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# SCOOP/STACK

## *The 2017 Playbook*

A supplement to

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*The 2017 Playbook*

**A supplement to *E&P, Oil and Gas Investor* *and Midstream Business***

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On the cover: Drilling is ongoing at Chaparral's Dover Unit in Kingfisher County, Okla. *(Photo courtesy of Chaparral Energy)*

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Wells drilling on Alta Mesa's Stack acreage are shown. *(Photo courtesy of Alta Mesa Holdings LP)*

# Probing the Limits of the **Scoop/Stack**

*As operators work to expand the limits of this Midcontinent hot spot, some interesting options are springing up.*

**By Susan Klann**
Contributing Editor

Only a few U.S. oil plays have demonstrated the economic resiliency to justify continued investment, drilling and A&D activity since oil prices began falling in late 2014. The Permian Basin is No. 1 on that short list, but close behind is the U.S. Midcontinent's Scoop/Stack play.

At Hart Energy's DUG Midcontinent conference held last fall in Oklahoma City, producers, financiers, service providers and other industry experts testified to the region's strength. Operators can make money here even with crude in the $40s. Not everyone, and not everywhere, of course. Like any production province, the Scoop/Stack has its core areas and sweet spots.

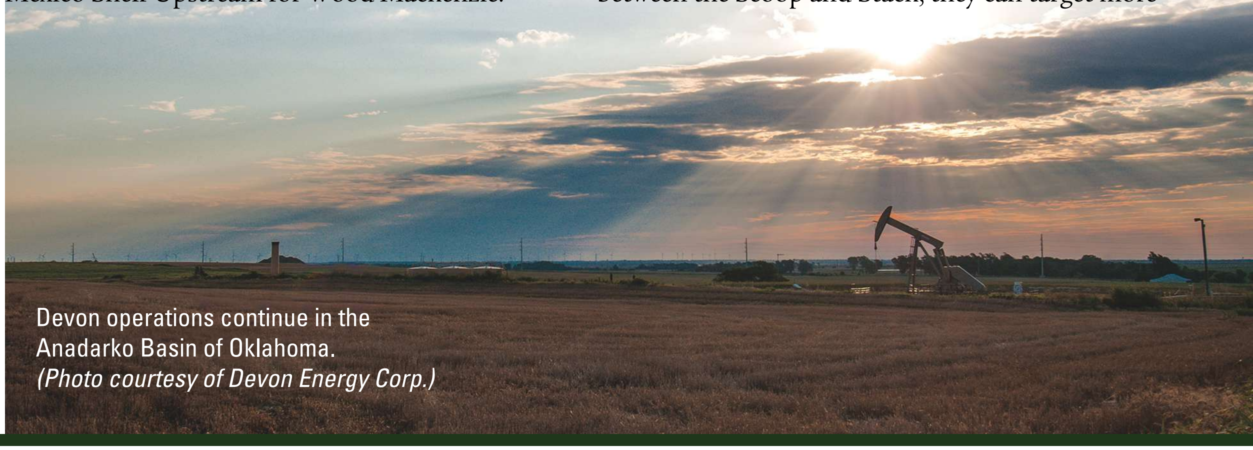
A recent Wood Mackenzie report noted two main drivers behind the Midcontinent rig count. First, the plays' cores are highly economic and can compete as the restructured industry rebounds. Second, operators are drilling to hold acreage.

The overarching Scoop/Stack theme today is delineation and extension, according to Jessica Van Slyke, research analyst, U.S. Lower 48 and Gulf of Mexico Shelf Upstream for Wood Mackenzie.

"The running room is limited," she said. "It can never be the next Permian in terms of contribution to Lower 48 supply. Contrast it with the Wolfcamp's reservoirs with multiple benches across vast areas. The Midcontinent's geology is quite variable, so formations disappear and reappear. But for operators in the core and those who can extend the play, it's great."

Proof of this potential made headlines with Devon Energy Corp.'s announcement in early July that it had brought online a monster, record-setting Meramec well, the Privott-17-H, in southwest Kingfisher County. It posted a facility-constrained peak 24-hour rate of 6,000 boe/d (50% oil). Four other Devon high-rate Meramec wells in the core of the overpressured oil window attained an average 30-day IP of 2,000 boe/d.

Over the past few years, Newfield Exploration Co. and others have been proving the viability of the Meramec that lies above the original Cana Woodford target. Activity has been moving west and north from the Stack core. Operators say that, between the Scoop and Stack, they can target more



Devon operations continue in the Anadarko Basin of Oklahoma. *(Photo courtesy of Devon Energy Corp.)*

than seven reservoirs. (The Mayes is another Mississippian target, according to WoodMac, but results are not yet available.)

"But the rule of thumb, in any area, is that there are two economic targets—and for the most part, just one, with upside from another," Van Slyke said. "In the Scoop, it's Woodford with upside from Springer. In the Stack proper, it's Meramec with upside from Woodford."

WoodMac estimates that at $50 oil, the Cana-Stack, the Stack oil and the Scoop core are in the money.

Devon, Continental Resources Inc., Newfield Exploration, Cimarex Energy Co. and Marathon Oil Corp. are the heavyweights in the Scoop/Stack, joined by an increasing number of private companies, many backed by private equity.

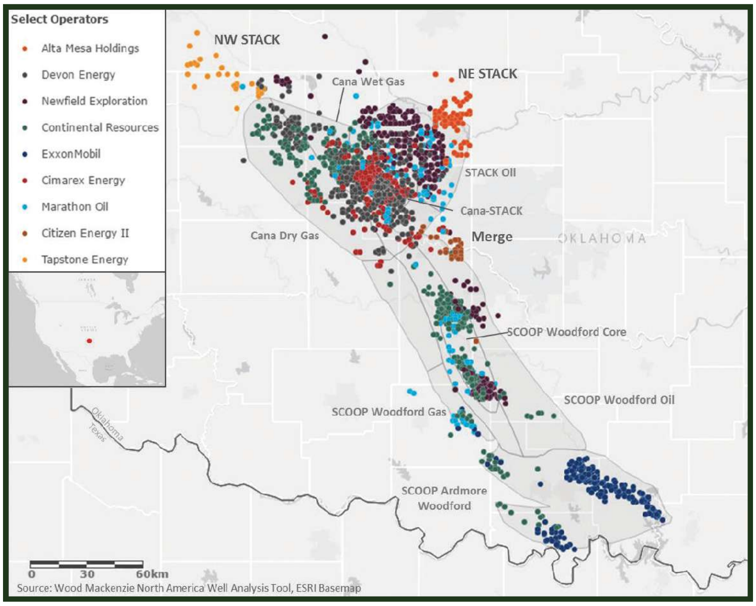

Jessica Van Slyke

The Scoop/Stack is still immature, and in 2017 and beyond companies will put more science and technology to work to determine optimum drilling and completion strategies and spacing density, stacked pay potential and more.

## Stepping out

Operators have been testing three main play extensions, according to the WoodMac analysts. The first, the "Merge," is a private-equity success story, Van Slyke said. Citizen Energy II LLC, backed by QuadTwo Capital Partners, has proved the Scoop/Stack border can work with Woodford as the main and Sycamore as the Mississippian target. The play centers on where the Meramec thins toward the south and the Sycamore emerges.

Citizen began drilling in the Merge in 2016 along with companies that bought into the learning experience or held legacy positions, like Continental Resources Inc. and LINN Energy Inc. Citizen is focusing its entire portfolio on the Merge; Jones Energy Inc. bought into the play last year through its acquisition of assets in southern Canadian and Grady counties from Scoop Energy Co.




Operators are testing play extensions while optimizing drilling and completion methods in the core areas of the Scoop/Stack. *(Data courtesy of Wood Mackenzie North America Well Analysis Tool, ESRI Basemap)*

In its early May earnings call, Jones Energy told investors it was pivoting away from the Cleveland play toward the Merge and hoped to ramp up to three rigs there later this year. At press time, the company had put its first two Merge wells on production and its first Sycamore well was imminent. "We optimistically await company Merge results given strong positive releases we have seen from offset operators in the play," said SunTrust Robinson Humphrey analyst Neal Dingmann.

"There are two main issues with the Merge," Van Slyke said. "First is infrastructure, because gas gathering lines and processing capacity are needed. The second is Oklahoma's forced pooling. Jones Energy bought into 200 units and is still trying to gain operatorship of those units, making it hard for it to ramp up quickly."

Chesapeake includes the Merge in its "Wedge" play, which comprises all its acreage prospective for the Mississippian reservoir. A recent report from Guggenheim Securities' Subash Chandra said Chesapeake Energy Corp. had reported a "handful of new, encouraging well results" in Canadian County to derisk the Wedge Meramec.

"One in particular caught our attention," the analyst and co-authors said. "The Johnston 1H in the southern Canadian County 'Meramec Silt' had an IP-30 of 1,360 boe/d (31% oil). This was 30% better than the previously reported Hunt offset well, though Hunt was 45% oil.

"Historically, we have not seen much Meramec activity in Canadian," Chandra added. "The activity has been more Woodford-focused, particularly in the southern part of the county. Continued success and de-risking of this area could drive upside to expectations and valuations for the 'Wedge' or 'Merge,' where the Stack meets the Scoop."

Van Slyke cautioned that the results to date in the Merge are still quite variable, and it remains an exploratory effort.

## The Nor'easter

Operators are also pushing into new areas of the Stack in northeast Kingfisher County. Smaller E&P companies such as Alta Mesa Holdings LP, Chaparral Energy Inc., Gastar Exploration Inc. and Longfellow Energy, in addition to Chesapeake, are leading the charge.

"We haven't given the area much credit in the past," the WoodMac analysts said. "But we're seeing more Osage development here rather than Meramec. The issue is we've heard of high water cuts, as high as 20 parts water per one part oil. Because it's normally pressured, it can also have lower IP rates than in the core area."

Alta Mesa has reported well costs as low as $3 million, however, so the wells can be economic.

Smaller operators that didn't have capital to drill during the downturn are beginning to delineate their acreage here. "It's an interesting area to watch," Van Slyke said. "It is oilier than the core of the Stack."

A recent report from Tudor, Pickering, Holt & Co. (TPH) looked at Stack economics and suggested operators' expansion efforts to the northeast are paying off through liquids yields and oil gravity.

"We see properties comparable to the Scoop given a similar shift from the dry gas to the oil window as E&P [companies] move northeast across the basin," TPH analysts said in a May report. "Our analysis shows Stack oil gravity is about 46 to 60 degrees in the liquids-rich window and about 41 to 45 [degrees] in the oil and volatile oil windows.

"Additionally, we've mapped out oil-to-gas ratio shifts across the basin over time, from which we note that GORs [gas-oil ratios] decline to a lesser degree of magnitude in the liquids-rich window relative to the wet gas and condensate windows in the Scoop."

Chesapeake Energy is targeting an additional formation, the Oswego, in the northeast. "We don't see it as repeatable," Van Slyke said. "But Chesapeake has found some hot spots with high oil ratios and high IP rates in Kingfisher County."

## Northwest Stack

Producers are also probing the wet gas Stack to the northwest. Previously, based on 2013 and 2014 activity, the WoodMac analysts had assigned the area an $85 breakeven price. Reduced well costs have brought that number down significantly.

Tapstone Energy, backed by Tom Ward, is leading development and delineation in this hot spot. The company announced one well with a hefty IP-30 of 2,600 boe/d (62% oil)—"but it's a small cluster of oilier activity surrounded by gas wells," Van Slyke said. "Is it a sweet spot, or can it be replicated? I think many operators agree that it would be tough to replicate that level of success; the average producer is about 800 boe/d at 30% oil. However, there is thick Mississippian reservoir pay in this area (greater than 1,000 ft), and it could be a matter of finding the right landing zone."

Devon is also testing in the northwest extension.

## The big five

At press time, Devon had just two rigs in the northwest but planned to run 10 in the Stack overall by year-end 2017 as it puts $750 million to work. In its first-quarter earnings call it reported that initial spacing pilots were successful, and the Meramec was moving to full field development. In the Stack's eastern core, Devon is ramping Woodford development and said extended-reach laterals are on the horizon. By year-end it expected to boost Stack production by 35%, exiting with about 120,000 boe/d. Its current type curve is for 5,000-ft laterals.

The Privott well was drilled with a 10,000-ft lateral and landed in the upper Meramec interval near Devon's Showboat development, which will spud in the third quarter, according to the company's press release. "A key contributor to this prolific well result was an improvement in stimulated rock volume around the wellbore through a new proprietary completion design," the release added.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Showboat will include about 25 wells across four landing zones.

Newfield Exploration and Marathon Petroleum Corp. also plan to average 10 rigs in the Scoop/Stack by year-end 2017 (Newfield is currently running 10 in the Anadarko Basin), while Cimarex Energy indicated it would hold at five to six.

Newfield, an early leader in the Scoop, found the Stack when in late 2011 it decided to go updip in the Cana gas field in search of oil—a "wild and risky concept at the time in a field that had only 2% to 5% porosity," said Steve Campbell, vice president of investor relations. The E&P company's initial Stack well took a core of Meramec shale on its way to the Woodford and found live oil.

Campbell said Stack/Scoop economics can weather lower crude prices because the oil is high quality and lease operating expenses are contained due to little or no formation water. Further, producers can sell into Cushing for a Nymex price $4 or $5 better than Permian barrels fetch.

Steve Campbell

The company's rigs will be split about equally between Scoop and Stack this year, with $850 million of its $1.1 billion capital budget earmarked for the Anadarko Basin.

Chairman, president and CEO Lee K. Boothby said the company would test well densities, optimize completions and explore new stacked pay potential across its position in 2017, and that the Stack is the foundation for the company's transition to a company that "can sustainably grow its production by double-digits within cash flow—even if today's oil prices persist."

Through its new "Score" program, the company will test Sycamore and Caney in the Scoop and Osage in the Stack to ascertain commerciality and drilling sequencing. Newfield has allocated $100 million to test these horizons.

In mid-May, the company, which holds more than 300,000 net Stack acres, released news of its stellar Burgess well in Kingfisher County, which yielded a 24-hour flow rate of 2,931 boe/d (69% oil) and a 30-day average rate of 2,492 boe/d (70% oil). It was a Scoop/Stack record for 24-hour oil production per 1,000 ft of gross perforated interval, or 417 bbl of oil per interval.

"The Burgess had the largest completion put on to date, almost two times as large as the standard completion we've used," Campbell said. "It was a way of stepping out. There is a point at which it's only bigger, not more economic, however, so we are seeking that point of diminishing returns and then will back off. The Burgess is far above our type curve, but we don't know how long that production level will last."

The Burgess is one of 16 wells with enhanced completion designs using 2,100 lb of proppant and 2,100 gal of liquids per interval. The 13 wells with 60 days of production history were outperforming the company's 1.1 MMboe estimated average type curve by an impressive 45%.

Newfield plans to drill about 90 wells in the Stack, about 50 in the Scoop and five to seven in the Score effort this year, according to Campbell. The company has baked in a 10% increase in service costs. It curtailed drilling on its Bakken assets and cut Utah activity to zero to direct more capital to the Midcon effort.

Scoop/Stack returns justify the capital injection. "We can generate through our current position, at current service costs, returns of more than 40% at today's oil prices," Campbell said.

## Cimarex Stack

Over the last six months, Cimarex Energy has been drilling mostly long laterals to secure acreage and delineate and expand the scope of the Meramec play. Cimarex is focused on just two plays—the Delaware Basin and the Stack. "Given current strip pricing and cost structure, right now certain aspects of the Stack compete very nicely with the Delaware," said John Lambuth, senior vice president of exploration.

Operators agree that sharing best practices of major players has fast forwarded development in the Scoop/Stack. Spacing pilots underway will help define ultimate development so companies can begin to monetize acreage, Lambuth said.


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John Lambuth

Cimarex holds 116,500 net prospective acres, 90,000 de-risked, in the Meramec, and has 136,500 net undeveloped acres in the Woodford. Its 24 5,000-ft Meramec laterals have posted an average 30-day peak IP of 1,417 boe/d (34% oil, 43% gas and 23% NGL), while its nine 10,000-ft laterals have upped 30-day IPs in the Meramec to an average of 2,057 boe/d. Cimarex holds an interest in or has data on all but three of the downspacing pilots.

"The recent Cimarex-operated Leon Gundy pilot was a very successful outcome for us," Lambuth said. "We drilled eight total wells, with four Meramec wells testing 10 wells per section, and four Woodford wells testing nine wells per section. Those Meramec wells are exceeding their parent wells."

While this represents just one pilot result, he said, it is a placeholder for the company to proceed.

In the eastern core of its Woodford holdings, Cimarex has an increased density pilot underway. Also on deck is the Leota-Jacobs infill project, a long lateral Woodford development.

The company has drilled some "really good wells" in the northwest extension area in Blaine County, Lambuth said, where it jumped out early to acquire acreage. "We're also keeping an eye on a company that's moving into the deeper, gassier part of the play, bringing on some interesting wells, as well as operators moving down to the Merge," he said. Cimarex has drilled one well in the Merge and plans more.

The company has about 35 wells scheduled in the Stack play this year, a mixture of Woodford and Meramec. During the first quarter, Cimarex completed and brought on production about 10 net wells in the Stack and has 15 more net waiting on completion.

The company estimates wells currently cost $10.5 million to $12 million for a long lateral (10,000 ft). "The wells have about the same D&C [drilling and completion] cost as seen at the peak, but we have dramatically increased the amount of sand we're pumping," Lambuth said. "For the same cost, we're getting far better wells because of enhanced stimulation."

Within the Meramec, Cimarex is still seeking the right recipe. "Based on recent wells, we are homing in, but we still have a lot left to get out by changing the design," he said.

## Continental ups type curves

Continental Resources, meanwhile, continues to report big wells. Scoop net production averaged 62.178 Mboe/d, or 29% of the company's production for the first quarter. Five rigs were working the Scoop. The company highlighted its Scoop Springer wells in Grady County, all of which were outperforming the company's historical 940 Mboe Springer type curve for a 4,500-ft lateral in the first 30 to 60 days on production. These are the first Springer wells Continental has completed since third-quarter 2015, and it plans to complete up to 10 more Springer wells this year.

In the Scoop Sycamore Formation in Grady County, the company reported results of 7.8 MMcf and 225 bbl/d on a 5,800-ft lateral and 12.2 MMcf and 109 bbl/d on a 7,900-ft lateral on about 60-day tests. It plans to drill five to seven additional Sycamore wells to help delineate the high-liquids windows of the play.

Other Scoop Sycamore action was recently highlighted by Heikkinen Energy Advisors' David Heikkinen in a note about a big well by Ward Petroleum Corp. The Lynda 26-23-1XH in southern Grady County hit with a record Scoop IP rate of about 860 bbl/d of oil and 15.9 MMcf/d of gas.

