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Sweet spots and proven frack recipes help new Bakken wells work at $50.

BAKKEN AT $50

The oldest U.S. fracked, horizontal, tight-oil play turned 16 in June. Operators are leveraging those years of knowledge about the rock into the sweetest spots with the most proven frack recipes to make new wells work at sub-$50 WTI.

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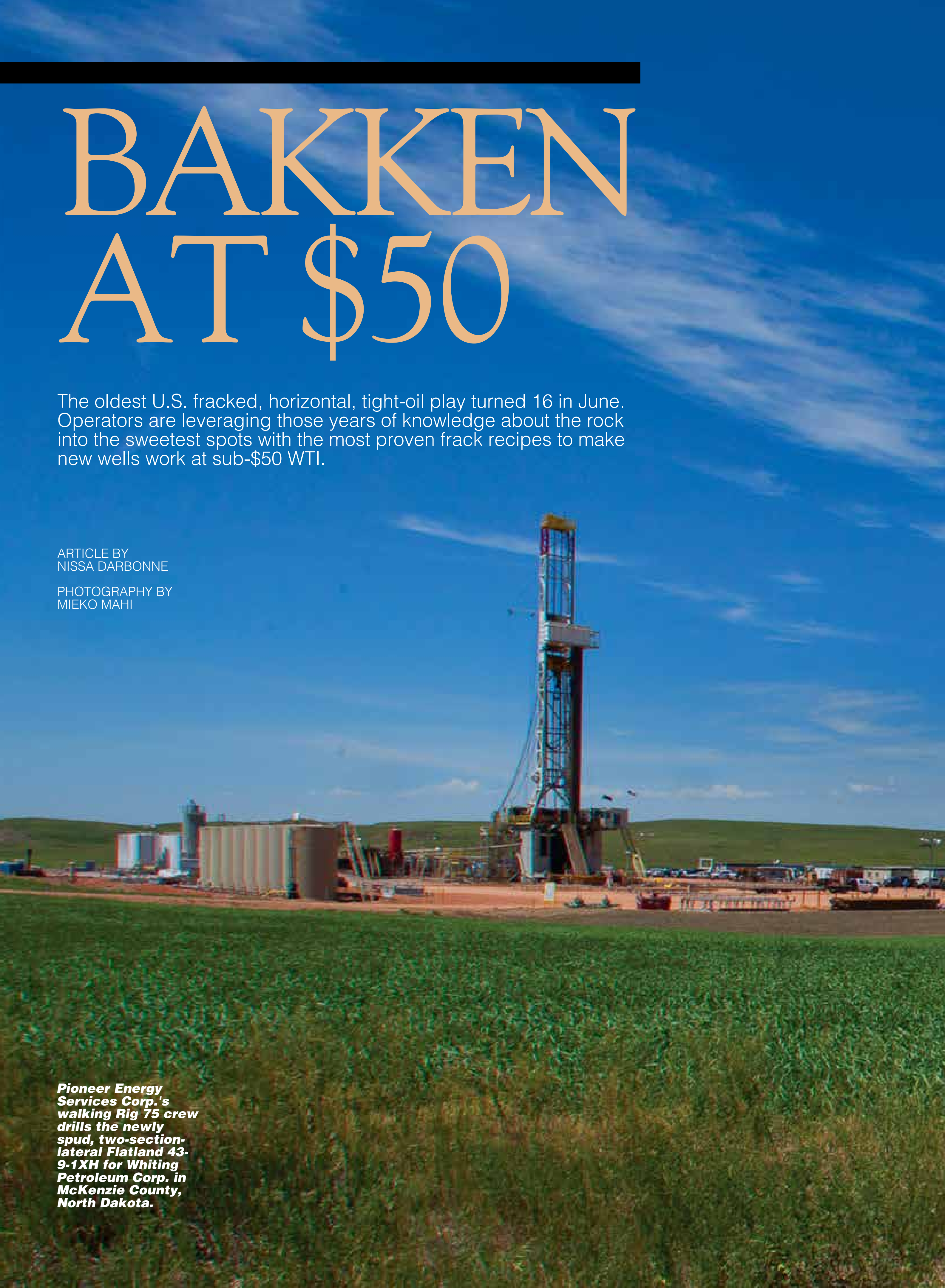


Pioneer Energy Services Corp.'s walking Rig 75 crew drills the newly spud, two-section-lateral Flatland 43-9-1XH for Whiting Petroleum Corp. in McKenzie County, North Dakota.

In January—19 months into the oil-price downturn and while the prompt-month WTI contract fell below $27—North Dakota's daily oil production was still 91.4% of the December 2014 all-time high. Further, the Williston Basin spot price averaged $21 that month, the state's drilled-but-uncompleted (DUC) inventory was 945 wells and about a third as many rigs were drilling as in 2014, according to state records.

Strong output persisted into February, declining just 4,100 barrels to 91.1% of the all-time high. "Some folks needed some money, so they mobilized some frack crews. They went and got some oil," Lynn Helms, director of the state's natural-resources department, told Williston-area community members, according to Reuters.

The number finally broke free in April, however, declining 70,000 barrels to 84.8% of the all-time high. Greg Hill, Hess Corp. president and COO, told *Investor* recently that this was inevitable.

"It's a one-time reset, if you will. There aren't as many simultaneous operations going on. When we (at Hess) had 17 rigs running, on any given day we had 8,000 to 9,000 barrels shut in because someone was fracking next to us."

Hess' daily shut-in average has fallen to about 1,000 barrels. "There was a kind of hidden inventory of crude that was always shut in for sim-ops that has unwound itself. 2015 production picked up because of the sim-op effect. I think that confused people. They thought the Bakken should be dropping faster than it was."

