BUILDING A BIGGER BAKKEN

The Bakken's operators are seemingly locked into a dwindling geography in North Dakota, but companies are increasingly returning to their wildcatter roots to see how far they can stretch the Williston Basin's core.

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The first horizontal wells drilled in North Dakota were fierce and untamed. The rock seemed to buck and fight, pushing the drillbit away. In 1995, Continental Resources Inc. began drilling the Red River B Formation in an interval of 8 to 10 feet. Geosteering hadn't advanced past the pencil and paper phase. The goal was to stay in the oil-saturated top half of the zone, said Harold Hamm, chairman and CEO of Continental.

"But, in the beginning, you were out of zone more than you were in," he said.

Horizontal drilling was in its infancy. Fracture stimulation of oil wells was years away. And the wells that Continental drilled in Cedar Hills Field were tough.

"Drilling the Red River was kind of like drilling blind with a cane, and you're tapping the top of the zone and the bottom of the zone and then trying to stay in," Continental president Jack H. Stark said.

But by March 2004, Continental's Robert Heuer 1-17R well in Divide County, N.D., had become the Bakken's first commercial producer from a hydraulically stimulated horizontal well. And the world changed.

"I will never forget looking at the core and seeing oil staining down in the Three Forks Formation," said Continental Resources Inc. chairman and CEO Harold Hamm.

Previous page, Hess Corp.'s Tioga gas plant is seen from a farm in the outskirts of Tioga, N.D. Facing page, a tanker is on its way to a Hess workover rig in Williams County, N.D.

Fifteen years have passed since Continental Resources drilled the first commercially producing, horizontally stimulated well in the Bakken. The Williston Basin might be considered middle aged as shale oil plays go, but it continues to surprise the industry with its vitality.

For years, Continental has created sophisticated, five-year plans that offered a precise outlook for the company. While Continental already produces about 14% of the Bakken's oil, this year's plan caught Hamm and Continental's management team off guard.

"It really shocked us," Hamm said. "We knew we had really had good inventory, but when you look out there and Continental's inventory still totals 4,000 wells in the Bakken," Hamm said. That figure does not include the company's nonoperated well interests.

Continental has drilled roughly 1,800 Bakken and Three Forks wells, according to Stark. "So we're through maybe 25% to 30% of our inventory at this point," he said.

Despite the basin's maturity, North Dakota trails only Texas in production, which has soared this year. In January 2019, operators set a record by producing an average 1.4 million barrels per day, 96% of which were from the Bakken and Three Forks formations.

But questions of longevity continue to pester the Williston Basin. In a June report, analysts at Seaport Global Securities said of WPX Energy Inc., for instance, that "the best stuff in the Bakken seems drilled up."