"The well targeted the Sycamore (Meramec) Formation that had previously not seen nearly as much attention as the Meramec in the more northern Stack play," Heikkinen said.

In the Stack Continental upped its production 20% from the previous quarter to 29,216 bbl/d. It reported three operated standalone wells in the Stack Meramec overpressured oil window and one in the condensate window with strong production rates. It has 11 operated rigs in the Stack, with six targeting the Meramec overpressured oil and condensate windows and five targeting Woodford in the Northwest Cana joint development agreement area in Blaine and Custer counties.

### Marathon spurs production

Marathon Oil's unconventional Oklahoma production averaged 44,000 net boe/d during first-quarter 2017, according to its earnings report, up more than 60% from the year-ago quarter. Of the 12 gross operated wells brought to sales in the first quarter, five were part of the company's first operated Stack infill spacing test, the Yost pilot, and the others were focused on lease retention and delineation.

The Yost, in the normally pressured black oil window in central Kingfisher County, tested 107-acre well spacing with completions of about 2,500 lb of proppant per lateral foot. The 30-day IP rates from the five new standard-lateral Yost wells and parent well averaged 990 boe/d (57% oil). The company said it plans to bring 90 to 100 gross operated wells to sales this year, including four to five Stack infill pilots and two Scoop infill pilots, and will test secondary horizons.

School's not out yet for operators working the Scoop/Stack play, and they'll learn a lot in the next several years. ■

## MidContinent Acquisitions and Divestitures

There are plenty of startups in the Scoop/Stack, but since Gulfport's hefty purchase in December 2016, no major deals have been struck. There will be more transactions in the coming year, particularly as the five major operators cooperate to trade sections and block up acreage for better development.

According to a recent note from analyst Neal Dingmann with SunTrust Robinson Humphrey during a late March presentation at the Society of Petroleum Engineer's Scoop/Stack event in Houston, "the highlight was when HighMark Energy's Ali Ahmed predicted deals to be announced in the next two to five weeks that would be valued at $25,000 to $30,000 per acreage or the highest on record in the play. The previous high watermark for the Stack was set by Devon in late 2015 with the $20,000/acre acquisition of Felix Energy LLC."

The deals were expected to focus on the core Stack, and would not necessarily involve the current large publics in the play, according to the note. ■

**Anadarko Basin Scoop/Stack Transactions**

| Announced Date | Buyer(s) | Seller(s) | Area | Transaction Value ($ millions) | Production (Mboe/d) | Total Value of Production ($ millions) | Net Acres | $/Undeveloped Acre |
|---|---|---|---|---|---|---|---|---|
| 12/7/2015 | Devon | Felix Energy | Stack-Kingfisher, Canadian, Blaine | $1,900 | 9 | $270 | 80,000 | $20,375 |
| 4/22/2016 | Casillas Petroleum | Chesapeake | Garvin, Grady and McClain counties | $106 | | $0 | 12,000 | $8,833 |
| 4/28/2016 | Triumph Energy Partners | RRC | Stack-Blaine, Canadian, Kingfisher, Major | $77 | 0.8 | $20.8 | 9,200 | $6,105 |
| 5/5/2016 | Newfield | Chesapeake | Stack-Kingfisher, Canadian, Blaine, Dewey, Custer | $470 | 3.8 | $114 | 42,000 | $8,476 |
| 6/20/2016 | Marathon Oil | PayRock | Stack-Kingfisher, Canadian | $888 | 9 | $166.5 | 61,000 | $11,828 |
| 7/28/2016 | Rimrock Resource Partners | Undisclosed | Scoop | $150 | 2.1 | $38.9 | 24,500 | $4,537 |
| 8/18/2016 | Jones Energy | Aubrey McClendon's estate | Stack/Scoop-Canadian, Grady and McClain | $136.5 | | | 18,000 | $7,583 |
| 10/17/2016 | Casillas Petroleum | Continental Resources | Scoop | $296 | 0.7 | $17.5 | 30,000 | $9,283 |
| 10/20/2016 | Red Bluff Resources | Gastar | Canadian/Kingfisher | $71 | 0.2 | $2.6 | 25,000 | $2,737 |
| 12/14/2016 | Gulfport | Vitruvian II Woodford LLC | Scoop-Grady, Stephens and Garvin counties | $1,850 | 30.5 | $810.0 | 46,400 | $22,414 |
| 1/16/2017 | Apollo-backed Zenergy | Staghorn | Stack (East) | $613 | 2.8 | $55.5 | 41,386 | $13,472 |
| 3/22/2017 | Gastar | Multiple private sellers* | Stack-Kingfisher County | $51.4 | 0.3 | $8.3 | 5,670 | $7,610 |
| **Weighted Average** | | | | **$6,608.9** | **59.2** | **$1,504.0** | **395,156** | **$12,919** |

*John B. Kleinheinz, Kleinheinz Capital Partners Inc., GKK Husky LLC, Husky Oklahoma LLC and Strong Oil and Gas Ltd.

*(Data courtesy of Williams Capital Group)*

# Get the **Scoop** on the Scoop/Stack

*Operators continue to prove themselves as major shale players in the Oklahoma region.*

**By Ariana Benavidez**
Associate Managing Editor

The South Central Oklahoma Oil Province (Scoop) play was discovered in 2012 and followed a year later by the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (Stack) play. These Oklahoma areas have since proven to be a hot commodity for operators.

"While development in the Scoop/Stack has been tempered by volatile commodity prices in recent months, operators like Devon, Continental and Newfield continue to see quarter over quarter production growth. The recent $57 million acquisition by Unit Corp. further illustrates the Anadarko Basin's growth potential moving into the second half of 2017," said Cory Regal, senior upstream analyst at Stratas Advisors.

In the following section, Hart Energy profiles some of the most active operators in the Scoop/Stack plays.

## Key Players

An Alta Mesa well drills on the company's Stack acreage. *(Photo courtesy of Alta Mesa Holdings LP)*

### Alta Mesa Holdings LP

Since 2012 Alta Mesa Holdings LP has focused on the horizontal development of the Mississippian-age Osage and Meramec formations as well as the Pennsylvanian-age Oswego Formation, according to the company's website. Alta Mesa has about 4,000 potential drilling locations across four benches, with multiple upside locations possible through optimized spacing and targeting of additional producing horizons.

Alta Mesa has increased its Stack acreage position from 45,000 net acres in early 2015 to more than 100,000 net highly contiguous acres as of first-quarter 2017, most of which are HBP, according to the company's first-quarter results report. The company is operating six horizontal drilling rigs, targeting the Mississippian-age Osage, Meramec and Manning formations and the Pennsylvanian-age Oswego Formation, the report stated.

In the first quarter Alta Mesa completed 25 horizontal wells in the Osage Formation. The company had 35 horizontal wells in progress at the end of first-quarter 2017, seven of which were completed subsequent to the end of the quarter, the report stated. The company has allocated about 95% of its 2017 capex budget, including acquisitions, to the Stack. Capex for this area in first-quarter 2017 was $58.3 million out of the total company expenditures of $60.6 million, according to the company's report. Average production for this core area in first-quarter 2017 was about 19.3 Mboe/d (70% oil and NGL), an increase of 75% compared to 11.0 Mboe/d in first-quarter 2016.

## Apache Corp.

Apache identifies its Midcontinent/Gulf Coast region as the Granite Wash, Tonkawa, Canyon Lime, Marmaton and Cleveland formations of the West Anadarko Basin, the Woodford-Scoop and Stack plays located in central Oklahoma, and the Eagle Ford Shale in southeast Texas. In 2016 the region accounted for 11% of the company's production and about 9% of the company's year-end estimated proved reserves, according to the company's website.

"In 2016 Apache drilled or participated in drilling 35 wells with a 94% success rate. Activity was focused primarily in the Woodford-Scoop and Canyon Lime formations," the company stated on its website. "In 2017 Apache plans to run a targeted program, drilling 11 wells in the Woodford-Scoop play. In addition, the region will continue its focus on high grading acreage and building its inventory of future drilling locations."

First-quarter 2017 production for the region was about 45 Mboe/d, according to the company.

## Carrera Energy LLC

Carrera Energy LLC was formed in 2014 by members of the management team from Limestone Exploration II. Based in Midland, Texas, Carrera has assets in the Permian Basin and Midcontinent region.

In 2015 the E&P company completed two horizontal Mississippian producers in Blaine County's Longdale southeast field in Oklahoma nearly 25 miles to the east-southeast, according to IHS. The company continued its drilling progress in Oklahoma, completing wells during 2016 and 2017.

In the Anadarko Basin, the company has leased more than 8,000 acres to date in a stacked, multipay unconventional prospect. Within the prospect, Carrera has identified up to eight potential reservoirs for horizontal drilling at true vertical depths ranging from 7,500 ft to 11,000 ft.

In December 2016 Carrera received four permits for Blaine County and one permit for Kingfisher County in the Stack region, according to an *okenergytoday.com* report.

## Casillas Petroleum Corp.

Formed in 1986, Casillas Petroleum Corp. is a closely held privately owned company headquartered in Tulsa, Okla. The company's current assets exceed 1,000 producing wells within five states in the Midcontinent region.

In April 2016 Casillas Petroleum Resource Partners LLC, a partnership between Casillas Petroleum Corp. and Kayne Anderson Energy Funds, closed on the purchase of certain oil and gas assets owned by Chesapeake Energy Corp. in the Scoop play for $106 million, according to a Casillas press release. The assets include an interest in 260 producing wells that cover about 12,000 net acres (100% HBP) in Garvin, Grady and McClain counties in Oklahoma.

In October 2016 Casillas Petroleum Resource Partners closed on another purchase of certain oil and gas assets, this time owned by Continental Resources Inc., in the Scoop play in Oklahoma for an adjusted purchase price of $294 million, a company press release stated. The assets included net production of 550 boe/d and about 30,000 net acres (90% HBP) in Garvin, Grady and McClain counties.

## Chaparral Energy LLC

Chaparral Energy is a Midcontinent operator with operations focused in Oklahoma's Stack play. The company has potential net reserves of more than 1 Bboe and about 400,000 net surface acres, of which more than 110,000 acres are in the Stack.

Chaparral Energy's first-quarter 2017 production was 22.5 Mboe/d. *(Photo courtesy of Chaparral Energy)*

The company has more than 3,000 operated unrisked Stack drilling locations, with stacked pay potential in the Oswego, Meramec, Osage and Woodford formations.

According to the company's April 2017 investor update presentation, Chaparral achieved total net production of 24.4 Mboe/d in 2016, of which 55% was oil, 16% was NGL and 29% was natural gas. Its first-quarter 2017 production was down slightly to 22.5 Mboe/d, which is in line with its 2017 annual production guidance of 8.2 MMboe to 8.6 MMboe.

Chaparral produced 8,040 boe/d in the Stack during the first quarter, which marked a 21% year-over-year growth in Stack production. According to its website, the company has unrisked Stack resource potential of more than 900 MMboe. In addition, its 2016 average drilling and completion cost for its Stack Meramec wells was $3.3 million. The company also decreased its lease operating expenses in the Stack by 17% to $3.77/boe in 2016.

The company will dedicate about $85 million of its $125 million to $150 million capex budget to Stack operations, particularly the development of its Garfield County and Merge acreage. As of April, Chaparral was operating two drilling rigs in the play. It plans to drill 18 to 20 Stack wells this year with potential to increase its drilling and completion budget in late 2017, according to the company's April presentation.

The company recently announced its plans to transition to a premier, pure-play Stack operator. As part of its new strategy, Chaparral is marketing its EOR assets, including its Texas/Oklahoma Panhandle and North Burbank fields. According to the company's website, the North Burbank Unit is Oklahoma's largest EOR project with more than 824 MMboe of estimated original oil in place and the state's single largest unitized field. Net production in the North Burbank during the first quarter totaled 3,100 bbl/d of oil.

## Chesapeake Energy Corp.

Chesapeake has about 870,000 net acres in the Wedge Play in the Midcontinent region, with 1,400 additional upside locations.

Chesapeake drilled its first extended-lateral well in Major County targeting the Saint Genevieve Formation (Meramec silt) in the Midcontinent region, according to the company's first-quarter 2017 report. This well had a completed lateral length of 9,900 ft and was placed in production in late April. Chesapeake expects to drill up to 20 additional extended-lateral wells in the Saint Genevieve Formation in 2017.

"The company also expects to test additional formations in its Midcontinent area, including the Chester limestone and sandstone formations, later this year. Chesapeake controls about 230,000 net acres that it believes are prospective for the Chester and has drilled and collected two full core samples of the section earlier in 2017 to help optimize its completion designs," the report stated. "The company expects first results from the Chester in the third and fourth quarters of 2017."

As of May, the company had four rigs and two fracturing crews in Oklahoma with 15% of the company's overall budget directed toward drilling and completion asset funding in that area. The company reported a peak rate in the Midcontinent area of 1,458 boe/d (67% oil) and is drilling on newly acquired acreage in Major County, according to a May investor presentation.

Chesapeake's second-half 2017 plans include moving Meramec to development and beginning testing on the Chester Formation, according to the investor presentation.

## Cimarex Energy Co.

Cimarex defines its Midcontinent region as the Anadarko Basin in Western Oklahoma, Southern Oklahoma and the Texas Panhandle. The bulk of the independent company's activity takes place in the Woodford Shale in Western Oklahoma.

Woodford wells target the liquids-rich Woodford Shale formation. The infill program is taking place in Canadian County, Okla. Cimarex has 136,500 net undeveloped acres (88% HBP) in the Woodford Shale, according to a May corporate update presentation.

In addition to the Woodford Shale, Cimarex is actively testing the Meramec Shale. The Meramec sits above the Woodford Shale and early results have been encouraging, the company said on its website. Cimarex has 116,500 net prospective acres (90,000 de-risked) in Meramec, according to the May presentation.

The Midcontinent region accounted for 63% of Cimarex's year-end 2015 proved reserves and 44% of total production, according to the company's website.

Cimarex invested $306 million in exploration and development during first-quarter 2017, with 30% of that dedicated to the Midcontinent, according to the company's first-quarter 2017 report.

Production from the Midcontinent averaged 484 MMcfe/d for the first quarter, down 2% vs. first-quarter 2016. Crude oil volumes were up 20%, natural gas production grew 3% and NGL volumes increased 16%, the report stated.

During the first quarter Cimarex completed and brought on production 45 gross (10 net) wells in the Midcontinent. At the end of the quarter, 68 gross (15 net) wells were waiting on completion, according to the report. The company operates six rigs in the region.

## Citizen Energy II LLC

Citizen Energy has a strong focus in the Midcontinent region, developing horizontal plays and actively pursuing new play concepts. The company has more than 100,000 net acres, more than 300 operated sections and more than 2,000 gross operated locations in the Scoop/Stack.

The company's highest internal rate of return well drilled in the Stack area to date is the Governor JBE #1H-32 in the Meramec Formation. Citizen reported 1,898 boe/d and $4.6 million, according to a May company presentation.

In March Citizen was the high bidder for two 160-acre leases encompassing the south half of the western Stack play. The operator paid $480,000 each ($3,000 per acre) for Tracts #21 and #22, according to an IHS Energy report.

In February Citizen completed three exploratory wells on a common pad that's about 3 miles northwest of Union City, Okla., according to another IHS Energy report. The 1H-17-20 Oppel in southern Canadian County flowed 712 bbl of 49-degree oil, 2.01 MMcf of gas and 855 bbl/d of water during initial tests of an acidized and fractured Mississippi interval at 11,367 ft to 19,117 ft.

The company expects its four-rig program to produce more than 25 Mboe/d by year-end 2017, according to the May presentation. Citizen also expects production to ramp up to more than 34 Mboe/d by year-end 2018. The program has 41 operated producing laterals and 12 operated laterals, and production is more than 90% operated.

In addition, LINN Energy signed an agreement with Citizen Energy II LLC in which both companies will contribute certain upstream assets in Oklahoma to a newly formed company, Roan Resources LLC, focused on the accelerated development of the Merge/Scoop/Stack play in the Anadarko Basin, a June press release stated. Roan will have about 140,000 total net acres forming a core, largely contiguous position with LINN and Citizen each contributing about 70,000 net acres.

The company's 2017 Scoop plans include increasing activity in the Springer area and completing up to 10 Springer wells. *(Photo courtesy of Continental Resources)*

## Continental Resources Inc.

Continental Resources has significant positions in Oklahoma, including its Scoop Woodford, Scoop Springer, Scoop Sycamore discoveries and the Stack play.

According to Continental's first-quarter 2017 report, the company produced 29,216 boe/d in the Stack play, a 20% increase compared to fourth-quarter 2016. The company has 11 operated rigs in the play, with six rigs targeting the Meramec Formation in the overpressured oil and condensate windows and five targeting the Woodford Formation in the Northwest Cana joint development agreement area in Blaine and Custer counties, the report stated.

In addition, Continental has about 197,000 net acres in the Scoop Springer, which is located about 1,000 ft above the Woodford Formation, according to the company's first-quarter 2017 report. The company's Scoop production averaged 62,178 boe/d (27% oil) in first-quarter 2017, which was 29% of the company's total production for that quarter. Continental had 14 gross (five net) operated and nonoperated wells with first production in first-quarter 2017. Continental has five operated drilling rigs working in the Scoop.

The company's 2017 Scoop plans include increasing activity in the Springer area and completing up to 10 Springer wells. The company also recently announced its new Scoop Sycamore play, where it has 300,000 net reservoir acres of leasehold. The company also announced two successful wells in the Sycamore and plans to complete additional operated wells by year-end 2017.

## Council Oak Resources LLC

Founded in 2015, Council Oak Resources is a privately held company with about 40,000 net acres in the northwest Stack play of Oklahoma with controlling interest in more than 65 sections. The private E&P company operates multiple wells in northwest Blaine and Dewey counties. As of the end of June, Council Oak was producing about 3,000 net boe/d. The company was drilling its eleventh well at the end of June and expected to have anywhere from 12 to 20 operated wells online by year-end 2017. The company has a $300 million commitment from Encap Investments LP.

## Devon Energy Corp.

Devon Energy Corp., an independent E&P company, has Stack operations in the oil-prone Meramec and the liquids-rich Cana-Woodford Shale. Last year net production averaged 93 Mboe/d in the Stack play.

The company reported that its Stack net production rose to an average 95,000 boe/d in first-quarter 2017, an 8% increase compared to fourth-quarter 2016, according to the company's first-quarter 2017 operations report.

Devon exited first-quarter 2017 with seven rigs and plans to run as many as 10 operated rigs by year-end 2017, the report stated. This year the company plans to invest $750 million of capital in the Stack play. Devon also intends to maintain its Stack production guidance of more than 120 Mboe/d by year-end 2017.

