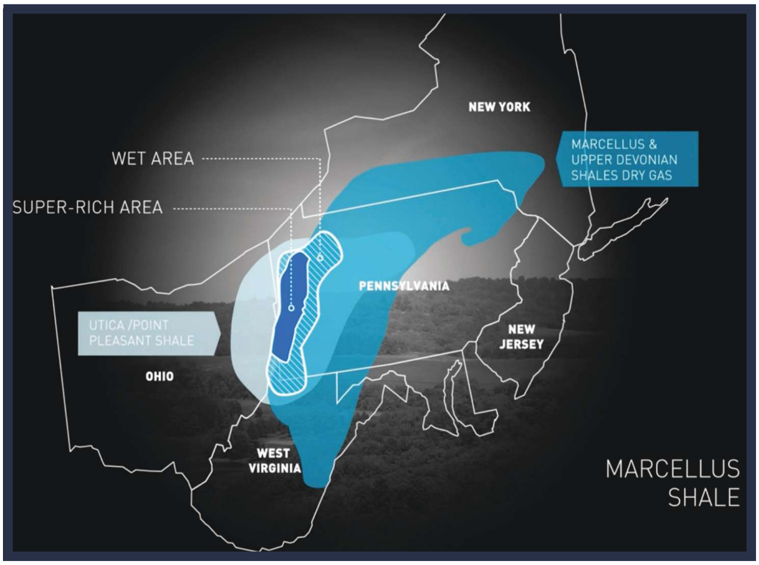
The Marcellus Shale plays a big part in the company's growth plans. It pioneered the play with the Renz #1 vertical well in 2004 and now holds more than 900,000 net acres of land in the largest natural gas field in the U.S.

Production for third-quarter 2015 averaged 999 net MMcfe/d in the southern Marcellus, a 28% increase over the quarter in 2014. Third-quarter 2015 net production included 635 MMcf/d of gas, 51,967 bbl/d of NGL and 8,676 bbl/d of condensate. During third-quarter 2015, 23 wells were turned in line in southwest Pennsylvania. The division averaged completing 7.5 frack stages per day in third-quarter 2015, compared to 5.2 stages in third-quarter 2014, a 44% increase.

During third-quarter 2015, Range brought online 22 Marcellus wells, four in the super-rich area, 10 in the wet gas area and eight in the dry gas area. The 14 wells brought online in the wet and super-rich areas had a 24-hour IP average of 16.1 MMcfe/d (6.6 MMcf of gas, 1,179 bbl of NGL and 404 bbl of condensate), from an average lateral length of 5,360 ft, using 27 stages.

In northeast Pennsylvania, production for third-quarter 2015 averaged 278 net MMcf/d for the division, a 22% increase over the same quarter in 2014. In third-quarter 2015, four wells were brought online. The four wells averaged a 24-hour IP of 11.3 MMcfe/d and a 30-day IP of 9.2 MMcf/d, from an average lateral length of 6,504 ft using 28 stages.

There were no rigs operating in the region as of late October 2015, and Range did not anticipate bringing online any wells in fourth-quarter 2015.




During third-quarter 2015, Range brought online 22 Marcellus wells, four in the super-rich area, 10 in the wet gas area and eight in the dry gas area. *(Map courtesy of Range Resources Corp.)*

### MIDCONTINENT

Range lumps its Mississippi Lime, St. Louis Lime, Cleveland and Woodford properties under its Midcontinent division, and it holds about 360,000 combined net acres in the plays with a resource potential between 7 Tcf and 11 Tcf of gas equivalent.

Production for third-quarter 2015 averaged 109 net MMcf/d in the region, a 2% decrease compared to the same quarter in 2014, and flat with the second quarter. Production remained flat compared to the second quarter while only turning in-line three wells. The company drilled one coalbed methane well and completed two additional wells in third-quarter 2015.

## Southwestern Energy Co.

- **Sets records in Southwest Appalachia**
- **First well is spud in the Utica**

Southwestern, credited with opening the Fayetteville gas shale play in Arkansas has spread its expertise to other shale opportunities, including Brown Dense, where it has 304,000 net acres of leases, and almost 380,000 acres in the Niobrara play in the Sand Wash Basin of northern Colorado.

### MARCELLUS SHALE/NORTHEAST APPALACHIA

Southwestern began leasing in northeastern Pennsylvania in 2007; by early 2015, it had 312,773 net acres in the state and spudded 376 wells operated by the company, 255 of which were on production and 367 of which were horizontal.

In 2014, Southwestern invested $695 million in Northeast Appalachia and spudded 99 operated wells, acquiring five horizontal and two vertical wells in the process. Also in 2014, the company's operated horizontal wells had an average completed well cost of $6.1 million per well, average lateral length of 4,752 ft and an average of 15 fracture stimulation stages.

In 2015, the company planned to invest about $605 million in Northeast Appalachia and participate in 88 to 92 gross wells. Southwestern estimates that net production from the region will be in the range of 363 Bcf to 366 Bcf.

In third-quarter 2015, the company placed 26 new wells on production and had net gas production of 93 Bcf, up 41% from 66 Bcf in the same quarter in 2014. As of September 2015, gross operated production in the region was about 1,237 MMcf/d.

During third-quarter 2015, average time to drill to total depth was reduced to eight days from reentry to reentry compared to nine days in the second quarter.

As of September 2015, Southwestern had 394 operated wells on production and 102 wells in progress.

## UTICA SHALE/SOUTHWEST APPALACHIA

In fourth-quarter 2014, Southwestern acquired 443,000 net acres in West Virginia, and at year-end 2014, net production was about 370 MMcfe/d, with more than 95% of the production coming from 255 horizontal wells.

In 2015, the company planned to participate in 50 to 55 gross wells. The rig count in southwest Appalachia is currently four rigs.

During third-quarter 2015, the company's net production from the region was 37 Bcfe, and in the 10 months of operating in this new area, it set a number of company records, including longest completed lateral, most proppant in a single well, most pounds of sand per foot and most stages per well.

Southwestern drilled 16 wells, with an average lateral length of 6,376 ft and average time to drill to total depth of 18 days from reentry to reentry during third-quarter 2015. The company also placed five wells in production during the same time period.

The company received a permit for its first Utica well, located in Marshall County, W.Va., during third-quarter 2015 and spudded the well, which was scheduled to be completed during fourth-quarter 2015, and placed on production in early 2016. More wells are expected as part of the 2016 drilling program.

As of September 2015, Southwestern had 281 operated horizontal wells on production and 43 operated horizontal wells in progress. Of those 43 wells, 19 were waiting on completion.

## FAYETTEVILLE SHALE

A first-mover in the region, Southwestern leases 888,161, net acres of land in the prime part of the Fayetteville gas shale play, where it spudded 4,578 wells by year-end 2014, and of the 468 wells it spud that year, all were horizontal.

In 2014, the company's operated wells had an average completed well cost of $2.6 million per well, average lateral length of 5,440 ft and an average time to drill to total depth of 6.8 days from reentry to reentry.

In 2015, Southwestern planned to participate in about 235 to 245 gross wells, all of which it expected to operate.

In third-quarter 2015, the company's net gas production from the Fayetteville was 118 Bcf, compared to 126 Bcf in third-quarter 2014 and 121 Bcf in second-quarter 2015. Gross operated gas production was about 1,856 MMcf/d in September 2015.

The 50 horizontal wells that were placed on production during third-quarter 2015 had an average IP rate of 3,835 Mcf/d, average completed well cost of $2.7 million per well, average horizontal lateral length of 5,407 ft and average time to drill to total depth of 6.9 days from reentry to reentry. This compares to 68 horizontal wells the company placed on production in second-quarter 2015 that had an average IP rate of 4,405 Mcf/d, an average horizontal lateral length of 5,861 ft, average time to drill to total depth of 7.1 days from reentry to reentry and an average completed well cost of $2.8 million per well.

(Photo by Ole Jørgen Bratland, courtesy of Statoil)

By fourth-quarter 2014, Statoil's average production in the Marcellus was 133,500 boe/d from interests in 1,115 wells.

## Statoil ASA

- **Locked in on three shale plays**
- **Company taking on operations**

Norway's Statoil started its work in shale plays in 2008 as it acquired properties as a nonoperating partner learning the ropes from companies more experienced in shale operations. Statoil has since taken over as operator in a good portion of its plays.

### MARCELLUS SHALE

Statoil made its first venture in shales through the purchase of an interest in Chesapeake Energy's property. Chesapeake was the operator of the play. In 2012, Statoil added another parcel in the liquids-rich segment of the Marcellus to bring its holdings to about 600,000 net acres, of which 91,000 are operated by Statoil.

In first-quarter 2015, the company decided to shed a bit of its interest in the play when it finalized a transaction between itself and Southwestern Energy, reducing Statoil's average working interest in the nonoperated southern Marcellus onshore play from 29% to 23%. The divested share represented about 30,000 acres.

By fourth-quarter 2014, average production was 133,500 boe/d from interests in 1,115 wells. The average approximate vertical depth of each well was 8,000 ft with an approximate lateral length of 5,500 ft.

### BAKKEN SHALE

The Bakken was Statoil's big operating leap into the shale industry when it bought Brigham Exploration in 2011. That acquisition made it a major operator in the Williston Basin with an experienced Brigham crew.

The company now holds some 265,000 net acres of land in the Williston, where average production was 59,800 boe/d from interests in 512 operated wells in fourth-quarter 2014. The average approximate vertical depth of each well was 10,000 ft with an approximate lateral length of 10,000 ft.

Statoil planned to increase its drilling and completion costs by 10% in 2015, according to an energy conference presentation in November 2014, and increase its recovery by 25% in the Bakken.

### EAGLE FORD SHALE

Statoil entered the Eagle Ford play in South Texas when it formed a 50:50 joint venture with Talisman Energy in 2010. Talisman was the initial operator on all of the acreage, but not for long. In 2013, Statoil completed a transition into operator of the eastern half of the partnership properties. That gives the Norwegian company some 58,000 net acres of leases in Live Oak, Karnes, DeWitt and Bee counties in Texas.

By fourth-quarter 2014, average production was 35,400 boe/d from interests in 537 wells. The average approximate vertical depth of each well was 13,000 ft with an approximate lateral length of 5,000 ft.

Statoil planned to increase its drilling and completion costs by 19% in 2015 and increase its recovery by 21% in the Eagle Ford. The company also sought to decrease its stage spacing to yield a 25% increase in stages and a 20% increase in EUR. In addition, Statoil planned to add additional horizons to extend its drilling program by more than 150 net wells for an added value of more than $400 million.

## Whiting Petroleum Corp.

- **High test rates in the Bakken**
- **Production up in the Redtail Field**

Whiting set its sights for unconventional production on two prolific areas in the Rockies, Bakken/Three Forks in North Dakota and Niobrara in Colorado.

### BAKKEN SHALE

Whiting holds about 1 million gross (667,668 net) acres in the Williston Basin of North Dakota and Montana. In 2015, the company estimated 7,399 gross drilling locations in the region.

At year-end 2014, Whiting was running 19 rigs in the Bakken/Three Forks, and it planned to decrease its rig count to 10 by mid-year 2015.

In third-quarter 2015, production from the Bakken/Three Forks averaged 130,895 boe/d, which represented 82% of the company's total third-quarter production, compared to the average production of 100,870 boe/d at year-end 2014.

In third-quarter 2015, Whiting completed 34 operated wells with average sand volumes of 5.2 million pounds that produced for 30 or more days compared to 54 operated wells with average sand volumes of 3.5 million pounds in the second quarter. Wells completed during third-quarter 2015 achieved an average 30-day rate of 1,102 boe/d, which was 44% better than the second-quarter wells.

The average estimated completed well cost for third-quarter 2015 was $6.6 million, down from about $8.0 million in 2014.

Between Aug. 31, 2015, and Sept. 7, 2015, Whiting completed a two-well pad at its Cassandra Prospect in Williams County, N.D. The P Johnson 153-98-1-6-7-16HA tested at a 24-hour IP rate of 5,062 boe/d from the Middle Bakken Formation. The P Johnson 153-98-1-6-7-16H tested at a 24-hour IP rate of 5,386 boe/d from the Middle Bakken Formation. They were the highest test rates recorded by Whiting at its Cassandra Prospect.

Both wells were completed with a hybrid-style completion, 7 million pounds of sand per well and have an estimated completed well cost of about $6.9 million, also down from about $8 million in 2014.

### NIOBRARA SHALE

Whiting's success isn't limited to the Williston Basin. The company holds 147,472 gross (118,436 net) acres in its Redtail Field, located in the Denver-Julesburg Basin in Weld County, Colo. The company has established production in four zones, the Niobrara A, B and C zones, and the Codell/Fort Hays formations.

At year-end 2014, Whiting was running three rigs in the Niobrara at Redtail, and it planned to maintain that rig count by mid-year 2015.

Net production from the Redtail Field averaged 16,575 boe/d in third-quarter 2015, compared to an average of 10,155 boe/d at year-end 2014.

The next significant round of completions at Redtail is scheduled for first-quarter 2016. ■


(Photo courtesy of Hess Corp.)

# Operators Demand Technology to Keep Production Edge in Era of Low Oil Prices

By **Scott Weeden**, Senior Editor, Drilling,
and **Jennifer Presley**, Senior Editor, Production

*Companies with new technology for unconventional plays are gaining new customers during industry downturn as operators seek cost-effective technological advantages.*

Finer than a single strand of human hair is the line between success and failure, so is the edge that operators today carefully tread. Much has been learned in the 30-plus years since that first vertical stimulation using nitrogen foam occurred in the Barnett Shale in the Fort Worth Basin. The application of offshore innovations like horizontal drilling and high-pressure water to fracture and deliver the sand necessary to prop open those fractures helped create the shale gale that roared across the U.S., from Pennsylvania to California.

Now in the era of low oil prices, getting the most production bang for the frack has become the mantra of the day. Harnessing technologies like dissolvable plugs or fiber optics with techniques like clustering and long laterals are, depending on the play, finding success. From drilling the well to completing it and then producing bountiful returns, the technologies and techniques delivering results are in great demand as operators seek to keep their production edge over the competition.

## Adapting through innovation

Making the case to support R&D efforts of new technologies can be difficult when times are lean. While shelving or dropping an R&D project might help today's bottom line, what is the impact on the company's future ability to prosper?

Lloyd's Register Energy, in its 2015 report "Innovating in a New Environment," found that 76% of the industry executives surveyed said that instability in the oil price has led them to slow down or halt most innovation initiatives. Primary drivers of these initiatives are focused on improving operational efficiencies, reducing costs and improving access to potential, at 46%, 36% and 35% respectively, according to the report.

A key enabler of the three is digital revolution, with the "rapid maturation of advanced data technologies having an impact" as these three "are not prohibitive in cost to deploy and offer near-term gains in efficiency improvements," the report said. The survey found that for 56% of respondents, data collection and analytics will be important to their innovation efforts over the next two years.

Data collection and analytics by operators and service companies is contributing more to the successes seen in the field. Daniel Mohan, senior vice president of marketing for Ayata, spoke on these successes during his presentation at Hart Energy's DUG Eagle Ford conference held in October. In his presentation, "Completion innovations that make $40 oil work," he discussed the role prescriptive analytics can play in wellbore placement, completion design and "quantifying intuition," which is the ability to apply synthetic variables to circumstances that can't be controlled.

A Hess Corp. drilling rig is onsite in North Dakota.

"Prescriptive analytics predicts the future, tells you what you need to do to make that future a reality and gets smarter the more you use it," Mohan said. "Operators in unconventional resource plays are using it to create better recipes for drilling, completing and producing wells."

An example of where conventional wisdom doesn't always stack up is "bigger isn't always better." This relates to completion design. Mohan said that one of the advantages of using prescriptive analytics is that it's not limited in the number of variables it can consider.

"We're looking at the near-wellbore geological variables and trying to find an explanation for variations in production," he said. "We started looking at different completion designs and the result was tighter, shorter stages, tighter cluster density, more clusters per stage and more sand. Today we're seeing better results when completions are designed to maximize the contact with the reservoir," he said.

The impact of big data on operations is one that is clearly felt throughout the value chain.

"When it comes to completions, there's a lot more front-end data integration going on now. That's a very welcome change, and operators value the additional science. I think as overall costs are going down, additional technologies are being used. Companies like Weatherford have the opportunity now to introduce some new technologies in a very low-risk environment," said Rob Fulks, director of completion optimization for Weatherford.

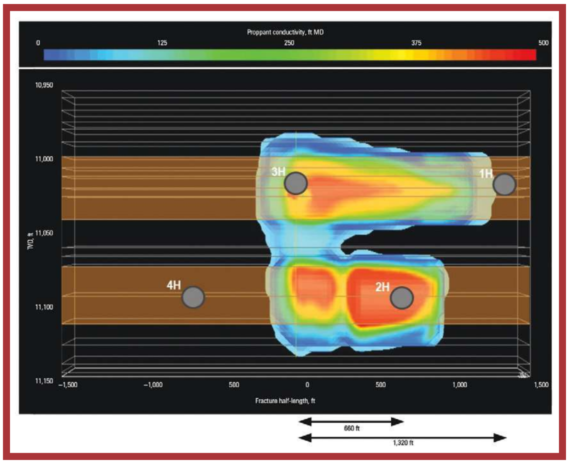
"For instance, as we research and develop best practices and new technologies, we frequently collaborate with our clients using their production data to prove our models. That is going on particularly with completion optimization, where we're developing proprietary, integrated hydraulic fracturing designs by basin," he continued.

"Let's say we've got a new proprietary algorithm to help us position the stages and perforation clusters. How do we know if that is effective or not? We can provide the technique or technology to our clients who give us a view into their production data. It's a win-win for both sides. And in this environment, we're seeing a lot of willingness from clients to do that," he explained.

## Case study:

### FRACTURE DESIGN ANALYSIS SAVES $1.2 MILLION ON NEW WELLS

Petrogulf Corp. worked with Schlumberger to quantify the impact of pressure depletion from existing producing wells on fracture geometries in new completions in a reservoir with higher than normal permeability. Mangrove Express fracture design's asymmetric fracture analysis model was used to determine fracture propagation toward the depleted area and optimize the completion design accordingly.




A 3-D asymmetric fracture propagation model was created using Mangrove Express.

*(Image courtesy of Schlumberger)*

Hydraulic fracture modeling and production history matching were completed—all in one platform—with the capability to rerun fracture modeling with the same grid system, thereby eliminating the use of independent models.

The initial production of 1,500 bbl/d from new wells was on par with the best offset producers, which would not have been possible by using the same design as the parent completion due to depletion effects. The design optimized completions and resulted in $1.2 million in savings for Petrogulf.

### Transferring drilling technology from offshore to onshore

Some technologies that have been used offshore have now made their way onshore because it has

Weatherford's Revolution Rotary-Steerable System enables operators to drill with a wide array of capabilities.

*(Image courtesy of Weatherford)*

been made much more affordable, according to Fulks. "We've seen that in some of the more high-end LWD and MWD tools. For instance rotary steerable systems, which at one time were only used offshore, are now routinely being used onshore.

"On the drilling side we're also doing a lot more on drilling predictive software and analysis capabilities. Basically we are engineering on the front-end to include rotating control devices, choke mechanisms and other tools," he said.

"Our customers are always willing to utilize rotary steerable type drilling apparatus, or drilling BHAs [bottomhole assemblies] to ensure that they're staying in zone most of the time," Fulks said. "While it is a more expensive method of drilling than using just standard bits and motors, at the end of the day, it still does provide a better well than a regular drilling assembly, so customers are still willing to utilize that sort of technology to drill better wells."

Azimuthal resistivity tools now help onshore operators stay in zone better. Pressure monitoring and software tools also are being used onshore," Fulks explained.

Days-to-depth targets that are being reached by drillers in every major onshore play have seen dramatic improvements, again using technology developed offshore.