WTI pushed past $50 in June until encountering the undertow of the surprising Brexit vote. Amidst that and other noise in the marketplace that "we can neither control nor handicap," however, supply and demand data remained "constructive to bullish," Tudor, Pickering, Holt & Co. Inc. analysts reported.

North Dakota Gov. Jack Dalrymple told industry members in May that "any storyline depicting the end of the Bakken or a boom gone bust is inaccurate," *The Bakken* magazine reported. According to *Investor*'s findings, producers were considering at second-quarter-end how they would deploy a price-lift windfall—rather than just managing for their survival.

11 drill days

If the Bakken still worked for some at $40 WTI, it looked much better in June at $50. Williston Basin pure-play Oasis Petroleum Inc. had driven its cost structure down to $30 in January, having already recalculated for $60, $50 and $40. It budgeted 2016 capex at around $35 WTI.

As the price rises, "you make a decision on what you want to do with incremental cash flow—additional drilling, completing DUCs or even paying down debt. We will be thinking about all of those things," said Taylor Reid, president and COO of Oasis.

But there was reasonable concern over whether the price would remain at $50 or better. "This time last year," he said in June, "it was around $60, and it didn't hang in there as long as we all thought." If it sticks, though, "I think there will be a bias toward more spending."

Oasis' first-quarter production was 50,315 barrels of oil equivalent per day (boe/d)—about as much as in first-quarter 2015 and up from about 43,000 in the first quarter of 2014. It expects its 2016 average will be between 46,000 and 49,000.

Pure-play Bakken producer Oasis Petroleum Inc. has been able to keep production flat while living within cash flow during the down-cycle, according to Taylor Reid, president and COO.

It had brought 15 additional wells online this year and had 83 waiting on completion at the end of the first quarter. Lease operating expenses (LOE) per boe were $6.78, down from $8.62 in first-quarter 2015 and $10.37 in first-quarter 2014.

Oasis had been on an informal "watch list" in early 2015 among industry speculators in Houston as to whether it would succumb to the tumbling WTI. Its stock price fell to less than $5 earlier this year. In May, however, it was the JPMorgan research group's "favored Williston pure-play."

In late June, shares were trading at about $10. Its borrowing base was $1.15 billion with $100 million drawn. Its next debt maturity is $400 million in February of 2019. Its free-cash-flow generation in 2015 was $68 million. If at as little as $35 WTI, it expects to be slightly cash-flow-positive; about 75% of its expected 2016 oil production is hedged at more than $50.

Of its roughly 485,000 net acres, 91% is HBP. What isn't is mostly on the edges in Montana and along the eastern side of the northern end of the Nesson Anticline in its North Cottonwood area where the water cut approaches 60%.

"The results of the pilot wells there were in line with expectations," Reid said.

"They're just not as high an EUR [estimated ultimate recovery] as in the core. We wouldn't drill it in this environment. We could always elect to re-lease the land."

Oasis had 16 rigs drilling at year-end 2014; in late June, two. Its drilling and completion budget for 2016 is $200 million, down from nearly $1.4 billion in 2014. "As of the last quarter, we had held production for six consecutive quarters at 50,000 boe/d and were cash-flow-positive starting in the second quarter of 2015. It's been a great accomplishment to keep production flat, while living within cash flow," Reid said.

How did Oasis do that? Among the dynamics working in the basin now is that there are 16 years of understanding the target—the dolomitic Middle Bakken that is trapped between the Upper and Lower Bakken shales—Reid said.

Oasis, which entered the play in 2007, has gotten drill days from spud to release down to an average of 15 for two-mile laterals that are landed some two miles below the surface in basin center. "We've done it in as short as 11 days," Reid said.

That efficiency gain is part of what reduced the North Dakota rig count to fewer than 30 this past June from nearly 200 in June of 2014. "You're drilling so many wells per rig, so you don't see as many rigs."

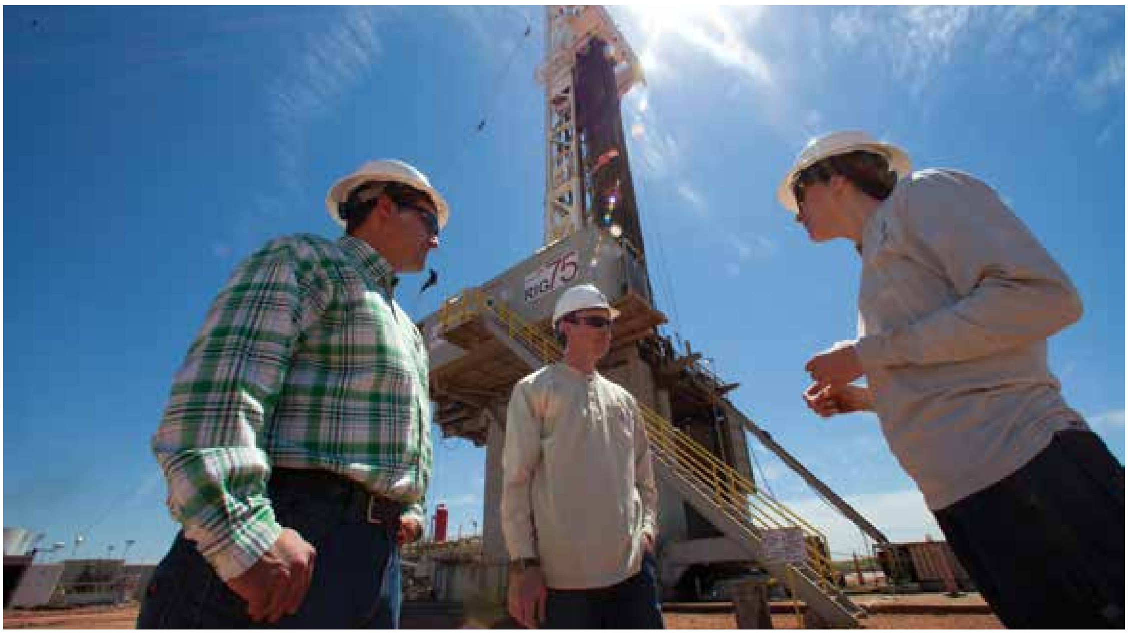
Meanwhile, on the completions side, not only is Oasis' cost down about 40%, but average output per well is greater than in the past. It is drilling and completing only in the sweetest spots and has stepped up its frack recipe, generating IPs and estimated ultimate recoveries (EURs) that are more than 30% greater than in 2014 on a per-lateral-foot basis.