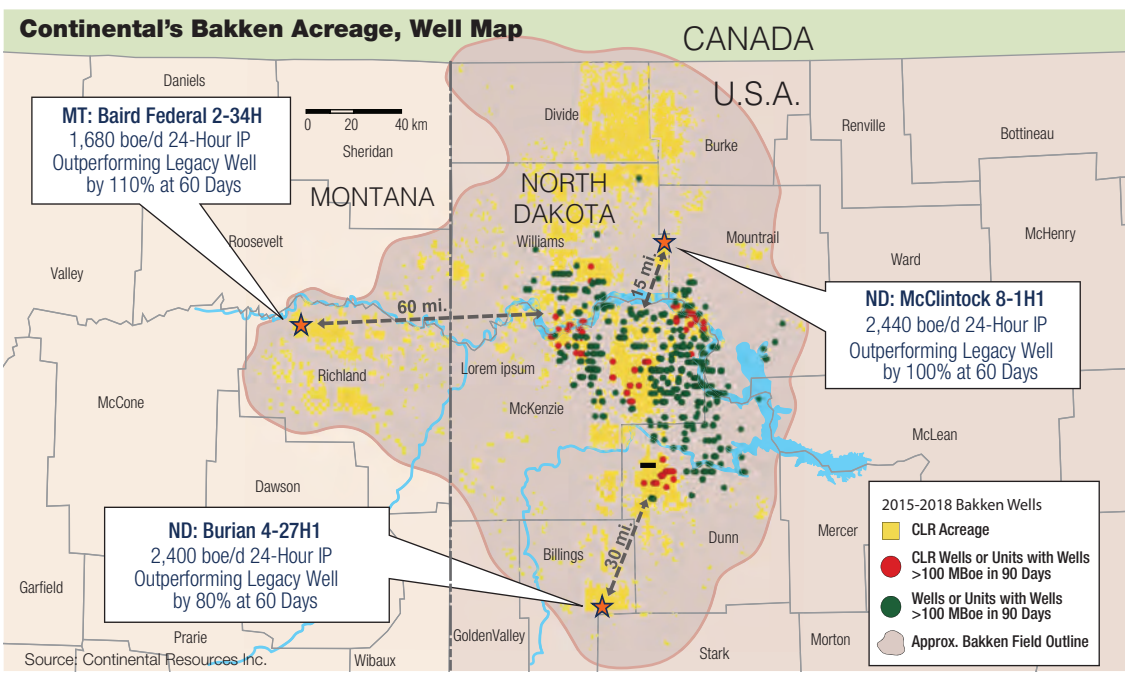
Despite construction of new oil pipelines, natural gas capacity remains limited. In some cases, companies have backed off production in order to meet the state's natural gas flaring and venting caps.

And while Bakken E&Ps face the same questions as companies in other shale plays, operators in the maturing basin are saddled with more pointed questions. As the basin's natural resources are depleted, how much is left? Is the Bakken truly boxed in?

Hess Corp., among other companies, has efforts to drill areas once thought to be second-tier.

"We're nowhere [near] done drilling in the Bakken," said Barry Biggs, vice president of onshore operations at Hess. The company's Bakken program will encompass 160 wells in 2019, mostly in the core of its position. About 25 of the wells will explore the hinterlands.

The Bakken's shelf life is a moving target. Its estimated remaining inventory is between



Continental is performing strategic step-out tests to optimize completions to uplift well performance in North Dakota and Montana.

34,000 and 98,000 well locations, according to a 2018 study by the North Dakota Pipeline Authority. At an assumed rate of 100 new wells drilled and completed monthly, North Dakota's initial run of wells could last up to 81 years—or as few as 28.

The Bakken's stamina hinges on the pace of drilling and oil prices, said Brian Velie, an analyst as Capital One Securities Inc.

Because of the oil price downturn and its continuing aftershocks, as well as takeaway constraints in the Bakken, companies have slowed down more than they have accelerated in the past few years, Velie said.

Continental used the time to learn "a great deal more about how to create additional stimulated rock volumes," Hamm said.

The delay in development has increased the lifespan of the Bakken's inventory. But beyond that, and outweighing pacing assumptions, is a shift toward new exploration in the fringes of the play.

"There's a movement now, and it's been ongoing, toward the development or the expanding of the core," Velie said.

Upstream companies are targeting their Tier 2 acreage not with the expectation of surpassing the core's economics, but with the goal of bringing wells online that make a similar return.

"If they're running out of core, they can't necessarily go back with a better recipe and get even better economics on that core because those locations are largely drilled," he said. "But they continue to get similar returns on lesser rock because of the completion improvements."

From a dollar and cents standpoint, Tier 2 wells perform similarly to the last well drilled in the core. Production rates are unlikely to match core acreage, but wells produce to the degree "that they're making good returns," Velie said.

Nicholas L. O'Grady, CFO at Bakken non-op company Northern Oil and Gas Inc., said that over the past few years, most rigs have hugged the core. Now, they're starting to push out toward western and northern Williams County, southern Billings County and even into Montana.

"We've seen a handful of results in those areas, and a handful of operators who have really gone after it successfully, like a few private-equity-backed companies," he said. "We are encouraged by what we're seeing outside of the core."