"What we're seeing is operators looking at hazard mitigation and nonproductive time reduction. Prediction of well behavior through dynamic modeling is routine offshore and is finding its way onshore," Fulks continued. "Avoidance of stuck pipe, which nobody likes to talk about much, is being used onshore. Monitoring and modeling of wellbore stability also is being used.

"Operators are willing to invest more on modeling on the drilling side. They're willing to use more sophisticated tools like temperature, LWD, MWD, RSS tools so they get better wellbores. Planning tools that were used offshore are now being seen onshore because these are price competitive," he added. "We've seen a lot more emphasis on planning drilling the well on paper."

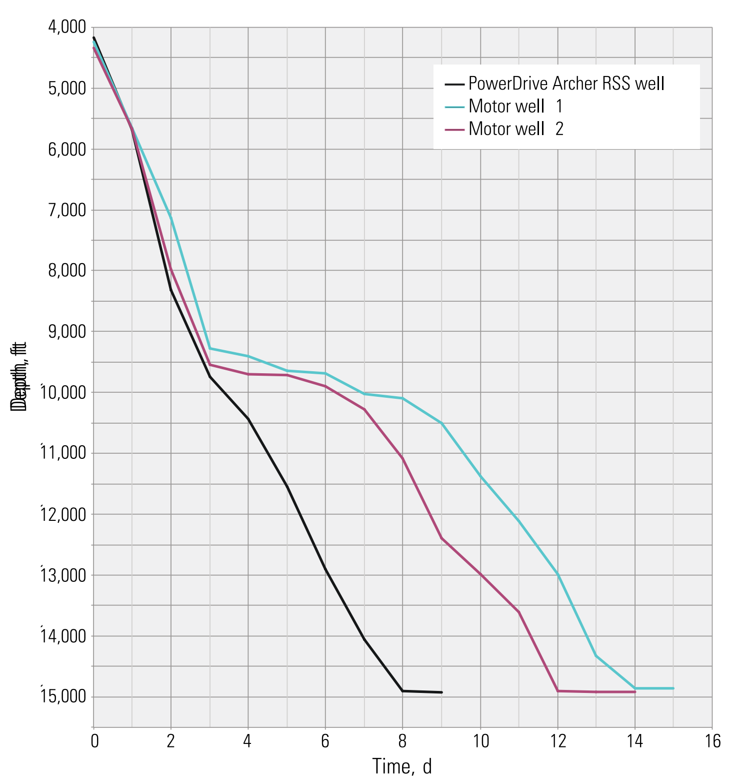
"On the drilling bit side, we're utilizing what we call DATCI. It stands for drilling at the customer interface," said Des Murphy, regional technology manager for Halliburton's Northeast area. "We're able to accurately design bits on the fly, almost, to really improve the rate of penetration and to help get these wells drilled and cased as quickly as possible to reduce the amount of time actually spent drilling wells. The DATCI process has really gained a lot of acceptance over the last couple of years, and a lot of customers are actively engaging our design engineers with the process."

## Case study:

### BHA FOR RSS CUTS FOUR DAYS OFF DRILLING TIME

An operator in the LaSalle County region of the Eagle Ford Shale play in central Texas contacted Schlumberger for options to improve drilling performance in horizontal wells for the field. The operator had previously drilled wells in the area using motors with great success, but wanted to increase efficiency further. The plan was to drill an entire 8½-in. horizontal well using a rotary-steerable system (RSS), avoiding at least one trip out and increasing ROP.

The Schlumberger team developed a BHA with the durability and performance specifications to meet the operator's challenging objectives. The 6¾-in. PowerDrive Archer RSS was selected for its ability to drill high-dogleg trajectories while maintaining a high ROP and superior wellbore quality. For maximum durability on the long run, a Spear SDi513 shale-optimized steel-body PDC drill bit from Smith Bits was specially designed for the project.




A time-vs.-depth plot shows the PowerDrive Archer RSS performance improvement that saved four days of drilling time compared with motors. *(Image courtesy of Schlumberger)*

Plans for performance improvement included an ROP of 55 ft/hr, with connection time. The objective was to drill the well in one run to beat the time to drill to TD achieved on previous wells drilled from the same pad using motors. At a planned TD of greater than 10,000 ft, the length of the well presented a challenge in itself.

The well was drilled to TD in four fewer days compared with best motor performance on the pad. The PowerDrive Archer BHA drilled the entire 10,754-ft well in one run, with a total of 137.67 drilling hours and an average on-bottom ROP of 78.12 ft/hr. The high ROP achieved exceeded expectations for the project, and the operator already drilled another well using this BHA in the Eagle Ford Shale.

### Pressurized coring

"Customers are still willing to utilize various forms of new technology, both drilling and completing, to make better wells for themselves," Murphy continued. "On the drilling side, we recently introduced the CoreVault pressurized coring system. While it is a new technology and does have an expense associated with it, customers are able to utilize it to realize greater than previously achieved gas reserves."

According to the company, the accurate economic evaluation of a shale well previously required drilling and completing it. Traditional coring tools let fluids escape from samples as they depressurized. As a result, analysis had to be based on estimates of fluids lost rather than measurement of fluids in place. Also, tools could take days to retrieve just one core.

"When the core lab is doing its estimation on gas in place or original oil in place it has to make some assumptions based on what it believes was lost during the core transfer or during the core recovery process," Murphy said. "Currently they use the GRI method, which makes several assumptions, and the amount of gas loss varies greatly. With the CoreVault system, they're not losing any of that oil or gas that's in the actual core."

The system is built into the hostile rotary sidewall coring tool and is capable of capturing up to 10 samples in a sealed container in a single run. The container prevents reservoir fluids from escaping during core retrieval and transport.

According to a company issued case study, an operator in Ohio and West Virginia used the system to retrieve 150 samples in five wells. Measurements of samples obtained with the system showed 2.5 times more oil and gas in place than previously estimated. The operator also found variability in organic content, enabling better targeting and completion efficiency.

### Completion technology

The completion side of field development is a bit envious of the gains in drilling efficiency over the last 10 years, according to Fulks.

"Refracturing is being looked at on the completion side because of sheer economics. Even though we're 10 years into unconventionals now, a lot of completion designs that we first went with had very little science behind it. We know that cluster efficiency and stage efficiency are not where we would like them to be," Fulks continued.

"All operators would like to see their assets developed in a more uniform and predictable fashion

The TruFrac Composite Frac Plug delivers significant economic value from higher speed deployment/reduced run-in times as well as reduced drill-out time with the first fully composite plug designed for stage fracturing operations. *(Image courtesy of Weatherford)*

with improved recovery rates," he emphasized. "We really can't live in the 6% to 8% effective recovery regime and attempt to compete on an international basis with conventional reservoirs that produce at a much higher percentage of effective recovery."

On the completion side some of the big breakthroughs include new completion hardware such as biodegradable diverters and new proppant types. "Completion hardware as a rule has gotten so good now, whether it is sliding-sleeve type or regular plug and perf [PNP] with new composite plugs that dissolve. That business is very robust for Weatherford," he added.

Two of the new products from Weatherford include TruFrac, which is for single- and multiple-zone PNP completions, and StealthFrac, which is a flow-through plug that can be run and sealed off with a dissolvable ball allowing fullbore access all the way to the toe.

Another Weatherford service, FracAdvisor, encompasses multiple technical disciplines that allow the operator to optimize the entire completion process by integrating multiple datasets. This includes new 3-D discrete-fracture network modeling.

"We're now able to take the fracture design, which has always been delivered as a text document, and provide it in a user-friendly log format. We look at all the logging data that comes in and focus on the parts that will help us best plan stage optimization and cluster placement. Then we place the completion hardware design and the fracture treatment schedule on the same log. That's what our clients are looking for right now," Fulks explained.

## Well design optimization

"From a completion side, it looks like operators are willing to take more time on designs for the wells. In the past it was more about factory mode, construction of wells, no look backs, really, to see what the wells did as far as production," said Gary Rodvelt, chief advisor for Halliburton's global technical services. "Obviously, production was the final measurement, but not a lot of attention to the job results, how things were placed, how many pounds of sand, etc. Now you see jobs being history matched, reviews of wells or pads to see lessons that were learned and can be carried forward in the next wave."

"There's a little bit more study upfront too in engineering their completions based on the rock properties that they've got along their lateral sections previously. When they're in the factory mode it's all geometric-type completions, dividing the lateral up into equal segments and then simulating it that way," Murphy said.

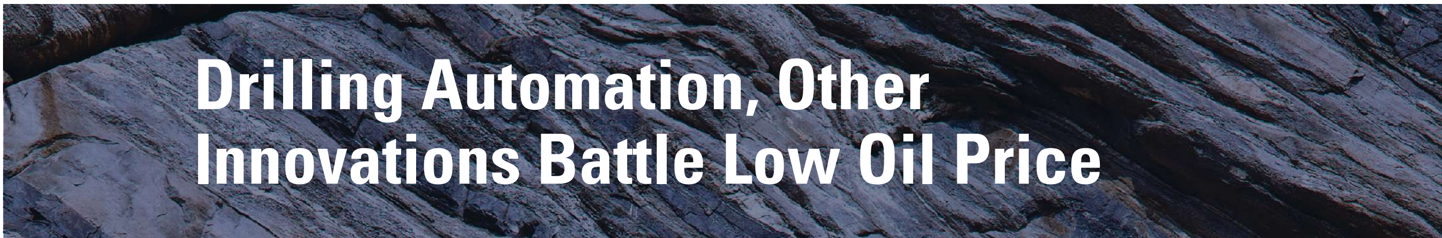
"Now you see a lot of people actually taking the time to review what they know of the rock along the length of the lateral and utilizing their own software methodologies or utilizing service companies and engineering their completions as opposed to just doing the standard geometric design. You're starting to more time spent designing their completions to get a more effective simulation," he added.

"We're seeing an increase in proppant use. We're doing a lot of candidate selection for refracks, for older, poorly completed wells. The trend is definitely more proppant, as per lateral foot, from several years ago," Murphy continued. "Original completions you see anywhere from 600 lbs to 700 lbs per lateral foot. Nowadays, with a lot of completions, you see in excess of 2,000 lbs per lateral foot of proppant being placed and more stages as well."

Other lessons—like optimal spacing between clusters or lateral lengths—are being gleaned from the company's refracking candidate selection process to help improve future jobs.

"Contacting as much rock as possible is critical," said Murphy. "With older methodologies, like large distances between clusters, we now understand that—especially in this tighter, nano-Darcy-type rock—that we need to contact as much of the reservoir as possible, which means adding more entry points."

It also means increasing the amount of reservoir contact and the amount of proppant used per lateral foot while also reducing the requirement on



# Drilling Automation, Other Innovations Battle Low Oil Price

A new generation of startups offers ways to cut drilling costs and NPT as oil operators adapt to low oil prices.

From robotic drilling to advanced seismic imaging, operators are using new technology to restructure and streamline operations to cut down nonproductive time (NPT) and shave costs, according to Lux Research.

"With many new technologies available, startups in the drilling industry that reduce NPT—from replacing personnel to preventing disaster—will be the most successful. The questions are which offer the most value in terms of the technology and, for the risk averse, which have a meaningful track record of deployment? Lux analyzed 21 companies based on their technical value and business execution and plotted them on the Lux Innovation Grid to identify those with high potential in this space," said Colleen Kennedy, Lux Research analyst.

"Robotics and AUVs will player a larger role in future drilling projects and will ultimately drive down project costs by reducing safety risks and personnel. Robotics is already on the cusp of playing a major role in offshore operations. Robotic Drilling Systems is developing an autonomous robotic drilling rig for unmanned operations and recently completed the installation of its first rig floor robot. This implementation took 10 years and several large investments but is the result of an industry consensus that investing in robotic technology to remove humans from dangerous physical routines is valuable."

Robotic Drilling Systems' autonomous robotic rig earned the company a "dominant" position on the Lux Innovation Grid, added Kennedy, who is lead author of the report titled, "Identifying Ways to Reduce Drilling Budgets in the Low Oil Price Environment."

"The new low oil price environment will drive innovation for reducing NPT during drilling operations," she continued. "Contingency costs arising from NPT typically account for about 10% to 15% of total drilling costs and can rise as high as 30%. So startups with technologies that reduce NPT can make attractive opportunities."

"Another low-key startup with applications in this space is BluHaptics, which has developed linear and crosslink gels, especially in the Marcellus, he continued.

"The nano-Darcy permeability is really affected by the residue left by guar-based gels. Going to a cleaner fluid, a pure slickwater fluid or a viscosifier and friction reducer aids in proper proppant transport," he said. "These are a few of the areas we feel that are definitely 'lessons learned.' Another is the need for longer lateral lengths. Some of the early wells have very, very short laterals—2,000 ft or 3,000 ft. The lateral length has a significant impact on the overall ultimate recovery that you're going to experience in these wells.

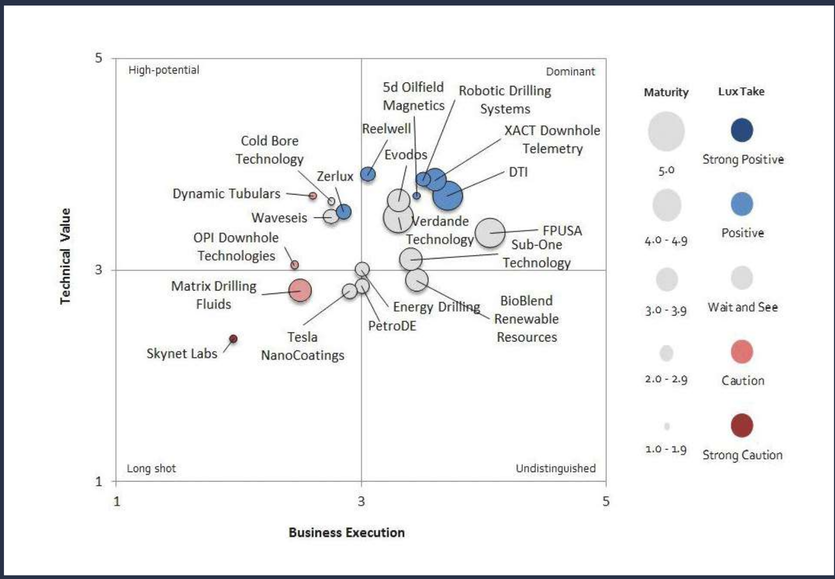
"On the completion side, with the focus on reusing as much produced water as possible, there's an increased interest in salt-tolerant friction reducers as being a very important part of the completion fluid system," said Murphy. "The more water that can be reused means less water to treat and dispose.

"Also, where we're drilling now is deeper and hotter, so we're starting to see more requirements for high-strength proppant, looking at resin coats or ceramics to handle the high-closure stresses that we're going to see in these deep Utica wells," he added.

"We're also looking at surfactant use to help improve the ultimate recovery of these wells by adding surfactants into the fluid system," he said. "Nitrate-reducing bacteria [NRB] are something that's gained a lot of acceptance in the Northeast

software to fuse data from 3-D sensors to visual models. The company is planning to leverage its digital mapping and situational awareness capabilities to provide more efficient mission planning and analysis for AUVs," she explained.

Waveseis leads "high-potential" firms. In this category, Waveseis is poised to be a long-term winner with its advanced seismic imaging for subsalt structures, which can improve well planning and aid in mitigating drilling hazards.




The Lux Innovation Grid compares cost-optimizing technologies for the drilling sector. Dominant companies are top performers that were first to the market with disruptive technologies. *(Image courtesy of Lux Research)*

**Grid quadrants**

The quadrants in the Lux Innovation Grid indicate where the companies are rated regarding introduction of new technology. "Dominant" companies are top performers. With strong business execution and technical value, these companies make strong partners and good investment targets. Companies in this group were first to the market with disruptive technologies and are poised for growth.

"High-potential" companies have attractive technologies, but struggle with business execution. This group contains both young companies struggling to gain market share and older companies unable to capitalize on their technologies. These companies are good licensing targets.

"Undistinguished" companies perform well in the market but lack technical value. These companies lack best-in-class technologies, but have strong business strategies and efficient execution. Companies in this quadrant make good partners.

"Long-shot" companies lag in execution and lack valuable technologies. The combination of poor execution and low technical value make these companies risky as investment, licensing, partnership and merger or acquisition targets, according to Lux Research. ■

(Photo courtesy of Hess Corp.)

Hess Corp. has Utica Shale drilling operations in Ohio.

for treating downhole to reduce the occurrence of sulfide generation.

"We've also found that in those wells where NRBs are being introduced, the produced water is of a better quality than the normal produced water that we're seeing from some of these wells. It takes less to actually treat that produced water to then reintroduce it into the system as wells that haven't had those NRBs associated with them," Murphy emphasized.

"Traditionally, there is not a lot of evaluation in the lateral sections of wells in the Northeast," he said. "We're starting to see a lot more interest with the engineering completion designs. People are trying to get an understanding of the formation properties in the lateral, so we're seeing increased interest in actually running some sort of formation evaluation program, be it an openhole logging suite or a cased-hole logging suite, to get a better understanding of the formation properties. Offsetting the cost of that formation evaluation run are the improvements in the production with the saving of some of the completion cost by not stimulating areas of the rock that are deemed to be non-productive."

### Increased emphasis on cementing, well life

"Flexible cementing properties that can withstand the rigors of hydraulic fracturing, traditional cement systems and cement slurries suffer when you have multiple cycles of the casing due to hydraulic fracturing is another area," Murphy explained. "Many of our customers are looking at additives to their cement system to provide compressibility and elasticity so as to maintain the bond to the formation and to maintain the bond to the casing when that casing is being expanded and contracted due to the hydraulic fracturing process.

"Well integrity is an extremely important part of the overall construction and completion process. We're running more high-end cement-bond evaluation tools, apart from the traditional 3-ft, 5-ft, CBL [cement-bond log]. We're looking at radial CBLs, and further off into the more high-end ultrasonic evaluation to get a full 360-degree understanding of the quality of the cement sheath behind the pipe," he said.

"We've seen a significant uptick in that as well, as well as making sure that the casing, where any issues with the actual casing integrity can be identified straightaway. Diverting technologies are not just for the refracturing process. We're utilizing diverting technologies for interstage diversion on new completions," he continued

"There's been a lot of work done on cluster efficiency, the number of clusters that are actually taking fluid and the amount of clusters that are actually producing fluid by utilizing a diverting unit," Murphy said. "In an interstage diversion you can really increase the number of clusters that you're actually contacting and making sure that you're effectively treating the full length of your lateral section; you're not leaving any rock left untouched.

The use of fiber optics on the outside of the casing for distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) is gaining momentum. "From the fiber you're able to accurately gauge the quality of the cement job from the DTS. Utilizing a combination DTS and DAS, you're able to get a great understanding of how effective the treatment was. Then while using the DTS to do real-time production logging, you're able to get a greater understanding of which clusters are actually contributing over the life of the well. Combine that with your microseismic, and you're able to get a really good understanding of how well you've treated your reservoir."

Operators increasingly want to ensure that the well is constructed optimally since that will save them money at the backend when it comes time to abandon that well. "Cement, casing, drilling, fracturing, the NRBs, all impact the production side as well. People are now taking into account the life of the well, and understanding that constructing a well correctly at the beginning of its life will impact how hard that well is to abandon at the end of its life," said Murphy.

"Utilizing buoyancy-assisted casing equipment to aid in getting casing to bottom in some of these long, tortuous, extended lateral sections has definitely been a technology advancement," he added.

"The HP/HT casing testable toe sleeves are another technology that we've definitely seen an increase in acceptance," said Murphy. "We're actually able to put a toe sleeve in the ground and do a casing test up to expected fracture pressure without actually initiating the toe sleeve. This saves customers time because they don't have to run in a hole with a plug and run a casing test, and then take it out and then get started fracking. By utilizing the casing-testable toe sleeve, we definitely save a lot of time."