Devon Tower is seen at dawn behind SkyDance Bridge, a 197-ft sculpture and pedestrian bridge near downtown Oklahoma City. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

"With the operational momentum created by the company's accelerated drilling program in the Stack in 2017, Devon expects even higher production growth rates in 2018," the report stated.

Devon also brought online a record-setting Meramec well and began production on several high-rate wells in the core of the overpressured oil window of the Stack play during second-quarter 2017, according to a July press release. The Privott 17-H well was brought online in southwest Kingfisher County in Oklahoma and achieved a facility-constrained peak 24-hr rate of 6 Mboe/d (50% oil). "When compared against publicly available data in the Stack, the Privott well achieved the highest initial production rate of any well by a wide margin and is expected to recover in excess of 2 MMboe over the life of the well," the release stated.

## Gastar Exploration Inc.

Gastar Exploration, an independent energy company and pure play Midcontinent Stack operator, has 89,600 net surface acres in Oklahoma, including about 62,600 core Stack surface acres. The company reported an average Midcontinent production of 5,700 boe/d in first-quarter 2017, according to its May financial update. This was 7% less than the 6,100 boe/d reported in the same quarter a year earlier. First-quarter 2017 Midcontinent production consisted of about 49% oil, 28% natural gas and 23% NGL, the report stated.

"In late March 2017 Gastar completed the acquisition of additional working and net revenue interests in about 66 gross (9.5 net) producing wells and 5,670 net acres of additional Stack oil and gas leasehold interests in Kingfisher County, Okla., for about $51.4 million," according to the May report. "Prior to the acquisition, Gastar held an existing interest in the majority of the acquired producing wells and leasehold."

The company's net capex, excluding acquisitions, in first-quarter 2017 totaled $24.9 million, which included $8.2 million for drilling, completions and infrastructure costs; $15.7 million for unproved acreage extensions, renewals and additions; and $1 million of other capitalized costs. For the remainder of 2017 the capex budget (as of May), including other capitalized costs, is $59 million, including $37.7 million for drilling, completion and infrastructure costs; $15.1 million for lease renewal and extension costs; and $6.2 million of other capitalized costs.

## Gulfport Energy Corp.

Oklahoma-based Gulfport Energy's Scoop acreage totals about 85,000 net acres (about 46,400 net Woodford acres and about 38,600 net Springer acres) with four gross operating rigs as of first-quarter 2017. The company reported Scoop production of 172 MMcf/d during the first quarter, according to its website. That production was made up of about 11% oil, about 69% natural gas and about 20% NGL.

For the remainder of the year, Gulfport's planned operated activity includes intentions to drill 19 to 21 gross (16 to 18 net) wells and turn to sales 14 to 16 net operated wells. The company's nonoperated activity includes intentions to drill and turn to sales 10 to 12 gross (one to two net) wells. The company will focus within the wet gas window this year.

In February Gulfport closed the acquisition of core Scoop assets from Vitruvian II Woodford LLC for $1.85 billion, according to the company's first-quarter 2017 report. Included in the transaction were 48 producing horizontal wells and interests in more than 150 nonoperated horizontal wells, according to a December 2016 IHS Markit report. Gulfport also acquired about 46,400 net surface acres in the core of the play, which includes rights to 46,400 Woodford acres and 38,600 Springer shale acres, the report stated. The estimated proved reserves attributable to the acreage were about 1.1 Tcfe. Four rigs were operating as of year-end 2016 on the acreage, and Gulfport intends to maintain that level of activity in the play during 2017 as well as add an additional two rigs at the beginning of 2018, according to the IHS report.

The company also had scheduled to spud both a Springer and Sycamore location in the Scoop this summer, according to a May presentation.

During second-quarter 2017, Gulfport turned-to-sales two gross (1.2 net) wells, the Vinson 2-22X27H and Vinson 3R-22X27H, located in the wet gas window in southern Grady County, Okla. Following 30 days of production, the Vinson 2-22X27H cumulatively produced 418.4 MMcf of natural gas and 1,382 bbl of oil, and the Vinson 3R-22X27H cumulatively produced 498.8 MMcf of natural gas and 1,552 bbl of oil, a June press release stated.

## Jones Energy Inc.

Jones Energy, an independent oil and natural gas company headquartered in Austin, Texas, has operations in the Anadarko and Arkoma basins in Texas and Oklahoma. As of year-end 2016, the company held 199,218 net acres with 1,659 net drilling locations, had average production of 19.2 Mboe/d and total proved reserves of 105.2 MMBoe, according to a Jones Energy investor relations representative.

Jones Energy entered the Merge play in September 2016 with an initial acquisition of 18,000 net acres predominately in Canadian and Grady counties, Okla. Since that time, the company has added about 3,688 net acres at an average price of $7,500 per acre to its position as of first-quarter 2017. The company's footprint is about 21,700 net acres.

Jones Energy initiated drilling in the Merge in December 2016, spudding its first well from a two-well pad targeting the Woodford Formation. During first-quarter 2017, the company continued the initial program by drilling two more wells and completing three wells, all Woodford interval targets. Subsequent to the end of the first quarter, Jones Energy initiated drilling its first Meramec target and expects to release results from its initial wells later this year, according to the company.

Jonny Jones, the company's founder, chairman and CEO, said in the company's first-quarter release that, "2017 is a transition year for Jones Energy from a Western Anadarko (Cleveland)-focused company to a Merge-focused company."

In addition to Merge drilling, during first-quarter 2017 the company spud 15 wells, completed 19 wells and brought 17 wells online in its Western Anadarko asset in the Northern Texas Panhandle and part of Oklahoma. The company achieved average production during the quarter of 18.9 Mboe/d.

Jones Energy continues to run three rigs in the Western Anadarko and one rig in the Merge area. The company anticipates adding a second Merge rig in summer 2017 with a third rig likely to follow by year-end 2017. Jones Energy projected average company production of 20,700 boe/d to 21,700 boe/d for second-quarter 2017.

According to a June press release, Jones Energy entered into definitive agreements to sell several noncore assets, including an agreement to sell its Arkoma Basin properties for up to $70 million.

### LINN Energy Inc.

LINN Energy Inc. was formed in February 2017 as the reorganized successor to Linn Energy LLC. The company's core focus is the Scoop/Stack/Merge areas in Oklahoma.

LINN Energy's Midcontinent key basins are the Anadarko and Arkoma. The company's Midcontinent proved reserves represented about 15% of total proved reserves as of December 2016, of which 81% were classified as proved developed, according to the company's website. This region produced about 101 MMcfe/d, or 12% of the company's 2016 average daily production. During 2016 LINN invested about $31 million to develop the properties in this region and about $40 million in exploration activity, the website stated.

As of February, the company had about 185,000 net acres in the Scoop/Stack/Merge area with 96% HBP, according to a supplemental emergence presentation. This area holds a net production of about 56 MMcfe/d (58% natural gas, 20% NGL and 22% oil) including existing vertical production in western Oklahoma.

"The company holds a significant acreage position in the NW Stack that is 99%-plus held by production. The primary horizontal drilling targets are the Osage and Meramec formations. Industry activity has significantly increased in the area, with 43 horizontal well permits in the first quarter of 2017 compared to 18 in the first quarter of 2016," according to the company's first-quarter 2017 report. "There are 17 rigs currently running and recently several companies have announced acreage acquisitions in the area. In the first quarter of 2017, the company participated in two gross (0.24 net) nonoperated horizontal completions in the NW Stack."

In addition, LINN Energy signed an agreement with Citizen Energy II LLC in which both companies will contribute certain upstream assets in Oklahoma to a newly formed company, Roan Resources LLC, focused on the accelerated development of the Merge/Scoop/Stack play in the Anadarko Basin, a June press release stated. Roan will have about 140,000 total net acres forming a core, largely contiguous position with LINN and Citizen each contributing about 70,000 net acres.

## Longfellow Energy LP

Founded in 2006, Longfellow Energy LP is a privately owned oil and natural E&P company primarily engaged in the exploration and development of new reserves in onshore U.S. basins that have been underdeveloped and overlooked, the company stated on its website.

Longfellow controls about 80,000 net acres and operations in about 125 sections. Through May, the company, with privately owned Viking Drilling LLC's rigs, has drilled more than 90 wells.

Located in the Stack play, the company's Nemaha project initiated in 2011 and drilling began in early 2012. The project has 88 horizontal lateral wells drilled and producing; four saltwater disposal wells; covers 128 contiguous governmental sections; controls 81,000 gross acres (60,500 net acres); has 51 drilling pads built to date; and 71 miles of 10-in. saltwater disposal pipeline connecting the drilling pads. In May Longfellow's Sandra 22-M3H well was drilled to a measured depth of 11,200 ft in 13.54 days (spud to rig release) setting a new record for a Nemaha Project well. The company also reported on its website that, "In March 2017 Longfellow engineers achieved a record fracture treatment on its Jodie 24-M3H well in the Nemaha Project. A total of 6.73 million pounds of sand was pumped in the treatment into 32 fracture stages. The well has been producing strongly, indicating the treatment was effective and leading to a significant increase in future well reserves."

The company's McGee Valley project is located in Atoka County in Oklahoma. This project has 16 producing vertical gas wells, 6,000 ft to 11,000 ft in depth, covers 11 contiguous governmental sections and has 7,040 gross acres (6,878 net acres).

## Marathon Oil

Marathon Oil has been involved in Oklahoma E&P for 100 years. As of year-end 2016, Marathon Oil held about 365,000 net surface acres in the Oklahoma resource basins, which includes acreage acquired in August 2016 in the Stack Meramec play, the company stated on its website.

In the Scoop and Stack areas the company holds net acres with rights to the Woodford, Springer, Meramec, Osage, Oswego, Granite Wash and other Pennsylvanian and Mississippian plays. The company also has production in other areas of Oklahoma from conventional operations.

According to the company's first-quarter 2017 results, Marathon reported an average 30-day IP rate of 990 boe/d from its Stack Meramec Yost spacing pilot (4,650 ft average lateral length). Marathon's unconventional Oklahoma production averaged 44,000 net boe/d during first-quarter 2017, compared to 45,000 net boe/d in the prior quarter and up more than 60% from the same quarter a

In 2017 Marathon Oil plans to focus its Oklahoma activity on Stack leasehold retention, Stack delineation and infill pilots in preparation for 2018 full-field development. *(Photo courtesy of Marathon Oil)*

year ago. Of the 12 gross operated wells brought to sales in the first quarter, five were part of the company's first operated Stack infill spacing test, the Yost pilot, and the others were focused primarily on Stack lease retention and delineation, the report stated.

The Yost pilot, located in the normally pressured black oil window in central Kingfisher County, successfully tested 107-acre well spacing with completions of about 2,500 lb/ft of proppant, the report stated. The 30-day IP rates from the five new standard-lateral Yost wells and parent well averaged 990 boe/d (57% oil).

Marathon Oil ended first-quarter 2017 running seven rigs and expects to average about 10 rigs in 2017, according to the company's report.

In addition, PayRock Energy sold its entire Scoop/Stack position to Marathon Oil in the summer of 2016.

## Newfield Exploration

Newfield Exploration is focused on domestic, liquids-rich unconventional resource plays. The independent E&P company was the first to name and develop the Stack. The company operates in the Anadarko and Arkoma basins of Oklahoma.

In 2016 Newfield acquired 42,000 net acres in the Stack from Chesapeake for $470 million, according to a press release.

In the Stack Newfield has completed 15 wells with new upsized completions of 2,100 lb/ft of proppant and 2,100 gal/ft of liquids, according to the company's first-quarter 2017 report. "Utilizing early data from 13 wells with 60 days of production history, the wells are outperforming the company's 1.1 MMboe estimated average type curve by approximately 45%," the report stated. "The Burgess was a record Stack well announced during the quarter. After 60 days, cumulative production from the Burgess well is significantly exceeding the estimated Stack type curve, adjusted for lateral length."

According to a May 2017 investor presentation, Newfield was running three to five rigs in the

In late 2014 Cactus Rocket Rig 140 was drilling Newfield Exploration Co.'s Laura 1H-17x well site near Okarche in Kingfisher County, Okla. *(Photo by Tom Fox, courtesy of Hart Energy's* Oil and Gas Investor*)*

Scoop and driving production through continued development drilling. The company also was running four to five rigs in the Stack, transitioning to infill development and testing upsized completions and downspacing.

## Unit Petroleum Co.

Unit Petroleum Co., a wholly owned subsidiary of Unit Corp., was formed in 1979 with an initial reserve base of 2 Bcfe. As of year-end 2016, Unit owned 118 MMBoe of reserves, primarily in the Anadarko and Arkoma basins, and operated or owned an interest in more than 6,500 wells, the company's website stated. Unit's reserves are 84% proved developed. The company's strategy is to drill low-risk field extension or development wells on internally generated prospects.

Unit resumed drilling operations in the Hoxbar (Marchand Sand) in Oklahoma in fourth-quarter 2016. The company has 60 to 65 locations in the area with average working interest of 50% to 60%. Unit reported EURs of about 550 Mboe, 83% liquids and 68% oil, and well costs of about $5 million, according to first-quarter 2017 information on Unit's website. Five to six wells are planned for 2017 in this area. The company is seeking approval from the Oklahoma Corporation Commission to drill Hoxbar extended-lateral wells.

## Ward Petroleum Corp.

Headquartered in Oklahoma City, Ward Petroleum is growing the assets of Ward Energy Partners with a leasehold position of 35,000 net surface acres and 80,000 net reservoir acres in the Scoop/Stack play, with its operated focus in the Scoop area. Ward is targeting seven primary reservoir objectives, with an inventory of more than 2,500 gross well locations. The company's resource base exceeds 500 MMboe, while projecting a production rate exceeding 10,000 boe/d by year-end 2018 with active operated and nonoperated well programs.

Ward has taken a lead role in the identification of the emerging Scoop Sycamore/Mississippian play. According to the "IHS Markit U.S. Industry Highlights, March-April 2017" report, Ward Petroleum reported completion details for a high-rate Mississippian producer 2 miles south-southwest of Alex, Okla. The 26-23-1XH Lynda produced 16 MMcf of gas, 861 bbl of 53-degree condensate and 2,156 bbl of load water during an initial 24-hr flow test in mid-March, the report stated.

Ward is also an active operator in the Hoxbar SoHOT play, which overlaps the Scoop play in Southern Oklahoma.

## XTO Energy

XTO Energy, an ExxonMobil subsidiary, operates in 25 counties and holds more than 1.1 million acres in Oklahoma. The company reported year-end 2015 production of 350 MMcf/d of gas and 14 Mbbl/d of oil.

XTO Energy had one of the biggest leaseholds across Oklahoma at year-end 2014 with an estimated 1.153 million acres and gross production of 12 Mbbl/d of oil and 396 MMcf of natural gas, according to *naturalgasintel.com*.

In November 2016 XTO Energy released details regarding a Marietta Basin Caney Shale discovery completed in fourth-quarter 2016 two miles south and slightly east of Marietta, Okla. The 1-33H28X Ronny went onstream flowing 620 bbl of 46-degree oil, 1.67 MMcf of gas and 1,453 bbl/d of water through perforations between 16,805 ft and 22,275 ft following acid treatment and a 28-stage fracturing job, IHS reported.

In June 2016 the company also completed two horizontal Woodford producers on a multiwell Ardmore Basin pad 5 miles south and slightly east of Tishomingo, Okla, according to an IHS report. The company's 4-11H2 Flenniken flowed 381 bbl of 39-degree oil with 380 Mcf of gas and 489 bbl/d of water through perforations at 6,228 ft and 11,239 ft following acid treatment and a 16-stage fracturing job.

In June of this year the company's workover program in the Hewitt Field resulted in the completion of a shallow multizone producer three miles east of the Healdton, Okla., according to another IHS report. XTO reported production of 58 bbl/d of oil and 254 bbl/d of water. With cumulative production of about 305 MMbbl of oil and 22 Bcf of gas, Hewitt Field ranks 10th in oil production from Oklahoma fields, the report stated. ■

# Sooner **Boomer**

*Technology is pushing Oklahoma's Scoop/Stack play further into the black.*

**By Blake Wright**
Contributing Editor

There is an old adage in the patch: The best place to find oil is in an oil field. Oklahoma has long been considered an oil-rich state. Most annual lists of oil-producing states will find Oklahoma in the top 20%, usually only outpaced by places like Texas, Alaska and California. Advances in technology have allowed operators to unlock more of the state's vast unconventional resources. Oil companies began drilling into the Woodford Shale as early as the 1930s, but it was only in the past decade or so that horizontal wells have been drilled to crack the region's hidden hydrocarbon potential.

The Woodford Shale covers virtually the entire state of Oklahoma and is far more complex than other Devonian black shales found in North America. Complex, alternating bands of amorphous silica and silica-rich shale of varied thicknesses have been historically tough on bits, adversely impacting horizontal drilling. However, two new plays in the trend have emerged over the past few years—the Scoop and Stack—that have been a pair for the record books.

Well results over the past year have been sensational. Devon Energy's Pony Express 27-1H, a July 2016 Stack record-setter in the overpressured oil window of southwest Kingfisher County was drilled with a 5,000-ft lateral and achieved a 30-day average rate of 2,100 boe/d, consisting of 1,500 bbl/d or 70% of the production mix. Oil productivity from the Pony Express was the highest of any well drilled in the Meramac section of the play at the time on a per-lateral-foot basis.

In December 2016 Continental Resources' Angus Trust 1-4-33XH, drilled in Blaine County, set a company IP record with flows of 4,642 boe (45% oil) in a 24-hr test, comprising 2,088 bbl of oil and 15.3 MMcf of natural gas.

Then there was Newfield's Burgess well in March of this year, also in Kingfisher County, achieving a 24-hr flow rate of 2,931 boe/d, of which 69% was oil, and a 20-day average rate of 2,492 boe/d, of which 70% was oil.

Smaller players got in on the action as well. Ward Petroleum's Lynda 26-23-1XH well, drilled in to the Mississippian reservoir of the Scoop, tested at an initial rate of almost 16 MMcf/d of gas, 860 bbl/d of oil and 2,150 bbl/d of load water.

Each of these successes owes a tip of the hat to improved and emerging technologies that have made it possible to accurately forecast, land and fracture these wells. Improvements in diversion, bits, and the gathering and processing of general formation information have all had a hand in some of the most impressive IP results in the Lower 48.

As with any play in its earliest days, players are still working through which recipes of software, hardware and other measurables make for the best economics and results, but industry success to date has prompted many to take a good look at investing in the area. The attraction is so acute that at least one producer—Oklahoma City-based Devon Energy—is preparing to sell off $1 billion of profitable operations in the Texas Barnett Shale to lever up in the Stack play without incurring debt, or as one Devon executive put it recently, selling good wells to drill great ones.