Bakken runway

Beyond the Bakken, clues to the next Williston formation were hiding in a library—a core sample library.

Three Forks core samples, stored at the University of North Dakota, had Hamm doing a double take.

"I will never forget looking at the core and seeing oil staining down in the Three Forks Formation," Hamm said.

The Tioga gas plant, in Tioga, N.D., was built in 1954 and has been in operation ever since. Hess is increasing its capacity from 250 MMcf/d of gas to 400 MMcf/d with a $150 million planned expansion.

He was convinced the formation was separate and distinct from the middle Bakken. Skeptics dismissed the idea.

In July 2008, Continental set out to prove them wrong by drilling its Three Forks well. In June 2009, to prove the Bakken was a separate formation, the company drilled over the Three Forks' ceiling, with the wells crisscrossing in McKenzie County, N.D. Continental's Mathistad 2-35H Bakken well came online and for its first seven days averaged 995 barrels of oil equivalent per day (boe/d). To that point, it was the company's strongest performing Bakken well.

"Sure enough, a year later, half of the people up there were staking a well in the Three Forks," Hamm said.

The Bakken's consistency has quieted any naysayers over its potential. In 2011, the U.S. Geological Survey put the Bakken's reserves at 3.8 billion barrels (Bbbl) of recoverable oil. By 2017, the Bakken had already produced 2.4 Bbbl, according to the U.S. Energy Information Administration.

Operators have thrived by beating the odds: improving cycle times, innovating with technology and completions and spending less to produce more.

Hess' presence in the Bakken is already massive. At $60 oil prices, Hess can drill its current inventory of 50% or better IRR wells for the next 15 years.

"We've got a lot of running room," Biggs said.

What constitutes the core Bakken areas is already starting to blur, O'Grady said. Northern's interests extend to 6,500 penetrations, and the company will be a participant in 40% of every Bakken and Three Forks well drilled in the basin.

Early results by operators have more than doubled Northern's productivity estimates.

One producer, which purchased extension acreage from a large independent, is bringing wells online that Northern foresaw having 300,000-bbl EURs.

"They're consistently making six, seven, 800,000-barrel wells," O'Grady said. Operators have been "very careful about how they complete them and the technology that they use."

More recently, E&Ps such as Continental are also making an effort to retrace their steps. In April, the company announced that three step-out wells in Montana and North Dakota, dozens of miles from the Bakken core, yielded IPs ranging between 1,680 and 2,400 boe/d.

Stark calls the wells "bold step-outs" to prove modern technology works in other parts of the basin.

"We've stepped out here to the southern reaches of our leasehold, to the western reaches of our leasehold" and toward the north, he said.

Continental drilled its step-out Montana well in Richland County, in Elm Coulee Field, where the company was solidly producing in 2011.

Continental was looking in the other direction at the time. The company's step-outs were headed toward the north, and the company was envisioning development of the North Dakota Bakken "on 320-acre spacing like Elm Coulee Field in Montana," according to Continental's August 2011 Securities and Exchange Commission filings.

Continental took new technology into what would be considered "older areas that hadn't been as active for us," Stark said.

"And that's not too far from where we started in North Dakota, really. It's just up the road," he said.

The Montana well outperformed a legacy well by 110% within 60 days.

Continental's 4,000-well inventory includes the outlying areas, but its stimulation work is proving the uplift in performance, reserves and rate of returns that the company expected.

"We've just uplifted the quality of that inventory through the technology," he said.

Hess is on a similar path, though one ultimately separated by time and geography: Bakken now, offshore Guyana later. In between, the company sees plenty of opportunity for detours outside of the Bakken core.

The company holds about 550,000 acres with 2,700 well locations economic at $60 West Texas Intermediate (WTI). And the Bakken will be the growth engine for the company in coming years. By 2020, Hess anticipates annual free cash flow of $750 million, depending on oil prices, Biggs said.

Producing that cash flow requires Hess to primarily drill its core, Tier 1 acreage.