Halliburton recently has been developing fully dissolvable fracturing plugs. "We've just started getting them in the ground. These are truly, fully dissolvable plugs that once they're in the ground you treat them as a standard frack plug. But over time and with temperature and borehole salinity, they'll actually dissolve out into just very, very small pieces. You don't have to go in and mill out the plugs after you finish completing," Murphy continued.

## Restricting production flattens decline curves

The production side of field development is "pretty exciting for Weatherford," according to Fulks. The company has sold software and hardware for artificial lift production for many years. With the advent of artificial lift in unconventional wells, the push for enhanced monitoring is changing how data are being used in designing wells to impact depletion curves.

For example, "imagine in addition to monitoring the effectiveness of the rod pump, the software, which is already up and running, also is monitoring the production gauge. We can use the real-time production data as one of the inputs, with the customer's knowledge, of course, into the selection of candidate wells for refracturing," he explained.

Even though that seems to be a simple idea, the industry has not been using production data in that way, certainly not by the service companies. "In our discussions with the operators that data hasn't been used much by them either. Now that we're starting to look at unconventional wells, their decline rates and which wells are underperforming or depleting perhaps faster than they should, we can incorporate production data into our analysis to see which wells are good candidates for rejuvenation," he continued.

This is another example of where Big Data can help make decisions about field management. Since the service companies have time on their hands during the downturn, they are doing more with the data than they ever have before.

"I really find this extremely productive. This is going to help improve recovery factors. We may not be able to attain the same efficiency as we have on the drilling side, but certainly the industry will be able to improve our completion practices because these will be based a lot more on hard data and science than ever before. You might call it a blessing in disguise," Fulks said.

For production, Weatherford has an integrated asset-management approach, addressing client challenges such as declining mature fields, integrated asset modeling and forecasting as well as helping clients optimize their production and lift strategy through real-time production monitoring, he continued.

"At Weatherford, we understand that unconventional exploitation is complex and involves a broad range of disciplines. Coupled with the economic challenges of today's market, increasing operational efficiency and optimizing production are fundamental requirements. Our unconventional solution meets that challenge and provides greater value to our clients' investments," Fulks concluded.

### Hedging keeps companies active

Each time the price of oil inches towards $50, a spate of hedges are placed by operators that will allow them to remain more active during the downturn. For example, Antero Resources placed hedges on about 1.6 Bcf/d of gas production in 2016 at an average price of about $4/MMBtu.

"Gas hedges will play a key role in supporting an active capital program despite weak gas prices. By comparison, management's 2016 guidance implies gas volumes of about 1.4 Bcf/d assuming the current production mix remains unchanged," said Barclays Equity Research Nov. 3.

"We estimate realized hedging gains could comprise about half of total EBITDAX next year based on our NYMEX gas price of $2.95 and result in an average realized gas price that is higher than the average hedge price. Antero's hedge book had a mark-to-market value of about $2.8 billion as of Sept. 30," Barclays continued.

"Management believes it can deliver that growth with a similar or slightly lower drilling and completion budget compared with $1.6 billion in 2015. The company expects to begin working through an inventory of 50 to 60 drilled but uncompleted Marcellus wells by year-end that could generate more capital efficient growth in 2016," Barclays added.

Hedges like this are how shale operators have been able to keep drilling at lower costs by focusing on more efficient production from the sweet spots. If this trend continues, it could impact how much oil and gas is being produced with higher production keeping prices lower for longer.

### New technology vs. old technology

"In a downturn, equipment manufacturers and service companies are challenged to develop new products and continue innovating. One of the biggest obstacles is changing the mindset of determining what new technology is potentially worth," said Garrett Frazier, director of sales and marketing, Magnum Oil Tools International Ltd. It is often a case of old technology vs. new technology.

Magnum offers a dissolving frack ball (Magnum Fastball) and a dissolvable frack plug (Magnum Vanishing Plug). "When developing the dissolvable technology we were focused on trying to decrease completion costs by eliminating the expense of well intervention. With the recent decrease in and well intervention prices, it has certainly made it more difficult for new technology to compete with the traditional composite plug. But this dissolvable technology eliminates risk and more importantly reduces the time it takes to put a well on production" he emphasized.

"The current industry climate is driving operators to look past new technology in favor of less expensive older technology, which oftentimes delays production. Our core value at Magnum is innovation, as we pride ourselves on developing products based on the current needs of our customers.

"But the real challenge in today's market is the amount of resources, people, time and effort that it takes to develop new technology at the price the market is willing to bear," he said.

(Photo courtesy of Magnum Oil Tools)

A Magnum Vanishing Plug, which is a dissolvable frack plug, is prepared for running into a well in Colorado.

"While the current industry can make it difficult to introduce new technologies, we have found great success with our innovations. Our job is to educate operators on the inherent advantages. Communication towards a common goal seems to be the biggest advantage," Frazier said.

The dissolvable PNP method has been very successful and is being accepted across a vast amount of shale plays. The technology is performing well in the areas where downhole conditions are suited for it.

With depleting resources during the downturn, it is harder for service companies to devote as much time and effort or as many people to a project. "Now is the time to try new technology when operating costs are down as deep as they are. There are companies with great ideas to reduce costs and create efficiencies and it's a buyer's market from an operator's perspective," Frazier said.

## Northeast

The Appalachian market is stable when it comes to downhole completions. However, stability in this instance means activity at very low levels, according to the results of a Hart Energy Market Intelligence survey conducted in late October 2015.

For operators in the Marcellus Shale, the times continue to remain economically challenging. As such, variety is not the name of the game in the region as operators there are reluctant to experiment with downhole completion techniques, citing slickwater fracking with PNP as the preferred method.

"There are no new methods being seen in a while," said one mid-tier operator that participated in the survey. "Results with current methods are good, but overall economics hinder experimentation at present."

Proppant volume averages 10.5 million pounds of sand per lateral, with some ceramic proppants being used for deeper HT/HP wells, the survey noted.

Stage spacing has stabilized at just under 200 ft with three to four perf clusters and 250,000 lbs of sand per stage on average.

The survey saw an increase in the percentage of wells completed with zipper fracks. Survey respondents reported 62% of regional wells were completed using the technique, up from 51% last quarter.

These results are reflected in the third-quarter efforts of Southwestern Energy (SWN) and Range Resources presented in recent earnings calls. SWN, in looking to maximize the value of the acreage secured across the region, is working the learning curve to its advantage in its southwest Appalachia holdings.

"We set a number of drilling and completion company records and achieved pacesetter performance during the third quarter," said Bill Way, the company's president and COO, in the third-quarter earnings call in late October. "One example is the work done on the Alice Edge Pad in Ohio County, W. Va., where nine wells are expected to begin production during the fourth quarter. One well on this pad had the longest measured depth the company has ever drilled on a single well at over 19,000 ft. The lateral length alone on this well is over 12,000 ft.


The sun rises at a Hess Corp. drilling site in Ohio. Hess is applying Lean manufacturing techniques in the Bakken and in the Utica. A primary goal of Lean manufacturing is to create a true learning organization. Hess has demonstrated that when lessons learned in the Bakken are applied in the Utica it can greatly improve learning curves and in turn reduce waste and bolster efficiency even faster. Some of the Lean lessons learned in the Utica are often applied back to the Bakken operations.

"This pad also had the company's longest combined total completed lateral length on a single pad at over 86,000 ft, and utilized more than 200 million pounds of sand in the completion operations, a new single-pad record."

The company for the third quarter had net production of 37 Bcfe with a net exit rate of 407 Mcfe/d, with 40% of the 2015 wells anticipated to be drilled and completed this year remaining to be brought online during the fourth quarter, Way added.

Five wells that were drilled and completed by the company in the third quarter are, according to Way, "materially outperforming their offset wells that were drilled and completed by the previous operator."

Citing its work at the Charles Frye Pad, also located in Ohio County, W. Va., there are three Southwestern drilled and completed wells online. These wells outperformed its offset wells by 54%, with an average EUR per 1,000 ft of completed lateral foot (CLAT) of 2.1 Bcfe.

"The wells in this area are being drilled nearly 100% within a tighter landing zone, where we have determined that productivity is greatly enhanced," he said. "In addition to the drilling accuracy, completion activities are being optimized, and we are seeing improved results as well. The wells are being completed with tighter stage spacing of about 260 ft and increased sand volumes of more than 2,000 lbs to as much as 3,000 lb/ft."

The company is seeing its total well D&C costs going below $1,000 per CLAT, he noted. "This compares to over $1,200 per CLAT that was assumed for the acquisition economics."

For Range Resources, success is being realized in longer laterals and increased frack stages. In its

acreage in southwest Pennsylvania for August and September, the company increased the average lateral length by 38% over the average for 2014, according to Ray Walker, the company's executive vice president and COO, during the third-quarter earnings teleconference in late October 2015.

"Despite drilling 38% longer laterals, our drilling costs per well have actually declined by 10%. We recently finished a five-well pad at 45% less cost per foot as compared to 2014," he said. "This was all accomplished by a combination of service cost reductions, the application of improved drilling technology and improved drilling efficiencies.

"On the completion side, we've achieved a 44% increase in frack stages per day as compared to last year. Three recent pads totaling 427 frack stages achieved an average between eight and 10 stages per day," he noted.

"Combined with service cost reductions, we've seen completion cost drop by more than 34% compared to this time last year. We believe that these efficiencies can continue to improve going forward," said Walker.

"One of the most important factors in improving capital efficiency is drilling longer laterals. Our average lateral length this year is about 6,000 ft, and we expect to see it closer to 7,000 ft next year and still growing longer after that," he continued.

"Recently we brought online a new five-well pad in the dry area of southwest Pennsylvania. The wells are producing under constrained conditions into a high-pressure gathering system, with an average initial sales rate per well of over 26 MMcf/d. The five wells averaged 8,200-ft laterals with 42 stages. I also want to emphasize that the total well cost, including facilities, was less than $900/ft."

The company's efforts include two wells in the Utica Shale. The Washington Co., Pa., wells are "producing into the new dry gas pipeline, and we're currently drilling a third well on a nearby pad."

Reservoir modeling for the first well, according to Walker, puts the EUR in the range of 15 Bcf from a 5,400-ft lateral with 32 stages.

"On a normalized basis that's approximately 2.8 Bcf/1,000 ft of lateral and is in the top tier of Utica wells to date. Again, looking at all the production data from across the entire Utica play, our first well appears to be in the Top 10 performers on both an absolute and a per-1,000-ft basis. And the second well is better.

"The first two wells are opposing laterals off the same pad, but the completions were different. The first well was completed with 400,000 lbs of proppant per stage, or approximately 2,400 lb/ft. And the second well was completed with 500,000 lbs per stage, or a little over 3,000 lb/ft. Both wells incorporated 100 mesh sand and 30/50 ceramic proppant and were similar in reservoir pressure, as you would expect, being direct opposing offsets.

"On the second well, we also utilized the choke management program designed to manage the near wellbore drawdown. The second well is currently flowing to sales at approximately 13 million a day. It's been online a very short time, but early indications suggest it will be better than the first. It was a 5,200-ft lateral also completed with 32 stages. As we evaluate these two wells and continue to develop our reservoir modeling, we will let the data and the modeling guide us in optimizing the completion design for our third well."

## Midcontinent

In the Midcontinent region, operators are doing just enough to finish program work and complete 2015 budgets. Meanwhile, service companies report that operators have gone back to vertical wells and workovers to maintain production levels. More costly horizontal wells have been postponed until commodity prices recover, according to Hart Energy Market Intelligence Series.

When operators drill horizontal wells, they delay completions. Midcontinent operators need $50 to $60 oil to make vertical wells economical and as much as $70 oil to make horizontal drilling viable.

Survey respondents insist pricing is at bottom. The average per-stage price for hydraulic fracturing has fallen to $31,000, which is among the lowest prices in the domestic market. Recent price reductions have come mostly due to sharply reduced costs for sand and chemicals that operators have negotiated with suppliers.

Operators are doing recompletions and acid cleanouts to restore production volumes in existing wells in the Midcontinent. This segment constitutes about 14% of job mix with new fracks accounting for the rest. Companies also are looking at refracks but actual demand is low as discussions continue on the best methodologies, stated the Market Intelligence Series.

At least one company has been working in the Southern Oklahoma Hoxbar Oil Trend (SOHOT) with one drilling rig. Unit Drilling Corp.'s current plan is to keep its drilling rig operating through the end of the year, according to the company's third-quarter 2015 results.

In the SOHOT area during the first nine months of 2015, a total of three Marchand wells and nine Medrano wells were completed. Production during the quarter averaged 6,574 boe/d, which is an increase of 186% as compared to third-quarter 2014. Unit will focus the SOHOT drilling program primarily on oil in the Marchand bench, which produces higher returns under current commodity pricing.

### Gulf Coast

Shale production proved to be resilient in two ways, according to Rystad Energy's November 2015 *Shale Newsletter*. Operators have benefited from lower unit costs and higher efficiency. At the same time each well's performance rose because of high grading and better completion techniques.

In the Eagle Ford Shale for example, the average breakeven was about \$70/bbl in 2012 and 2013. In 2014, the wellhead breakeven price dropped by about 10% reaching around \$63/bbl. For 2015, the reduction is estimated to be around 25%, noted Rystad.

However the average breakeven price does not provide a good overview of the profitability of a play. In 2015, operators are focusing the development on the very core areas where breakeven prices are significantly below average, the report continued.

The best wells in the Eagle Ford have breakeven prices lower than \$40/bbl. "The core counties include Karnes, DeWitt and part of Gonzales counties, where the main companies are ConocoPhillips, Marathon Oil, BHP Billiton and EOG Resources. ConocoPhillips is currently running three rigs in DeWitt County, where BHP Billiton has seven rigs. Marathon Oil also operates seven rigs in Karnes County. Wells located in Dimmitt and Webb counties are also considered core, where the main operators are Anadarko and Chesapeake," Rystad said.

Anadarko Petroleum Corp. is working on its Eagle Ford Shale play to continue cost cutting, work faster and cut the number of drilling rigs even while oil production increases.

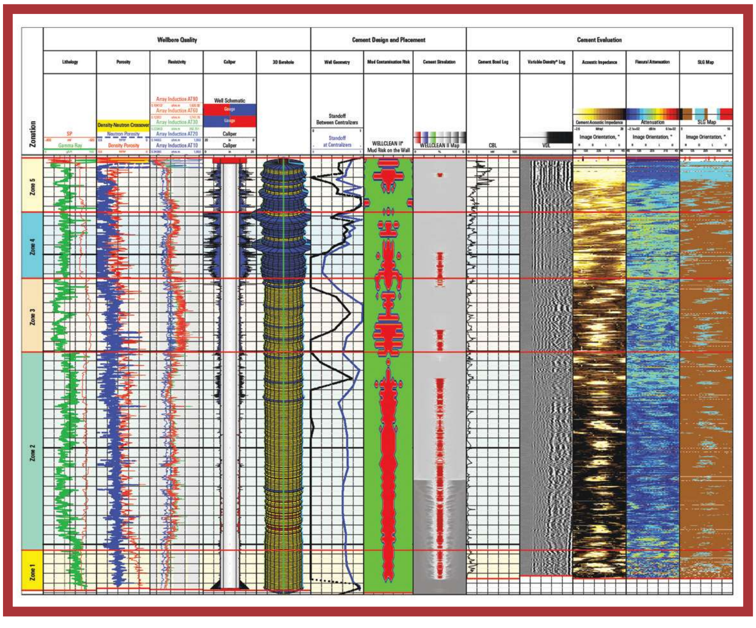
In a recent investor update, Anadarko said that its drilling time in the Eagle Ford has improved 8% so far this year compared with 2014, which equates to drilling the same number of wells with fewer rigs. For 2015 the company will operate about four rigs in the play, drill 200-plus wells and defer about 40 well completions.

The company is testing the play's stacked-pay potential and is using longer laterals at lower cost.

## Case study:

### STOPPING GAS MIGRATION, PROPERLY ISOLATING SHALLOW FLUIDS

An operator in the Eagle Ford Shale was not satisfied with the well integrity resulting from conventional cement barrier placement practices and decided to perform an integrated analysis on the well to optimize operations. The operator also needed to develop best practices to mitigate shallow fluids based on the well integrity workflow interpretation of a 13½-in. openhole section using formation evaluation logs, cement barrier placement data acquired during job execution and cement bond logs for the 10¾-in. surface casing.




Data integration and analysis using Invizion Evaluation service enabled the operator to determine the quality of the cement bond and confirm that the cement had properly set. *(Image courtesy of Schlumberger)*

Working with Schlumberger, the operator drilled a 13½-in. hole vertically from surface to 4,525-ft MD while maintaining inclination below 1.5 degrees, with top of cement designed to reach the surface and isolate potential flow zones to enable drilling to the next section. Based on data from offset wells, the potential flow zone was identified between 250-ft MD and 600-ft MD. An integrated team of petrotechnical experts collaborated to optimize cement barrier design by using the openhole formation evaluation and caliper data.

Although the wireline openhole logs did not confirm the potential gas flow zone seen at the offsets, a gas migration system was carefully planned to cover the annulus length. Lead cement slurry using a lightweight cement blend with a gas-migration control agent and tail slurry proved to be a quicksetting design using Class A cement.

A centralization program was designed to provide better standoff across the potential flow zone above 3,000-ft MD. Isolating the surface barrier was paramount to ensure that the 5½-in. lateral could reach 12,947-ft MD.

After losses were observed during the cement barrier placement, the Isolation Scanner cement-evaluation service was run to verify annular zonal isolation. Using the Invizion Evaluation service's well integrity workflow, a comprehensive log display was generated within four hours of processing the Isolation Scanner service's logs. Interpretation was enhanced by having cementing placement information and openhole logs displayed in the same place, which enabled easier identification of top of solids and azimuthal cement coverage of isolation areas.

A solid, liquid and gas map was used to complete further analysis, which allowed the operator to identify post-placement indication of shallow water and confirm the need for the external casing packer as a secondary surface barrier.

As a result of the integrated approach, no gas migration was observed, proper isolation for shallow fluids was implemented, drilling continued to the next section, and the 5½-in. segment of the lateral was successfully completed as planned. The integrated data interpretation workflow and cement job recommendations provided critical guidance to achieve isolation of shallow fluids by the surface casing for continued well integrity.

### Permian

The Permian play is one of the newer opportunities. Operators are still learning about the various shales throughout the basin and what technologies will most benefit drilling and production.

Anadarko is focusing its efforts on an emerging oil play in the Delaware Basin Wolfcamp Shale. As a result of improved well recoveries, now approaching 1 MMboe per well; efficiency gains; and cost reductions in the Wolfcamp, this emerging oil play is competing with the company's Wattenberg acreage in terms of the most attractive economics in the company's U.S. onshore portfolio, according to its third-quarter 2015 report Oct. 27.

> **As a result of improved well recoveries, now approaching 1 MMboe per well; efficiency gains; and cost reductions in the Wolfcamp, this emerging oil play is competing with the company's Wattenberg acreage.**

"Anadarko has successfully reduced drilling costs in the Wolfcamp Shale to around $7.5 million per well with the expected ability to achieve further reductions of $1.5 million to $2 million per well with a future move to field-wide pad drilling. The company wants to optimize spacing and completion design as well as utilize longer laterals.

During the quarter, the company also successfully drilled its first test well in the Second Bone Spring, which demonstrated an initial production rate of more than 1,000 bbl/d," Anadarko stated. The company plans to operate seven-plus rigs in the Delaware Basin in 2015, drill 70-plus wells and defer 40-plus well completions.

RSP Permian (RSPP) is drilling both horizontal and vertical wells in the Wolfcamp and Lower Spraberry. "RSPP continues to be at the forefront in developing the Lower Spraberry bench; its Wolfcamp long laterals also look impressive. We are eager to see how its Glasscock County wells perform; if successful, those could enhance the depth of its quality inventory," said Sam Burwell, Canaccord Genuity analyst Nov. 3.

