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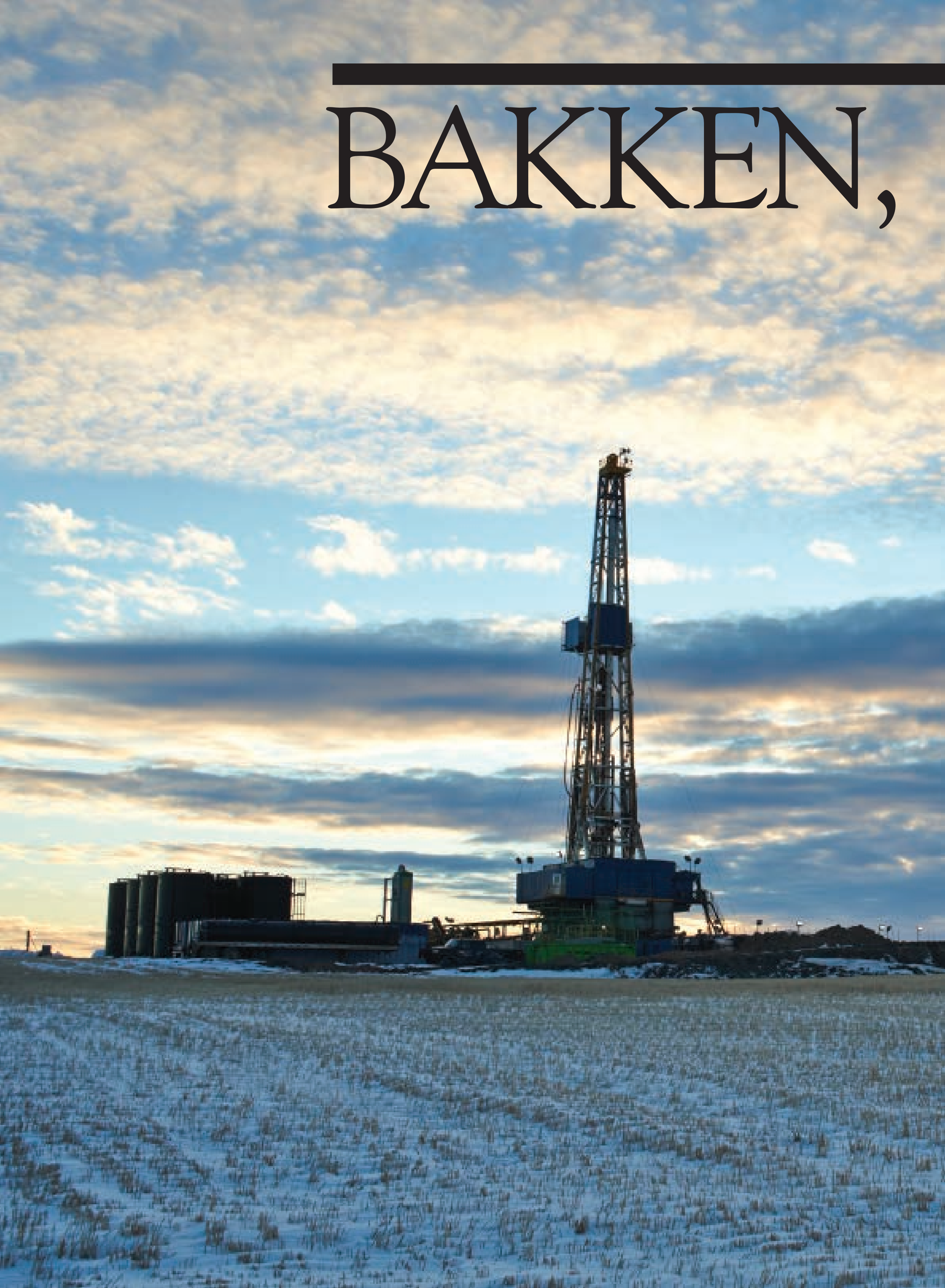
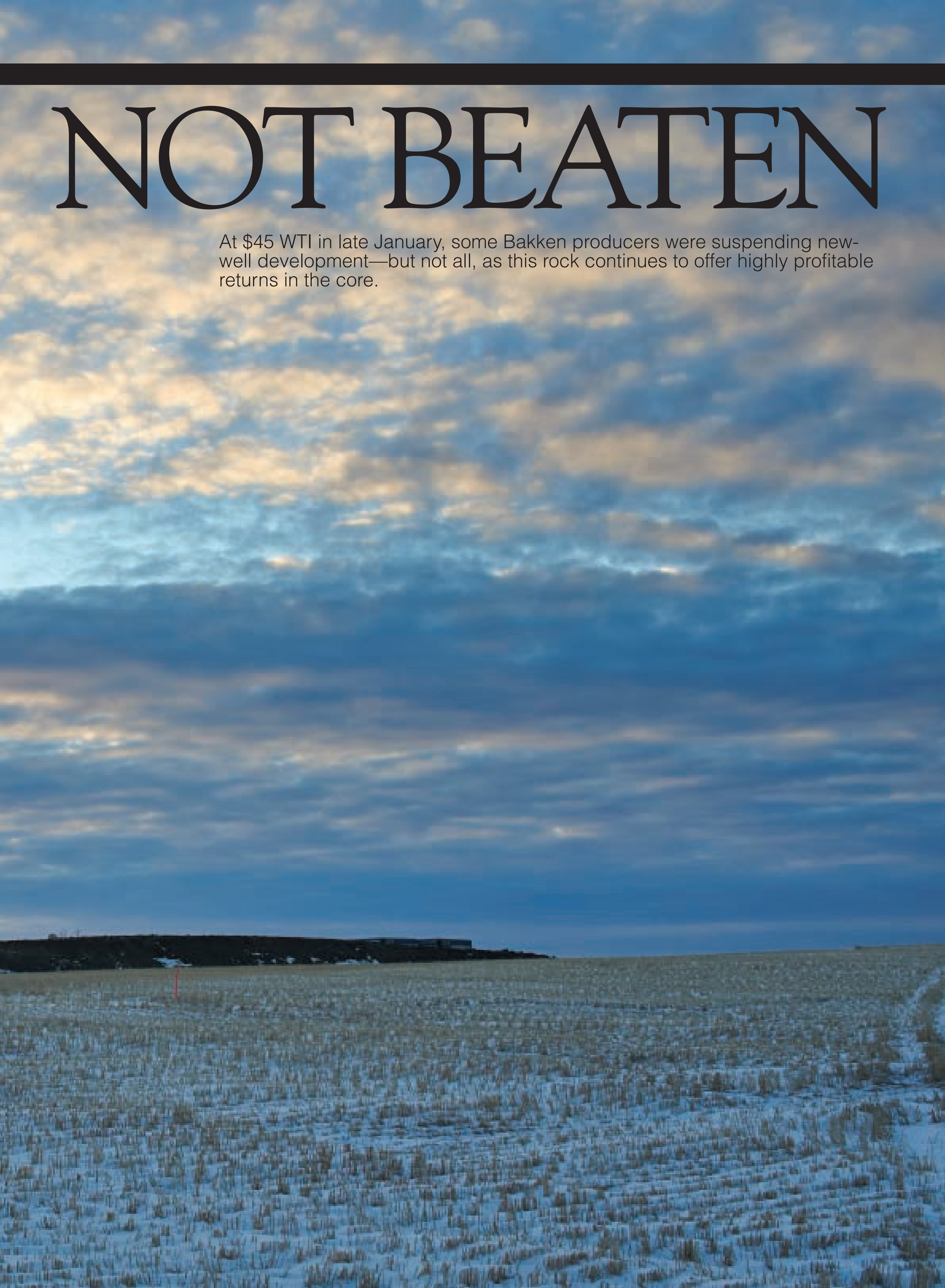