What comes after 2021 is what Hess is at work on now.

"What we're trying to do here is prepare ourselves, to give us time to further crack the code, for lack of a better term, to where our drilling locations will be coming out further out in our campaign," he said.

This year, Hess will test areas in the east, north and northwest, in fields called Red Sky, Goliath and East Nesson. Last year, the company ramped up to six rigs and will keep up the pace through 2020 before ratcheting down to four rigs in 2021. Some of the rigs will conduct drilling tests in an effort to create a bit of Tier 2 to Tier 1 alchemy.

"We don't talk about it much either, but Little Knife, which sits down south of Keene, is another area that has inventory remaining out further in our drilling program," Biggs said. "We're trying to prove out where we have large inventory left after this 2021 time frame. That's the gist."

Hess Corp. 2019 Drilling Program By Field

Field	Keene	Stony Creek	East Nesson	Beaver Lodge/Capa	Other[1]
EUR (Mboe)	1,350	1,300	1,100	1,100	950
IRR	>100%	80%	60%	70%	45%
2019 wells online	45	30	40	20	25

Source: Hess Corp. 1) Other fields include Goliath, Red Sky and Buffalo Wallow.

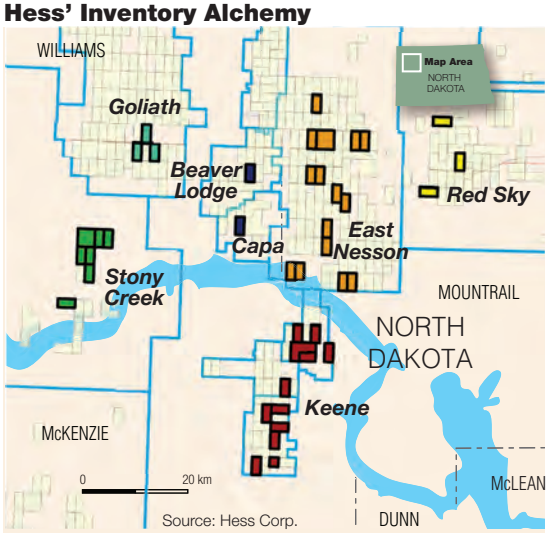
Testing boundaries

In its early days in the Elm Coulee portion of the Bakken, Continental's stimulation technique was essentially "pump and pray," Hamm said.

Barry Biggs, vice president of onshore operations at Hess, said the company is moving out of its core areas to "prepare ourselves, to give us time to further crack the code" in outlying areas.

Hess rigs are conducting tests in the Red Sky, Goliath and East Nesson fields to expand its inventory of economic locations.

Hess' Inventory Alchemy



While the technique proved effective and profitable in Montana, moving into North Dakota, the zones were deeper, higher-pressured reservoirs with far less porosity in the rock, he said.

As Stark put it, the middle Bakken is tight rock. "If you pull out the core and look at it, the middle Bakken looks like the concrete in your driveway," he said.

As the company shifted to North Dakota, Continental found that Montana completion methods "didn't work at all," Hamm said.

Last year, Continental's well completions averaged about 11 days. Today, the company can complete a well in as little as seven or eight days, said Chris Nichols, northern regional completion manager at Continental.

"That allows us to reduce our cost per well," he said. "It's really helped drop costs out of the system. And we're just making bigger wells in the process."

As a pioneer in the Bakken, Continental progressed through trial and error. Rather than coast on their success, the company and its peers have stepped up experimentation.

"Each of these are iterative points," Stark said. "As you go through time, each new turn of events stimulates a new thought and a new direction, or a new approach. And it just expands your perspective and understanding."

After years of technological breakthroughs, the push to expand bounds of the Bakken core will rely on proven successes combined with advances in data and technology.

In the fall of 2007, Continental was just beginning the transition to multiple-staged completions. A dozen years later, wells that once used 3 million pounds of proppant now use 10 million pounds. Stage counts have risen from five or six to as many as 60. And the company has tinkered with how to gain more exposure to the reservoir and the optimum spacing for perforation clusters.