In its third-quarter 2015 report Nov. 2, the company reported it completed 11 operated horizontal wells in the Lower Spraberry (five), Wolfcamp A (two) and Wolfcamp B (4). It also drilled five operated vertical wells.

Four wells in the Spanish Trail area in the Wolfcamp A and Wolfcamp B had average lateral lengths over 11,000 ft and averaged 53 stages.

RSPP completed a spacing test in the Lower Spraberry on five horizontal wells in two different operating areas, testing 500-ft spacing in the same stratigraphic interval (not in a chevron development pattern). Early production data indicates the wells are ahead of type curve, according to the quarterly report.

Occidental Petroleum Corp. in its third-quarter 2015 report Oct. 28 stated that its domestic average daily production increased by 17,000 boe to 332,000 boe in the quarter with the majority of the increase coming from oil production, which grew by 22,000 bbl/d to 204,000 bbl/d. All of the increase was attributable to its Permian Resources.

Stephen Chazen, president and CEO, Occidental, at the Bernstein Strategic Decisions Conference 2015 on May 28, listed four reasons for the company's improvement: investing in characterization and optimization to improve well productivity; applying manufacturing principles to improve time to market and cost; aggressively working with suppliers to improve productivity and lower cost structure; and enhancing base management and well maintenance operations.

Pioneer Natural Resources Co. believes it can grow production by more than 15% over the next three years with fewer rigs. The company in November was operating 18 rigs in the Spraberry/Wolfcamp in the Permian.

Joey Hall, executive vice president, Pioneer, speaking at Hart Energy's Executive Oil Conference on Nov. 10, said, "We've discovered that we can keep production growth as we've projected with less."

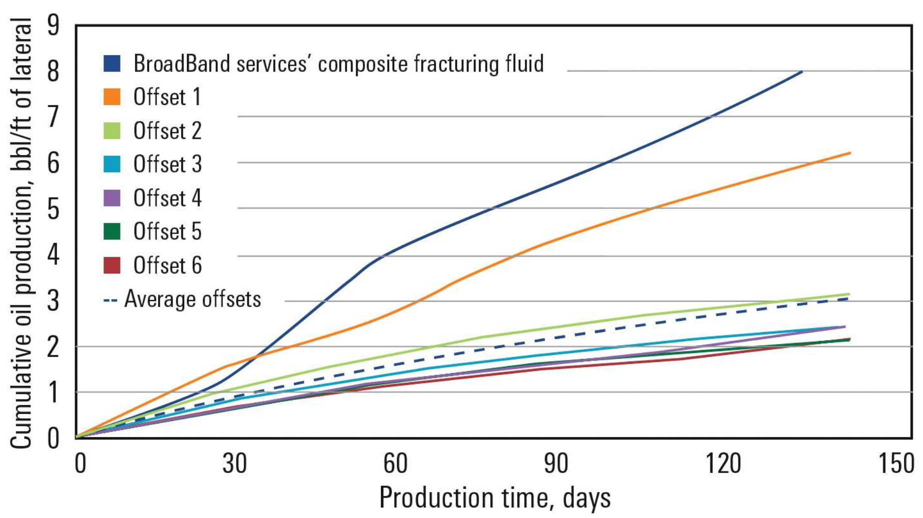
In the third quarter, Pioneer completed 33 horizontal wells in the northern Spraberry/Wolfcamp, targeting Wolfcamp A (three wells) and Wolfcamp B (30 wells). Nineteen wells of the 30 benefited from Pioneer's completion optimization program, which includes optimizing stage length, clusters per stage, fluid volumes and proppant concentration. For Pioneer, it's all about finding the right formula for optimization, which might get tricky. During the downturn, it is focused on its best areas, cutting costs and keeping its balance sheet in shape.

## Case study:

### COMPOSITE FRACTURING FLUID ENHANCES PROPPANT DISTRIBUTION

Comprising sandstone layers separated by carbonaceous and shaly siltstones, the Bone Spring Formation in the Permian Basin is primarily developed using horizontal wells with multiple fractures. For a particular well, Endeavor Energy Resources needed to maximize the proppant amount per foot of lateral while reducing the fracture face damage caused by polymer presence in the fracturing fluid. Slick water, while less damaging than other fluids, is an ineffective fluid

In comparison with the offset wells completed using slickwater and similar proppant amounts, the BroadBand services' well outperformed all the offset wells by more than 33%. *(Image courtesy of Schlumberger)*



(Photo courtesy of Liberty Oilfield Services)

Liberty Oilfield Services performs hydraulic fracturing on a well in the Denver-Julesberg Basin.

transporter that leads to proppant settling on the fracture bottom close to the wellbore. Its use had led to poor fracture height coverage and limited the formation-to-fracture contact areas, which are essential for production in tight formations.

Endeavor contacted Schlumberger to resolve the issue. It proposed using BroadBand services' composite fracturing fluid, which features next-generation fibers and is applied in high-frequency sweeps to minimize potential screenouts. A total of 32 fracturing stages out of 33 were pumped with the service's composite fracturing fluid—80% slickwater tailing with 10-lbm linear gel—with 2 lbm of proppant added per gallon of fluid. Additionally, asymmetric pulses—30 sec of slurry for every 10 sec of clean fluid—were applied.

The well was stimulated as designed, and no operational issues were reported. After stimulation, the well returned to production and was monitored for 145 days. In comparison with offset wells treated with similar amounts of proppant and water, the well treated with BroadBand services' composite fracturing fluid had effective vertical proppant distribution with an enlarged reservoir contact area, which led to a 33% production improvement over that of the best-performing offset well. Due to the success of this operation, Endeavor plans on using BroadBand services' composite fracturing fluid when developing future wells in the Bone Spring Formation, Permian Basin.

### Western U.S.

For operators working in the Western U.S. basins, it is the tale of two shales. To the north is the Bakken/Three Forks that stretches across North Dakota, while the Niobrara spans across portions of northern Colorado and southern Wyoming.

Before completions activity slowed to a near standstill, operators in the Bakken were finding success with the tried and true completion methods like PNP and large proppant volumes in their slickwater fracks, according to a Hart Energy Market Intelligence Survey conducted in August 2015. Operators there will certainly make good use of the additional year granted to them by regulators to frack drilled but uncompleted wells. The North Dakota Industrial Commission unanimously approved in October the change from one to two years to bring the wells into production, according to a Reuters article.

Continental Resources, one of the Bakken's largest operators, announced in September plans to defer completions of its drilled wells to 2016. In the time since that announcement, the company has redoubled its focus on making improvements to its drilling and completing processes.

"Our Bakken drilling team has been committed to decreasing the spud-to-TD drilling times throughout the year," said Jack Stark, president and COO of Continental. "And in the third quarter, they achieved an average reduction of 15% in days spent drilling compared to the average for the first quarter.

The average day spud-to-TD during the first quarter was 17.6 days and 16.6 days in the second quarter.

"During the third quarter, it was an impressive 15 days, and they tell me they're not done yet. Some of the biggest strides are being made in the days in the lateral. During the quarter, we set a new Continental record by drilling a 9,490-ft lateral in a remarkable 2.4 days."

Stark's comments came during the company's third-quarter earnings call held in October. In the same call he noted that the Bakken completions team "has taken a new approach to drilling out plugs that has reduced average drilling, drill-out times by 50%, saving approximately $300,000 per well.

"Overall, our enhanced Bakken completion well costs are down 27% year-to-date to $7 million per well, thanks to the drilling and completion teams' ingenuity and service cost reductions," he added.

For EOG Resources, the focus in the Bakken was on completing infill wells in its core areas in the third quarter. EOG's activity in North Dakota remains focused on the Bakken core and Antelope Extension areas, according to its third-quarter report. The company continued to improve its drilling and completion techniques including the expanded use of high-density completions.

"Even though these infill wells are among oil-producing wells, our integrated completion approach ensures that we effectively stimulate the reservoir and deliver high rate of return and maximum value," said David Trice, executive vice president of E&P for EOG, in an earnings call held in November.

"An example of infill wells in our core acreage is a three-well pad on the Parshall 3029 unit. This pad came online with an average initial rate of over 1,800 bbl/d and 1 MMcf/d of rich natural gas per well," he said. "These wells are spaced just 500 ft apart and use shorter laterals that average less than 6,000 ft. Our latest Bakken wells are averaging just 7.6 days spud-to-TD for an 8,400-ft lateral and cost $7 million.

"This is a reduction of 20% from 2014. In addition, we have lowered lease operating expenses in the Bakken core area up to $5 a barrel through infrastructure investment such as water gathering systems."

In the Niobrara, EOG is refining its drilling techniques and implementing its high-density completions, Trice noted in the call.

In the third quarter, the company brought online a four-well pad targeting the Codell Sandstone. The wells "produced an average initial rate in excess of 1,100 bbl/d with 600,000 cf/d of rich natural gas per well using an average lateral length of 8,700 ft. Recent well costs in the Codell are averaging just $7 million for a 9,400-ft lateral."

For Noble Energy, slick water is the primary method of choice for its D-J Basin wells. The company's refined completion techniques continue to enhance overall productivity. One development area brought online in the third quarter 13 wells in the Wells Ranch Field, including nine completed with slickwater fluid and four completed with hybrid-gel systems, a third quarter report noted.

"The cumulative production from the slickwater completions is outperforming the hybrid-gel wells by more than 20% on average after 30 days," the earnings reported stated. "For a standard lateral length well, those designed with slick water are approximately 10% lower total well cost versus hybrid-gel wells."

In the company's recent earnings presentation, Gary Willingham, executive vice president of operations for the company, noted that they are "constantly looking for ways to improve our completions. We don't expect one optimal completion design to work across the entire field. It's likely to be different, depending on where we are operating at any given time.

"Where we've been focusing the slickwater completions most recently is in our East Pony Field and Wells Ranch Field, which are in the oilier part of the field."

## Case study:

### RSS DESIGNED TO MINIMIZE TORTUOSITY, DELIVER HIGH-QUALITY BOREHOLE

WPX Energy was drilling extended reach wells in the Williston Basin to target the Bakken and Three Forks formations. Using conventional motor BHAs, WPX experienced premature tool wear and extreme borehole tortuosity in these abrasive environments. Dissatisfied with the results from conventional motor BHAs, WPX sought to find a system capable of high ROP while maintaining a high-quality borehole.

Schlumberger recommended the PowerDrive Orbit vorteX motorized RSS, which can perform at speeds up to 350 rpm while maintaining directional control and consistent steerability. Equipped with hold inclination and azimuth mode, this motorized RSS automatically maintains the trajectory specified to minimize tortuosity and achieve target TD. The PowerDrive Orbit vorteX RSS also features an advanced actuation pad designed with metal-to-metal seals to tolerate corrosive drilling fluids and challenging hydraulic designs.

Using the IDEAS integrated drillbit design platform, Schlumberger modeled downhole conditions and operator requirements, such as a handling speed of 0.29 rev/gal U.S. to select the exact configuration of directional PDC bit that would optimize drilling. SlimPulse retrievable MWD service was also recommended to mitigate vibration and stick/slip by providing formation evaluation and BHA drilling mechanics data.

Using the recommended BHA configuration, WPX reached the target TD of its nearly 3-mile lateral nine days faster than the average achieved in five nearby lateral sections drilled using conventional motor BHAs. As compared to the best of those five lateral sections, the PowerDrive vorteX RSS saved 3.5 days.

As per WPX's objective, the PowerDrive Orbit vorteX RSS achieved an ROP of 76 ft/hr, a 20% increase over the average ROP for other wells in this field. In part, this was accomplished by elimi-

# Newly Designed Missile Could Cut Pump Downtime, Maintenance Costs

By **Scott Weeden**, Senior Editor, Drilling

The lifespan for a valve in a hydraulic fracturing pump is about 40 stages. At the end of slickwater fracking of an average well pad with eight wells and 50 stages per well, a frack fleet of 10 quintuplex pumps will have replaced 1,000 valves. An innovative new frack manifold trailer (missile) uses a device called a pressure exchanger to pump proppant-laden fluid downhole without passing through a frack pump.

"We know for a fact that if we only pump water that the pumps will last a lot longer. Our downtime decreases, maintenance costs go down and the life of the pumps goes up," said Ron Gusek, vice president of technology and development, Liberty Oilfield Services.

"In this missile if we're successful in our testing in the field, and so far the yard testing indicates we will be we will have an opportunity to significantly impact the efficiency of a frack fleet on location lower maintenance cost, less maintenance time, more pump time and lower cost per stage," he emphasized. "We know if we don't have to pump sand through these pumps that the wear factor goes down significantly."

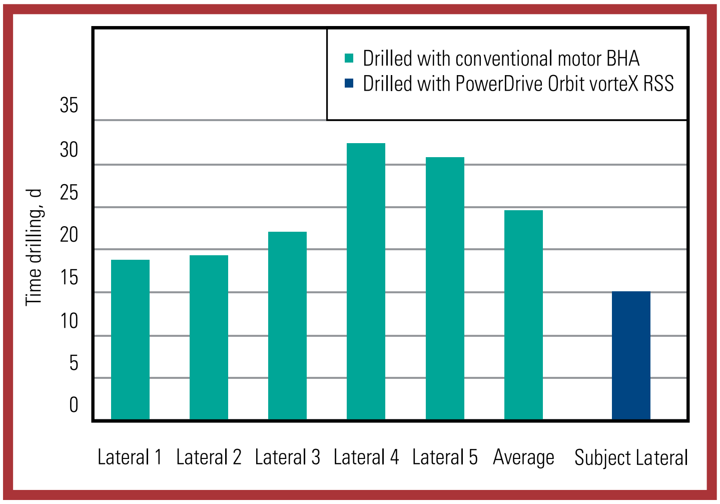
**How the system works**

The primary technology behind the missile is a pressure exchanger. "It is called VorTeq. It is similar to a turbocharger in a car. It is a device that takes energy from one fluid stream and transfers it to another fluid stream. A turbocharger spins a shaft that takes energy from the exhaust stream and turns another turbine. That pressurized air goes into the inlet stream," Gusek explained.

According to Gusek, the pressure exchanger is a more efficient version of this idea as it does not have a mechanical intermediary. Pressure is transferred directly from on fluid to the other.

The pressure exchanger is like a revolver chamber in a six-shooter. It has a series of ports all the way through the cylinder. As the device rotates the ports on one side are exposed to a low-pressure slurry consisting of water, proppant and chemicals that comes from the blender. It rotates further and is exposed to high-pressure clean water from the other side of the missile.

"We pressurize clean water from the water tanks to treating pressure using the frack pumps," Gusek said. "Then we displace the low-pressure




The PowerDrive Orbit vorteX RSS saved WPX 3.5 days as compared to the best of five nearby motor BHA runs and reached TD nine days faster that the average of those five wells.

*(Image courtesy of Schlumberger)*

nating the need to slide. The wellbore was drilled so smoothly that no reaming was required, and WPX was able to set casing to bottom in one run.

Additionally, gamma ray measurements from the SlimPulse service helped WPX confirm downhole steering commands, enabling WPX to optimize well placement. This 14,717-ft section set a lateral footage record for Montrail County. ■

slurry that is in the exchanger with clean water at high pressure elevating the slurry to treating pressure. The fracture fluid is then pumped down the treating line to the well."

**Field test scheduled**

"The field test is scheduled for a job in mid-December. We've done all the yard testing. Energy Recovery wants to test it on a job that uses ceramic proppant first. That was their preference because that was what they had done the bulk of their testing in the lab with, rather than introducing sand as another variable," Gusek explained.

The job will be done with Liberty Oilfield's sister company Liberty Resources in the Bakken. "Once we're done with field testing we're going to build generation two of this device. We've uncovered some things we could do better in the future. We have the opportunity to simplify it and make it easier to use in the field," he said.

After the second generation is built and tested in the field, the company will build a commercial model. If Liberty does dream up some improvements, Energy Recovery has the rights to incorporate those improvements into the device, which would be shared, Gusek added.

Liberty Oilfield has been working with Energy Recovery since about April 2015 to do all of the yard testing. On Oct. 19 Energy Recovery announced it signed a $125 million deal with a unit of Schlumberger for the VorTeq technology. Going forward, only Liberty


Low-pressure slurry with proppant and chemicals is pumped from the blender to one side of the missile. High-pressure clean water is pumped down the other side. No proppant goes through the high-pressure pumps, reducing wear and tear on valves, seats and fluid-ends.

*(Photo courtesy of Liberty Oilfield Services)*

and Schlumberger will be able to use the missile.

Schlumberger "is certainly going to bring all their engineering horsepower to bear on this device, and they've probably got some ideas we haven't thought of. It's probably a win-win in that regard," he said. ■

*Acknowledgement*

*Information from SPE paper 174806-MS, "Innovative New Frac Manifold Trailer Offers Step Change in Slickwater Pumping," was included in this article.*

(Photo courtesy of Navitas Midstream Partners LLC)

# An Urge to Merge
## as Growth Continues

By **Paul Hart**, Editor-in-Chief, *Midstream Business*

*Some growth as well as M&A activity continued in 2015 despite the weak commodity price environment.*

The midstream entered 2016 in unfamiliar territory. The sector's breakneck growth of the past five years—spurred by rapid development of North America's unconventional plays—slowed in 2015 as the energy industry pulled back in response to dropping commodity prices.

But "slow" is a relative term. Midstream operators still have billions of dollars of expansion projects underway or have committed to planned projects that will assure capital expansion remains brisk well into the next decade. The unconventional plays are in new, underdeveloped regions. For mature areas such as the Permian Basin, unconventional output has overwhelmed existing infrastructure or requires separate handling facilities.

Some growth in oil and gas production from the unconventional plays continues, even in the currently weak commodity price environment. Midstream is a customer-service business, so North America's vast midstream infrastructure of gathering lines, processing plants, transportation systems and terminals must change to fit new producer-to-customer profiles.

Meanwhile, merger and acquisition (M&A) activity builds. There's still money available from investors attracted to the comparatively good returns offered by midstream players in a so-so economy. Midstream observers generally agree the small players will get fewer in number and the big players will get bigger in the next few years.

A challenge to many firms has been the sharp drop in midstream share and partnership unit prices, mostly a guilt-by-association response by investors to low commodity prices plaguing oil and gas producers. The midstream-heavy Alerian MLP Index recorded a 30% decline through the first three quarters of 2015 and remained weak in the final quarter.

Midstream's lot is not bad in comparison to upstream producers but a substantial change from years of climbing midstream share prices—and that has impacted M&A deals. Weak stock prices give acquirers less money to work with and bring smaller rewards to those being acquired.

"The equity marketplace has clearly been difficult, particularly for the small and mid-cap players," CFO of Azure Midstream Partners LP Eric Kalamaras told Hart Energy. "It's been a little bit more favorable for the larger caps or for those that have very strong growth stories."

However, most midstream operators today operate on a fee-for-service or "toll gate" business model. That assures more level financial returns, even with some decline in oil and gas production, than commodity-based service models that dominated in the past. The hardest-hit midstream operators have been those that still have a large proportion of the percent-of-proceeds, commodity-based pricing mechanisms.

And like most industries, a rapid growth period created dozens of comparatively small, mostly privately held midstream players that are not large enough to finance expansions on their own. The greater immediate reward for their financial backers is often to sell these smaller firms—usually backed by private-equity firms—to larger midstream players.

Analysts expect fewer but bigger midstream players in the near future as the M&A trend continues. The large players have an added advantage

Facing page: Navitas Midstream's Midland County Processing Plant serves producers in the core of West Texas' active Permian Basin.


(Photo courtesy of Boardwalk Pipeline Partners LP)

This compressor station at Hardinsburg, Ky., keeps gas moving through Boardwalk's Texas Gas Transmission system.

of public ownership that creates another source of capital through stock sales.

The sector has been greatly fragmented, and business combinations that can support the strong payouts typical of the MLPs common among midstream operators have come into vogue. One trend developing is a move away from MLPs to conventional corporations—particularly among the biggest midstream players. These firms find it hard to grow or acquire assets rapidly enough to assure rising partnerships distributions. For them, conventional capital gains and stock dividends provide better rewards for investors.