These fracks are 100% slickwater, which is less expensive than gel. Stages have grown to between 36 and 50. Proppant is 4 million pounds for a two-section lateral and is entirely white sand, tailing in with a small amount of resin-coated sand.

"The results we're seeing are the same as from wells completed with ceramic," Reid said. And it has tested a 10-million-pound job and two 20-million-pound jobs, which Reid expects to be able to report on later this year.

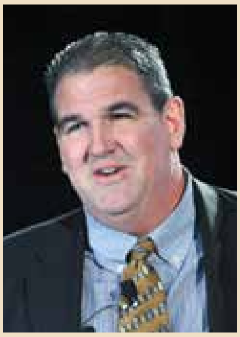
'More with less'

To distribute the fluid and proppant more evenly among stages, it is using a dissolvable diverter. Operators' mentions of diverting agents have increased since 2014, although physical and chemical diversion agents have been around.



Whiting production engineers Sean Vetter (left) and Greg Morehouse visit with a Whiting manager, Ashley McNamee, at the Flatland 43-9-1XH drillsite.

DIVIDE COUNTY REFRACK



Paul Favret
Resource Energy Partners LLC

Privately held Resource Energy Partners LLC entered the Bakken in November with the $37.5-million acquisition of American Eagle Energy Corp.'s wells in a sweet spot in Divide County, where SM Energy Co. was continuing drilling in June. Rather than drilling new wells—although it is participating as nonop in some of SM's—the operator is refracking American's wells.

"We classify it as Tier 2 and 3 rock," said Paul Favret, Resource CEO. It has a higher water cut than in the core, but it is becoming economic again. As the Middle Bakken play is 16 years old, "it's a great candidate for refracking. There are more than 12,000 horizontal Bakken and Three Forks wells. We believe approximately 30% to 50% are viable refrack candidates at $50-plus oil."

The wells it is testing this summer are about two-and-a-half years old. Favret's proprietary evaluation method for picking candidates had an 88% correlation in EUR improvement versus actual EUR improvement in 17 test wells.

The refracks are costing about $1.2 million. "It doesn't require building new pads and bringing in new infrastructure. The refrack cost is only about 40% of the original well completion cost, and the expectation is of a more than 50% improvement in ultimate recovery."

Trying to evenly distribute pressure and proppant in an openhole wellbore is daunting, however. The fluid and proppant are taking the first exits left and right. Also, there is a risk of proppant duning farther down the 10,000-foot lateral. The remedies now are multiple cleanouts.

Instead, "floating proppant, we believe, will be a big component of future success," Favret said. In addition, Resource is considering dissolvable sleeves to put temporary patches over the initial section to force fluid toward the toe. He is optimistic solutions will be found.

"I would argue that we are, with refrack technology in horizontals in tight rock today, where we were with new-well completion technology a decade ago," he said. "It's going to be a growing technological investment during the coming decade."

"It is just being reapplied to a new situation, like a lot of things in the oil field," Reid said. "You challenge your operations staff that you've got to make more with less money. 'Let's figure out how to do that. What can we do from a technological standpoint?'"

While challenging to balance sheets, downturns can be healthy in how they drive innovation, he added. Reid began his E&P career in 1986. "You have innovation in normal times, but you really have to get everything out of your wells in this environment. It puts a premium on innovation."

Oasis' stepped-up fracks in the core are generating EURs of more than 1 million barrels of oil equivalent (MMboe) in the Middle Bakken and 875,000 boe in the underlying Three Forks 1. It isn't putting laterals in the Three Forks 2 or 3 benches currently and has removed them from its inventory for now.

"With a price recovery, we may put those back in the inventory. What we've done with the first bench, though, we think we can recover the reserves across the full column," he said.

The 1MMboe wells are costing $6.5 million, and Reid expects Oasis will get the figure down to $6.1 million by year end. The company has some 600 gross operated well locations in the core for 13 years of inventory at its current drilling pace.

What else works at $50 WTI? Its more than 700 near-core locations are economic at about $45 with current oilfield-service costs; outside of the core and near-core, its more than 1,600 locations work at more than $55.

Reid said, "There are areas in Red Bank (west of the Nesson) that, at $50, will make about a 25% rate of return. At a break-even rate of return of 10%, the Red Bank area works in the $40s."

In North Cottonwood, where the target is shallower than in the core, wells cost around $5 million; at $60, they have a 20% rate of return. "What would have taken more like $80 (before the downturn) in North Cottonwood now works well at $60 and $65," Reid said.

Frack-sharing

In February, Oasis had one remaining frack crew at work. With just two rigs drilling and two-section-lateral drill days down to 15 this year, Reid said, it only needed one frack crew.

Adding a second crew will depend on if it decides to accelerate completing its DUCs—at first-quarter-end this year, it had 83—or if it adds one or two rigs and has a continuous-drilling plan. "The most likely scenario," Reid said, "is we will do some of the DUCs first and then start to draw down on the DUC balance."