"We've dialed in on a lot of those variables," Nichols said. "We've figured out through design of the perforations, the job size and the pressures, the rates" to increase the number of perforation clusters stimulated per well stage. The results have cut days off of completion times, allowing for reductions in costs per well.

Pictured above, the refrigeration process equipment at Hess' 250-MMcf/d Tioga gas plant in Tioga, N.D.

Pipe Up

The Bakken's chief vulnerability for most of this decade has been a choking lack of pipelines to ship out its rich, low-sulfur oil.

With the construction of the Dakota Access Pipeline, among others, shipments of oil by rail have dropped from a highpoint of 700,000 barrels per day (bbl/d) in December 2014 to about 300,000 bbl/d in April 2019, according to estimates by the North Dakota Pipeline Authority.

While oil infrastructure is available in 2019, oil price differentials have shot up from time to time in the recent past due to takeaway constraints, said Brian Velie, an analyst at Capital One Securities Inc.

Piping out natural gas remains a weak spot.

Hess Midstream Partners COO John A. Gatling said the company has executed a disciplined strategy to support not only Hess Corp. but other third parties in the basin. The company will also take advantage of Hess' push toward average production of 200,000 barrels of oil equivalent per day.

"That obviously creates a substantial platform for us to build our midstream on top of and in support of Hess' upstream operations," he said. "We were very fortunate to have built our strategic infrastructure in the best acreage of the basin, right on top of Hess' position."

Hess Midstream has continued to carefully expand its infrastructure in the basin in 2018 and 2019.

In February, Hess Midstream announced it would purchase Summit Midstream Partners' Tioga Gathering System that overlays some of Hess' key acreage position in the West.

"We've been able to integrate that and transfer that value both to Hess Midstream but also to the upstream, offering some better economies as it relates to gathering and ultimately transporting, processing, terminaling and exporting the upstream's business," Gatling said.

> "We'll have the largest single plant in the basin at Tioga, and then we'll have the second-largest processing capacity available in the basin as well."
>
> —John A. Gatling, Hess Midstream Partners

In April, Hess Midstream also announced it would expand the capacity of its Tioga gas plant to 400 million cubic feet per day (MMcf/d) from its current capacity of 250 MMcf/d. The expansion is expected to cost $150 million.

"As we see [Hess Corp.'s] production growth continue to move up, we also see third parties growing as well, and that created an opportunity for us to triple the size of our original expansion plan, which was previously discussed at about 50 MMcf/d," Gatling said. "So now we're kicking that to the total expansion of 150 MMcf up to 400 MMcf/d. So that's going to be great."

In 2018, the company began a $325 million capital expansion program. Hess Midstream also partnered with Targa Resources to build a gas plant south of the Missouri River that will increase its gas processing capacity to 500 MMcf/d.

"We'll have the largest single plant in the basin at Tioga, and then we'll have the second-largest processing capacity available in the basin as well," he said.

Together, Hess and Hess Midstream have been able to establish long-term takeaway capacities for crude residue and NGL.

"When you look at the full value stream from the wellhead, all the way to the markets, we feel like we're in a very strong position to deliver all the hydrocarbon to where it needs to be, and when it needs to be there," Gatling said.

Despite the Bakken's high oil cut, operators in the basin continue to struggle with throttling back natural gas flaring. In 2017, Bakken operators vented or flared 88.5 billion cubic feet (Bcf) of gas, nearly 18.5 Bcf more than in 2016, according to the U.S. Energy Information Administration.

North Dakota Industrial Commission Flaring/Venting Order

Deadline	Percentage of natural gas captured
Oct. 1, 2014	74%
Jan. 1, 2015	77%
Oct. 1, 2020	90%

Source: North Dakota Pipeline Authority

The Environmental Defense Fund estimates North Dakota flared and vented gas is worth $220 million.