## Debut, demystify and de-bundle

Devon Energy has been a key player in western Oklahoma's Cana-Woodford since 2007; the liquids-rich natural gas play is one of Devon's bread-and-butter assets. In 2014 a new play started to emerge in the area—an interval in the Mississippian Formation dubbed the Meramec. The Meramec is separated from the underlying Woodford Shale by the Osage Formation. The target resides between 8,000 ft and 11,000 ft below the surface across the play. The specific hydrocarbon targets are found in 700 ft of oil-saturated siltstone, with the Meramec accounting for up to 475 ft of that column. The Meramec is the current sweet spot in Oklahoma's Stack play. With legacy assets in the area and recognizing the emerging play's potential, Devon made a move at the end of 2015 to dole out $1.9 billion for Felix Energy's 80,000 net acres in the Stack.

"We were drilling some of the early Meramec wells and watching various peers and competitors try to bring on some of these Meramec-type wells," explained Todd Moehlenbrock, vice president of Devon's Anadarko Basin business unit. "It became really an identification of where the pay zone was located because it's a fairly thick section—500 ft to 700 ft. The initial part of delineating the field was identifying the pay zone and then continuing to use existing horizontal drilling and fracturing techniques to unlock the potential. Through all of that reservoir characterization, we have a very robust geological model of the entire Meramec. We still have a lot of work to do, but we have a good understanding of what drives performance and where we need to land the wells, which is critical. Techniques have come a long way in just a couple of years around the Meramec to create the best completions to maximize returns."

IP numbers in the area have been encouraging. Last September Devon revealed its third successful Stack spacing test. The pilot tested a seven-well pattern across a single-section interval of the upper Meramec. Initial 15-day production rates averaged 2,200 boe/d per well. Well performance in similar programs has been good enough for Devon to announce plans to sell about $1 billion of upstream assets, including a portion of its legacy Barnett Shale holdings, to fund future activity in the Stack and the Delaware Basin, part of the Permian Basin in southeast New Mexico. While there's that kind of excitement for the play, the players realize it's still early innings.

Devon operations continue in the Anadarko Basin of Oklahoma. *(Photo courtesy of Devon Energy)*

"The whole industry is shifting toward this stacked, lateral-development concept," Moehlenbrock said. "There are multiple benches or zones that stack on top of each other. In each of these benches, we have to decide how many wells it will require to effectively process the reservoir. It becomes a 3-D question for us. A lot of what we're trying to figure out is how to process the reservoirs using the least amount of money. We're learning a lot about not only the lateral communication between the wells but the vertical communication between the different intervals. From a subsurface standpoint, we've put a lot of technical work into understanding that."

To that end, Devon has formed an Integrated Reservoir Characterization team with the purpose of pulling together different disciplines and integrating the volumes of data collected from various tools that assist in painting the true picture of the reservoir.

"The vertical-data well is key," explained Kyle Haustveit, completions engineer in the region for Devon. "It's one of the most useful tools in understanding what our stacked pay potential is and where to land our laterals to effectively drain the resource and avoid stranding reserves. We integrate the vertical-data well understandings with a fiber-optic job, where we strap a fiber-optic cable to the outside of our casing to obtain a real-time view of where our proppant and fluid are being placed during the stimulation. Optimizing the completion is going to improve our drainage area and improve our individual well and infill performance."

In addition, Devon is using electromagnetic imaging to map both the fluid and proppant geometry, offering a 3-D volume view of where the operator is placing its fracturing fluids.

The company also is using conventional offset pressure monitors in new ways. The goal is to integrate offset pressure responses with additional technologies and learn how to apply them in units without fiber optics or without a vertical-data well and continue to improve completions in real time.

With Devon and its peers ramping up activity in the area, concerns over required volumes of sand and water start to arise. Devon alone is now running 2,400 lb or so of proppant per lateral foot. In a 10,000-ft well, that could mean pumping 24 million to 25 million pounds of sand, and it takes about 500,000 bbl of water to fracture one well. When talking about 25-well programs, the numbers escalate exponentially.

For sand, one of the things Devon has done to help defray cost on the supply chain side is shifting away from using full-service fracturing companies. They are de-bundling these offerings to find the best deals direct from sand suppliers, pumping companies, diesel distributors and so on.

"Obviously the sand and water supply chain is critical for our certainty of execution," Moehlenbrock said. "We're working to secure the water sources, and we've got some good leads on that. We're also building infrastructure in the field—basically million-barrel ponds that we can use to store our frack fluid. We'll have a series of these around the field and then a network of piping that will allow us to move water around the field as needed. We're being very thoughtful about the volumes we need and how to get those volumes on location for the cheapest cost. We're also looking at our produced water and plan to recycle and reuse that water to help with the frack supply side. Unlike the Delaware, where the water rates and ratios are fairly high, it's much lower in the Stack and Meramec. Approximately 30% of total fluids are water. It's much less than some other plays. We'll also have procedures and infrastructure in place to dispose of any water we don't plan on reusing for fracking."

## Targeting water needs

For an area that has limited groundwater supplies plus a known history of drought, sourcing adequate water supplies to meet demand for planned increased drilling activity is a challenge for the industry. That is what faces many operators with programs on tap in the Scoop/Stack play in Oklahoma. Sometimes the natural resources—lakes, ponds, etc.—cannot fulfill the need if the rain has not been delivered by Mother Nature. That uncertainty, coupled with forecasts of increased use across the region, has companies like Newfield Exploration looking for alternatives. In March the operator broke ground on a water recycling facility located in its Stack play in the Anadarko Basin (Kingfisher County, Okla.). The complex, named the Barton Water Recycling

Facility, is expected to process about 30,000 bbl of produced or wastewater per day upon completion early in third-quarter 2017.

"We're producing about 30,000 barrels of wastewater per day from our Stack play and that's what we've designed the recycling facility to handle," said Reed Durfey, Newfield's water and technical services manager. "We plan to recycle both the flowback and produced water from our Stack wells and hydraulic fracturing operations. Currently, on average, our freshwater usage is about 75,000 barrels per day of water. Depending on future drilling and completion activity, freshwater utilization could increase proportionately."

Newfield has invested more than $40 million to date in water management infrastructure in its Stack play. The new recycling facility is a multimillion-dollar investment located on a 30-acre site and will connect to seven pits with nearly 6.5 MMbbl of storage capacity utilizing more than 70 miles of underground pipeline by year-end 2017.

The Barton facility itself is decidedly low-tech. The facility foregoes higher cost water treatment technologies such as membrane filtration, reverse osmosis and electro-coagulation that have been used in the past, in favor of an aerated biological treatment.

"Basically we're introducing oxygen into the water to convert the produced water from oilfield waste to recycled water for fracturing operations," Durfey explained. "We're using a naturally enhanced bio-remediation to separate and break down the contaminants. Incoming raw produced water goes through a tank battery where initial oil and solids removal is performed. The water is transferred to a series of aerated pits, with built-in bubble diffuser aerators that very efficiently introduce oxygen into the water. It's here that the treatment

Pit construction was proceeding at Newfield's Barton water recycling facility as of mid-June 2017. *(Photo courtesy of Newfield)*

process uses natural and enhanced bioremediation, or good bacteria and nutrients, to separate and breakdown any existing impurities that may be contained in the produced water. The end result is a high-quality water primarily free of impurities—very similar to what is initially found in the reservoir rock. An additional water pit serves as the final storage area and also contains aerators, which Newfield utilizes to maintain the quality of the water and limit bacterial growth."

Newfield and its peers are also aware that certain disposal wells have been linked to seismic activity in the region. A number of the earthquakes have been traced back to injections into the Arbuckle Formation and in the watery Mississippi Lime area of the state. Oklahoma averaged almost more than five magnitude 2.7 or greater quakes per day in 2015, but the rate fell to 3.6 per day in 2016 and 1.4 per day so far this year, according to data from the Oklahoma Geological Survey.

"Our operations are not located in the watery Mississippi Lime area and none of our SWD [saltwater disposal] wells are injecting into the Arbuckle," Durfey said. "We have our own injection well within our own infrastructure that we utilize, and we have a couple of third-party disposal wells, but none of them are injecting into the Arbuckle geological formation. That has been the zone of concern for seismicity activity. Right now, there seems to be enough disposal capacity from third parties and the operators that own their own, but as activity increases it could become a concern. That's another big advantage to recycling. If we can recycle and reuse what we bring out of the ground, then we don't have to worry about going to an alternative disposal solution like disposal wells."

Newfield's experience with produced water recycling goes back to 2004. By year-end 2016 the company had reused more than 150 MMbbl during operations in Utah, Texas and Oklahoma. Newfield's Barton facility is Newfield's first recycling facility in the Stack play, but the company isn't ruling out plans for additional water recycling plants in the region.


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"We want to recycle and reuse all we can," Durfey said. "There could always be plant No. 2. We've started to work together with some of our peers on how we could share recycling resources and infrastructure to make our combined assets work for the industry to get a better bang for our buck."

## Frack management and workflow efficiencies

The rush of activity in Oklahoma caused by escalating delineation work on oil fields in the state's Scoop/Stack regions has put pressure on service providers to effectively and safely ramp up following one of the most prolonged and damaging industry downturns in history. Idle iron is being reinvigorated and put back to work. Service companies are hiring hands in the region. The Midcontinent has seen rig activity more than double year-over-year, and the scramble is on to drill and complete these prolific oil wells. Halliburton has a raft of specialty offerings to support both the fracturing process subsurface and improved efficiencies aboveground, enabling it to deliver these higher rate wells faster than ever before.

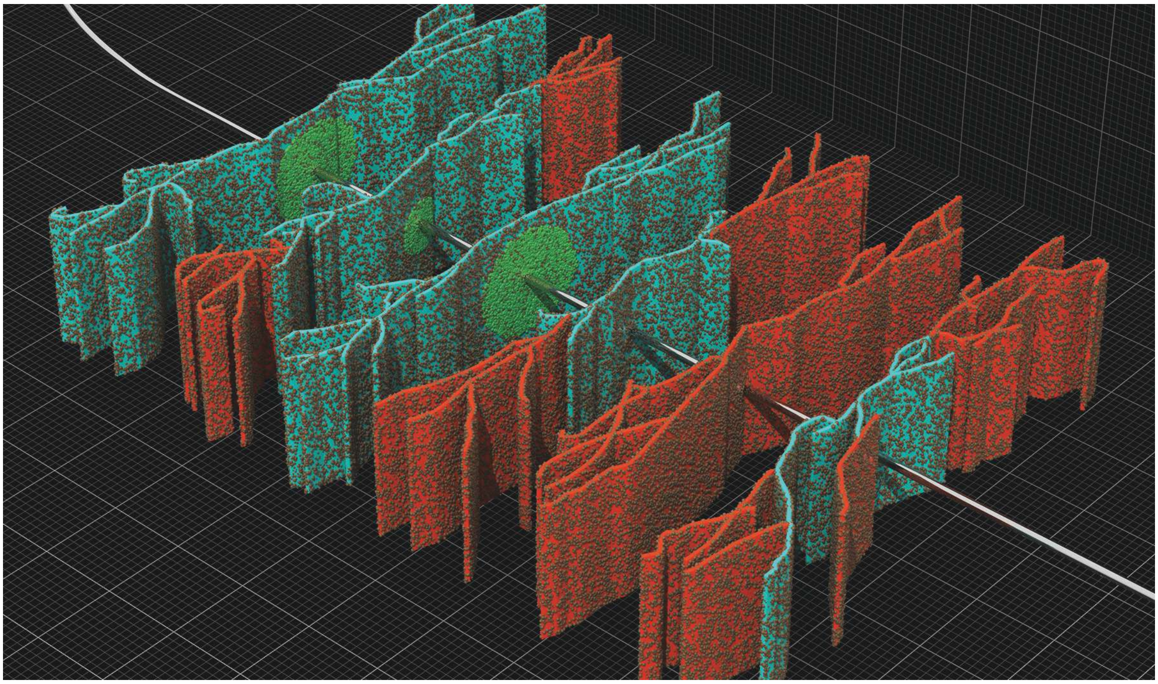
Using its AccessFrac service for near-wellbore diversion, Halliburton is able to improve cluster efficiency when conducting multistage treatments.

"Some operators might have three perforation clusters, others may have four, five, up to seven clusters in a stage," said Mark Parker, Halliburton's technology manager for the Midcontinent. "Our near-wellbore AccessFrac service allows us to effectively treat all perf clusters. In some cases without diversion a couple of primary fractures would be developed, but you wouldn't see any others developed in the stage. So even though you desired five fractures created, you might only get two. These diversion products increase cluster efficiency to create the designed fractures in the near wellbore."

There is also a component to complexity in the reservoirs. In the far field, when fractures are being created and extending into the reservoir, additional AccessFrac products divert and create complexity in the far field away from the wellbore.

"That has been a real benefit to operators as far as increasing production and getting these high productivity rates," Parker said. "We think it helps with the near-term productivity, the IP rates, but also on the ultimate recovery of the reservoirs—increasing the EURs in these unconventional plays."

Another tech leader in the region is Halliburton's MicroScout service.

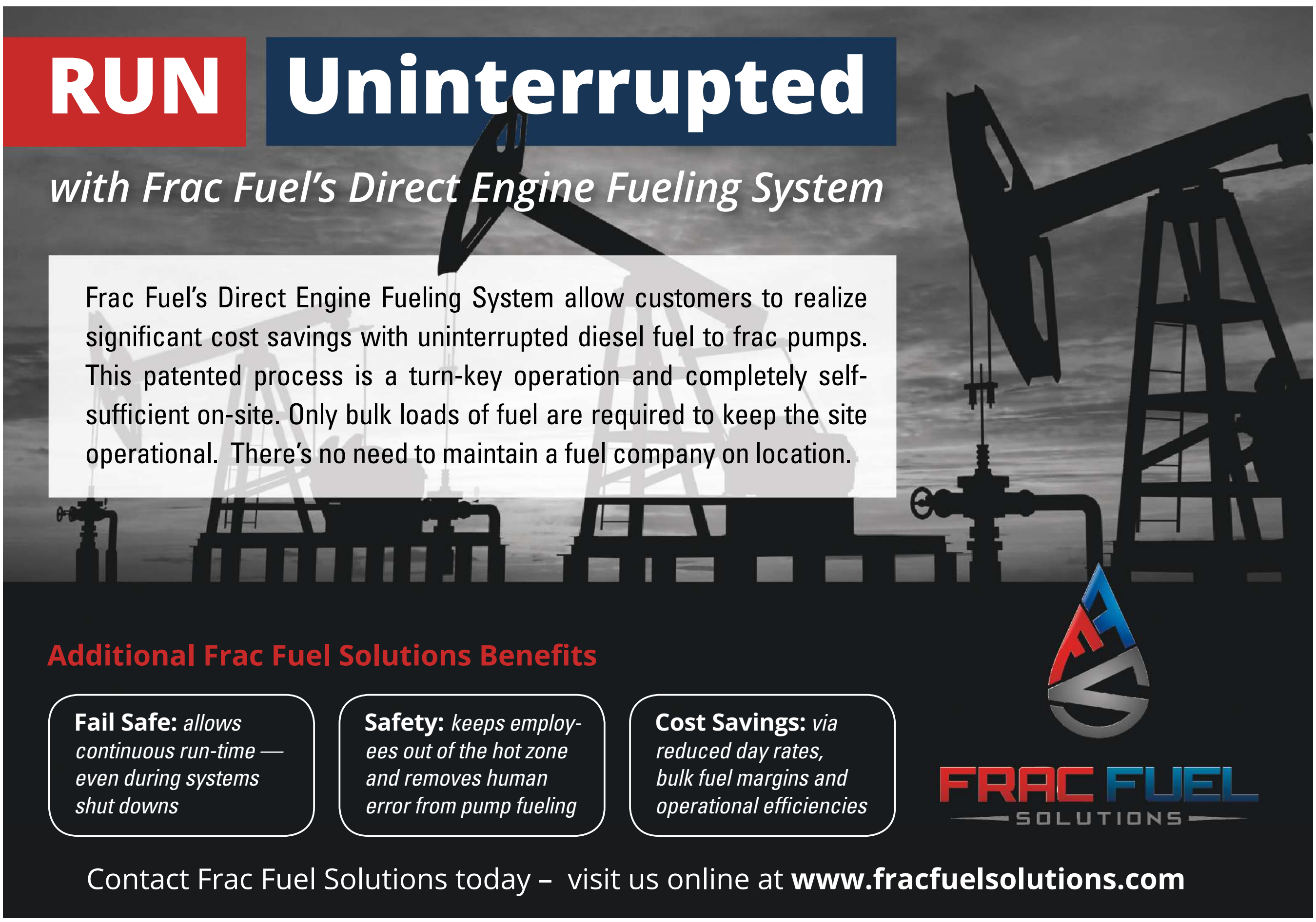


Halliburton's AccessFrac technology keeps well fractures open and flowing. *(Image courtesy of Halliburton)*

"MicroScout material is smaller than conventional proppants that we consider for fracturing," Parker said. "Ever since the early days of fracturing, proppants have been relatively large and used to keep the fracture open and allow flow through a porous pack. This material is quite small, and it goes in the accessory fractures that conventional proppant wouldn't be able to fit into. Even though it is a small support structure it does give benefit to productivity by propping the complex microfractures to keep producing into the main fracture system and into the wellbore." An additional benefit of this material is in pressure reduction while we're pumping the stages because it impacts the near-wellbore region.

Workflow also remains a key component to successful well delivery. From operations guided by Halliburton's FracInsight—a repeatable interpretation workflow that leverages the best available horizontal well data to select perforation clusters and frack stage locations—to time-saving hardware like the company's recently rolled out wellhead connection unit.

"The new ExpressKinect wellhead connection unit is a single line connection to the wellhead," said Steve Jolley, product line manager for Halliburton in Oklahoma. "It basically utilizes a remote connector that links together the wellhead adapter for each well that is to be treated. If you're working on three to four zipper wells, this connection unit can go from wellhead to wellhead with one connection. All of these wellheads are pre-fitted with the proper connection that fits our zipper manifold, which allows us to quickly unhook from the adapter of one wellhead and go to the next. It reduces our transition time out there. It has been a big win for us. Once again it reduces the amount of iron and the amount of connections we rig up."



Drilling nears production on a Chaparral lease in Oklahoma. *(Photo courtesy of Chaparral Energy)*

## Chips ride the Stack for Chaparral

Chaparral Energy is in the throes of transforming itself into a pure-play Stack company with more than 110,000 net acres located primarily in the oil window of Canadian, Kingfisher and Garfield counties. Part of that transformation includes the marketing of its EOR assets in the Oklahoma and Texas Panhandle region and its $CO_2$ flood project in Oklahoma's Osage County, and investing those gains back into its Stack asset development plans. The data room for its EOR assets opened in June and bids were due in July. The company filed for bankruptcy protection in May 2016—a victim of prolonged weakness in oil and gas prices. The company emerged from bankruptcy this past March.