Producers with continued activity in the basin will be first in line for rigs and frack crews in a rising oil price, he expects. "Others will be able to get services, but it will be the easiest for the early movers." First up will be operators that can keep a crew busy for some time, "at least where there is enough work for a provider to bring a crew back to the basin."

Operators could team up and share a contract. "You will have to pay for it. It's not an existing crew, and there is a cost to reactivating the equipment. We feel like we have an advantage in this scenario as we can reactivate our (own) second frack spread in pretty short order."

Continental Resources Inc. put aside step-out drilling in the Williston Basin in 2015 and turned to core development a year earlier than planned, said Jack Stark, president and COO.

'Sticky' reductions

Continental Resources Inc. had four rigs drilling for it in North Dakota in early June among the 28 at work in the state, among which all were drilling in core counties except for one for SM Energy Co. in a sweet spot in Divide County. Having entered the Middle Bakken play after Lyco Energy Corp. proved it in Montana in 2000, Continental began accumulating leasehold in North Dakota and tested the formation there in 2004.

In 2014, as WTI was $100, it was still defining the economic limits of the Bakken and Three Forks within its 1.1 million net Williston acres, which are mostly HBP today, said Jack Stark, president and COO. As the price began to plummet, "we moved operations back into the core.

"We were reaching the economic limits with our step-out drilling in 2014 and were making plans to begin developing the core, but we did it about a year early as a result of the price collapse," he said.

Continental estimates it has 10 years of drilling inventory that can produce EURs averaging 775,000 boe per two-section lateral with a 15-rig drilling program. And its stepped-up completions and focus on the core grew its average EUR from 550,000 boe per well in 2014 for 46 boe per $1,000 spent to 800,000 boe and 94 boe per $1,000 in 2015.

This year, it aims to average 900,000 boe and 117 boe per $1,000. In effect, from 2014, EUR per well will have grown 64% and barrels found per dollar spent up 154%, while completed well costs have declined 36%.

"Moving to the core and high-grading our inventory, along with operational efficiencies and enhanced completions, has taken the performance of the Bakken to a whole new level for Continental," Stark said. Total F&D cost will be down 61% from 2014 to $8.54 per boe.

"I tell investors, 'You can't look at a rear-view mirror and project what Continental's performance will be going forward.' That's because we've changed the complexion of the inventory we're drilling and our cost structure. We've never been more efficient with every dollar spent in the Bakken."

Its completed well costs for two-mile-lateral, 30-stage jobs were $6.3 million in early June and are projected to be $6 million when exiting 2016. "That's in the core of the Bakken," noted Pat Bent, Continental senior vice president, drilling, "where it is most difficult to drill."

And, Bent added, "between 50% and 70% of the cost reduction is 'sticky.' They're sustainable, repeatable cost reductions."

By year end, it expects to have 195 gross operated DUCs, up from 135 at year-end 2015. The DUC wells' average EUR is estimated to be 850,000 boe. "At $3.5 million

to complete a DUC, the rate of return at $45 is more than 100%. These are very capital-efficient barrels we can add to our production base," Stark said.

The operator's standard completion had been 30 stages per two-mile lateral with cross-linked gel and averaging 100,000 pounds of sand per stage. Last year, it began testing up to 40 stages, using 200,000 pounds of sand per stage and a 25% gel/75% slickwater fluid design, starting with gel and finishing with slickwater.

The last 10% pumped had been a tail-in with resin-coated sand; it has discontinued this. Bent said, "We found that wasn't necessary." More change-up is possible, he added. "I'm not sure if we've reached an endpoint."

Reserves at wholesale

The company's tradition has been to grow organically; its last significant producing-property purchase was during the 1980s downturn. Would it consider buying in the Bakken in this downturn? Stark said, "We remain opportunistic. We would consider it. But it is hard for us to pay retail (for reserves and production) when we, effectively, have it at wholesale."

Its newest grassroots plays are the Scoop and Stack in Oklahoma. One of its Stack wells, Verona 1-23-14XH, had an IP of 3,339 boe/d, 70% oil, from a two-section lateral. Stark, who's been an exploration geologist since 1978, said, "These Stack-Meramec wells are the biggest wells I've been involved with in my career.

"We really don't need more inventory to grow the company significantly. But, if the opportunity came around at the right price, we certainly would consider it."