"We thought over time as the basins matured, as the growth profiles matured, there would be an opportunity for consolidation," Christopher Sighinolfi, senior vice president, U.S. equity research with Jefferies LLC, told Hart Energy. "I think you're starting to see that. I think that's been accelerated by what's transpired on the commodity price front."

"What we see is that there's going to be an increasing consolidation trend," Azure's Kalamaras said. "I think you started to see it over the past year or two, and that was in a more bullish environment. That really exacerbates itself in a weakening commodity price environment where everyone starts feeling more exposed about where their position really lies, particularly when you start constraining some capital sources, so what we're expecting to see is a fair bit more consolidation and really more merger activity, if you will, on a corporate or partner-to-partner side."

The biggest midstream M&A deal of 2015 was Energy Transfer Equity's pursuit of The Williams Cos. Inc., which in turn had just completed its acquisition of Access Midstream Partners.

Much of the M&A activity involves asset dropdowns from a MLP general partners or corporate parents to MLP operating partners. Also, many upstream producers actively sold off midstream assets in 2015 to midstream operators to gain much-needed cash as commodity prices remained low. That trend may abate if oil and gas prices rise during 2016.

In this section, the most active midstream companies are highlighted, and snapshots of their 2015 year and plans for the future are offered.

## Boardwalk Pipeline Partners LP

- **Alerian adds Boardwalk to its MLP, equal weight and natural gas indexes**
- **Continues more than $2 billion in growth projects**

In February 2014 Boardwalk slashed its quarterly distributions from $0.5325 to $0.10 per unit and drastically reduced its distributable cash flow (DCF) forecast. This substantially improved the partnership's DCF coverage, but the unit price plummeted as investors sold its units.

But the move was "the right thing to do," CEO Stan Horton told Hart Energy, and it allowed the firm to keep its long-term focus in a challenging business environment.

In March 2015 Boardwalk announced its wholly owned subsidiary Boardwalk Pipelines LP closed a public offering of an additional $250 million aggregate principal amount of its 4.95% senior notes due December 2024. Boardwalk originally offered and sold $350 million in aggregate principal amount of its 4.95% senior notes due 2024 in November 2014. It said it intends to retire a portion of the outstanding $250 million aggregate principal amount of its Texas Gas unit's 4.60% notes and reduce outstanding borrowings under its revolving credit facility.

A more stable financial base allowed Boardwalk to emphasize that it will continue an ambitious internal growth strategy in the next few years. The company has spent well over $2 billion since 2011 on a number of capital projects—with an estimated additional $1.6 billion in capex work to come in out years.

These projects will add nearly 3 Bcf/d of natural gas transportation capacity, expanded brine services and expanded ethane and ethylene storage and transportation assets.

## Cheniere Energy Partners LP

- **Began commissioning of its first liquefaction train at Sabine Pass terminal**
- **First LNG export expected to leave port in early 2016**

The U.S. has prospects to become a major natural gas exporter with multiple midstream firms seeking federal licenses to build and operate natural gas liquefaction facilities. This new market for unconventional gas has the prospect to spur further growth in the midstream sector, which will need to invest billions in new gas processing equipment and pipelines as well as the gas liquefaction plants, terminals and docks.

Cheniere Energy will be the first to market. Its Sabine Pass liquefaction plant in Cameron Parish, La., across from Port Arthur, Texas, started commissioning the first liquefaction train in October 2015, according to industry reports. The firm said the plant's first load of exported LNG could weigh anchor by year-end 2015.

Cheniere had received U.S. Department of Energy permission to ship 2.2 Bcf/d of gas from Sabine Pass, which was increased to 3.6 Bcf/d in a June 2015 ruling.

Long term, Cheniere plans to build six liquefaction trains at Sabine pass with a combined capacity of 28 million tonnes per annum (mtpa) and a 3.8-Bcf/d export capacity. That would represent nearly 3% of total U.S. daily gas production in late 2015. Works is underway on the first five trains, and Cheniere said it will make a final investment decision by year-end 2015 on a sixth train for Sabine Pass.

Cheniere Energy began liquefying gas in late 2015 at its sprawling Sabine Pass plant in Cameron Parish, La. The plant's first shipment of LNG was scheduled for the first part of 2016.


(Photo courtesy of Cheniere Energy Inc.)

The company also is developing a five-train LNG terminal across from Corpus Christi, Texas, with first shipments expected in 2018. It also has two additional plants proposed at Louisiana sites that could begin production in 2021. If all are built, Cheniere would be capable of exporting 59.9 mtpa.

Securing feedstock for all of that liquefaction capacity has made Cheniere a major midstream player. The company said through third-quarter 2015 it has signed agreements with multiple producers and pipelines, representing about 4.2 Bcf/d.

## DCP Midstream Partners LP

- **Continued to rank as nation's largest natural gas processor and NGL producer in annual Midstream Business survey**
- **Corporate parents did asset dropdowns to strengthen DCP's balance sheet**

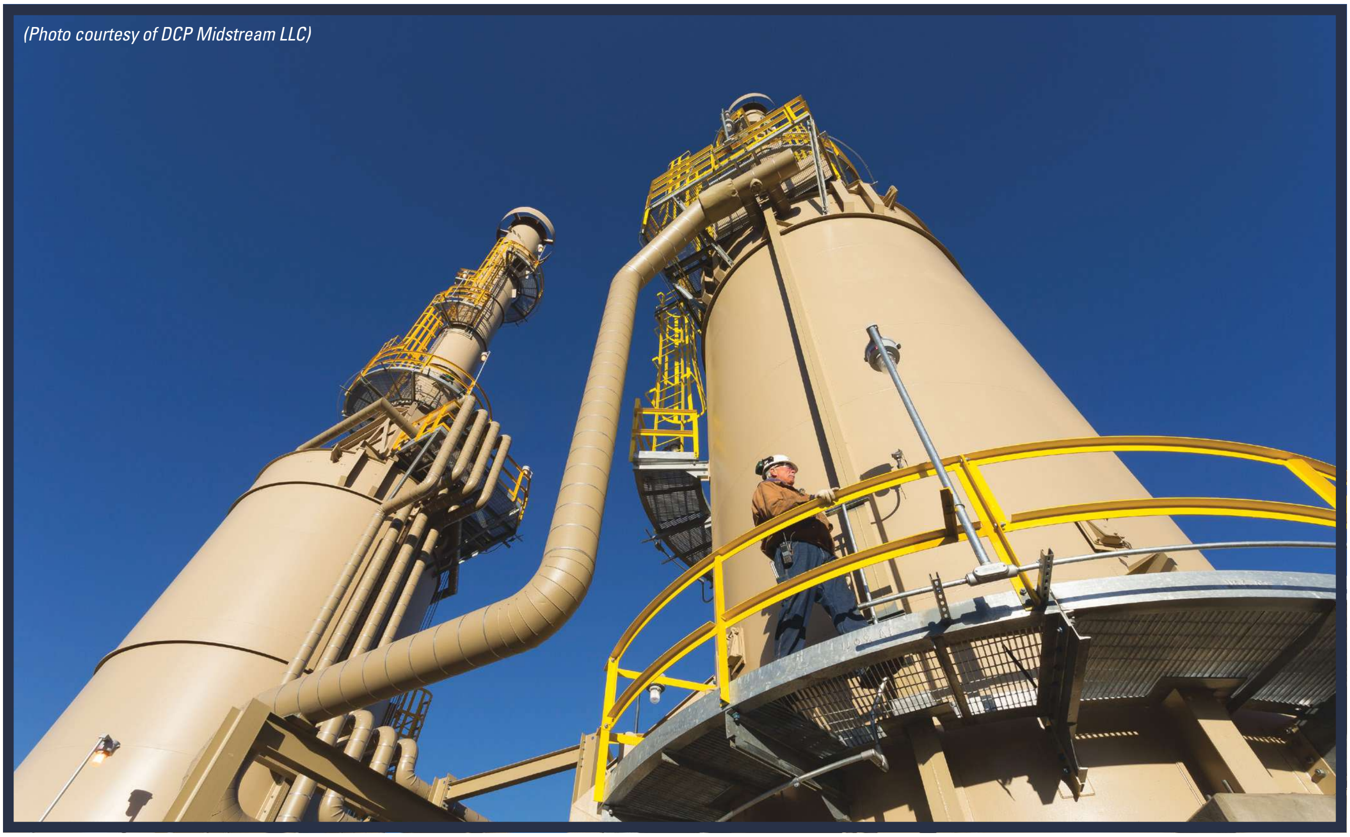
Phillips 66 Co. and Spectra Energy Partners LP, the 50:50 joint-venture (JV) owners in DCP Midstream, announced an agreement in September 2015 to contribute assets and cash to strengthen DCP. The firms said the moves would provide DCP with a stronger balance sheet and increased financial flexibility, adding DCP will be positioned to grow despite continuing commodity price cycles. The nation's largest gas processor and NGL producer, DCP had a comparatively high number of percent-of-proceeds processing contracts on its books that exposed it to significant impact from the gas and NGL price declines that continued through 2015.

Midstream operator Spectra Energy contributed its ownership interest in the Sand Hills and Southern Hills NGL pipelines that serve Texas and Oklahoma gas producers. DCP operates the two systems. For its part, downstream-focused Phillips 66 agreed to contribute $1.5 billion in cash to be used to pay down a portion of DCP's credit revolver.

The transactions complemented DCP's efforts to reduce operating costs, sell certain noncore assets and convert some of its processing agreements to fee-based arrangements.

"DCP Midstream is a valuable portion of our NGL value chain and part of our plans to grow," said Greg

DCP is the nation's largest natural gas liquids producer and gas processor. This plant serves producers in the unconventional Denver-Julesburg Basin of eastern Colorado.



(Photo courtesy of DCP Midstream LLC)

Garland, Phillips 66 chairman and CEO. "This infusion of cash and operating assets by the joint-venture owners will enhance the credit profile of DCP Midstream, provide stability to the existing business and allow pursuit of growth opportunities."

Separately, in February 2015 DCP and partners Enterprise Products Partners LP, Anadarko Petroleum Corp. and MarkWest Energy Partners LP announced formation of a JV under which Enterprise assigned a 45% ownership interest in its wholly owned Panola Pipeline Co. LLC. The interest was evenly divided among Anadarko's affiliate, WGR Asset Holding Co. LLC, MarkWest and DCP. Enterprise continued to hold the balance of ownership in Panola.

Panola Pipeline transports NGL from Carthage, Texas, to the big Mont Belvieu NGL hub east of Houston. This JV agreement followed Enterprise's announcement that it plans to install 60 miles of new pipeline as well as pumps and other associated equipment as part of an expansion project designed to boost Panola's capacity by 50,000 bbl/d. The incremental capacity addition was scheduled to enter service in first-quarter 2016.

## Enbridge Inc.

- **Announced plans for $29 billion in capex in the U.S. and Canada through 2019**
- **Asset dropdowns to Midcoast Energy Partners LP unit expected in 2016**

Canada's largest pipeline operator—also a major presence in the U.S. midstream—plans to continue an aggressive expansion program in the foreseeable future. Enbridge Inc. announced in fourth-quarter 2015 a $29.09 billion capital investment plan through 2019.

The Calgary-based energy company said, however, it was taking a cautious approach in what CEO Al Monaco described as a "challenging' environment for getting projects approved by regulators on both sides of the border.

The investment plan would include expanding proposed pipeline projects as well as power generation services, Monaco said, explaining that the company strategy also would focus on "incremental expansion" of its existing assets that would create minimal risk to Enbridge customers. He outlined 16 major projects Enbridge has underway.

Much of the capex budget will go to new pipeline capacity in the underserved Williston Basin. The Sandpiper Pipeline will move Bakken crude oil from western North Dakota east to the existing Clearbrook, Minn., and Superior, Wis., crude pipeline hubs. Capacity will be 225,000 bbl/d, with a future expansion of up to 375,000 bbl/d a possibility. Startup has been scheduled for 2017.

The rapidly developing Bakken unconventional play has been short of pipeline capacity, leading to rapid growth in the use of unit trains to move production, which stood at 1.1 MMbbl/d in second-half 2015, to refiners concentrated on the nation's coastlines.

Also, Enbridge's Southern Access project will move up to 1.2 MMbbl/d south from Superior to a pipeline connection at Flanagan, Ill., providing a direct pipeline link to the Cushing, Okla., pipeline hub and major refineries on the Gulf Coast. Startup is scheduled in 2017. Meanwhile, Enbridge expected to finish its Southern Access Extension by year-end 2015, providing 300,000 bbl/d of new capacity between Flanagan and the Patoka, Ill., pipeline hub.

The Western Canadian expansion will add 800,000 bbl/d of new capacity to Enbridge's existing system, which links Alberta to the U.S. Midwest. The upgrade is scheduled after 2017.

Midcoast Energy Partners, the MLP unit of Enbridge, said in 2015 it expect to receive $200 million to $300 million of Enbridge assets in 2016 with further dropdowns likely through 2019. Enbridge may take Midcoast units in exchange for the assets. Midcoast had a $340 million capex budget in 2015, of which $165 million was to be financed by Enbridge. Much of the work was focused on the emerging Eaglebine unconventional play in East Texas.

Like its competitor TransCanada Corp., Enbridge has been pursuing modifications to its extensive crude oil pipeline system to move western Canadian crude east. Final modifications to its Line 9 between Sarnia, Ontario, and Montreal were to be completed in November 2015. Flow in the line was reversed to move crude from Enbridge's existing system around the Great Lakes to serve Montreal-area refineries. Capacity is 240,000 bbl/d.

(Photo by Paul Hart, Hart Energy)

Sunoco Logistics' terminal at Hearne, Texas, handles both crude oil and petroleum products.

## Energy Transfer Equity LP

- **Sought to acquire The Williams Cos. Inc. for $37.7 billion**
- **Acquired Regency Energy Partners LP in $18 billion merger**

Energy Transfer Equity (ETE) announced at the end of third-quarter 2015 that it had agreed to acquire The Williams Cos. Inc. in a stock-and-cash deal valued at about $37.7 billion, including debt. It was the largest midstream merger and acquisition deal of 2015, with closure scheduled for early 2016 pending governmental reviews and a vote by Williams shareholders.

Ironically, the announcement came three months after Williams rejected a $53.1 billion offer from ETE. At that time, Williams said ETE's offer significantly undervalued the company—one of midstream's largest and oldest players with corporate roots going back more than a hundred years.

Williams wasn't the only deal ETE pursued in 2015. Its Energy Transfer Partners LP (ETP) unit and Regency Energy Partners LP announced an $18 billion merger as 2015 began. The merger was a unit-for-unit transaction plus a one-time cash payment to Regency unitholders. ETE owned the Regency general partner and 100% of the incentive distribution rights of both Regency and ETP. It agreed to reduce the incentive distributions it receives from ETP by $320 million over a five-year period.

ETP and ETE's Sunoco Logistics Partners LP formed a joint venture (JV) to build the Bayou Bridge pipeline that will deliver crude oil from the Phillips 66 and Sunoco Logistics terminals in Nederland, Texas, to Lake Charles, La. The JV also will launch an open season on a proposed expansion that would provide service to the market hub in St. James, La., on the Mississippi River. Phillips 66 holds a 40% interest, while ETP and Sunoco each hold 30%. The 30-in. line is scheduled to enter service in first-quarter 2016. A proposed expansion would enter service in second-half 2017.

## EnLink Midstream LLC

- **Acquired Delaware Basin assets from Matador Resources Co.**
- **Plans up to $500 million capex into 2017**

Major midstream player EnLink is a comparatively new name in the space. In March 2014, midstream operator Crosstex Energy and upstream producer Devon Energy combined substantially all of Devon's U.S. midstream assets with Crosstex's assets to create EnLink Midstream.

EnLink announced in September 2015 that a subsidiary would acquire the gathering and processing assets in West Texas' Delaware Basin from a subsidiary of Matador Resources Co. for about $143 million, subject to certain adjustments. The deal was an example of several deals in 2015 in which upstream producers sold gathering, processing and transmission assets related to their production activities to a midstream operator to sell cash.

EnLink called the acquisition "strategic," positioning it as a full-service midstream provider in the Delaware, located in the southwest corner of the Permian Basin. Matador continued to use the system as an EnLink customer under a 15-year fixed-fee agreement. EnLink added the acquisition complemented its existing crude oil gathering, transportation and marketing services in the region, which EnLink entered into when it acquired LPC Crude Oil Marketing LLC in February 2015.

EnLink's Delaware Basin assets include a cryogenic gas processing plant with about 35 MMcf/d of inlet capacity and about 6 miles of high-pressure gathering pipeline, which connects a Matador-owned low-pressure gathering system to the processing plant.

Including the Matador acquisition, EnLink said it expects to deploy growth capital of about $400 million to $500 million to expand its position in the Delaware Basin over the next 18 months following closure of the Matador deal in fourth-quarter 2015. "It is anticipated that this expansion will include additional processing capacity, including the installation of a 120 MMcf/d natural gas processing plant currently owned by the partnership and the construction of additional gathering pipelines in Loving and Reeves counties, Texas, and Eddy and Lea counties, N.M.," EnLink said in a statement.

In early 2015 EnLink said it completed acquisition of the Victoria Express Pipeline and related truck terminal and storage assets from Devon Energy Corp., which serves producers in South Texas' Eagle Ford play. Victoria Express is a 56-mile multigrade crude oil pipeline with a current capacity of about 50,000 bbl/d. Following completion of an expansion project, capacity will rise to 90,000 bbl/d. Other assets at the destination of the pipeline include an eight-bay truck unloading terminal, 200,000 bbl of above-ground storage and rights to barge loading docks.

EnLink also announced asset dropdowns from Devon and an expansion of its gathering and processing system in northwestern Oklahoma's Cana-Woodford play.

(Photo courtesy of EnLink Midstream LLC)

EnLink's Deadwood system serves North Texas producers.

## Enterprise Products Partners LP

- **New Aegis ethane line segment entered service**
- **Signed supply contract with Saudi Arabia's Sabic**

One of the midstream's major players, Enterprise had multiple capital projects underway during a busy 2015 in addition to multiple merger-and-acquisition and joint-venture (JV) deals.

In September 2015, Enterprise said construction of the Texas-to-Louisiana segment of the Aegis ethane pipeline had been completed and would enter service to deliver ethane to additional Gulf Coast petrochemical facilities. The segment runs from Beaumont, Texas, to Lake Charles, La. The 20-in. 425,000-bbl/d line now runs from Corpus Christi, Texas, to Lake Charles.

The new segment is 48 miles long and extended an initial 60-mile segment already in service. The final leg of Aegis, which totals 270 miles, will extend the pipeline from Lake Charles to Mississippi River petrochemical plants and was expected to be completed by year-end 2015. Combined with Enterprise's existing South Texas system, Aegis will provide shippers access to a 500-mile ethane header system between Corpus Christi, Texas, and the Mississippi River in Louisiana. Aegis connects to Enterprise's 1,265-mile ATEX Pipeline that moves NGL out of the Marcellus and Utica to Gulf Coast petrochemical plants.

Also in third-quarter 2015, Enterprise announced it had started shipping 480,000 bbl/d of crude on its Rancho II pipeline from Sealy, Texas, to its Echo Terminal in Houston. The pipeline was originally slated for completion in July 2015 but was pushed back to September. Through Echo, crude customers have direct access to every refinery in Houston, Texas City, Beaumont and Port Arthur, Texas, as well as Enterprise's dock on the Houston Ship Channel.

In second-quarter 2015, Enterprise said it signed a long-term agreement for development of a new 416-mile, 24-in. diameter pipeline to transport crude and condensate from the company's Midland, Texas, terminal in the Permian Basin to Sealy, Texas. Service is scheduled to begin in second-quarter 2017.