"Chaparral has more than 110,000 net acres in the Stack but due to our Chapter 11 process and our constrained balance sheet the last couple of years we have not been able to fully develop those assets," said Chaparral CEO Earl Reynolds. "Our Stack development is a true evolution of our company, but in some areas within the play we're still in a de-risking mode, testing zones and well spacing patterns. Overall, we feel extremely confident about our frack designs relative to the rocks across our Stack position. We're just beginning to realize the full potential of our outstanding position."

In the Stack the company is employing horizontal drilling and the typical fracture technology seen in other basins but continues to experiment with higher sand concentrations and tighter spacings.

"We've been using diversion fairly effectively on all of our completions in the past 12 to18 months," Reynolds said. "We have tested packers systems, slotted designs and plug-and-perf cemented liners depending on where we are in the basin. We'll continue to do some testing as we de-risk acreage in Garfield County and the Merge, but overall we feel like we have a solid understanding of the rock and corresponding frack designs, especially in the heart of our Kingfisher and Canadian County acreage."

Chaparral's emphasis on cost savings is also continuing to pay off, as it consistently records some of the lowest operating costs in the play. As part of its effort to maintain a low-cost structure, the company completed a dual well pad study in the region in 2016 to ensure it continues to capture the best possible rates of return for its Stack investment.

"We have seen a variety of systems used throughout the Stack, so in 2016 we completed five dual well pads to help us determine the most economical approach," said Scott Van Sickle, drilling and completions manager for Chaparral. "Each of the pads had one openhole multistage system and one suspended cemented liner system. We found that the total EURs were virtually identical isolation to isolation, but our rate of return on the openhole multistage systems was close to 50% higher due to the capex reductions and time-value we realized. As a result, we've moved to a standard openhole multistage approach in our current most active area, while we continue to experiment with increased stage count and diversion-cycle stimulation techniques as well as general isolation experiments in our other areas of activity."

Taking a hard look at costs and rates of return seems to be paying off for Chaparral as it continues to take advantage of pad drilling opportunities. In 2016 its average well cost for a 1-mile lateral in the Meramec was one of the lowest in the industry at about $3.3 million.

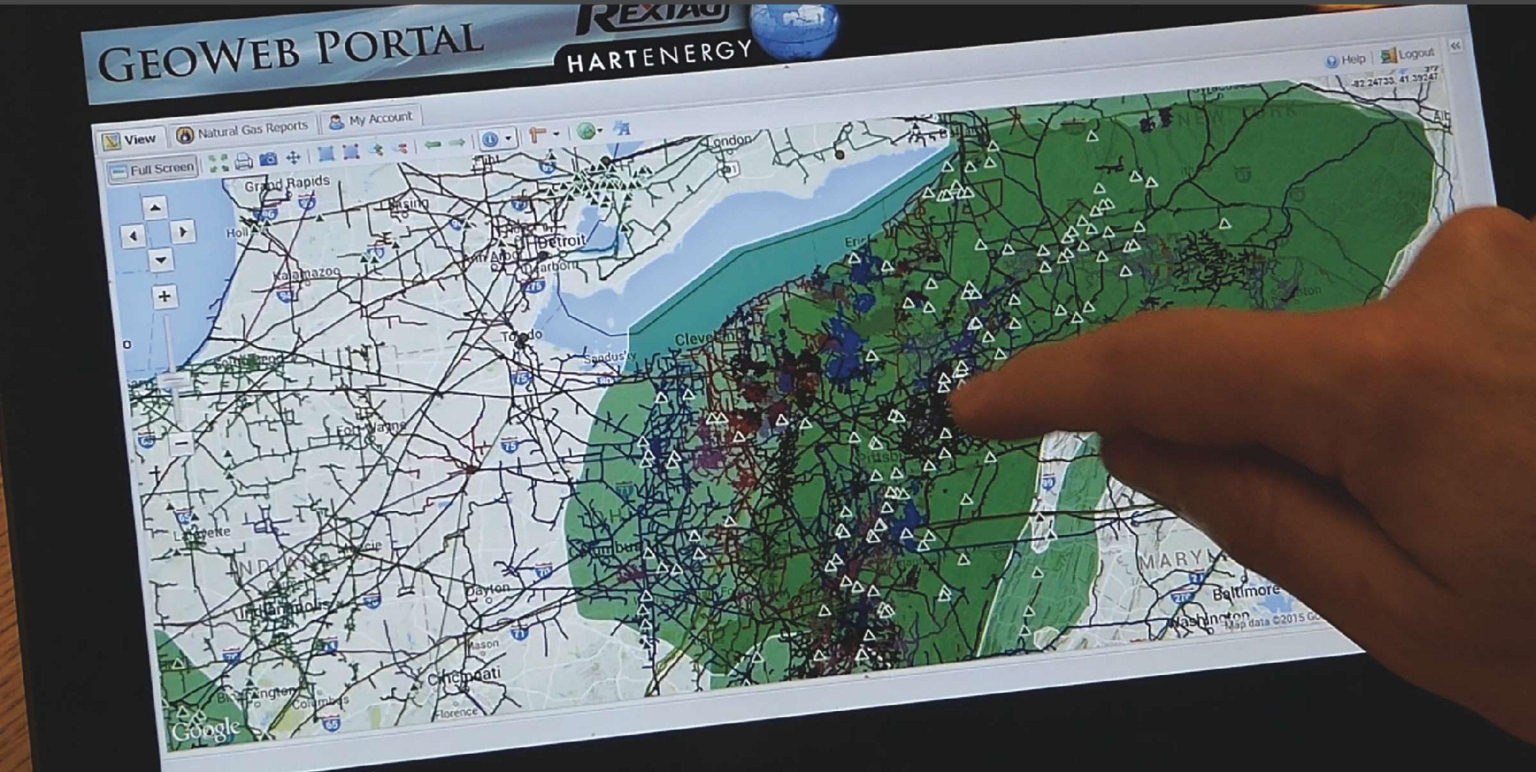
"Our vision is to become the premier pure-play Stack company," Reynolds said. "Our first step is to optimize our asset portfolio as we try to monetize our EOR assets this year. In the meantime we're working hard to de-risk all of our Stack position. With our constrained capital over the last two years, we have focused heavily on developing our 25,000-plus net acres in Kingfisher County. We think this was the right move, as we have essentially de-risked all of our Kingfisher position. This year, you will see us put more capital in our 40,000-net-acre position in Garfield County as well as our 23,000-net-acre position in the Merge in Canadian County, which is a hot spot in the play right now. In the Merge we may experiment with other completion techniques and, down the road, we'll look at 2-mile laterals where it makes economic sense to do so. We are also adding acreage where we can within the play in key areas where we think we'd like to get a little bit bigger.

"We believe Chaparral will have significant growth opportunities ahead of it and be well-positioned as a leader in the Stack," Reynolds said.

## Teeing up new tech

Drilling contractor Nabors Industries has seven rigs operating the Scoop/Stack regions of Oklahoma. Two of those units joined the active fleet earlier this spring. One is working for a major operator while the other is with a large independent. Operators have been targeting AC rigs here, carrying 1,500 hp


Nabors has PACE-X800 rigs operating in the Scoop/Stack featuring the Rigtelligent operating system to enable smarter and more automated operations. *(Photo courtesy of Nabors Industries)*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equivalent with plenty of setback space as longer laterals are explored. Of course, the two areas in the burgeoning Oklahoma oil play are not exactly the same. Scoop wells are a little bit deeper, traditionally anywhere from 22,000 to 28,000 measured feet. As you move northeast into the Stack, they get a little shallower—16,000 to 20,000 measured feet. It can be a tough slog in either area compared to the Delaware Basin of West Texas, for example.

"In general it is more difficult because of the longer wells, so we see 60 to75 days or more per well in the Scoop, and in the Stack we see about 45 days per well," said Todd Fox, Nabors vice president of operational management for the southern U.S. "The wells tend to be longer and typically require more trips. The bits aren't lasting as long. We looked at the Stack wells and, in some cases, have seen as many as 50 trips, spending approximately 22% of the well tripping, 50% drilling."

By integrating downhole measurements with surface equipment into AC rig designs and with an extensive portfolio of performance optimization software and wellbore placement solutions, Nabors can help take on these complex wellbores and help reduce trips and days to drill and, ultimately, cost. That's where Nabors' new RigWatch Navigator software comes in. Currently being piloted in North Dakota, the software is a directional drilling guidance system that uses analytics to solve the most significant problem associated with directional drilling—to be able to consistently follow a well path, stay within the targets and repeat the process in a consistent and predictable fashion across multiple wells. Following this pilot program, the system will soon be a commercial offering.

Nabors already offers other software packages as part of its drilling services. The company's Rigtelligent operating system is deployed across most of its fleet, enabling the easy application of drilling optimization software. For example, ROCKit software increases the ROP by rocking pipe and delivering ideal weight to the bit, according to the company. The soon-to-be-released ROCKit Pilot system will enable automated slide control and toolface steering.

"We're still implementing our REVit software to mitigate stick/slip and whirl on the rig," Fox said. "So our software offering is an integral part of the package and is a desired capability we see through operator requests."

Another move by Nabors that may eventually lead to lower cost in the Scoop/Stack is the addition of its quads rigs to the fleet. The first two quads were expected to be working in South Texas by the end of July. Nabors has added a section to its mast, so instead of a 93-ft stand, there will be a roughly 120-ft stand for drillpipe.

"That will optimize tripping efficiency substantially," Fox said. "We see this technology very suitable for the Scoop/Stack once it is field tested in South Texas. We should have some operational results by third-quarter 2017 on the rig."

According to the driller, all 53 of its current PACE-X800 rigs are eligible to be retrofitted with the quads package. ■

# **Scoop** and **Stack** Show Continuing Return on **Investment**

*As operators carry out drilling with more wells and tighter spacing, this complex play continues to deliver on its promise of profitability despite low oil prices.*

**By Judy Murray**
Contributing Editor

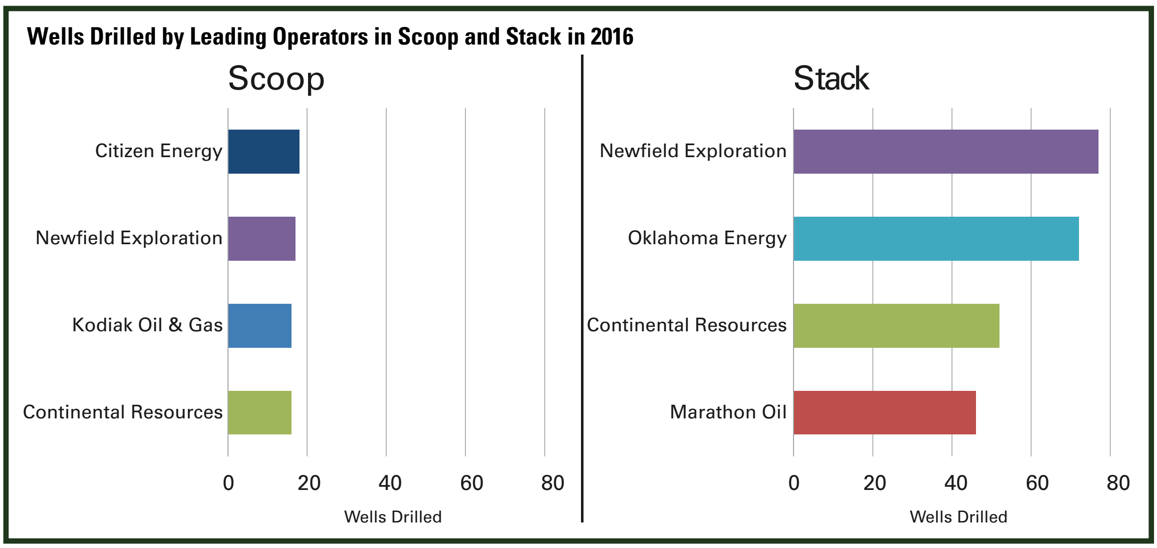
The Scoop and Stack plays are among the most highly sought-after shale assets in North America. Along with the Permian Basin to the southwest, this newly developed liquids-rich region seems to provide some of the best economics of the North American oil plays. Together, these plays are leading a resurgence in Oklahoma oil and gas drilling.

## The play and the players

Newfield Exploration, an early entrant into the region—and the company responsible for naming the Stack—assembled a play in the updip portion of the Cana Woodford in 2011. Over the last few years, the company has streamlined its portfolio, selling nonstrategic assets and investing heavily in its premier Scoop and Stack plays.

Newfield increased its 2017 capital budget to about $1.1 billion (up from $1 billion), primarily to build on recent successes through drilling and enhanced completions, which the company reported in its first-quarter results were "yielding superlative well results."

Representative of its success are recent results from the Stack acreage, where 15 wells had been completed by first-quarter 2017. Using early data




Operators in the Scoop and Stack have made public statements that these areas are more economical with lower oil prices than nearly anywhere else in the US. *(Data courtesy of Freedonia Group Inc.)*

from 13 of these wells with 60 days of production history, Newfield reported the wells were outperforming the company's 1,100 boe estimated average type curve by about 45%.

Continental Resources, another of the area's major players, reported in its first-quarter results that its Scoop Springer wells outperformed the 940 Mboe EUR type curve by an average 60% in the first 30 days. Positive results led Continental to expand its presence, with the Sycamore expansion adding about 300,000 net reservoir acres under existing leasehold in the play.

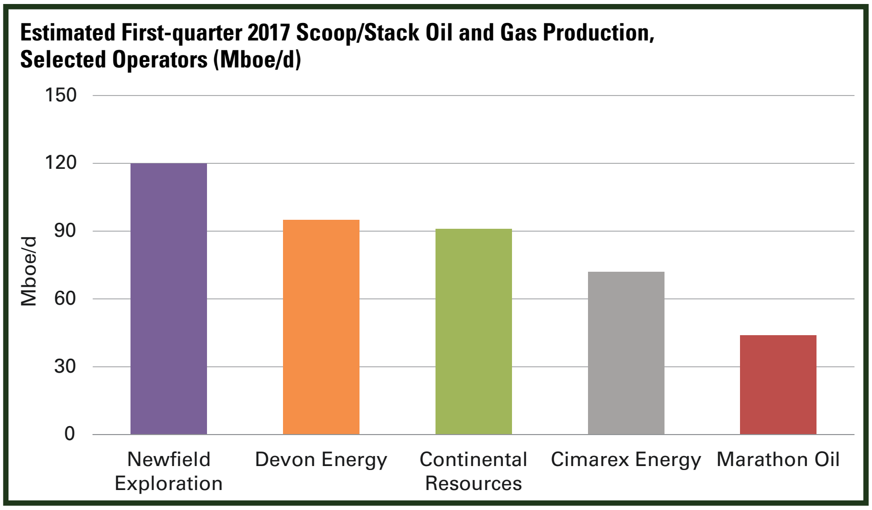
The company announced three Scoop Springer wells in Grady County, all of which were outperforming its historical 940 Mboe Springer type curve for a 4,500-ft lateral in their first 30 to 60 days on production. According to Continental, the wells were completed using the company's latest stimulation designs, including increased proppant per foot and tighter stage spacing. Continental said it would increase activity in the Springer in 2017 and plans to complete up to 10 Springer wells during the year.

Continental also saw positive results in the Stack, with its Meramec wells flowing between 1,907 and 3,011 boe/d during initial 24-hour tests. Stack production increased 20% to 29,216 boe/d in first-quarter 2017 compared to fourth-quarter 2016. In March the company had 11 operated rigs in the play, with six rigs targeting the Meramec Formation in the overpressured oil and condensate windows and five targeting the Woodford Formation in the Northwest Cana joint development agreement area in Blaine and Custer counties.

Devon Energy reported an equally optimistic outlook in first-quarter 2017, pointing to average daily production numbers that exceeded the top end of the company's guidance range by 5,000 bbl/d. The company attributed its production growth in large part to higher completion activity across its Eagle Ford and Stack operations. Devon's contiguous Stack acreage is in the overpressured oil window of the play and boasts stacked pay opportunities with potential in the Meramec, Osage and Woodford shales. Current efforts focus on the oil-prone Meramec and the liquids-rich Cana-Woodford Shale, where recent well completion design enhancements have continued to improve economics, which the company said are among the highest in its portfolio.

Devon said it is on track to deliver its previously announced U.S. oil production growth targets of 13% to 17% in 2017, driven by its Stack and Delaware Basin assets, which are projected to deliver production growth greater than 30% this year. To achieve that goal, the company will invest nearly 90% of its $2 billion to $2.3 billion capital budget in U.S. resource plays, increasing drilling throughout the year to as many as 20 operated rigs by year-end. Looking ahead to 2018, Devon believes the operational momentum created by accelerated drilling activity in the Stack and Delaware Basin will expand its domestic light-oil production by about 20% over 2017.

More than 90% of Marathon's 2017 capital program of $2.2 billion has been allocated to its high-return U.S. resource plays, and a fair amount of this investment will go toward accelerating production growth in Oklahoma and the Bakken. The company is ramping up in Oklahoma to progress its Stack and Scoop acreage toward full-field development. Plans are in place to increase activity to an average of 10 rigs in the Stack in 2017, anticipating 80% of the Stack assets HBP by year-end. Drilling this year will test Upper and Lower Meramec benches with six to nine Meramec wells per section.




Operators have seen positive results in first-quarter 2017. *(Data courtesy of Freedonia Group Inc.)*

In the Scoop 5% to 10% of the wells drilled this year will test secondary targets.

In its first-quarter reporting, Cimarex Energy Co. said 30% of the $306 million invested in exploration and development for the first three months of 2017—of which $197 million comprised drilling and completion activities—had gone into its Midcontinent acreage. Production from the area averaged 484 MMcfe per day, down slightly from first-quarter 2016, while crude oil volumes were up 20%.

According to Imre Kugler, senior consultant in energy research at IHS Markit, the potential impact production from these plays could have on individual companies is one of the things that makes the story of the Scoop and Stack so interesting.

"Neither of these plays is huge, especially in comparison to the Permian," he said. "The best part may be half a million acres in each of the plays." In comparison, the Permian Basin is five times as large.

"These plays are going to be pretty important for the portfolios of companies like Newfield, Continental, Devon and Marathon," Kugler said. "Companies that didn't get into the Permian in the beginning of the growth phase have an opportunity to capitalize on the Anadarko Basin. The Scoop and Stack are a growth engine for these companies."