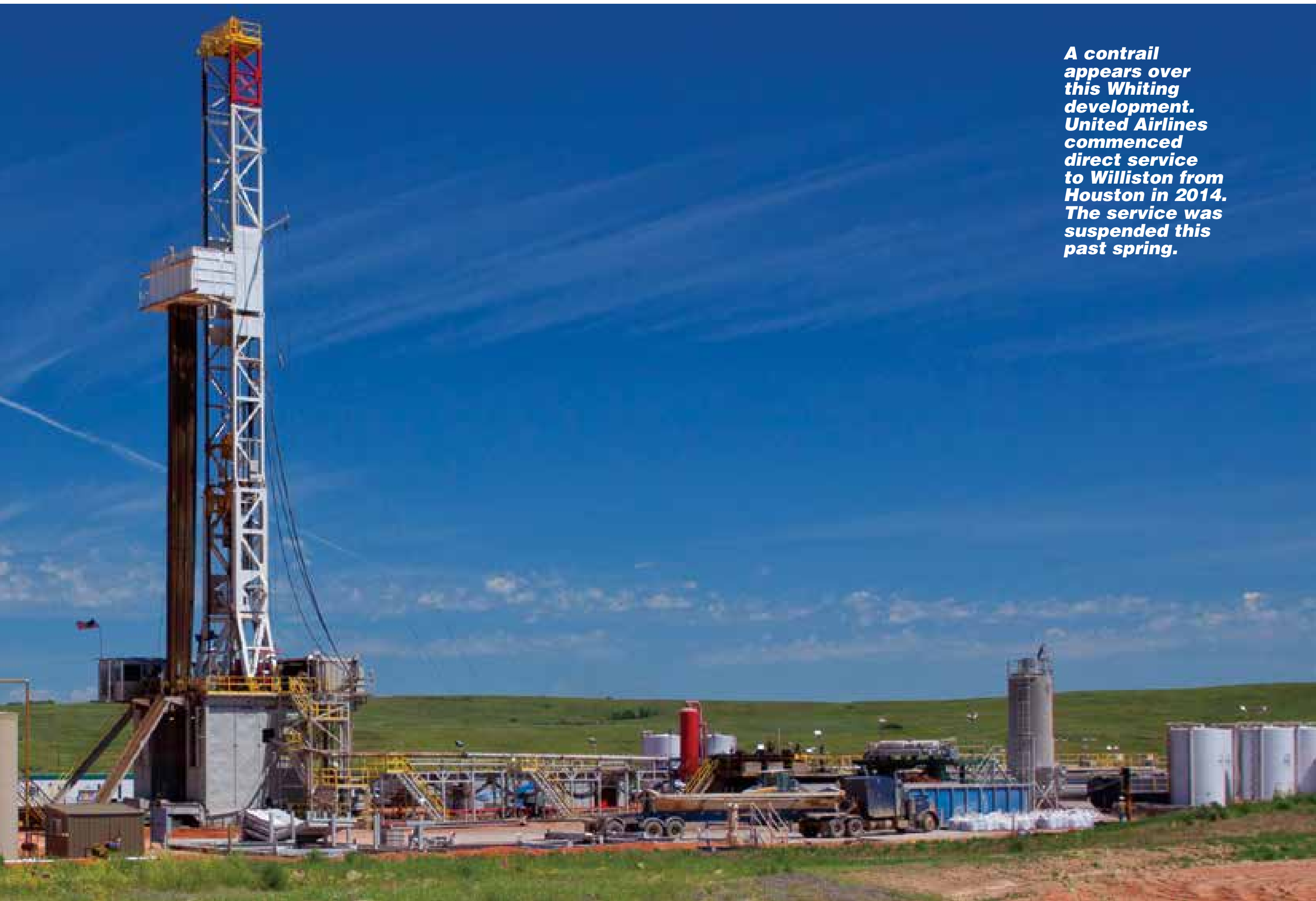
Continental's company-wide capex budget for this year is $920 million, down 63% from 2015, with $320 million of the 2016 spend planned for the Bakken. At first-quarter-end, it had $1.88 billion available on its $2.75-billion revolver. Its nearest debt maturity is $500 million in November of 2018. Other debt is $5.8 billion due between 2020 and 2044.

Its cash cost per boe produced in the first quarter was $10.20—among the lowest of its peers. G&A and production expenses were $4.87/boe. Its cash margin was $9.07/boe on an average realized price of $19.27/boe. Stark said, "We are operating at almost half the cost we were in 2009."

Its first-quarter North Dakota-side Bakken production was 129,000 boe/d, up 6.8% from a year earlier. Its Montana-side Bakken, which it hadn't new-drilled since 2014, declined 28.4% to 10,434.

Stark joined Continental in June of 1992. In the day of chasing conventional reservoirs, the company needed a new play every couple of years to keep production up—much less grow. "We've never had such a quality and depth of inventory as we have today—or as cost-effective. Our operations and technical expertise are second to none. We kept our

Pat Bent, Continental senior vice president, drilling, said between 50% and 70% of the cost reductions that have been achieved in the Bakken core are "sticky."



A contrail appears over this Whiting development. United Airlines commenced direct service to Williston from Houston in 2014. The service was suspended this past spring.

Whiting's Bakken well performance has increased 35% during the downturn, said Mark Williams, senior vice president, exploration and development.

teams together and improved our performance across the board."

The internal forecast is for an undersupplied market beginning in this half and into 2017. "We're confident and will be patient and disciplined as we step into the recovery that is on the way."

Completing DUCs

Whiting Petroleum Corp. is the largest Rockies oil producer now, with first-quarter production from the region at 136,790 boe/d. From the Williston, production was 124,900 boe/d. Its 446,000 net acres there are 99% HBP.

It is operating strictly within cash flow, said Mark Williams, senior vice president, exploration and development. The $50 price in June, "by comparison to where we were, looks pretty good. With prices at this level, we begin to really open up our capital budget to complete more wells."

Whiting had two rigs drilling in early June and stopped accumulating DUCs in January. "So all wells are being completed now as they're drilled," Williams said.

NONOP

A JV partner with two nonoperators in the Williston, privately held IOG Capital LP is currently investing only in the core. In the two arrangements, it had participated in 52 wells by early June, said Marc Rowland, founder and senior managing director.

Marc Rowland
IOG Capital LP

Contributing to the attractiveness of the basin is that infrastructure is already in place; with pipe and rail, there is a surplus of takeaway capacity, he said. "It's an area we found to be doable. You can make money there at $50 oil or even less."

Also, the depositional setting is pretty quiet. "You can keep the horizontal in zone for a long time. We've participated in two-mile and three-mile laterals. More lateral length is more economical." And the drilling is primarily offset. "There isn't any speculation as to how much oil is there."

Nonoperators in pad drilling in the basin are in an unenviable position, however; all the wells—for example, eight—have to be drilled and completed before flowing cash. The nonop might not be able to be out of pocket for that length of time and it might not have the borrowing capacity.

"You might have a year between the start of drilling and actually having cash flow. Since we're not a public company needing to demonstrate quarterly results, we have the advantage of being able to wait."