Barry Biggs, Hess vice president of onshore operations, said the company has kept in compliance with state rules and regulations and, taking into account appropriate credits, run slightly below North Dakota's 12% cap on flaring basinwide. Hess earned credits by investing in equipment in certain areas or well pads, including incinerators, or through the extraction of the NGL, he said.

"But those are short term [solutions] as infrastructure gets built out," he said.

Hess, like other operators, must ultimately meet state requirements that, by Oct. 1, 2020, set out to capture 90% of natural gas and 95% afterward.

As Hess Midstream's infrastructure keeps pace, Biggs said that upstream operations will be able to more easily hit the state's requirements.

"As our wells come online, there's a period initially of flaring, and then as the infrastructure in all areas is completely built out to meet it with this ramping up to Hess' gross of 500 MMcf across the basin," he said. "We will be in compliance, and we don't see any issues of being able to do that."

Continental Resources Inc. chairman and CEO Harold Hamm said the company's ambition is to lead the industry in the amount of gas it saves.

From time to time, that's meant delaying well pads from coming online until a pipeline is built, constructed, and then a plant can process associated gas from oil wells.

"Sometimes it delays production a little bit to get facilities that you need, particularly plants, and then one of the big holdups … is this is a very rich gas," he said.

Gatling said that it's unfortunate that operators are behind from an infrastructure perspective.

"We would like to be capturing more gas, but it's also a bit of a high-class problem in that the wells and the basin in general are meeting expectations and, over the last several years, it's continued to beat expectations," he said. "Because the wells had been performing so well, and in particular, as Hess has transitioned to plug-and-perf and seen even better improvement on overall production rates, we're playing catch-up a little bit."

Hess Midstream's infrastructure plans are intended to meet Hess' needs as well as those of third-party producers.

"Third parties are having the exact same issue Hess is having," he said. "So just generally across the basin wells are performing better than expected."

Midstream companies have had to play catch-up as new technological advances, drilling and completions and cycle times improve, putting significant pressure on the infrastructure.

"We're definitely flat out executing work, and that's another reason why, as an example, we announced a threefold increase in our process and expansion," Gatling said. "We see that opportunity of continued growth, in particular, as Hess makes its way to 200,000 barrels of oil equivalent per day."

Damon Knupp and Torrey Ollermann (left) check the oil level of the sight glass in a compressor building at the Tioga gas plant.

"Instead of treating five of those clusters, we can treat eight," he said. "And [we] can treat eight clusters with one staging event, so that reduces our wireline time, our time on location for our crews."

In addition to its step-outs in other areas, Continental is among those companies that operate large units in the basin, according to Hamm

Large-scale development units have the potential to create "tremendous efficiencies going forward," he said.

"We're doing another one of those now and certainly, carrying out those types of developments is going to be quite the economic deal," Hamm said, adding that Continental is working on an "exceptionally large unit." He declined to give more detail.

Hess is also turning toward refinement in its operations while also exploring ways to innovate through completion techniques, technology trials, fiber optics and fiber coil.

The company's most recent, significant move has been transitioning to plug-and-perf completions after being one of the last holdouts of sliding sleeves, Biggs said.

"We did a big study last year that looked at the incremental profitability coming from moving to a plug-and-perf," he said. "That's resulted in us now saying we should hit 200,000 barrels [of oil equivalent] a day by 2021, which translates into $750 million in free cash flow."

The company sees automation, analytics and well design as areas in which it can make breakthrough reductions in drilling costs.

Hess is also working with Nabors Industries Ltd. and evaluating fracking optimization and automation.

"We're working with Nabors to try to automate and optimize the drilling sequence using our real-time drilling center, rig automation—all underpinned by predictive data analytics," he said.

"From a geosteering standpoint, the wells can geosteer themselves. From a data analytics standpoint, we can have the right weight on bit, rotation—all the drilling parameters," he added.

Hess is also studying new well designs that use monobore or a one-casing string design only. The company also tirelessly experiments with completion techniques to fit different areas. Tests are run on the number of entry points, well spacing, sand loading and diversion techniques.