## Interest in the play

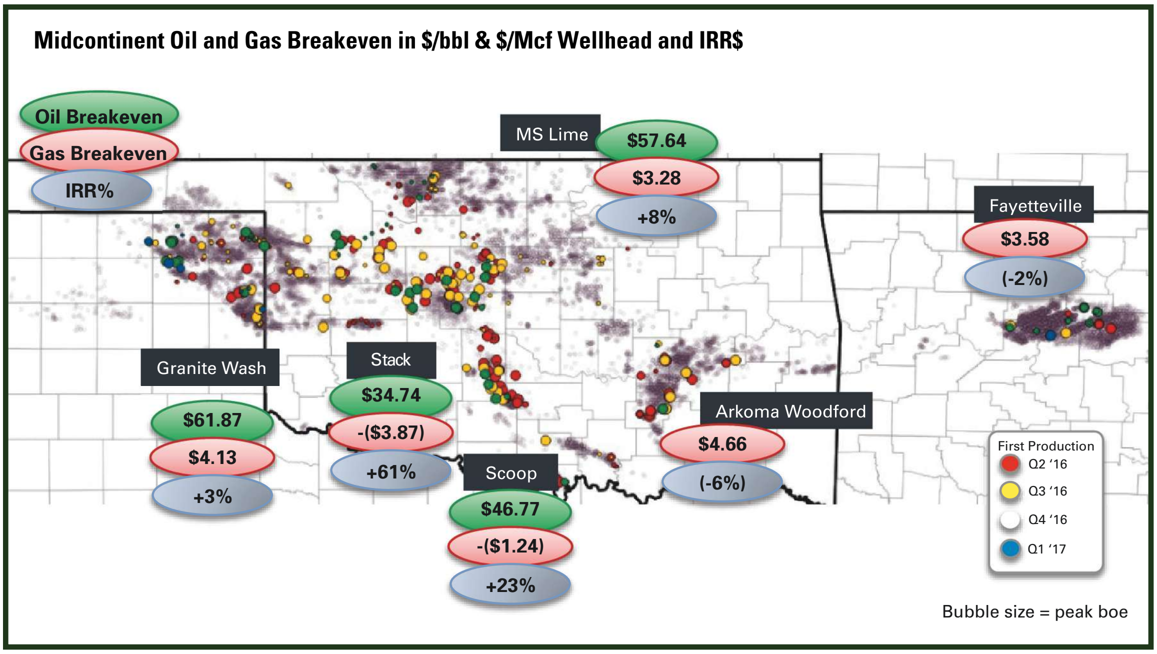
Ben Chu, manager of equity projects at Genscape Inc., pointed to the complexity of these plays—and the potential that presents—as their biggest draw.

"The area was geologically 'wrinkled up,' so to speak, and pushed into a big fold, creating a whole host of plays embedded in one," he explained. "In the last year or so, other layers of rock, such as the Mississippian layer (which is oilier than the gassy Woodford) and the Silurian and Springer layers, have helped these plays along in terms of generating additional interest."

The fact that multiple, distinct strata are drillable from the same surface acreage is clearly a draw, said Dan Debelius, an industry analyst with Freedonia Group Inc. "Plays in the Stack such as the Meramec have high levels of oil. They are overpressured and traditionally have exhibited high initial production rates. These characteristics, coupled with their low water content, make them high producers."

This acreage is desirable right now because it is potentially quite lucrative, Debelius said. "The companies that are active in this region could make lots of money for long periods of time."

Fellow analyst Jason Carnovale agreed. "Operators in the Scoop and Stack have made public statements that these areas are more economical with lower oil prices than just about anywhere else in the U.S. right now," he said.




The breakeven costs for the Midcontinent show the region is profitable even at a low oil price. *(Data courtesy of Genscape Inc.)*

Because of the region's complexity, it is tricky to characterize using generalizations, said Allen Gilmer, chairman at Drillinginfo. "You have the Scoop and Stack, which represents the Woodford and various Mississippian plays, along with the Cleveland and Tonkawa and a variety of other plays that are being drilled unconventionally. Each has its own economics," he said.

"When you move away from that which has always been considered the Scoop and Stack and expand that aperture a little, you start to see some very interesting things. The sexy part of the extended play is that it is a nice column of rock that has a lot of carbon-generation capacity throughout."

"What's going to be interesting is to find out how many benches there are, particularly in the Stack," Kugler said. "Are there really three zones in the Meramec? If so, where are they present? What do some of the other formations have to offer? What will the Stack pay really look like once we get it a little bit more de-risked and know where the effective acres are in each bench?"

## Rig counts and drilling activity

Rig counts have been relatively constant, but the rigs in these plays have been very active and have produced positive results.

Gilmer said Drillinginfo recorded rigs being added in the play until four or five months ago. "Now it is pretty stable," he said. "The economics of some of these emerging plays are such that I would think they would be encouraging for rigs, but that isn't across the whole play."

Some analysts, like IHS Markit and Freedonia, do not consider rig count to be a big indicator of the level of drilling activity in these plays. According to Freedonia's Carnovale, "The biggest thing about the rig count is that we don't think it matters as much as it used to."

One of the reasons, he said, is that pad drilling is expanding the number of wells drilled by a single rig in a small space; so rig moves within the plays—rather than the number of rigs working—are a better gauge for determining productivity.

Simply put, "Rig count is not the strong indicator of future production that it used to be," Carnovale said. "We look much more at well count than at rig count."

According to Chu, there are two philosophies for drilling. "The 'old school' approach is to go after the best wells first," he said. The other is to drill as many wells as possible in a section. The reason, he explained, is that if they fracture them at once, the entire area is pressured, raising more rock above the frack gradient; so higher volumes of sand can be pumped into the cracks. The end result is not only an increase in production but also a lower drilling cost per well from operating and logistical efficiencies.

"Continental has mentioned that more wells per drilling unit not only increases the productivity of the producing wells but decreases the cost of the well by as much as 30%," he said.

Gilmer believes positive results have to do with three things: the fracturing job, the well spacing and when the adjoining wells are drilled. "Tight spacing works if all these happen in a short time frame but tends not to add value when wells are drilled later to infill," he said.

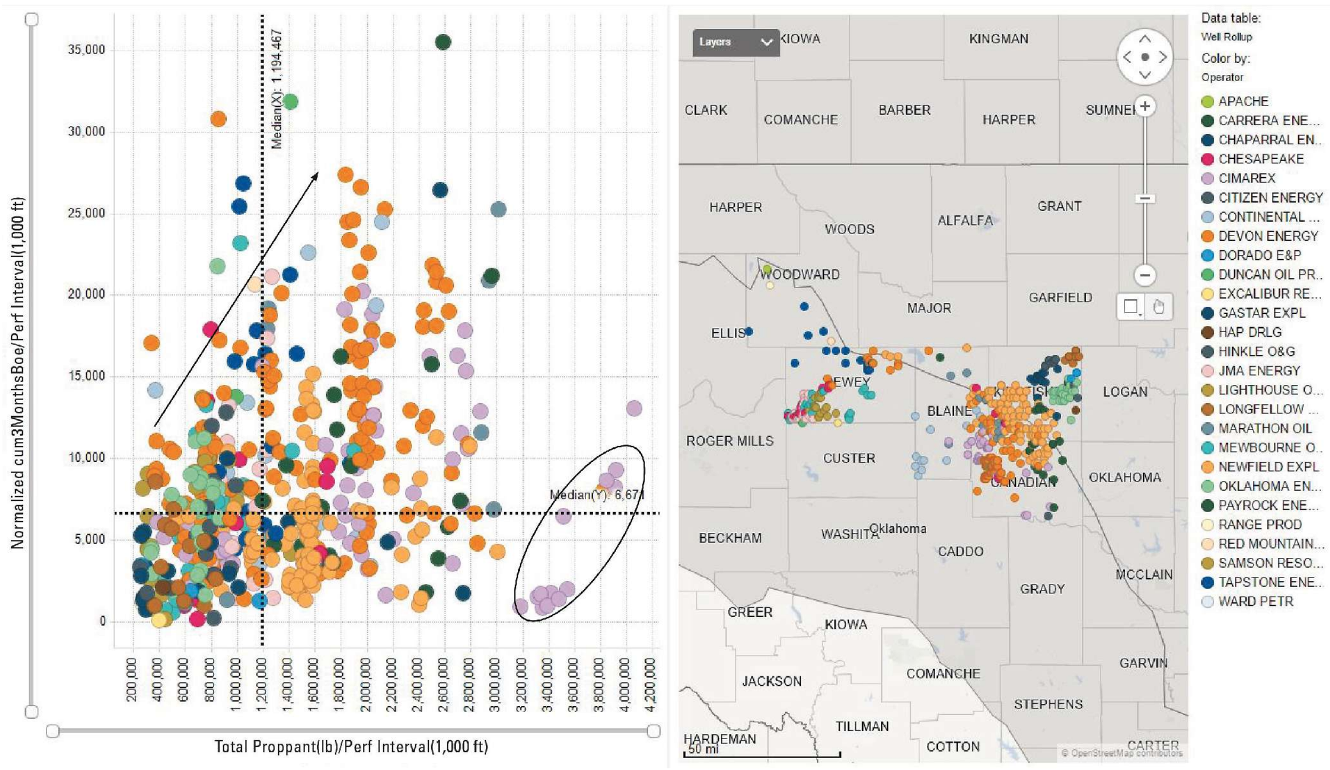
Well spacing pilots carried out in 2016 produced sufficient data for companies to develop more precise drilling plans into this year and next. "Cimarex conducted a 10-well pilot that has informed its decision to carry out a 19-well pilot, which would precede a 19-well-per-section development in 2018," Chu said, "and Devon is looking at 20 wells per section."

## Capitalizing on new ideas

As operators drill more wells, they are looking for ways to do so as effectively as possible. According to Debelius, "The biggest thing is more complicated fracturing, with tighter stages and more clusters within the stages." In short, "Operators are trying to find out how far they can push the technologies." One result is a drastic increase in the amount of proppant being used. Today, proppant usage is nearly twice as high as it was a couple of years ago, he said.

Kugler agreed, noting that proppant intensity nearly doubled between early 2015 and mid-2016 in the Stack, made possible by applying lessons learned from other shale plays. "Operators are comfortable ramping things up," he said. "When you have high-quality reservoirs and high-quality rock, it will respond pretty well to proppant."

**Proppant Intensity vs. Three-month boe**




A map of the region illustrates how proppant intensity has increased in relation to production. *(Data courtesy of Drillinginfo)*

"When we started looking at some of these technologies maybe five years ago, it seemed 20 fracturing stages was a lot," Freedonia's Carnovale said. "Now 40 is relatively common, and it is economical to do that. The increase in production more than offsets the cost."

This is different from 2008-2009 when the Haynesville came online, Chu said. "Then it was slickwell completions and ceramic proppant."

This has led to challenges in completions logistics for sand and the emergence of sand sources in areas outside Wisconsin, which produces Northern White sand. Now, operators are trying Texas Brown Sand to lower logistics costs. "What they've found so far is that it's just as good, and the cost of moving it is lower," Chu said.

## Production: then and now

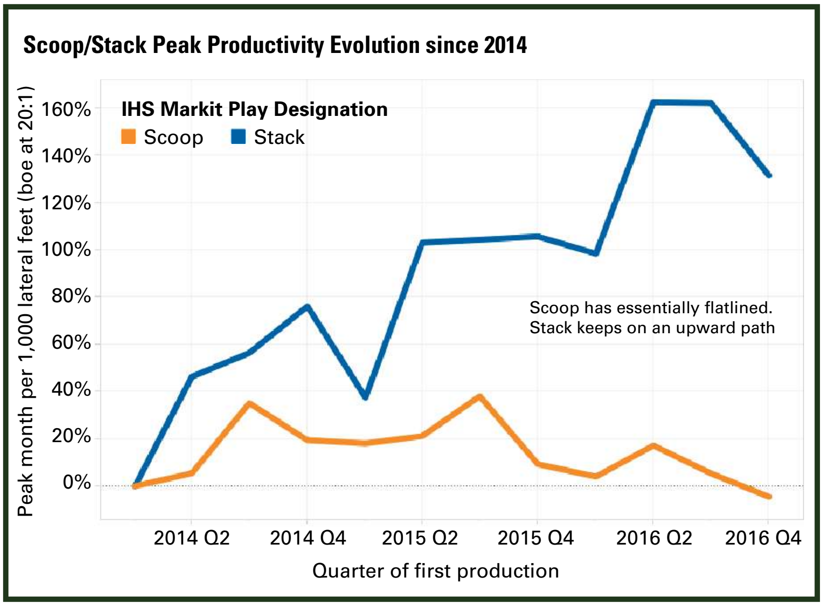
Analysts have agreed that these plays have a lot of life left.

"In the Scoop, we have a pretty good handle on what the wells are capable of and what operators are likely to get," Kugler said. "There seems to be upside remaining, and activity is on an upward path. We're still figuring things out in the Stack, but it too is on an upward path," he reported, noting that both plays are profitable at about $45/bbl.

The amount of produced gas in these plays is significant, Kugler said, and with a comeback in the gas price from a year and a half ago, gas is very profitable at $3/MMcf. "Some operators are getting 4 Bcf or 5 Bcf out of these wells," he said. "That's a lot of revenue.

"When oil prices crashed, all of the plays in the U.S. dramatically decreased their rig counts," he said. "The Stack was the only play increasing rig counts throughout the downturn."

According to Chu, the reason is that operators had adopted horizontal drilling in an overpressured Mississippian layer in the Stack that was difficult and therefore uneconomic to drill vertically. "The overpressure impeded vertical drilling by requiring too many casing strings but made for a great horizontal play. We saw a ramp-up by Devon and Continental. It was on the cusp of being developed at the edge of the downturn." Counter to the retreat




Records indicate the Scoop has essentially flatlined in terms of production, while the Stack continues on an upward path *(Data courtesy of IHS Markit)*

happening in other plays, the Stack saw increased application of proppant loading and more enhanced completions early on.

In contrast, the oilier Scoop began to take off in 2010-2011. The drop in oil prices dramatically impacted rig count, which dropped from 70 rigs prior to the Thanksgiving 2014 OPEC meeting to fewer than 10 in July 2016. "Though each play has seen cyclic drilling and completion activity, they were hot again by end of last year," he said. According to Chu, these two plays are driving production growth, which is expected to be up 10% this year, for the state.

"These plays are competitive," Debelius said. "Everything we are seeing indicates there will be continued activity in this area."

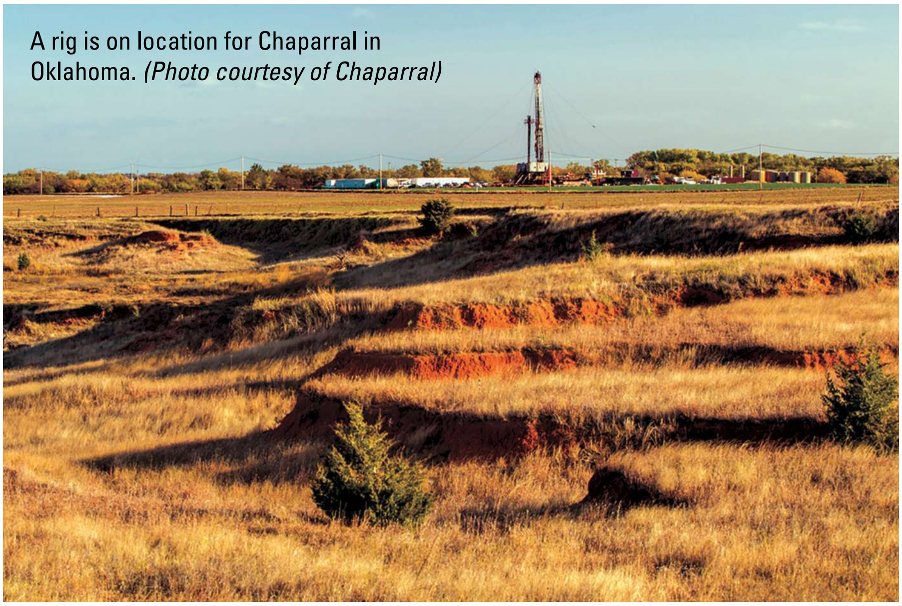
## What's next?

Operators are continuing to drill the Scoop and Stack, and work already is taking place to delineate the producible extent of the play. Genscape is following play extension being carried out by companies like Alta Mesa and Tapstone, which are testing both to the east and west of the Stack to determine the lateral extent of the play.

"In the Scoop the Sycamore is the emerging target," Chu said, explaining that the Woodford layer had been the focus until a couple of years ago, when the Springer, which overlays the Woodford, was identified as a target.

IHS Markit has validated some of Tapstone's results. According to Kugler, one promising area is northwest of what traditionally has been considered the Stack. "They've had some good results," he said, "and there may be more discoveries in the Anadarko Basin."

Not much exploration is going on elsewhere, Kugler explained, noting that there are other areas like the Powder River Basin that have some potential. "It's going to be perhaps not as grandiose as finding the next Permian, but individual companies may be able to find their 'next Permian' in the area," he said. ■



A rig is on location for Chaparral in Oklahoma. *(Photo courtesy of Chaparral)*

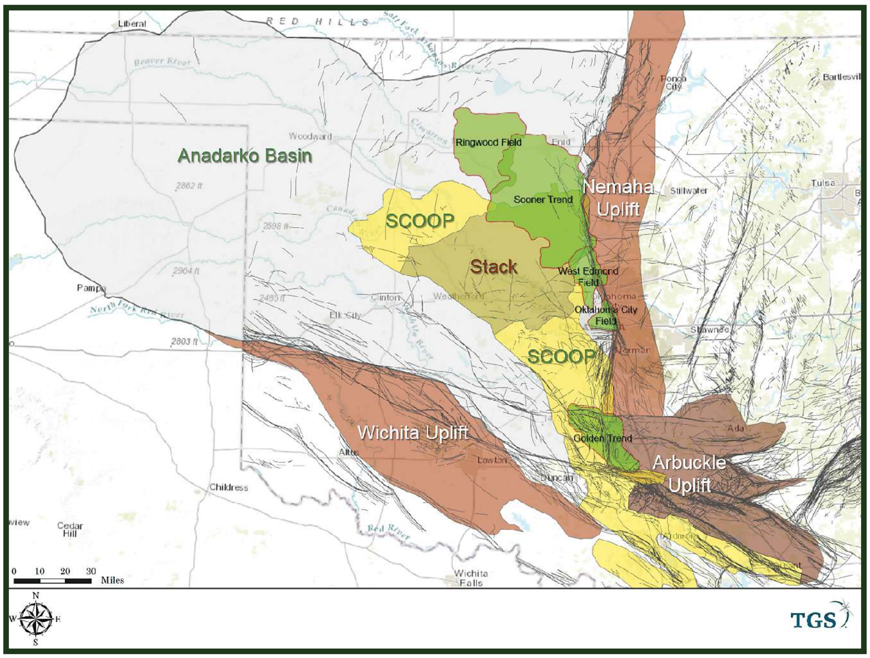
# Production Forecasting in the Scoop/Stack Play

*Advances in forecasting algorithms facilitate an EUR analysis of the last 10 years of well completions.*

**By Ted Mirenda and James Keay**
Contributing Editors

Oklahoma is one of the most mature oil- and gas-producing states, yet the industry continues to innovate and make headlines with new investment opportunities. As the industry focuses on resource plays, advances in drilling and completion technologies along with the accumulated geoscience knowledge continue to tighten constraints on technical uncertainties. The science of running risk-based economics has migrated to a broader matrix of engineering sensitivities focused on optimizing operational investments. Fundamental to calibrating these complex economics is the accuracy and availability of well performance data for forecast models. Investment decisions continue to pivot on the context that forecasting provides in terms of ultimate recoveries and breakeven points.