Before founding IOG in 2014, Rowland was CFO of Chesapeake Energy Corp. and CEO of pressure-pumper FTS International Inc. He doesn't expect DUC inventory to continue growing in the Williston Basin. "I don't see any more operators drilling wells they don't intend to complete. The operator wouldn't spend the money to drill the well, but not complete it, if he has no leasehold reason to do that."

This is aided by a joint venture it entered this spring. The partner—an undisclosed, privately held producer—will pay 65% of completed well costs in 44 gross Williston wells, earning a 50% working interest. At closing, Whiting received $30.7 million for 65% of what was already spent.

Its two-rig program and one frack crew are dedicated to the JV. With a second frack crew, it expects to exit 2016 with 30 DUCs in North Dakota.

Its fracks today are resulting in a 35% improvement in its Bakken wells' performance and a 50% improvement from the Three Forks. "2015 and early 2016 were pivotal for us in increasing our well performance," Williams said.

The standard job on a two-section lateral had been 3.5 million pounds of sand. Whiting has increased this to 7 million and is now testing 10 million. Two pad wells in Williams County, each with some 7 million pounds and 40 stages, had first-60-day average rates of between 904 and 1,501 boe/d. The one landed in the Bakken performed 232% better than another operator's smaller-frack offset wells; the Three Forks well, 124% better.

It is also using a diverter agent. "It's a benign material that allows you, in any stage, to maximize the number of entry points into that formation." In the wellbore, the liquid reconfigures itself into a plug.

"The diverter limits the amount of frack load delivered to a given entry point into the formation and diverts it into others, thereby fracturing more of the reservoir in the near-wellbore environment. It allows us to put sand into two or three entry points in each of the stages, doubling and tripling the number of entry points."

Whiting is mostly using slickwater. "We will start with a gel to open things up. How much we use depends on how much sand we're pumping," Williams said. Completed well costs are averaging $6.8 million this year. At $50 oil, the core expands for Whiting to nearly all of its leasehold, Williams said.

With two-section laterals, it has 5,530 potential gross drilling locations in the core with an average working interest of 60%. 2016 well targets are 900,000 boe EUR. It is looking at additional JVs in its leasehold to increase its rig count and/or work down its DUCs.

The 2016 capex budget is $500 million. LOE in first-quarter 2016 declined to $8.56/boe from $11.07/boe a year earlier. It reduced its debt by $1.5 billion through second-quarter-end this year, trading shares for notes. Of its $2.75-billion borrowing base, $1.5 billion was drawn.

"Spirits are up in the Williston, based on re-starting drilling and completion. Instead of being in a purely defensive posture, we're starting to complete wells. As the oil price rises, we will be adding rigs."

The rig count in North Dakota grew by a few in June. A couple of years ago, reviewing the state's online "Active Drilling Rigs" report required a dozen or so scrolls; in mid-June, it was done with just two. Drilling were 18 operators. Williams said, "We're bouncing around the bottom here, but it is better bouncing up rather than down."

'Core, core, core'

In January of 2015, as WTI was about $47, Hess Corp. was certain of its plan for the Williston Basin: It would keep drilling and keep completing. It still is.

"We have a very strong balance sheet," Hess' Hill said this summer. "Rather than buy out the rig contract, you're better off drilling the well. We can advance through the cycle and complete those wells.

"Really, if you think about it, once you drill that well and have invested that capital and don't complete it for two or three years, good luck making any return on it. That's how we think about it."

Every $1 improvement in the oil price generates $75 million a year of free cash flow to Hess' bottom line. Meanwhile, the company has a gas project offshore Malaysia coming online in 2017 and Stampede in the Gulf of Mexico in 2018.

"When we come out in 2018, we will have significant production coming on and lose the capex associated with those investments," Hill said, "which means your cash-flow generation as a company is stronger in 2018. I don't think that is all that well understood about Hess."

In early June, it had four high-horsepower rigs drilling for it and a spud rig was working on a new pad. It planned to pare to two rigs in this quarter.. "If you look at everyone (still drilling), it's the core, core, core. That is the biggest factor in the basin. If the rock isn't good to start with, you have an uphill battle. That is probably the biggest single distinguishing factor of the last man standing in the Bakken."

Hess is advantaged in that its 575,000 net acres are concentrated along the Nesson Anticline and it has 40% more drilling spacing units (DSUs) in the core than any other operator, he said. "We could drill 12 rig years of inventory in the core of the core at $40 that generates a 15% return or higher."

Its standard pad design is 17 wells with nine landed in the Middle Bakken and eight in the Three Forks—some in 1 and some in 2, depending on the nature of the Three Forks in the area. During the past 18 months, it switched


Connecting drillpipe at Rig 75.

Hess Corp. broke its Bakken well data into some 50 attributes during 2014, determining completion characteristics that produce the highest-return wells, said Greg Hill, president and COO.

Pumpjacks belonging to Lufkin Industries Inc., a subsidiary of GE Oil & Gas, at a four-well Whiting pad near Williston, North Dakota.

to 50 stages per two-section lateral, but it is sticking with 70,000 to 100,000 pounds of sand per stage. It has transitioned from gel to a high-concentration friction reducer.

Predicting performance

The recipe is the result of a Hess analysis of its operated and nonop Williston well data that it broke down into some 50 attributes. With this, Hess developed a proprietary algorithm in 2014 to determine the best completion design.

"And, when I say 'best,' it is what completion design generates the highest return. It's not necessarily the highest-EUR wells or the cheapest. It's only about how to generate the highest-return Bakken well," Hill said.

According to its findings, "where we are in the Bakken, the highest-return completion is a 50-stage sliding sleeve with 110,000 pounds of proppant per stage." The algorithm, which was deployed in 2015, is predicting individual performance within a narrow margin. "That is a huge advantage in how we prioritize our drilling. We can pick the best wells to drill.