In July 2015 Enterprise closed the sale of its offshore Gulf of Mexico pipelines and services business to Genesis Energy LP for about $1.5 billion in cash. Proceeds of the sale would be used to enhance the company's financial flexibility for Eagle Ford and Permian Basin projects, the firm said. When they were included, liquidity rose to more than $6 billion, composed of cash and credit facility borrowing capacity.

Saudi Basic Industries Corp., the world's second-biggest chemicals manufacturer, announced in third-quarter 2015 that it plans to expand investment in U.S. shale gas projects through JVs. Sabic, as the company is known, signed an agreement with Enterprise to get ethane. The company may use the feedstock in the U.S. or export it to other countries, including the U.K. Sabic has converted crackers at its U.K. plants to use ethane as feedstock to produce olefins and their derivatives more competitively.

Sabic, which in 2007 bought General Electric Co.'s plastics unit for $11.6 billion, said it plans to expand in China and the U.S. because it's difficult for the company to grow in Saudi Arabia due to a shortage of gas feedstock.

In July 2015 Enterprise closed the $2.15 billion purchase of EFS Midstream LLC member interests from affiliates of Pioneer Natural Resources Co. and Reliance Holding USA Inc. EFS Midstream provides gas gathering, treating, compression and condensate processing services in the Eagle Ford. The EFS Midstream system includes about 460 miles of gas gathering pipelines, 10 central gathering plants, 780 MMcf/d of gas treating capacity and 119,000 bbl/d of condensate stabilization capacity.

A joint development dedicated Pioneer and Reliance's Eagle Ford acreage to Enterprise under a 20-year fixed fee gathering agreement with a minimum volume requirement for the first seven years. There were also related 20-year fee-based agreements with Enterprise for gas processing; NGL transportation and fractionation; and for gas, processed condensate and crude transportation.

Enterprise announced in second-quarter 2015 an agreement with an Occidental Petroleum Corp. affiliate to jointly develop a new 150 MMcf/d cryogenic gas processing plant and pipeline in the Delaware Basin. The 50:50 JV developing the plant is Delaware Basin Gas Processing LLC, with operations to start mid-2016.

Another major capex project Enterprise said it is considering is repurposing the Centennial Pipeline, a refined products system designed to move petroleum products north from Beaumont, Texas, to Bourbon, Ill. Idle since 2011, flow would be reversed to move 100,000 bbl/d of NGL from the Marcellus and Utica unconventional plays south to Gulf Coast refineries and petrochemical plants. Enterprise and its 50:50 partner, Marathon Petroleum Corp., had the project under review in late 2015. If approved, construction would take 18 to 24 months, Enterprise said.

## Kinder Morgan Inc.

- **Five-year capex plan set at $22 billion**
- **Acquires Hiland Partners in $3 billion deal**

The biggest midstream operator has plans to make itself even bigger in 2016 and beyond. Its five-year capex plan calls for $22 billion in growth projects across its system, the company said in investor presentations released in late 2015.

And that number does not include some big—but still not confirmed—projects, such as a proposed Utica Marcellus Texas Pipeline NGL line linking the Marcellus-Utica and Texas and new gas pipelines to serve the proposed LNG export terminals going in around the Gulf Coast.

Kinder Morgan also has been active in the merger-and-acquisition market. Early in 2015, Kinder Morgan closed its acquisition of Hiland Partners for about $3 billion. The purchase price included about $1 billion of debt. Hiland's fee-based midstream assets include crude oil gathering and transportation pipelines and natural gas gathering and processing systems in the Bakken Shale.

Hiland had been among the interests of Continental Resources Inc. CEO Harold Hamm and is a major midstream operator in the Williston Basin. Hiland's assets include the new Double H Pipeline that entered service at the first of 2015. It can move 84,000 bbl/d of Bakken crude from North Dakota to Tallgrass Energy Partners' Pony Express Pipeline in Wyoming. From there, Bakken flows to the Cushing crude oil hub in Oklahoma.

Kinder Morgan is looking to add to its network of pipelines and terminals with an expanding presence in the Jones Act shipping business that can carry crude oil and petroleum products between U.S. ports. In late 2015, Aker Philadelphia Shipyard said it began constructing the third and fourth U.S.-flagged product tankers for Kinder Morgan Inc.

The new 600-ft-long vessels will carry 345,000 bbl of crude oil or refined products. Deliveries are planned between November 2016 and November 2017. After construction, they will be sold to Kinder subsidiaries, Aker said. For a four-ship series, the total value is $568 million.

Already a pioneer in the production and export of lightly processed condensate, Kinder Morgan started a second 50,000-bbl/d splitter on the Houston Ship Channel in third-quarter 2015. A similar-sized splitter entered service in first-quarter 2015.

Due to the boom in output of condensate in the U.S. shale plays, the energy industry is investing up to $2.4 billion in condensate splitters to process the very light crude oil.

Another export market drawing midstream attention is just to the south. Mexico's market for U.S. gas continues to grow, and Kinder Morgan is among the players interested in serving the growing market. An open season for a capacity expansion on the Mier-Monterrey Pipeline belonging to a Kinder Morgan Inc. unit was held in third-quarter 2015. Kinder Morgan Gas Natural de México S. de RL de CV owns and operates the 85-mile pipeline. It has been in service since 2003 and stretches from Starr County, Texas, to Monterrey, Mexico, at the U.S.-Mexico border. The pipeline connects to a 1,000-MW power plant complex and to the Pemex natural gas transportation system.

An expanded Mier-Monterrey Pipeline could carry about 1.34 Bcf/d of gas. The existing pipeline will be looped from the Mexico-U.S. border to Huinalá, Nuevo León. There will be a new lateral from Pesquería, Nuevo León, to Escobedo, Nuevo León. The expansion is scheduled for completion by fourth-quarter 2017.


(Photo courtesy of Magellan Midstream Partners LP)

Magellan's Longhorn Pipeline proves a direct link between Permian Basin crude producers and Gulf Coast refiners. The system has a capacity of 275,000 b/d.

## Magellan Midstream Partners LP

- **Continues move into crude oil, marine terminals**
- **JV to add crude storage and pipeline capacity in Houston area**

A major midstream player in petroleum products pipelines for 90 years, Magellan has moved into crude oil pipelines and marine terminals to complement its existing assets.

The firm said in investor presentations in late 2015 it has invested $3.8 billion in organic growth projects and acquisitions in the last decade, and it expects to spend $1.4 billion through 2016 to finish construction projects currently underway. Magellan has emphasized organic growth but added future acquisitions are under review.

Its BridgeTex Pipeline, linking Permian oil producers with Gulf Coast refiners, began initial service at year-end 2014. Volumes during 2015 averaged 200,000 bbl/d, Magellan said, adding it expects the line to reach its 300,000-bbl/d capacity, possibly by early 2016. It also is considering an expansion for BridgeTex.

Adding infrastructure to and through the Houston refinery and petrochemical complex, Seabrook Logistics, a joint venture (JV) between Magellan and bulk liquids storage operator LBC Tank Terminals LLC, will own and operate Houston Gulf Coast-area crude oil storage and pipeline infrastructure, Magellan said in mid-2015.

More than 700,000 bbl of crude oil storage capacity and other infrastructure will be built. A new 18-in. pipeline will connect the new storage to a third-party pipeline carrying crude to a Houston refinery. The storage will be next to LBC's terminal in Seabrook, Texas. LBC's dock will be used, which can handle industry-standard Aframax vessels with 45-ft drafts. The terminal also has two barge docks. Seabrook Logistics' crude oil storage and pipeline will cost about $95 million, supported by a long-term commitment with a major refiner. Magellan will construct, maintain and operate the pipeline, and LBC will construct, maintain and operate the storage tanks and other terminal assets. Subject to the receipt of permits and regulatory approvals, the project will be operational in first-quarter 2017, Magellan said.

Also on the Texas coast, Magellan is constructing a 50,000-bbl/d condensate splitter at its Corpus Christi, Texas, terminal. The fee-based project is fully committed, with long-term, take-or-pay agreement with Trafigura, the international commodities trading firm. The project is budgeted at $250 million, including terminal infrastructure, dock improvements and pipeline connections. The service date is expected to be in second-half 2016.

Outside of the Gulf Coast, a JV between Magellan and Plains All American will deliver multiple grades of crude oil from the Denver-Julesburg Basin—and potentially the broader Rocky Mountain region—to the Cushing complex. The 600-mile line will have initial capacity of 200,000 bbl/d. In-service date will be mid-2016, with a lateral to startup at year-end 2016.

Cost will be up to $950 million, with Magellan holding 40% interest, Plains 40% and Anadarko Petroleum Corp. holding the remaining 20%.

In line with its traditional focus on petroleum product movements, Magellan expects to have a new product line to Little Rock, Ark., in service by mid-2016. The Arkansas capital has not had product pipeline service and has relied on shipments from Mississippi River refineries for supply.

The new line will extend from Magellan's existing terminal at Fort Smith, Ark., to Little Rock, moving products supplied by Midcontinent and Gulf Coast refineries. Cost has been set at $180 million.

## MarkWest Energy Partners LP

- **Acquisition by Marathon Petroleum's MPLX unit one of the largest midstream deals of 2015**
- **Hidalgo Complex to service Delaware Basin producers**

When it comes to midstream mergers and acquisition (M&A) activity in 2015, close behind the Energy Transfer-Williams combination is the Marathon-MarkWest merger. The $15.7 billion deal, announced in July 2015, brings together two major midstream operators in the rapidly growing Marcellus and Utica unconventional plays.

The deal is indicative of a subplot in the current midstream M&A arena—a downstream, refining and marketing player moving up into the midstream space. Marathon Petroleum is the refining and marketing arm of the historic Marathon organization, which split in the late 1990s. Marathon Oil Corp. holds the upstream assets.

Marathon Petroleum and its midstream MLP, MPLX LP, positioned themselves to increase raw earnings by nearly $1 billion through the purchase of MarkWest. The deal combines MPLX and MarkWest into the fourth-largest MLP, based on a market capitalization estimated at about $21 billion.

MPLX was to acquire MarkWest in a unit-for-unit transaction paying a 32% premium. Marathon will supply a one-time cash payment of $675 million. All told, Marathon and MPLX will pay about $15.7 billion for MarkWest. Following the deal, the companies' operational scale will include 6.8 Bcf/d of gas processing capacity, 379,000 bbl/d of fractionation capacity and about 7,600 miles of pipelines.

Ownership was to be divided among Marathon at 21%, MPLX at 8% and MarkWest with 71%. Marathon will retain control through continued 2% ownership of general partner interest. However, the deal drew strong opposition from some MarkWest shareholders.

MarkWest's footprint in the Marcellus and Utica region possesses significant overlap with Marathon's existing refining footprint in Ohio and Kentucky and to the East Coast via its downstream retail assets.

Prior to the announcement, MarkWest completed long-term fee-based agreements to install the Hidalgo Complex cryogenic gas processing plant in the Delaware Basin, the company said in June 2015. The plant, in Culberson County, Texas, is scheduled to be operational in second-quarter 2016.

## ONEOK Inc.

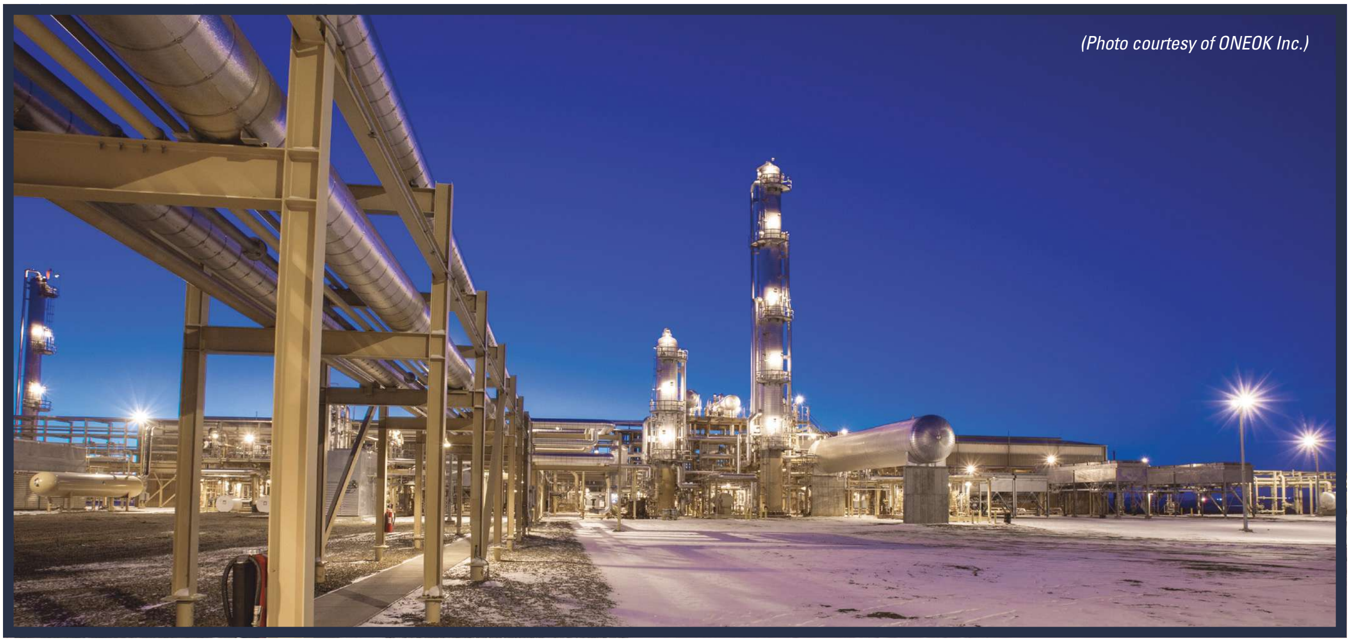
- **Mexico to get gas via new and expanded West Texas systems**
- **Bakken system to get increased capacity**

A major player for years in the Midcontinent, ONEOK continues to expand further afield into the Williston Basin, West Texas and south into Mexico. It made financial arrangements in 2015 to help cover the necessary capex and to respond to the current commodity price slump.

ONEOK injected $750 million into its ONEOK Partners MLP, financed by $500 million of 7.5% senior notes plus cash on hand along with $100 million in funds managed by Kayne Anderson Capital Advisors LP. The deal removed ONEOK Partners' equity overhang during 2015's equity market conditions.

The ONEOK Partners LP unit said in third-quarter 2015 it will invest $70 million to $100 million to expand its ONEOK WesTex Transmission intrastate gas pipeline system. The system will be expanded by increasing throughput by 260 MMcf/d by first-quarter 2017.

ONEOK WesTex is in the Texas Panhandle and West Texas Permian Basin. The expansion includes building two new compressor stations and upgrading or expanding three existing stations. There will be about 38,800 extra horsepower, the company


(Photo courtesy of ONEOK Inc.)

added. The qualifying bids for ONEOK WesTex surpassed 500 MMcf/d.

The new capacity will be used to ship gas south into Mexico. The Comision Federal de Electricidad, Mexico's electric utility, will be the anchor shipper, with firm capacity for 25 years. Phase 1, about 100MMcf/d, will be available in first-quarter 2016. Phase 2, about 400 MMcf/d, will go online in first-quarter 2017. The ONEOK WesTex Transmission system runs about 2,227 miles.

Also in second-quarter 2015 ONEOK Partners signed a 50:50 joint venture with a Mexico City-based gas infrastructure company to construct a pipeline that would transport gas from the Permian Basin to Mexico. The $450 million to $500 million Roadrunner Gas Transmission pipeline will be built by ONEOK in partnership with a subsidiary of Mexico midstream company Fermaca Infrastructure B.V.

Roadrunner will extend from ONEOK's WesTex system at Coyanosa, Texas, west to a connection at the U.S.-Mexico border near San Elizario, Texas. There it will connect with Fermaca's Tarahumara Pipeline, which owns and operates the Chihuahua Corridor pipeline and offers another gas import route into Mexico.

The project will be constructed in phases, including about 200 miles of new 30-in. diameter pipeline designed to transport up to 640 MMcf/d.

ONEOK has been a major player in gas processing and has pushed development of gas processing capacity in the Bakken play, which has had significant problems with flaring of stranded gas due to a lack of pipeline capacity. The firm has added new gas processing capacity in the Williston Basin and has plans to add additional compression and gathering lines, boosting capacity by 300 MMcf/d.

ONEOK operates three gas processing plants on its Garden Creek system in the Bakken unconventional play, which has been short of gas gathering and processing capacity. When completed, ONEOK's total gas gathering system in North Dakota will be able to gather and processing 1.2 Bcf/d of natural gas.

## Plains All American Pipeline LP

- **2015 capex set at $2.2 billion with a Permian focus**
- **New Cactus Pipeline received immediate capacity boost**

Plains All American outlined an ambitious $2.2 billion capex program for 2015, the largest share of which, $410 million, was earmarked for Permian Basin projects. It also had $150 million set aside for expansion of its brand-new Cactus Pipeline project, which links both Permian and Eagle Ford production to the firm's existing pipelines around the Gulf Coast.

Plains added pumps to increase takeaway capacity of the Cactus system. The expansion is in response to higher production forecasts and shipper demand for the region. Installation of booster stations along the pipeline, which runs from McCamey, Texas, to Gardendale, Texas, will increase throughput capacity from about 250,000 bbl/d to about 330,000 bbl/d.

In conjunction with its previously announced Eagle Ford Joint Venture (JV) Pipeline expansion, this project will allow the company to move increased production volumes from the Permian Basin to Corpus Christi, Texas, and other delivery points along the system. The Cactus Pipeline entered service in April 2015, while the expansion was to be completed in fourth-quarter 2015.

In June 2015 Plains began an open season for a proposed new pipeline that would carry crude oil from Cushing, Okla., to Longview, Texas, the company said. The pipeline would carry about 120,000 bbl/d of light sweet crude from Plains' Cushing terminal to Longview.

Also, Plains and refiner Delek Logistics Partners LP held an open season in June 2015 for the proposed Caddo Pipeline LLC, a 50:50 JV between the companies. The new pipeline will take about 80,000 bbl/d of light sweet crude from the Longview terminal to refineries in Shreveport, La., and to Delek's pipeline system that supports the El Dorado, Ark., refinery owned by Delek US Holdings.

A California oil pipeline leak dominated media attention of Plains in 2015. The firm said an unknown amount of crude leaked from a 24-in. line on a beach in Santa Barbara County, Calif.

The pipeline moves oil from Las Flores, Calif., to Gaviota, Calif. Plains shut down the pipeline and began an emergency response plan and cleanup.

## Spectra Energy Partners LP

- **U.S. Transmission segment working on $6 billion in projects through 2020**
- **Western Canadian system budgeted for $1 billion through 2017**

Spectra said it has multiple gas transmission projects underway that will link the Marcellus and Utica unconventional plays to markets, it told investors in late-2015 presentations. Important projects include the Atlantic Bridge proposal, serving the Northeast and New England; Access South to the Gulf Coast; and Sabal Trail to the Southeast.

In Canada Spectra plans improvements to its Western Canadian Gathering and Processing system as well as the new Empress NGL pipeline from Manitoba to Alberta, just north of the U.S. border.


(Photo courtesy of Plains All American Pipeline LP)

Plains All American expanded its extensive Bakken crude-by-rail assets in 2015 with the purchase of Legion Terminals LLC's new facility in McKenzie County, N.D.

In Ontario, Spectra's Dawn Storage facility in Ontario is the second largest physical gas trading hub in North America, the company said. The linking Dawn-Parkway gas transmission pipeline will boost capacity to some 7.5 Bcf/d by 2017.