Operators are often able to forecast with confidence using proprietary data in their operating area but industry investors looking along trends and assessing new and unfamiliar opportunities must often work on comparison forecasts with public data. State production recording and databases continue to improve; however, they can be notoriously incomplete and ambiguous. In part, this is due to a lack of standardization of oil and gas reporting procedures and requirements. As the industry improves forecasting algorithms, production volume data can be qualified more efficiently but nomenclature used to describe and isolate the zones(s) of production continues to be a challenge.




A generalized extent of the Anadarko Basin with Nemaha and Wichita uplifts bounding the east and south flanks is shown. The Scoop/Stack trend in central Oklahoma is adjacent to and overlaps some of Oklahoma's most famous giant fields, shown in green. Faults (gray lines) are modified from Oklahoma Geological Survey shapefiles. *(All images courtesy of TGS)*

The science of forecasting depends on the ability to correctly categorize local nomenclature, nicknames, abbreviations and handling entry errors such as spelling mistakes. In terms of data useful for forecasting, the TGS database accesses reservoir fluid data vintage 1973; however, in today's domain the data TGS requires is well-based production from horizontals that it can calibrate—typically, relevant data are from the past 10 years.

In this chapter, TGS introduces advances to forecasting algorithms, in particular for lease reporting states such as Texas and Oklahoma. The company illustrates some of the many spatial and temporal relationships the TGS datasets can provide and highlights some of the extensive basin analytic capabilities.

This study uses a select well dataset covering the Scoop/Stack. The primary targets the data support include the generic Mississippian system, the Meramec group, the Devonian Woodford and Silurian Hunton formations as well as data in the Oswego, Springer and numerous Pennsylvanian reservoirs.

As a brief overview, the Scoop multizone play trend extends about 200 miles north-south in central Oklahoma, along the eastern edge of the Anadarko Basin corresponding to one of the most prolific conventional oil production areas on the continent. Numerous historic giant (more than 100 MMbbl) oil fields have been discovered along this trend.

It's interesting to look back at the long and colorful history of exploration here. Most accounts agree the Oklahoma oil boom began around Bartlesville near the turn of the 20th century, but the first series of major discoveries occurred between 1926 and 1928, including the Oklahoma City Field in 1928. The field is a huge anticlinal structure with production initially from the Arbuckle Limestone and ultimately from the Basal Oil Creek sand and the Ordovician Wilcox sand. The Oklahoma City field produced more than 1 Bbbl. From the late '20s through the war years when demand skyrocketed, numerous giants were discovered, including the Ringwood and West Edmond Field, which was located using reflection seismic. In 1947 a cluster of fields termed the Golden Trend were discovered in south Oklahoma, and by the mid-1950s the string of major discovery activity was waning with the Sooner Trend. By this time the Woodford Shale—with naturally fractured chert zones—was one of the primary targets as well as the tight Mississippian carbonates interbedded with marls and chert. Fast forward to present and the Scoop and Stack are recognized as a light oil and gas liquids trend along the western flank of the historic Sooner Trend, straddling the edge of the overpressured corridor that extends downdip into the basin and exploiting many of the same historic producing zones.

There are dozens of reservoir zones in the Scoop/Stack extending through the Mississippian system and the Woodford and Hunton formations. The ongoing effort and objective is to subdivide the Mississippian system for production allocation using completion data, perf information and well reports, and confirm production from the Chester, Sycamore, Meramec, Osage and possibly more detailed intervals.

## Production forecast model

In this analysis, TGS utilizes and leverages its newly released Production Forecast Database. This database is a library of every well in the U.S. containing both a monthly production projection and EUR value for all active wells. The forecast database combined with the Longbow desktop visualization tool provides the backbone of the analysis and results contained within this report.

TGS Production Forecast creates projections of producing oil and gas data streams, which allow the calculation of EURs and other values needed to perform well, field and basin evaluations. The projection of oil and gas data can be challenging because of the variety of reservoir and outside influences that can change producing trends. Production Forecast is designed to recognize production variations and to forecast future production based on the best available data, accomplishing this through proprietary algorithms and heuristic rule-based decisions.

The forecast engine leverages the TGS Well Performance Database of monthly well production volumes to create forward curves for all active producing wells derived from historical production data. Curves are generated utilizing hyperbolic fitting, but this model's advantage includes Extended Kalman Filter (EKF) techniques incorporated into the process. EKF emphasizes the most recent data, identifies trends and adjusts logic on the fly using a series of matrix math techniques, resulting in improved efficiency and accuracy. Wells are forecasted to their economic limit based on multiple parameters including estimated operating costs. Every month the new historical production volumes are updated into the database, then new forecast curves are generated for all active producing wells. The database is kept current and all wells are updated once a month.

## The Scoop/Stack dataset defined

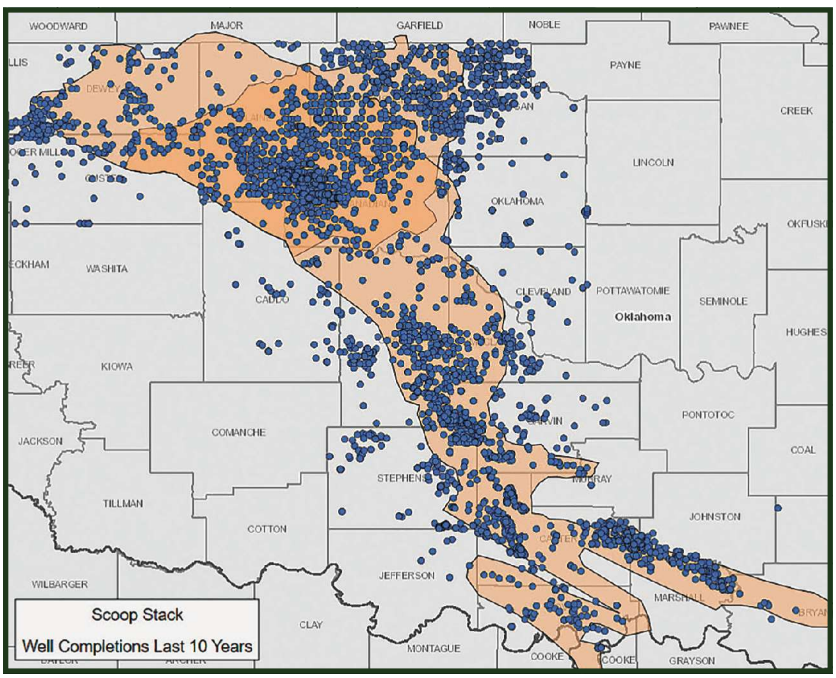
For this study, TGS took a comprehensive look at the last 10 years of well completions in the Scoop/Stack play (Figure 1). The dataset used in this analysis consists of about 5,300 wells. The wells and corresponding data were extracted from TGS' Well Performance Database and specific criteria for including wells in the study were:

- The location of the well had to fall within the county boundaries that constitute the geographical description of Scoop/Stack;
- The well was completed and put on IP after Jan. 1, 2007. TGS was looking at the last 10 years of activity in the play; and
- The well is still actively producing.

## Future drilling activity

What do future drilling activity levels look like in the play? Before analyzing historical production rates and EUR forecast trends of the completions in the Scoop/Stack, let's take a look at expected upcoming drilling activity in the near term for our study area. Drilling permits, which are valid for six months from the date of approval in the state of Oklahoma, are a leading indicator of expected drilling activity. Analyzing recent drilling permit counts by month in the Scoop/Stack indicate high industry confidence in the continued ecomomic viability of our area of interest (Figure 2). While the industry as a whole and many basins individually saw an enormous crash in permit activity beginning in early 2015, the recent permit counts in the Scoop/Stack have returned to remarkably high levels. In fact, March 2017 tallied 165 new approved permits-to-drill, which signifies the third highest monthly level in the last five years of Scoop/Stack permit activity.

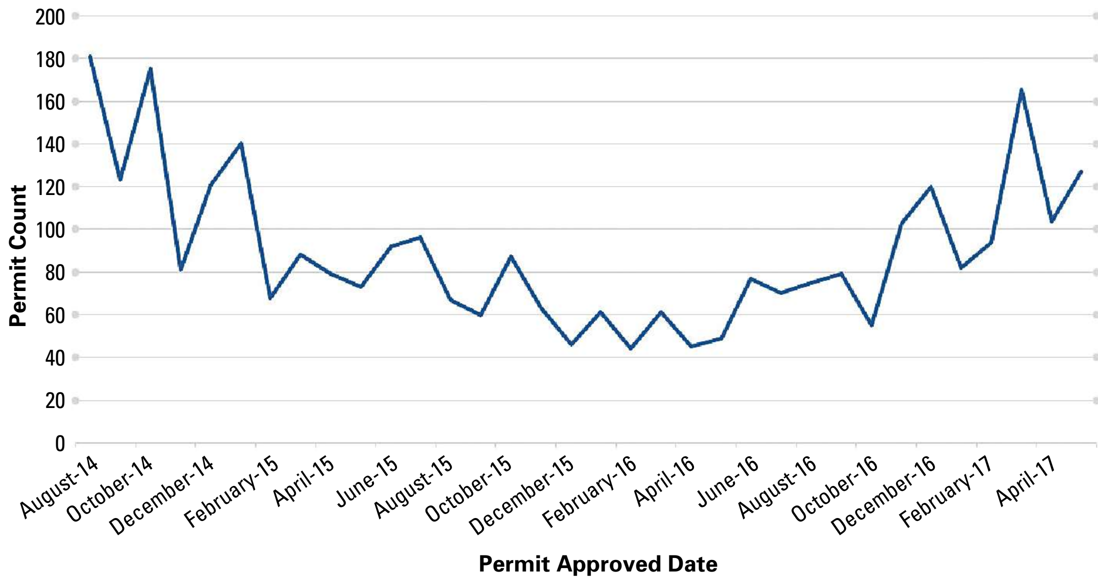
**FIGURE 1. Last 10 Years of Well Completions**




## Where are the new locations?

Drilling permit locations in the Scoop/Stack approved in last five years are color-coded in Figure 3 by the year the permit was approved. Red indicates the most recent permit locations—those approved in 2017. Spatial patterns indicate, as resource development matures and industry conditions transform, where the newer locations geographically focus. Although the play

FIGURE 2. Drilling Permit Counts in Scoop/Stack by Month Approved




reflects a wide swath with numerous location opportunities, TGS clearly sees high concentrations of the 2017 new locations across northern half of the Stack.

## Which operaters are investing in new locations?

In the last 12 months 1,206 new drilling permits have been approved in the Scoop/Stack, which corroberates industry commitment to belief in sustained economic viability of the play. Further, there is a wide range of players as 133 different operating companies filed permits in the last 12 months (Figure 4). The top 10 operators in the region account for 748 permits or 62% of the total.

## EUR analysis of the play

Where are the biggest wells? EUR hot-spot maps are an effective way to visually reveal high value wells across an entire play or basin. Since the Scoop/Stack is both an oil- and liquids-rich province, when calculating EURs and ranking commercial success of wells, one must consider many wells produce both gas and oil and, therefore, account for the economic value of different commodity streams. Calculating EURs requires three different unit-of-measurement perspectives (boe, oil and gas) to obtain accurate results. To properly identify spatial patterns of the highest performing wells within the area of interest, mapping of EURs is best performed as a three-tier approach. The first look is total boe ultimate (bbl), defined as the total EUR of a well using a 6-1 ratio to convert Mcf to barrels equivalent. The second is total oil ultimate (bbl), and last total gas ultimate (Mcf). Finally, combining hot-spot maps with a gas-oil-ratio (GOR) window map (cf/bbl) completes the picture between oil and gas commodity streams. Figure 5 shows forecast data from all producing formations in the area of interest.

## Interpreting the oil and gas window-GOR (cf/bbl)

The TGS Well Performance Database calculates and maintains GOR values for all wells. The GOR value is calculated from the monthly oil and gas production volumes reported for each well. The individual volumes are summarized to a cumulative total and a ratio calculated and measured as gas (cf) per oil (bbl). Mapping GOR values across the play visually interprets the wet and dry windows relative to oil and gas EUR values. Asset evaluators can focus on high value acreage correlated to the different commodity streams. Additionally, GOR maps are normalized to a specific producing formation to identify the transition line from oil to gas for a specific zone. As

An oil derrick is at work on the Oklahoma plains. *(Photo courtesy of Anthony Butler, Shutterstock.com)*

**FIGURE 3. Drilling Permit Locations Approved in Last Four Years**

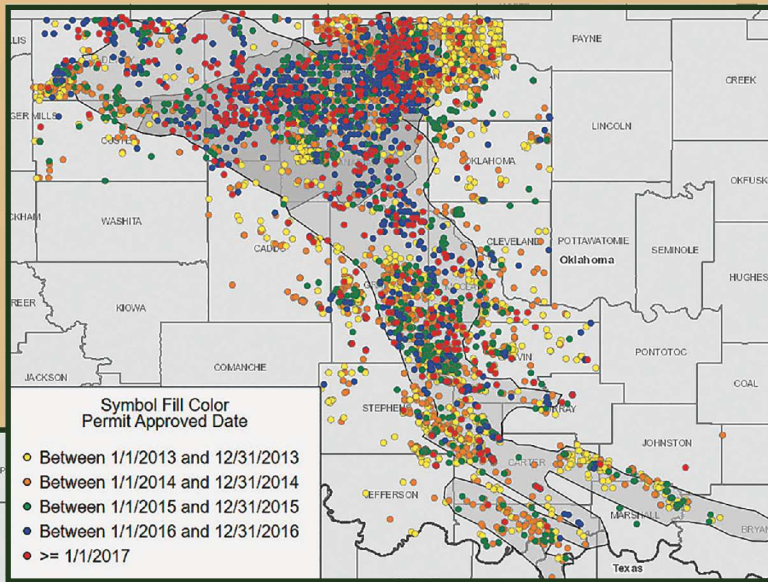
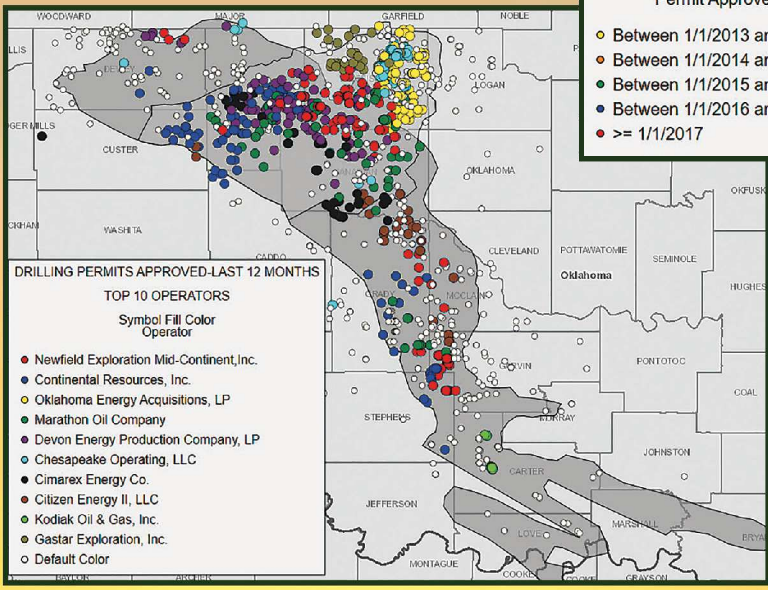



**FIGURE 4. Top 10 Scoop/Stack Operators**



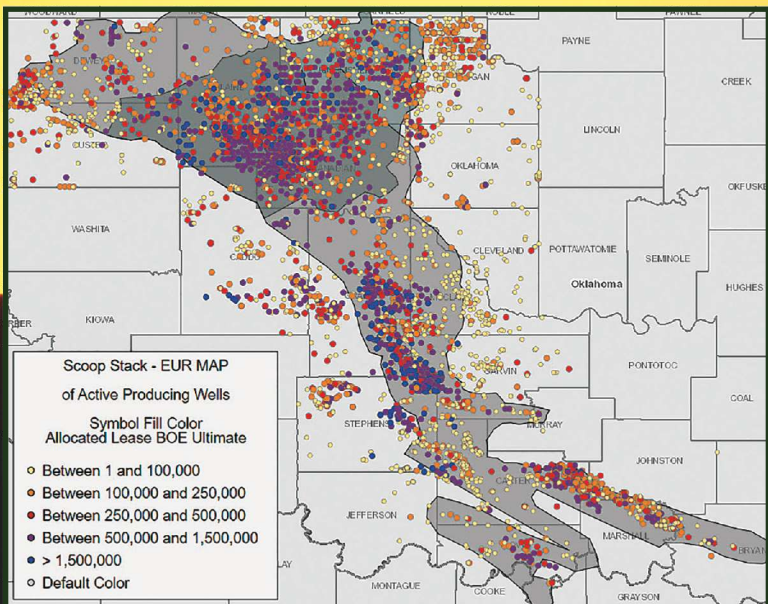




FIGURE 5. Left, the high-performing wells are spotted across the trend suggesting a broad distribution of high recovery potential and opportunity to grow the play.

an example and contrast, figure 9 shows GOR for all wells/all zones and figure 10 shows GOR perspective for the Woodford Formation only.

## Horizontal drilling impact on EURs

Despite recent hardships in the oil and gas industry, the Scoop/Stack area has experienced renewed interest and revitalization by horizontal drilling while remembering its past is home to some of Oklahoma's legacy hydrocarbon production. Companies continue to test which areas show the most promise and what completion processes provide the best well performance. Utilizing scatter plot visualization confirms the dramatic effect horizontal drilling and new completion techniques have made. Comparing well completions by year displays constant improvement in well performance and EUR totals year-to-year with an upward trend (Figure 6, below).

## Footage drilled vs. well performance

How has the length of the well impacted economic success? Taking the same dataset, TGS compared footage drilled vs. well performance over time, normalized for horizontal well type only, to ensure data integrity by utilizing comparable well types (Figure 11). Looking first at the play over-all (all zones),

**OPPOSITE PAGE**

**FIGURE 7.** The oil EUR map shows the highest performing wells clustered across the central to eastern Stack and highlight the central and southern part of the Scoop. **FIGURE 8.** The gas EUR map shows the highest performing wells focus on western side of the Stack and highlight western and southeastern part of the Scoop. The value of the well based on commodity type abruptly shifts where the "big" wells are located. The EUR values can also be calculated by producing formation for further comprehensive analysis.