With further technology trials, Biggs said Hess' goal is to whip up the best completion recipe for each area and "get the most out of the rock."

Buying Bakken

In 1985, Hamm began his exploration of the Williston. Oil prices had fallen, and the Williston wasn't just out of favor, but "pretty much dead to the world," he said.

In 2003, its impressive success in Montana, Continental stepped into North Dakota and leased 300,000 acres.

After the Heuer well, the company leased another 400,000 acres and continued to build a position that would top out at 1.2 million acres in the Bakken alone.

"Go find the next one," Hamm recalls telling his exploration team after confirming Elm Coulee Field. "This is good, but it's under our belt. Go find the next one.

"And they did."

Williston operators in need of inventory always have acquisitions open to them. But buying Bakken is no longer an easy or desirable task for public companies.

So far this year, the most notable A&D move seen in the Bakken was QEP Resources Inc.'s termination of a deal to sell its North Dakota and Montana assets for $1.73 billion. The first quarter was bleak for upstream A&D generally as oil prices nosedived to end the year.

Facing page, a row of propane bullet storage tanks at the Tioga gas plant.

Large-scale acquisitions are dangerous to companies, particularly in a market environment that punishes any deals, no matter how enticing to a board of directors.

"In North Dakota, you're not going to put your company at risk to go make big acquisitions," Hamm said. "We continue to do strategic things that make sense for the company. I'm talking about a few sections here . . . that make sense within our plays."

All public companies face a tightrope walk on Wall Street. Investors want to see an adequate number of drillable locations without the need to acquire more, Velie said.

"No matter what price you get for the next 100 locations you buy, if they're at the end of that location queue and you don't get to them in 15 years, from a net present value those aren't worth much at all in today's dollars," he said. "It's hard to justify that capital outlay today for wealth that won't produce for a decade or more."

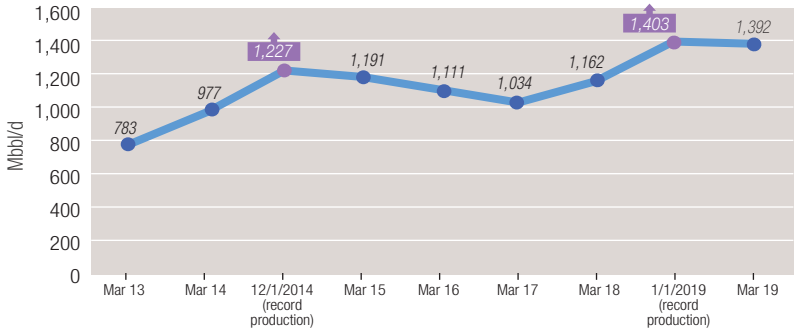
In the past 18 months, Northern Oil and Gas has been the basin's most consistent acquirer, albeit of nonop interests. Since the start of 2018, the company has made four large publicly announced transactions totaling more than $820 million.

Because it seeks out nonoperated interests, Northern is able to target slices of acreage in units operated or being developed by the largest producers. To find the best deals, the company has built a vast and complex database to track oil and gas development and deals in the basin.

In deals this year, Northern acquired assets from Flywheel Energy LLC and W Energy Partners for about $300 million each. Both come with a roughly 50:50 split of PDP and inventory.

"These assets have a good, healthy producing base," O'Grady said. "They're midlife cycle, but they've got significant growth left on them."

Bakken Oil Production



Of its four major acquisitions since June 2018, the company gained significant inventory while just one transaction was "truly a PDP deal, but the price was right," he said.

"In general, our ability to build core inventory is still strong. But I do think that the Bakken is mature. That's a good thing for making money: its midlife cycle, with strong well control," he said. "To be totally candid, in the deals we've done, most of the focus has been on adding additional inventory in the core."

While Northern has plenty of largess, like other companies it has noncore acreage, much of which has zero ascribed value to it—though it appears promising.

But Northern's data also show that what is considered core and noncore is a matter of perspective.