Like its partner Phillips 66, Spectra Energy was involved in 2015 in strengthening DCP Midstream. The firms said the moves would provide DCP with a stronger balance sheet and increased financial flexibility, adding DCP will be positioned to grow despite continuing commodity price cycles. Spectra Energy contributed its ownership interest in the Sand Hills and Southern Hills NGL pipelines. Phillips 66 agreed to contribute $1.5 billion in cash to be used to pay down a portion of DCP's credit revolver. The transaction complemented DCP's own efforts to reduce operating costs, sell certain noncore assets and convert some of its processing agreements from commodity price-based contracts to fee-based arrangements.

Greg Ebel, Spectra's chairman and CEO, said the agreement "retains the upside for owners as commodities improve."

## TransCanada Corp.

- **Energy East would boost Canada's crude export capacity**
- **Keystone XL permit request vetoed**

TransCanada has ambitious growth plans for its assets on both sides of the border, projects that it called "transformational" in 2015. The largest is the $9.1 billion Energy East project that would convert an existing natural gas pipeline across the country to crude oil service.

Energy East is a proposed 2,900-mile oil pipeline that would move 1.1 MMbbl/d of crude oil from Alberta and Saskatchewan to refineries and port terminals in eastern Canada. Exports would focus on Atlantic markets—a new customer base for western Canadian crude.

Energy East would convert 1,900 miles of one underused pipeline in TransCanada's Canadian Mainline gas system to crude service. This conversion would lower the comparative cost of transmission service for local gas companies, power producers and industrial clients, the company said. Tentatively, service would begin in 2020.

The Eastern Mainline Project will add between 155 miles and 186 miles of new gas pipeline in the Toronto/Montreal corridor. TransCanada plans open seasons in 2016 and 2017 to take bids for gas capacity on the Eastern Mainline Project.

Looking west, TransCanada has earmarked $3.8 billion for the Prince Rupert Gas Transmission system that would move gas produced in Alberta and northern British Columbia to the port of Prince Rupert, British Columbia, on the Pacific coast. A proposed gas liquefaction plant would make LNG for shipment to Asia-based customers. But the project does face challenges from environmentalists, Canada's First Nations tribes and the remoteness of the mountainous region.

TransCanada in late 2015 announced a project agreement with the Metlakatla First Nation, a member of the Coast Tsimshian Nation. The agreement, the eighth with First Nations along the pipeline route, outlines financial and other benefits and commitments that will be provided for as long as the project is in service.

The Metlakatla First Nation is located near Port Edward and considers Lelu Island, the proposed location for the Pacific NorthWest LNG facility, as a significant part of its traditional territory.

Timetables for the Energy East and Pacific Coast pipelines were indefinite in late 2015.

The company also lists some $9.1 billion in small- to medium-scale projects scheduled to enter service in 2016 to 2018. TransCanada has been a major player for several years in building new gas transmission capacity inside Mexico. Building on that expertise, its capex plans include a $1.4 billion line serving Topolobampo and Mazatlan on the Mexico's Pacific coast. The system is scheduled to enter service in 2016.

Then there was Keystone XL. The highly political issue finally received a rejection from President Obama in late 2015. However, the rest of the 2,640-mile Keystone system is in place and functioning normally following completion of the system's Gulf Coast Pipeline linking the Cushing crude oil hub to Texas in 2014.

Related to the southern end of the network, TransCanada announced an open season in late 2015 for its MarketLink service between Cushing and the Gulf Coast. Service could begin as early as first-quarter 2016.

## The Williams Cos. Inc.

- **Agreed to be acquired by Energy Transfer Equity in $37.7 billion deal**
- **Transco expansion enters service**

In the biggest midstream transaction of 2015, The Williams Cos. Inc. announced at the end of third-quarter 2015 that it had agreed to be acquired by Energy Transfer Equity LP in a stock-and-cash deal valued at about $37.7 billion, including debt.

Ironically, the announcement came three months after Williams rebuffed a $53.1 billion offer from Energy Transfer in June 2015. At that time Williams said that it significantly undervalued the company. However, the firm's stock lost nearly a third of its market value between June and the September agreement. The parties pointed to a drop-off in stock prices for the difference but left many Williams shareholders unsatisfied. The deal is subject to a Williams shareholder vote scheduled for early 2016.

Energy Transfer's accepted offer of $43.50 per share represented a slight premium of 4.6% to Williams' close on Sept. 25, 2015. Williams stockhold-

(Photo courtesy of The Williams Cos. Inc.)

Williams' Ignacio plant outside Durango, Colo., serves the San Juan Basin of Colorado and New Mexico.

ers electing to receive stock will get 1.8716 Energy Transfer shares for each share held, the companies said in a joint statement. Pending a vote by Williams stockholders and standard regulatory approvals, the firms expect to close the deal in first-half 2016.

Williams operates gas pipelines spanning the Gulf of Mexico to the Canadian oil sands, while Energy Transfer operates natural gas, crude and refined product pipelines. There is little overlap, but the size of the combined company may give pause to federal regulators.

In fourth-quarter 2015, press reports stated Williams was planning to sell its 50% stake in the Gulfstream Pipeline that serves Florida. Williams Partners is the actual owner of the interest in Gulfstream, with the other 50% owned by Spectra Energy. That sale may be required to satisfy the Federal Trade Commission, according to some industry observers.

Energy Transfer had previously said that its offer was contingent on the termination of Williams' pending acquisition of natural gas MLP Williams Partners, announced in second-quarter 2015. Williams Partners said following the announcement by its parent and Energy Transfer it would terminate the deal and would receive $428 million in a termination fee from its Williams parent.

When it was announced prior to Energy Transfer's first offer, the Williams-Williams Partners deal would have created a large C-corp modeled on Kinder Morgan's roll-up of its C-corp parent and four MLPs in 2014. That move generally brought favorable reviews from investors.

Earlier in 2015 Williams closed on its acquisition of Access Midstream Partners LP, which was merged into the Williams Partners MLP. Announced in fourth-quarter 2014, that deal was valued at $50 billion—at a time when commodity prices were far higher than they were a year later when Williams was acquired by Energy Transfer.

Meanwhile, in third-quarter 2015 Williams announced it had placed into service a major expansion of its Transco natural gas pipeline to fuel new electric power generation in Virginia and serve increasing local distribution demand in North Carolina. Transco is the nation's largest-volume and fastest-growing interstate natural gas pipeline system, with enough transportation capacity to serve the equivalent of more than 50 million households each day in North America, according to Williams.

The about $300 million Virginia Southside Expansion is providing 270,000 dekatherms per day of incremental transportation capacity. The expansion consists of about 100 miles of new, 24-in. diameter pipeline extending from the Transco mainline in Pittsylvania County, Va., and through Halifax, Charlotte and Mecklenburg counties in Virginia. It terminates in Brunswick County, Va.

Transco placed the majority of the pipe parallel to its own existing pipeline alongside an existing utility corridor. In addition, Transco added more than 21,000 horsepower of compression at Station 165 in Pittsylvania County, Va.

"From New York City to the Gulf Coast, we are executing on unprecedented growth on our Transco system as customers continue to seek opportunities to connect to long-lived U.S. natural gas reserves," said Rory Miller, senior vice president of Williams Partners' Atlantic-Gulf operating area. "As we work to connect the best supplies to the best markets, we are sharply focused on bringing these large-scale projects into service on time and on budget. These key expansions to our already premier infrastructure base are driving significant growth in our fee-based revenues and creating shareholder value."

The Virginia Southside Expansion is part of $4.8 billion in Transco growth projects, which Williams previously announced it plans to bring into service between 2015 through 2017. Williams said it is executing on 15 projects in 10 eastern states to serve growing demand for gas to serve power generation, industrial and local distribution customers. Once complete, these projects will increase Transco's system capacity by more than 57%.

The work also will redesign Transco to handle gas produced in the Marcellus and Utica plays. Dating from the 1940s, Transco was designed as a one-way system to move gas from the Gulf Coast to gas customers in the Northeast. ■


320
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# North American Production Remains Resilient

## Despite Rig Count, Oil Price Collapse

By **Gabriel Martinez**, Stratas Advisors

*In this downcycle, operators have focused on improving efficiencies and positioning themselves for healthy growth when the price of oil rebounds.*

Despite tumbling crude oil prices, North American unconventional production has remained steadfast. Sub-$60 oil was thought to be toxic for North American unconventional oil producers that carry with them high breakeven prices, but production has remained resilient as prices have tested the $40 range. The idea of a breakeven cost per barrel is a floating point that is dictated by a series of variables. Service costs have declined by 20% to 30%, helping to drive that breakeven price per barrel even lower.

In addition to improved efficiencies and decreased costs, wells waiting on completions will help to dampen a precipitous decline in production since these wells provide an inventory of quick and easily accessible oil to produce. Many have looked at the rapidly declining rig count as an ominously prescient sign of the future state of domestic oil production. The days of simply extrapolating production levels based on the number of rigs actively running are quickly running out. Several key factors have changed when considering production attributable to each rig, such as the number of wells drilled per rig, the production improvements per well and the areas being actively drilled out. These rigs are drilling wells with improved production at an increasing rate for a lesser cost.

Stratas Advisors has implemented a new methodology for generating its production forecasts by using well-level production data compiled from across North America provided by TGS. When querying and downloading the well-level data, an emphasis is placed on more recently completed wells to capture the current trends in completion techniques and associated recovery rates. Stratas Advisors begins the process by inputting the dataset into a type curve model built to clean, structure and calculate associated type curves for each well in the set. Stratas Advisors begins the process by normalizing the production profiles for each well based on first production dates and identifying the highest IP rates. Stratas Advisors calculates its type curve by using the standard Arp's equation with a calculated B-factor and decline rate. Each calculated type curve is then compiled into a spread of five representative type curves for each operator. The quintile spread showcases the overall production range within the actual well data. Once the quintiles have been calculated, Stratas Advisors inputs the results into its economics model to generate a detailed economic analysis and production forecast.

### Rig count

Despite a 64% decline in rig count from its 2014 high of 198, Bakken oil production remains resilient. According to the North Dakota Department of Mineral Resources, crude production from January through September 2015 averaged roughly 1.2 MMboe/d. Rig count in the region has hovered in the low 70s as of late, potentially signaling stability in the rig count with an average September count of 71. Bakken rig counts are currently comparable to levels not seen since 2009.

Rig count in the Rockies has followed a very similar trajectory to the oil price collapse. At its height in 2014, the Rockies rig count was more than 100 rigs before falling to the low 40s. Rig count in the Rockies has continued its slow downward trend in 2015 but seems to have found a bit of a floor at the 40-rig mark. The Denver-Julesburg (DJ) Basin has acted against the declining trend and added rigs sporadically throughout the year. In contrast, most drilling activity in the Uinta seems to be suspended for the time being.

During the past 3 years, the Eagle Ford rig count has remained relatively steady in the oil and dry to wet gas regions, averaging 260 rigs playwide. More recently, the rig count has declined to about 110 rigs throughout the play; however, the count is expected to level off and potentially increase as prices begin to recover in 2018 (according to Stratas Advisors' forward price curve estimates). A rig count of about 110 active rigs has not been seen since 2010.

Rig counts in both the Utica and Marcellus have been somewhat reactive to the decline in gas and NGL prices throughout 2015. In the Utica, rig count peaked in December 2014 with an average of 49 rigs employed. By August 2015, the rig counts in the play decreased by more than 55% to an average of 21 active rigs. Although active rigs decreased significantly as prices fell, production in the play remained strong for much of 2015. Production in the Utica reached more than 3 Bcfe/d in September 2015, nearly double September 2014 volumes.

Active rigs in the Marcellus peaked in May 2014 with an average of 84 employed rigs in the play. Rig count decreased nearly 30% by August 2015 to an average of 53 active rigs. Similar to the Utica, production in the Marcellus remained strong despite the price-driven decline in active rigs. Production growth remained positive throughout most of 2015 amid the downturn, peaking at 16.8 Bcfe/d in July 2015 and representing 17% production growth over the same period in 2014. However, in August production growth declined marginally by about 3.5 MMcfe/d to a playwide average of 16.81 Bcfe/d.

Rig counts in neighboring plays have fallen by nearly 50% throughout 2015 from 2014 levels; however, the opposite has occurred in the Woodford. Rig count in the Woodford-Cana has remained steady for most of the year with an average of nearly 40 employed rigs, compared to an average of 33 throughout 2014 and 32 throughout 2013. Many operators have demonstrated a continued focus on drilling improvements and activity. Cimarex Energy announced in second-quarter 2015 that rig activity would actually increase in second-half 2015.

### Drilling improvements

In the Bakken enhanced completions have allowed operators to realize production improvements of 40% to 50% over previous iterations of completions designs. Production improvements have been possible due to improved slickwater fracks in conjunction with increased proppant volumes. Average lateral lengths in the region now exceed 8,400 ft. The extended-reach lateral length wells also are being drilled at a record pace. Spud-to-total depth times are currently down to the 13-day range compared to an average drilling time of 26 days in 2014 in the four core counties. Along with wells being drilled quicker, there has also been a greater emphasis placed on pad drilling and tighter interwell spacing. Interwell spacing in the core of the play is currently being tested at as low as 600 ft between the lateral sections of adjacent wells targeting many benches of the Bakken and Three Forks.

Drilling preferences in the Rockies, and specifically the DJ Basin, have shifted toward the drilling of extended-reach lateral wells. In certain instances these extended-reach lateral wells are reaching lateral lengths of up to 9,000 ft. These extended-reach lateral wells also have been accompanied by an increase in the number of frack stages used. For Bonanza Creek, a 9,000-ft lateral might be completed with as many as 50 frack stages per lateral in the DJ Basin. Well spacing in areas of the DJ Basin, such as Wattenberg Field, has continually trended downward to where it currently sits at roughly 80 acres per well.

In the Permian Basin Stratas Advisors has observed several operators increasing lateral lengths by 15% to 50%. The number of average stages per well also has increased by about 30% accompanied by an increase of 30% to 70% in the amount of proppant per well. All of these enhancements have been able to occur while reducing well costs by 10% to 30% to a current range between $5.5 million per well and $7.5 million per well throughout the play.

Eagle Ford operators have increased the lengths of their laterals to a current range of 5,000 ft to 6,000 ft. Drilling times have been improving by up to 50% to an average drilling time of 17 days. Wells also are being drilled closer together as well spacing has been reduced by 24%-34% to an average of 50 acres per well. Similar to the Permian, Eagle Ford well costs have fallen between 10% and 30% to a current range between $4.2 million per well and $7.5 million per well. Stratas Advisors also has noticed a few operators extending laterals to 9,000 ft and beyond in search of improved production rates.

In the Marcellus and Utica, improvements in drilling and completion techniques along with an inventory of uncompleted drilled wells positively influenced production rates and capital efficiency in both plays. Lateral lengths have increased substantially, with several operators reaching more than 10,000 ft from previous averages of about 6,500 ft. Signaling the success of implemented efficiency programs, many operators across the Utica and Marcellus reported increasing EURs as a result of these technical improvements. Chesapeake Energy, for example, reported an expected 15% increase in EUR per foot for new Utica wells.

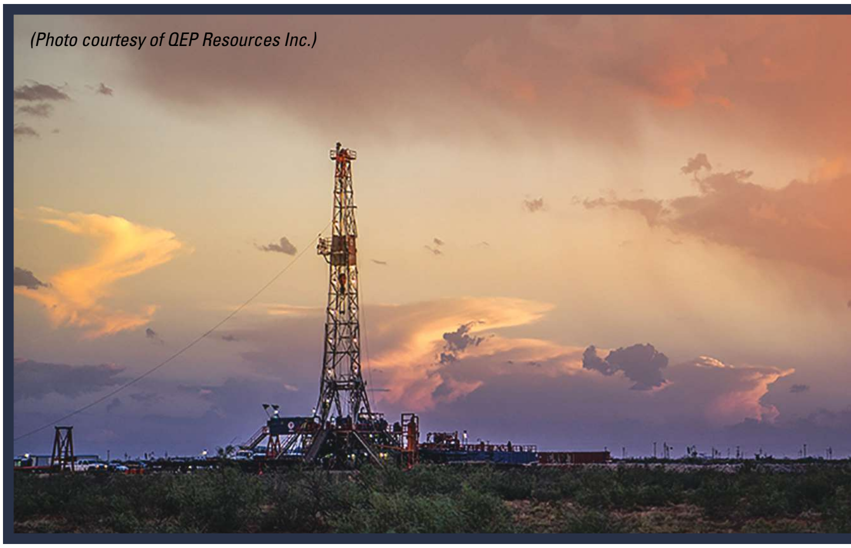
Economic success in the Woodford has been driven by improvements made in drilling techniques. Improvements have included the extension of lateral lengths to nearly 10,000 ft, resulting in record-setting IP rates, for a modest average well cost hovering between $7 million and $8 million. Additionally, the high NGL composition of the hydrocarbon stream in the South-central Oklahoma Oil Province (SCOOP) and STACK regions also are increasing returns for operators in the play. Despite the challenging economics currently being endured across the sector, opportunities in the Woodford continue to draw capital investment over alternative investments by several operators including Continental Resources and Newfield Exploration Co., which have allocated more than $700 million and $840 million to the play, respectively.

### High-grading acreage

Operators have spent many years drilling and delineating their acreage portfolios. As a result, operators have not only found their most geologically favorable areas but also have realized how to efficiently produce them. Improved well results from enhanced completions and improved drilling practices are providing greater production rates per well. In plays across North America, operators are retreating to their core proven economic acreage. This trend is markedly visible across the plays covered as many plays have seen an increase in activity levels within certain core regions and a complete suspension of activity in other regions of the play.

Although rig counts have declined dramatically in the Bakken, the rig count alone does not tell the entire story. Along with the decline in rig count, rigs have been consolidated to the core. The entirety of the rig fleet now lies within four core counties of North Dakota: McKenzie, Mountrail, Dunn and Williams counties. In this area, operators enjoy a thicker target formation, low clay concentration and favorable total organic carbon. In addition to that, the core counties are also home to the Nesson Anticline, Antelope Anticline and Heart River Fault. These geologic features create regions with greater potential for preexisting fractures that will allow for an increased hydraulic fracture complexity and, ultimately, greater reservoir conductivity.

In the near-term, production in the Rockies will be primarily focused in the DJ Basin. The DJ Basin



(Photo courtesy of QEP Resources Inc.)

QEP Resources Inc. grew its production 47% in third-quarter 2015 over the same period in 2014.

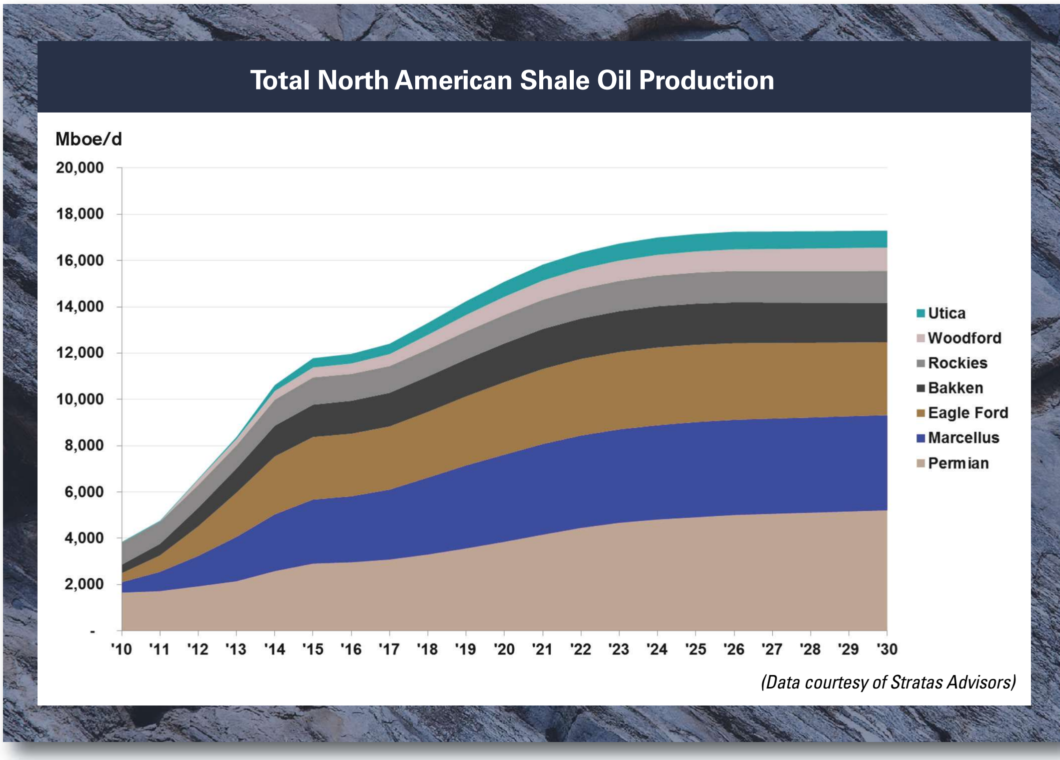



FIGURE 1. Production attributable to seven plays was forecasted to average 11.8 MMboe/d in 2015 from all hydrocarbon streams.

has offered some of the best well results alongside a more favorable hydrocarbon split. In addition to this, the DJ Basin offers easily accessible drilling locations that reduce rig downtime and ultimately drilling costs. Activity in the Uinta, Piceance and Green River basins is anticipated to continue its decline.