"Why not plug and perf? We may apply it in some areas in the future, but, right now it is so much more expensive. Again, we are trying to generate the highest-return Bakken well and not necessarily the highest IP well."

Hess has held drilled and completed well costs at about $5 million despite the increased number of stages. With the 50-stage completion, IP has grown between 10% and 15%.

EUR is rising toward 1 MMboe and Hill expects Hess will be at 1 MMboe by year-end. Most of this is due to focusing on the best areas of the core of the play. Its average across its acreage and when including those drilled before 2015, is some 600,000 boe. It estimates ultimate recovery from its leasehold as 1.6 billion barrels (Bbbl).

Meanwhile, it has maintained its 25-cent quarterly dividend, which costs it $285 million a year. In 2015, it sold a 50% interest in its Bakken midstream assets for $2.675 billion and raised $1.6 billion in an equity issuance.

"One of the inherent advantages we have as a company is we have the strongest balance sheet of our peers," Hill said. "We have the lowest net debt capital of our peers. We have a $4.7-billion undrawn line of credit.

"We don't really need to touch the dividend. And it is a precious return for shareholders, so you don't want to pull that trigger if you don't have to."

Like Continental, Hess is heavily weighted to organic growth in its portfolio. Would Hess buy more Bakken? "We would love to," Hill said. "I'm always trying to improve the quality of the portfolio, but we have great stuff in our portfolio.

"When you go out and buy, it better be better than what you have. Onshore, unconventional valuations are pretty high. We are finding the best deals offshore on ground-floor terms—Guyana, Nova Scotia, ground floor."

At what point would Hess add rigs in the Bakken? "I would like more rigs in the Bakken. We probably will as prices approach $60."

Northern Nesson

On the northern end of the Nesson Anticline, privately held Liberty Resources LLC was still drilling in June, but it was planning to let the contract go later this year. It sold its first Bakken portfolio in 2013 to Kodiak Oil & Gas Corp., which is now part of Whiting.

In the spring of 2014, it picked up 53,000 net acres and sold the roughly 30,000 that were in southern McKenzie County in September of 2014 to Emerald Oil Inc., keeping some 20,000 in the Tioga area of the northern Nesson. It has since added to its Tioga-area holding to total some 35,000 net acres.

About letting the last rig go, Mark Pearson, president, said, "Breakeven for us is in the low $40s, but we only have 130 Tier 1 and Tier 1.5 drilling locations in inventory right now. It gets back to 'Why drill, if you're just going to break even? Where is the return?'

"We would be happy to be drilling at $60 oil and above. But why work our tail off at $50 WTI and not make any money, when we could be holding off six months to a year and see a $60-plus number?"

This year, it drilled five new DSU wells; the last two were being completed in June, resulting in Liberty having 100% of its 18 two-section Tier 1 DSUs HBPed. In another pad, it drilled six wells and put them into DUC inventory. Of all of its leasehold, about 85% is HBP. What acreage Liberty is adding is in Tier 1.5 to generate more DSUs.

Liberty began working in the basin in 2009 and with 100% slickwater fracks, which was unusual at the time. "Now, 70%-plus of all new Bakken well completions are slickwater or a hybrid of slickwater and gel."

Also, its fracks were with ceramic proppant. "For cost reasons, we did convert from ceramic fracks that were 400 pounds per foot to pumping sand fracks that are 650 pounds per foot," Pearson said. It is using white sand exclusively now.

"The data still show ceramic is better," Pearson said. "It's just that, if you're not making any money, you can't afford it. The payout is so far out with ceramic. You can get better economics by just pumping more sand."

Is there potential to refrack the wells later with ceramic? "No. You've lost the zonal isolation. Plug-and-perf completions perform so much better than sliding sleeve that 90%-plus of the basin now is doing plug and perf. It is very hard to get adequate diversion in a refrack to adequately stimulate the wells.


LUFKIN
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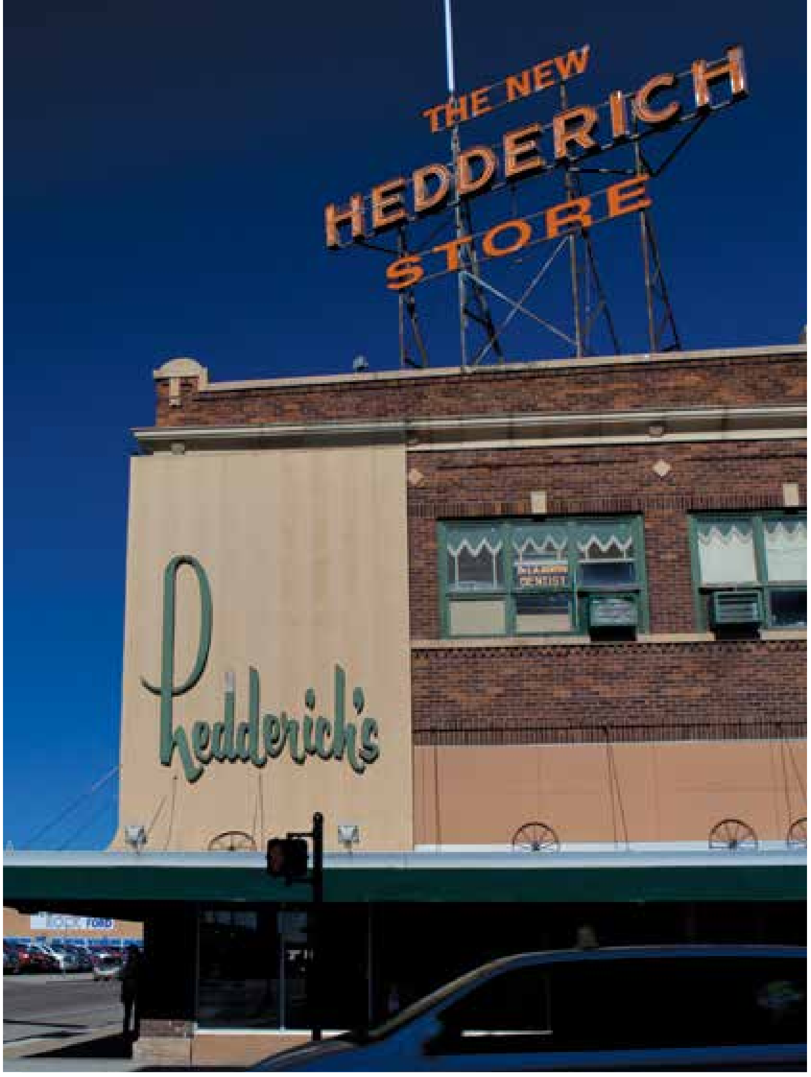
THE NEW
HEDDERICH
STORE
Hedderich's
DENTIST