"Is it what we deem as core? Not always. But new areas are often what a core well was three or four years ago," O'Grady said. "We always tell people that our view is that there's the rock and there's the operator. The rocks definitely vary in quality, but we believe that the performance is driven by the quality of the operators as much as the rock."

In January 2019, operators set a record by producing an average 1.4 million barrels per day, 96% of which were from the Bakken and Three Forks formations.

While the results in other areas are encouraging, it doesn't mean extension areas won't be sensitive to oil prices. Extension wells also tend to decline more sharply or have higher water cuts.

On a broader scale, O'Grady said that even if core wells were to show no major improvement, successful extension wells that the company participates in are getting materially better.

"And we think many operators within the core continue to refine their techniques. If they're catching up to the best practices, that in turn means there's still room for the average well to continue to get better," he said.

In May, KKR and Western Natural Resources LLC entered into a partnership to acquire producing and undeveloped oil and gas assets in the Williston Basin.

Velie said that privately funded ventures may have more of a presence in the Bakken because, with oil prices suffering, "these assets are probably getting picked up for what, in historical terms, would be very favorable terms."

While new entrants may be scouting the Bakken, it's likely that more private-equity-backed teams are looking for an exit, O'Grady said.

"I think it really depends on how they're capitalized and if there is a clock on that capital," he said.

Private companies also don't face the pressures of fitting an acquisition in with a narrative or lining up the company balance sheet.

"They can act on strictly an economic basis that doesn't have to fit with a narrative of the broader company that has to report publicly," he said.

Below, a historic cabin, built in 1895, sits near Iverson Road in Williams County, N.D. Facing page, West of Ray, N.D., in Williams County, a vintage truck carrying a cheeseburger and fries display is parked in a field as an advertisement for Mattie B's restaurant.

With the public markets in disarray and credit markets souring, A&D has stagnated to some degree in the Bakken as well as other plays.

"That's not Bakken specific. That's really oil and gas specific. And I think there's less new capital in general, public or private," O'Grady said.

In the Williston, Northern Oil and Gas estimates $5 billion worth of nonop packages are up for sale, including a large percentage that is tied to private-equity money or is distressed.

"We see all these packages when they're being shopped," he said. "And what I tell you is that a lot of them are not trading because often the prices have gotten low enough that a lot of people have not been willing to accept where the market prices are today. We deal with it every day. We continue to raise our return thresholds, because the clearing price has been falling."

Nevertheless, money always flows into the basin, where its maturing properties appeal to certain types of investors.

"These assets are generally producing cash the day you buy them, but without the data and experience it would be very easy to make poor returns on capital," he said.

But private equity's problems are mounting. "I think that there is a coming storm in which some of these funds have to ultimately monetize their assets due to fund life issues," he said, noting that Northern sees some of the same assets come to market in two or three failed processes and the price keeps going down.

That's worked to Northern's advantage. "Not even four years ago, to get acreage in the Bakken you would have paid PV7 or PV8 for the PDPs, and then had to pay a per acre or per location value to everything that was undeveloped, despite minimal well control," O'Grady said.

In today's market, it's not uncommon to buy a well and get several locations thrown in so an operator, mineral owner or family office can be free of its capital obligations.

The Bakken is genuinely a money-making business now, he said.

"If you have the engineering and technical expertise, you can go and buy things with a true private return … earning a solid return on capital," he said. "Any development you get is generally just gravy to that. That is not the way this space has been for the last 10 years since shale took off. I've covered this space for 18 years, and I haven't seen this since probably 2002 or 2003."

Hamm said that private-equity teams also weren't a factor early in the Bakken, and most leases are held by eight to 10 large companies.

"I wouldn't say that nobody's for sale," he said. "I mean people do that. But you don't have as many of the private equities up there in that field just because it wasn't the flavor of the day."

And the real players, including Continental, are in the basin to stay.

"We made it work and were willing to stick with it," he said. "The evolution that you see today, you know, we're that evolution. I'm not sure it's complete, but we're beginning to level off here at the top." □