In the Permian, drilling activity is currently focused within the Midland and Delaware basins; however, a few operators have been able to delineate and extend their current strategies to include the New Mexico Shelf and Central Basin Platform. If operators continue this trend, production could increase faster than current forecasts suggest. Since the downturn in oil prices in mid-2014, Eagle Ford operators have focused on developing the core highly productive acreage within the oil window. Stratas Advisors has seen a recent shift toward enhanced completions within the oil and wet gas/condensate windows. Stratas Advisors sees increases in the number of wells waiting on completion as a direct result of reductions in the number of operated rigs.

In a reversal of previous trends, operators are now currently seeking out the dry gas opportunities of the Utica as opposed to the liquids-rich Marcellus. Stacked pay acreage in the Marcellus liquids-rich region overlies the dry gas window of the Utica, where operators are currently targeting Utica dry gas from existing Marcellus well pads. While Henry Hub natural gas prices have declined about 40% from an average of \$3.91/MMcfe in September 2014 to a low of \$2.34/MMcfe in October 2015 largely as a result of oversupply, NGL composite pricing declined more than 50% from July 2014 to July 2015. The lower price incentive as well as additional processing costs associated with NGL production led many operators to shift activity from liquids-rich targets to Utica dry gas targets, optimizing portfolio positions with existing Marcellus assets.

While activity has decreased across most onshore plays throughout 2015 in response to the price decline, the Woodford has uniquely drawn substantial investment despite the downturn. Led by operators including Newfield Exploration Co., Continental Resources and Devon Energy Corp., significant drilling activity and delineation of the play has focused on drilling and completion techniques largely targeting the liquids-rich areas of the SCOOP and STACK area that covers Canadian and Kingfisher counties. The SCOOP and STACK areas of the play both lie along the eastern boundary of the Anadarko Basin in central Oklahoma.

## Play production outlook

Virtually all oil production in the southwest region of the U.S. comes from the Permian Basin. The Energy Information Administration (EIA) expects oil production to continue its increasing trend

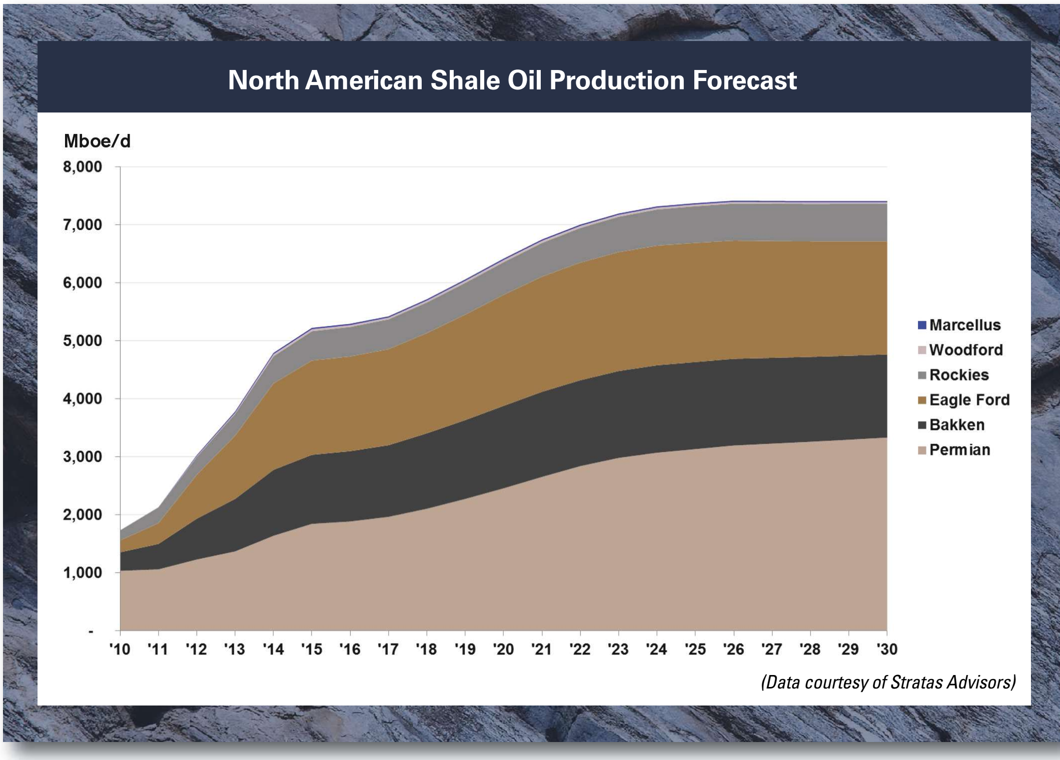



FIGURE 2. Oil production across these plays was anticipated to average 5.2 MMbbl/d in 2015.

within the Permian as new drilling in the southwest region targets the various stacked tight oil formations rather than the conventional oil formations previously developed.

The Permian Basin continued to show production growth of about 13% in 2015 despite the depressed state of oil commodity prices. This trend is likely to continue throughout the long term as operators maintain strategies of lowering well costs and increasing drilling efficiencies. Much of the total production activity has not been as closely affected by the downturn in oil commodity prices as seen in other less-developed shale plays across North America such as the Eagle Ford and Bakken. In total, production stemming from the Permian Basin is likely to double by 2025. Given the current development stage of the basin, there are vast areas left to be developed. Should commodity prices not recover as much as anticipated, it can be assumed operators in the Permian will adjust their drilling schedules accordingly.

Stratas Advisors forecasts growth in the Permian Basin to exceed 2.9 MMboe/d in 2016 representing a 2% increase in total production. It is anticipated that the play will increase further in 2017 in conjunction with the expected increase in commodity prices. Stratas Advisors expects production to increase by 4% to average 3.1 MMboe/d in 2017. Production increases are likely to prevail given the advancements in completion design and well recovery. In addition to the technical advancements seen on a well-level basis, service costs also have adapted to the recent downturn, which is aiding operators in maintaining their overall drilling and completion costs.

With the decline in overall Bakken rig count, drilling activity has been consolidated within Mountrail, McKenzie, Williams and Dunn counties. Stratas Advisors anticipates that all drilling activity in the near term will occur within these four core counties. Operators are continuously reducing well spacing as they continue to de-risk their acreage positions. Continued downspacing could result in a significant increase in potential well locations within the core area and an upward revision to Stratas Advisors production forecast in the life of the play. Drilling efficiency has increased significantly in less than a year. The EIA estimated that in September 2015 new-well oil production per rig would be at 692 bbl/d. As prices begin to stabilize or rebound, Stratas Advisors expects total production to increase within the play by 5% in 2015 over 2014 levels. Stratas Advisors then sees production increases by 2% in 2016 over 2015 levels.

Drilling activity in the Rockies has been consolidated into the DJ Basin, including the Wattenberg Field, Redtail region and the East Pony region. Production growth in the Rockies region is anticipated to occur within these core areas. Within the Uinta, Piceance and Green River basins, production rates are expected to decline throughout the short term as operators focus in on the more lucrative DJ Basin. Stratas Advisors estimates total production to increase within the play by 5% in 2015 over 2014 levels. Stratas Advisors then anticipates production to decline by 1.5% in 2016 over 2015 levels.

Production growth in the Eagle Ford is expected to average 2.71 MMboe/d in 2016 representing a flat growth in production over 2015 due to the greater than 50% drop in rig counts since August 2014. It is anticipated that the play will moderately increase in 2017 in conjunction with the expected increase in commodity prices. Stratas Advisors expects production to increase by 1% to 2.74 MMboe/d by year-end 2017. In line with EIA estimates, Stratas Advisors believes that Eagle Ford operators will begin to run out of high-quality acreage in the oil and condensate windows beginning after 2020. Operators will then have to shift drilling activity toward the less economic regions of the Eagle Ford's gas window in attempts to maintain production levels.

Both the Marcellus and Utica have remained resistant to production declines throughout the weakened oil and gas price environment. Production in both plays is likely to show substantial year-over-year growth despite the downturn in prices. In the Marcellus, total production reached 16.8 Bcfe/d in July 2015 and is on target for 13% annual growth over 2014 volumes. Similarly, Utica total production reached 3.2 Bcfe/d in September 2015 and is on target for 50% annual production growth over 2014 levels.

Condensate opportunities are no longer as alluring as they once were. Dry gas opportunities in the East are currently more economic as condensate prices have declined substantially against the decline in natural gas prices. The sustained low oil and gas price environment has shifted the strategic focus of operators across the Utica and Marcellus, and activity in the play in the short term will continue to focus on improving capital efficiency and operating within cash flows. In 2016 Stratas Advisors anticipates that drilling activity will focus primarily on lease obligations to hold acreage by production. Additionally, because the current economic environment makes resources less expensive to acquire than to discover, acquisition and divestiture (A&D) activity is likely to continue throughout the short term as operators such as Gulfport Energy Corp. and Chesapeake Energy strategically refine or expand asset portfolios.

Stratas Advisors forecasts that production growth in the Woodford will continue, reflecting the strong capital investment allocated to the SCOOP and STACK regions. Total production from the play is expected to top 425 Mboe/d in 2015, more than 15% growth from 2014 levels. Additionally, the play is anticipated to continue to show growth into 2016 reaching nearly 450 Mboe/d, resisting the price-driven decline expected of similar onshore plays. Growth in 2016 will likely be driven by drilling activity and improvements by top operators Newfield Exploration Co., Continental Resources and Devon Energy Corp. Additionally, Stratas Advisors forecasts that capital and drilling efficiency currently being developed and improved will position the Woodford for substantial growth in the short term. Particularly in the liquids-rich regions of the SCOOP and STACK, production is likely to continue to show significant potential, with nearly 80% growth possible by 2020 under favorable economic conditions.

### Price environment

The Stratas Advisors breakeven analysis is based on the company's forward price curve estimates for West Texas Intermediate and Henry Hub. Through the process outlined in the introduction, Stratas Advisors begins at the operator level to gain a more complete understanding of the playwide production trends and the resulting economics. After compiling individual well data and calculating the operator EURs using the Arp's equation, Stratas Advisors uses the forward price curves to calculate a net present value per well quintile and ultimately breakeven prices ranges for the plays and their respective sub-plays.

Stratas Advisors has calculated an average EUR for the Midland and Delaware basins based on historical well data. Stratas Advisors estimates for the Delaware Basin is 540 Mboe and 385 Mboe for the Midland Basin. After compiling individual well data and calculating the EURs for each basin, Stratas Advisors finds that breakeven prices range

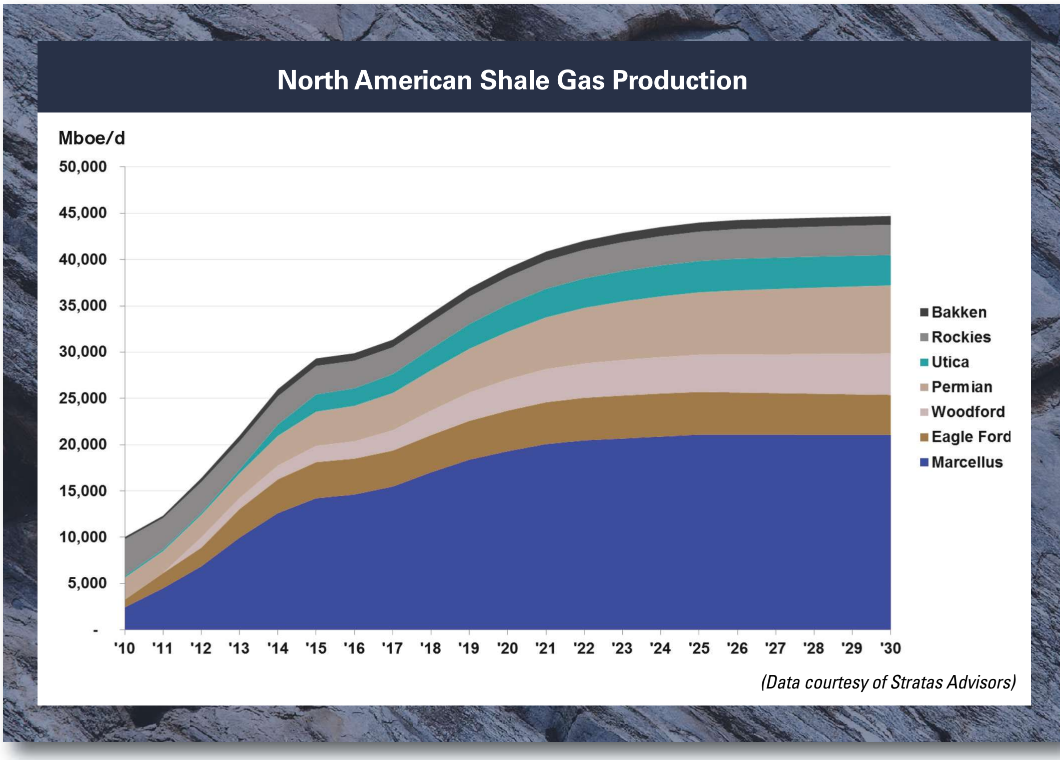



FIGURE 3. Stratas Advisors estimated that gas production would average 29.3 Bcf/d in 2015.

between $43/bbl and $80/bbl for the Midland and between $43/bbl and $61/bbl for the Delaware. Well costs in the Permian Basin currently range from $5 million per well to $7.5 million per well and have fallen about 11% to 30% from peak 2014 well costs of $6.2 million per well to $9.4 million per well. Further upside potential exists for breakeven prices in the Midland and Delaware basins as operators are confident that the reduction in well costs has not yet reached fruition.

Well costs in the Bakken currently sit between $6.4 million per well and $9.5 million per well. Stratas Advisors has found that breakeven prices in the Bakken range between $31/bbl and $78/bbl. With the deflation of service costs, operators are taking this time to drill more expensive wells at a cheaper price. With only a 15% increase in well cost, operators are able to use enhanced completions that allow for production increases of 40% to 50%.

In the Rockies well costs currently range from $3.5 million per well to $8 million per well. The large range in cost highlights the variability in wells designs currently being seen throughout the play. This includes the depths of the zones of interest, complexity of terrain and length of laterals. Stratas Advisors has found that breakeven prices range between $31/bbl and $111/bbl in the Rockies. In the DJ Basin, the most proven economic play in the Rockies, breakeven prices average roughly $43.2/bbl. Conversely, in the Piceance and Uinta basins, breakeven prices average $7.8/MMcf. The breakeven analysis for the Rockies further substantiates the migration of drilling activity into the DJ Basin.

Stratas Advisors has found that in the oil window of the Eagle Ford there is currently an average breakeven oil price of $42.80/bbl. Well costs in the Eagle Ford currently range from $4.2 million per well to $7.5 million per well and have fallen between 10% and 30% from peak 2014 well costs. Stratas Advisors believes breakeven commodity prices have further potential for improvement as operators continue to enhance well economics through drilling and completion techniques along with the use of longer laterals.

Going forward, the Marcellus and Utica region will likely continue to see increased exposure to demand from importing markets as infrastructure opens transportation across domestic regions and new LNG exports to Norway and the U.K. provide international demand for Appalachian gas.

## North American outlook

As Figure 1 illustrates, production attributable to the seven plays discussed will average 11.8 MMboe/d in 2015 from all hydrocarbon streams. In 2016, production from this basket of plays is anticipated to see modest growth as production

reaches 11.97 MMboe/d. Moving into 2017, production is anticipated to grow at a greater rate as production approaches 12.4 MMboe/d stemming from the expectation of a positive commodity price shift and more supply and demand balance. The wells that are being drilled and completed today are coming online with greater IP rates and substantially greater EURs. Operators have taken this time to improve well results and position themselves for rapid growth in the next uptick of commodity price.

Figure 2 displays the forecasted oil production across the discussed plays. Oil production across these plays is anticipated to average 5.22 MMbbl/d in 2015. Unconventional oil production from this group of plays contributes 57% of the oil production generated within the U.S. based on the 9.25 MMboe/d total given by the EIA as 2015 average U.S. production volume. Given the drawback of activity thus far, oil production is anticipated to plateau moving into 2016 to average 5.29 MMboe/d. In 2017, oil production in North America is anticipated to resume its growth, albeit at a slower rate than before averaging 5.42 MMboe/d. In the Marcellus and Utica, improved production per rig and capital efficiencies will likely prevent sharp production declines leading to flat production growth in 2016. Activity in the region will likely focus on HBP efforts to retain leased acreage.

Figure 3 displays the gas production across the discussed basket of plays. Stratas Advisors estimates that gas production will average 29.32 Bcf/d in 2015. In 2016, production will approach 29.89 Bcf/d. Following that, Stratas Advisors anticipates that production will average 31.34 Bcf/d in 2017. It is anticipated that gas production in the Eagle Ford will decrease by roughly 1% in 2016 and remain virtually flat in 2017 as operators continue to focus on their core acreage positions in the oil window of the play.

Given the well composition of all data obtained, the commodity mix for the Permian is estimated to be roughly 20% natural gas. On an operator level, Stratas Advisors has not yet seen any indications of large production slowdowns within the Permian. Gas production in the Permian is expected to increase by 4% in 2016 to 3.84 Bcf/d and by 5% to 4.04 Bcf/d in 2017 as operators continue to target the gas stream. In the Bakken, operators have consistently continued development while maintaining a large inventory of drilled but uncompleted wells. This vast inventory will help to dampen a precipitous drop in production in the Bakken. Operators in the Rockies have migrated toward a small subset of fields in the DJ Basin that offer the greatest productivity and economic returns. The DJ Basin offers easily accessible drillsites and a favorable hydrocarbon split. Operators in the region are now transitioning to extended-reach lateral wells with revised completion designs to create drastically improved well results.

## Conclusion

The improvements in drilling techniques and capital efficiencies that have resulted from the strained economics over the past year will likely position operators that have implemented them to withstand the sustained downturn relatively well. Additionally, as commodity prices begin to recover over the short term, the improved efficiency designs are expected to bolster well level economics and portfolios overall. In the near term, as well-hedged operators see their hedges expire, further consolidations and more extreme A&D might be seen. Operators are beginning to sell off not only noncore acreage but also acreage to exit certain plays entirely. From this downcycle there may be the emergence of larger pure-play operators. Operators also will have narrowed focus on the plays they wish to pursue development in. Once commodity prices return to a more favorable level, operators will be able to tap into their inventory of drilled but uncompleted wells, capitalize on the improved speed of completions and be able to supply the market in a fraction of the rate previously seen. Production from the basket of plays discussed makes up a good portion of overall oil and gas production in the U.S. With several other plays in the early stages of exploration and development, North America has the ability to supply a significant share of the growing global demand. ■

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