**FIGURE 9.** Representation of GOR from Pennsylvanian through Silurion Hunton formations is shown. In general, TGS observes a transition from low GOR (black oil) along the northeast to dry gas in the southwest for the combined zones. **FIGURE 10.** TGS restricts the data to the Woodford Formation only and the transition from oil to dry gas in this source rock is more distinct. This suggests the liquids yield in the Woodford may be predictable along this trend. On the left display, the scattered distribution and clusters of downdip oil suggest fluid migration and/or source zones other than the Woodford.

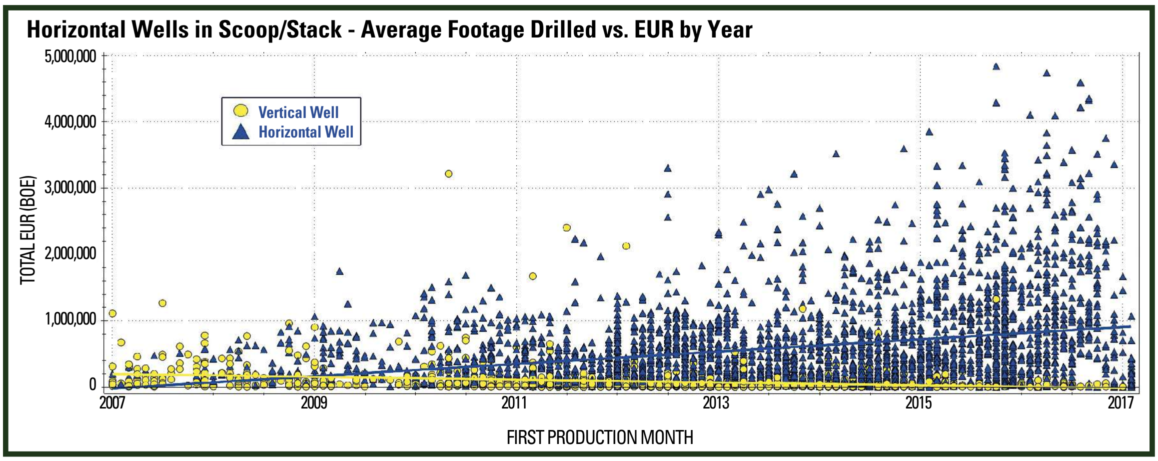



FIGURE 6. In the above plot the X-axis represents first production date and the Y-axis is a measure of well performance, in this case total EUR is used. Additionally, vertical wells are indicated as yellow circles and horizontal wells as blue triangles. There are 5,000 datapoints on the plot. Progressing across the X-axis first production date, a dramatic shift from vertical to horizontal completions intensifying in late 2012 and beyond is seen, correlating to rapid increase in well performance EURs. The industry continues to improve and verify optimum completion techniques, and trend lines indicate improvement will continue.

Oil rig in the Oklahoma sun. *(Photo courtesy of Stephen Kumor,* Shutterstock.com*)*

**FIGURE 8. Gas EUR of Active Producing Wells**

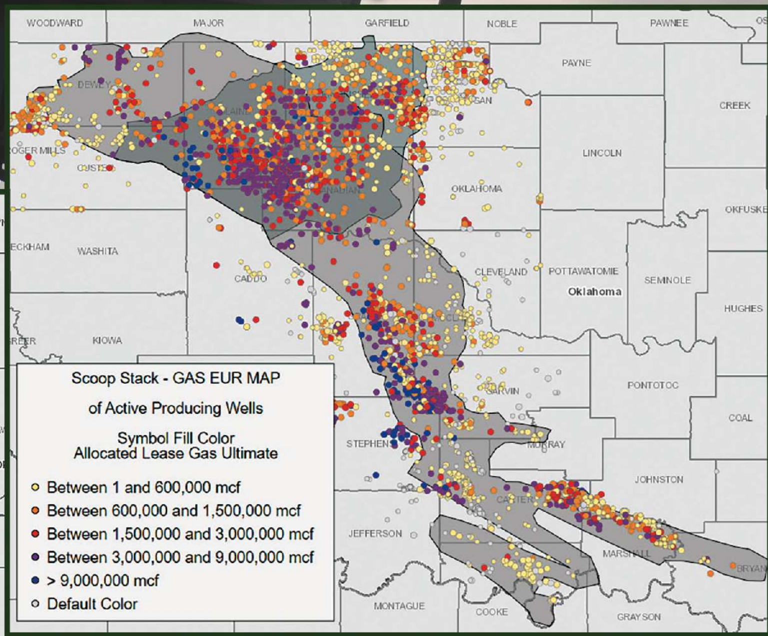



**FIGURE 7. Oil EUR of Active Producing Wells**

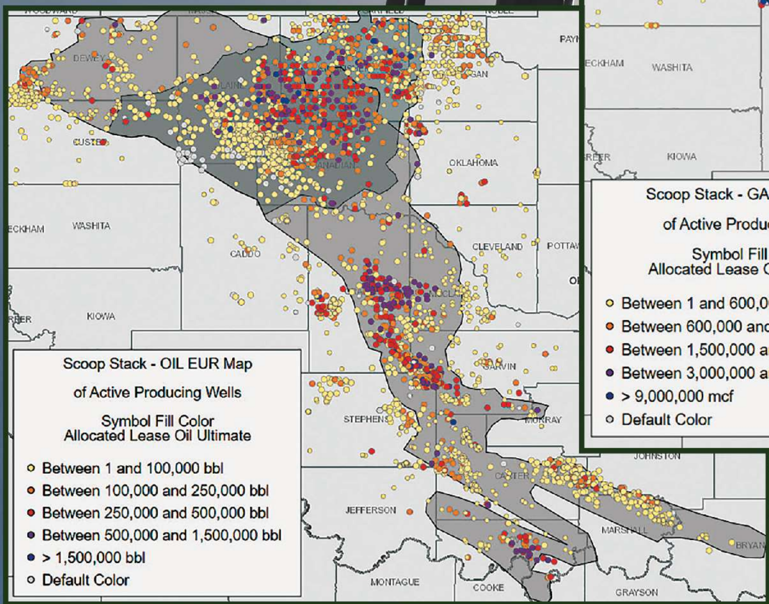



**FIGURE 10. Woodford GOR Total Average**

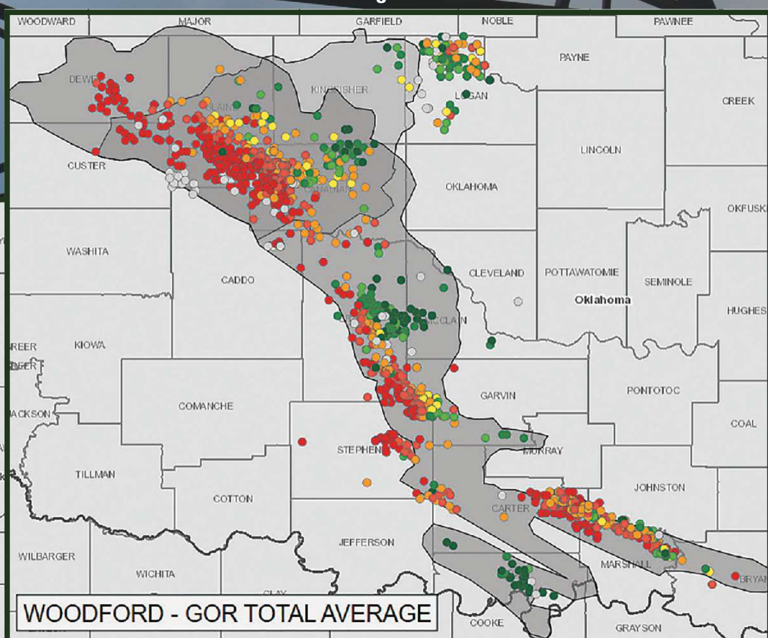



**FIGURE 9. Allocated Lease GOR Total Average**

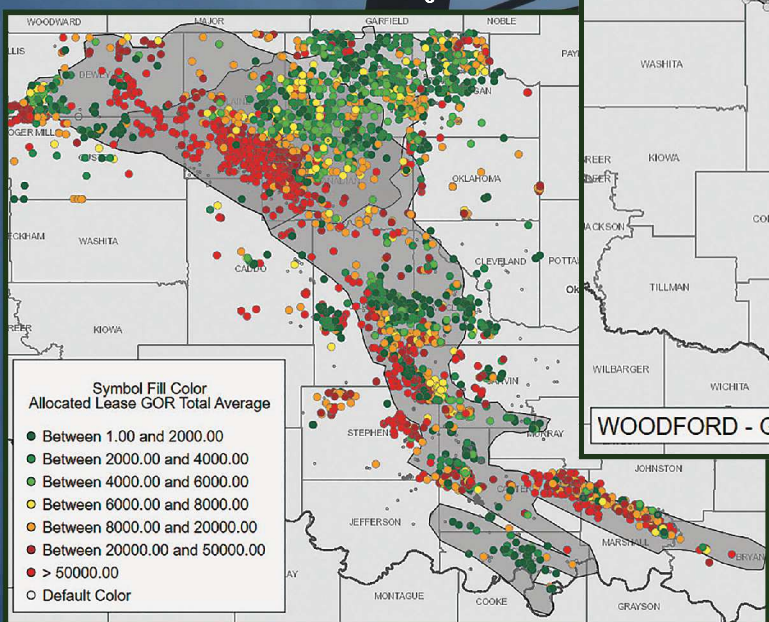
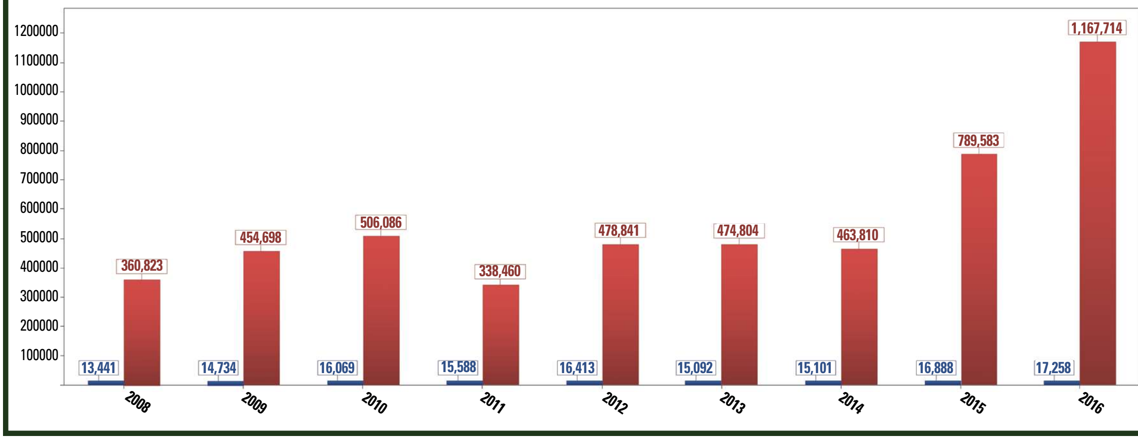


FIGURE 11. Horizontal Wells in Scoop/Stack - Average Footage Drilled vs. EUR by Year




average footage drilled per well has increased nearly 4,000 ft over the company's time line while impact on well performance has more than tripled.

Further analysis of footage drilled vs. well performance now normalized by producing formation reveals the top producing formation targets for operators: Woodford, Mississipian and Hunton (Figure 12).

In the Woodford average footage drilled has increased by more than 5,000 ft—the average well length in 2016 increased to 19,457 ft—with well performance tripling. Mississippian analysis shows average footage drilled per well increased by 3,200 ft over TGS' time line—the average well length increased to 16,120 ft—while well performance improved a whopping five times over earlier, shorter-length wells. In the Hunton there is a smaller dataset of horizontal producing wells to analyze and the recognized increase in footage drilled and well performance is a more current phenomenon. The major increase in length and performance transpires moving from 2015 to 2016. Hunton doesn't show the more gradual increase as the Woodford and Mississippian results. However, as this is a much smaller sample size, TGS continues to analyze these recent trends going forward to see if the 2016 increases are maintained in 2017 and beyond as the Hunton continues to be developed horizontally.

## Average EURs by formation

TGS' final analysis will continue to narrow the scope and explore EURs within the play down to the producing formation (Figure 13). To effectively do this, it is important TGS conditions the data from its raw form. Historical monthly production data used in production forecast model originate, as reported

Footage Drilled vs. EUR by Year

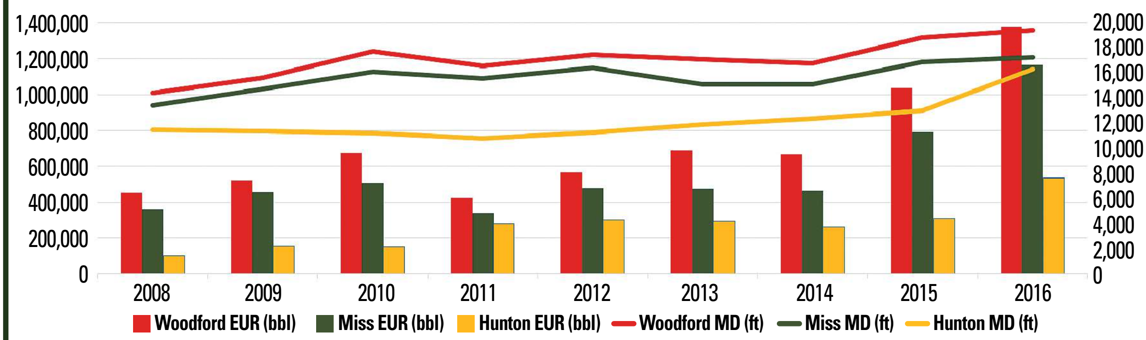



FIGURE 12. The left Y-axis represents EUR (bbl) and the right Y-axis represents footage drilled (ft).

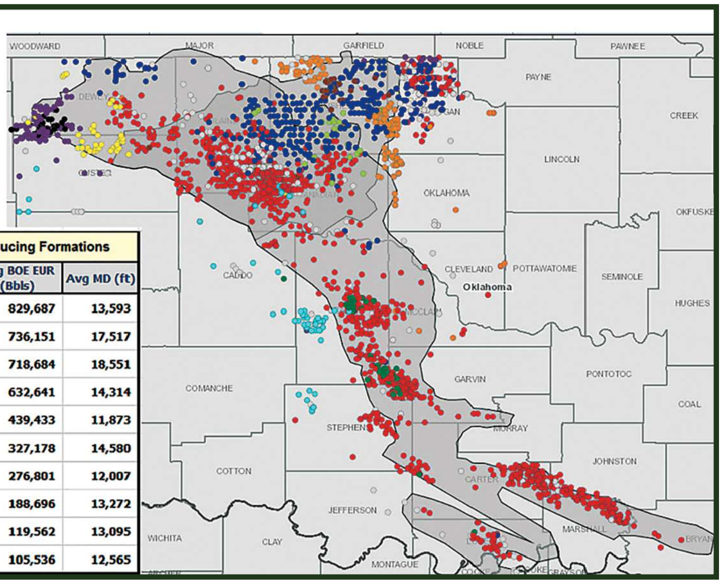
publicly, from the state regulatory authority—in this case, the Oklahoma Tax Commission and Oklahoma Corporation Commission. To derive accurate EUR results at the formation level, TGS' approach only considers horizontal wells in its original dataset that report single-formation production streams. In other words, wells that report monthly volumes comingled among two or more formations are not included in the calculation of formation EUR statistics and averages. TGS includes the undifferentiated Mississippian as a separate EUR calculation as many wells are publically reported as such. Other wells are specifically reported as Meramec and isolating those enables accurate EUR calculations specifically for that zone. Taking these precautions and standardizations with the raw data improves confidence and results in quality, accurate playwide statistics by improving and normalizing the original public data.

Results in this study show the highest averge EURs are producing from Meramec, Woodford, Springer and undifferentiated Mississippi. From an oil EUR perspective, the top formations include Springer, Oswego, Meramec and undifferentiated Mississippi. The top gas EUR performance is seen from Woodford, Meramec, undifferentiated Mississippi and Springer. Other Pennsylvanian age reservoirs (Cleveland, Cottage Grove, Oswego, Hoxbar and Tonkawa), which some consider part of the Scoop, are provided for additional reference. TGS is seeing horizontal well activity in these reservoirs producing economically successful EURs.

## Summary

This article has shown numerous high level and detailed examples of forecasting and basic analytics in the Scoop/Stack. Analyzing permit counts, new well locations, drilling costs and completion techniques and calculating EURs show favorable economics with future growth opportunities. Improvements in forecasting models aided by formation assignments to individual well production streams continue to increase the volume of data and quality of interpretation and results. Ongoing efforts for consistency in the assignment of production to ever more granular formation and zone designations assist our industry colleagues leveraging high powered, machine-learning tools. TGS does this through straightforward database cleanup supported with direct input from completion reports and perforation data to better qualify zone assignments. The future is exciting for the Scoop/Stack play as a major U.S. producing province and the data that help us get there. ■

**FIGURE 13. Scoop/Stack Average EURs by Producing Formation**




**Horizontal Wells in the Scoop-Stack - The Top Ten Producing Formations**

| Producing Formation | Avg Oil EUR (Bbls) | Avg Gas EUR (Mcf) | Avg BOE EUR (Bbls) | Avg MD (ft) |
|---|---|---|---|---|
| MERAMEC | 362,974 | 2,706,933 | 829,687 | 13,593 |
| WOODFORD | 128,288 | 3,525,602 | 736,151 | 17,517 |
| SPRINGER | 491,445 | 1,317,988 | 718,684 | 18,551 |
| MISSISSIPPIAN | 310,096 | 1,870,759 | 632,641 | 14,314 |
| OSWEGO | 375,612 | 370,163 | 439,433 | 11,873 |
| HOXBAR | 129,271 | 1,147,858 | 327,178 | 14,580 |
| HUNTON | 116,755 | 928,265 | 276,801 | 12,007 |
| CLEVELAND | 75,301 | 657,688 | 188,696 | 13,272 |
| COTTAGE GROVE | 98,100 | 124,481 | 119,562 | 13,095 |
| TONKAWA | 62,781 | 247,979 | 105,536 | 12,565 |

*Ted Mirenda is general manager, Geological Products & Services, at TGS. James Keay is chief geologist at TGS.* *The authors wish to acknowledge Alexander Laws for his help in compiling the graphics used herein.*

# Additional Information on the Scoop/Stack

For more details on the Scoop and Stack plays, consult these selected sources.

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Associate Managing Editor

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