You would be much better off just spending the money on a new well nearby."

Pearson considers Tier 1 acreage to be that which produces 800,000 to 1 MMboe wells. This isn't unique to just Mountrail, Dunn and McKenzie counties. "The Tier 1 also runs up the anticline where we are around Tioga. Too far north, you have north of 50% water cut and a 400,000 to 500,000 boe well."

Its completions are increasingly geo-engineered rather than geometrically engineered, he added. "Some stages could be closer together. We are also perforating at 15-foot intervals to create more fracture-initiation points. We used to be every 40 feet, and now we're at every 15 feet."

Can it get better? Using dissolvable balls to enhance completions could help, "but you don't get as much fracture-initiation points. We are typically perforating 12-plus perf clusters per stage. So, if we're doing 15 frack intervals per day, we're pumping 180 fracks per day.

"Our diagnostics say 85% of those perf clusters are actually fracking—actually breaking the rock. In a lot of other basins, people say a third of the perf clusters take fluid."

Its EUR ranges from 600,000 to 1 MMboe, depending on the tightness of the spacing. The figures rival those from wells in northern Dunn and southern Mountrail. Pearson said, "On the north end of the anticline, there is very good rock. We are in Tier 1.5 rock. But, when you put the frack on it, you end up with a Tier 1 performance as if you are in the New Town area."

Sleeping giant

The prospect in Montana that led to the fracked, horizontal Middle Bakken discovery well in June of 2000 was named "Sleeping Giant" by Dick Findley, the geologist who mapped the porosity streak in Richland County. While the giant has been awakened, there is still more fire left in it.

"The oil in place is tremendous," Whiting's Williams said. "As our technology for completion continues to improve our recovery, we are getting more of the oil in place. That bodes for a bright development future.

"Combine that with lower costs and higher oil prices. It means we have more drilling locations and more profitable wells."

Pearson at Liberty Resources expects WTI to improve to $60 in the fourth quarter. "The declines we are seeing are real and it is questionable how much more capacity can be put into the marketplace."

Oasis' Reid said the Bakken has overcome far more challenges than just this downturn. First, industry figured out how to get economic amounts of as large a molecule as oil out of tight rock. "People said it couldn't be done."

Then, the area lacked sufficient take-away infrastructure; prior to this century, the most oil North Dakota produced a day was some 140,000 barrels in the mid-1980s. Differentials were a concern too; at times, operators' oil was discounted $20 off WTI or more.

Yet, "it is probably the most predictable oil play," Reid said. "It doesn't have as much unknown as the basins earlier in their lives like the Permian and Stack. A lot of people had an under-appreciation for the core of this basin. We are seeing recognition that the core of the Williston is as good as, if not better, than the core of other shale basins."

Continental's Stark said refracking is something the team has talked about, but a great deal of new-drill inventory remains. "I'm sure there will be opportunities for us down the road. Look at the evolution of the completions we're doing today. We are so far beyond what we were doing in the early days of the Bakken." □

Liberty Resources LLC, which is focused in Divide County, is dropping its last rig in the Bakken. "Why drill if you're just going to break even?" asked Mark Pearson, president.

Facing page, clockwise: The historic Williston rail station was built in 1910, 41 years before the state's first oil discovery. The Hedderich's store, downtown Williston. The city's former post office is now an office development, Renaissance Station. In 2010, cattle outnumbered people in North Dakota almost three to one, according to a state report.

PRIVATE EQUITY

Eric Mullins
Lime Rock Resources LP

Privately held Lime Rock Resources LP is participating in some nonop wells in its leasehold. But it isn't drilling. It was planning in 2014 to pick up a rig; in 2015, it canceled that. "We never did it," Eric Mullins, managing director and co-CEO, said.

For the balance of 2016, "we have a small capex budget. It's obviously significantly reduced from our expectations a few years ago, but it's not zero."

In areas of the basin with the highest EURs, $50 WTI is good enough, he said. "But that is a changing threshold. You have to look at the drilling cost and operating cost. If drilling costs remain where they are now, several areas are economic, but, if drilling costs go higher, it changes."

The producer closed on its fourth fund in May, raising $754 million. Between 50% and 70% of its production is hedged in the mid-$80s into 2018. "We did that even though the market was in backwardation at the time. But, any time you're taking on leverage, we feel it's prudent to put on hedges, just in case there is a downturn. We can't say we saw this coming."

Its acquisitions in the Bakken include Occidental Petroleum Corp.'s op and nonop positions last November for an undisclosed sum that Reuters reported was $500 million. In late June, it signed a $116-million purchase of Natural Resource Partners LP's nonop position.

Mullins doesn't expect fire sales in the basin—or anywhere. "Whenever everyone has expected distressed sales in a down market, it has never materialized. For those that have to transact, there is a lot of competition, and people are generally willing to pay up."