NOT BEATEN

At $45 WTI in late January, some Bakken producers were suspending new-well development—but not all, as this rock continues to offer highly profitable returns in the core.



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Greg Hill couldn't be more optimistic about Hess Corp.'s portfolio and personnel. "I'd put us against anybody," the president and COO said in late January shortly after the company's 2014 year-end earnings call.

Hill had also just spoken to members of the Louisiana Midcontinent Oil & Gas Association during the group's annual meeting. How were folks doing in Louisiana? "They're struggling—just like anybody—with where this is going," Hill said.

"But this is an amazing industry. It is probably the most resilient in the world. It's the only industry that can respond to these shocks and survive. It's a phoenix. It survives and innovates its way to prosperity."

Innovation certainly applies in North Dakota, where soaring oil output has created new prosperity. Looking at the North Dakota Department of Mineral Resources' (DMR) map of well paths in the state, one- and two-sections swaths are striped with lateral wellbores. Many travel from a single pad and cascade.

From these, producers made 1.19 million barrels of oil a day (bbl/d) from more than 11,900 wells in November—the last month for which the state had released data by late January. The production was No. 3 to Texas' 3.4 million a day in November and the federal-water Gulf of Mexico's 1.38 million, according to EIA data.

It represented 13% of the U.S. total of 9.02 million a day—an amount approaching the U.S. peak of 10 million a day in 1970. In 1984, when North Dakota's oil output first peaked, its 148,000 bbl/d was 1.6% of the U.S. total.

Among North Dakota's nearly 12,000 wells, 8,640 were producing from the Bakken petroleum system, which also includes the Three Forks and Sanish formations. Representing 72% of the state's producing wells, these were making 95% of its daily oil. The average per well: 130 barrels daily; the balance, 19.

On Jan. 14, however, the day of DMR director Lynn Helms' monthly report, he noted the wellhead price for the state's light, sweet crude was $29.25. It was the lowest since December 2008, he added, which was during the 2008-2009 financial-markets crisis.

Lean manufacturing

With WTI at about $45 and Hess netting some $10 below that, why was Greg Hill so positive in January? Hess was ready for this, he said. "We have a strong balance sheet and a resilient and flexible portfolio."

The company announced its Bakken spend in 2015 would be $1.8 billion, with about a third of that in this quarter while finishing up a 14-rig program and, then, paring to eight for the balance of 2015; fourth-quarter 2014 drilling consisted of 17 rigs.

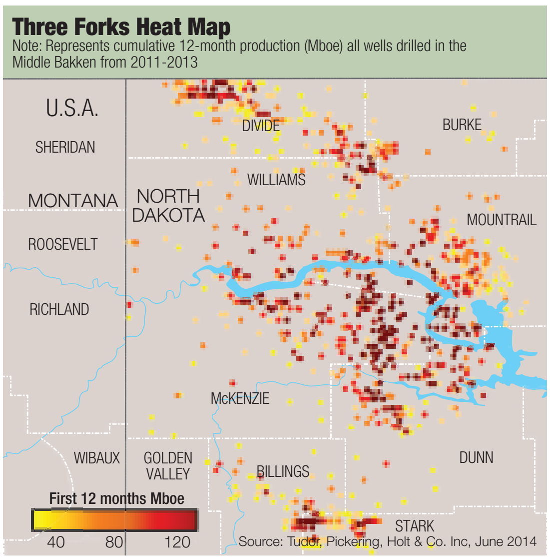
Even with a 2015 average of 9.5 net rigs at work for Hess, however, it expects to drill 180 wells and complete 210, including 50 wells that were waiting on completion at year-end 2014. Its 2014 drilling and completion program brought 238 wells online. Average daily net production this year will be 14% to 27% more on an annualized basis than in 2014, Hill said.

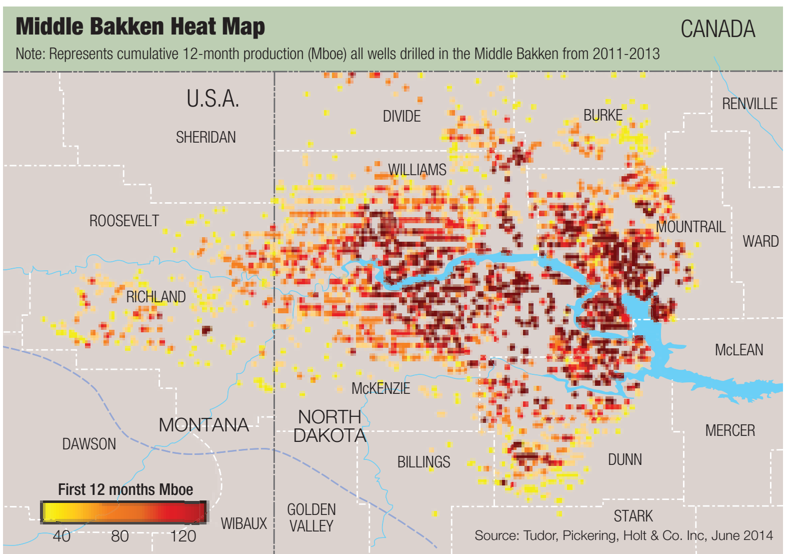
How does that math work—nearly as many wells with roughly half the rigs? It is a result of efficiency gains, he said. "We expect to drill approximately 20% more wells per rig in 2015. So that's 18-plus per rig in 2015 versus 15 in 2014."

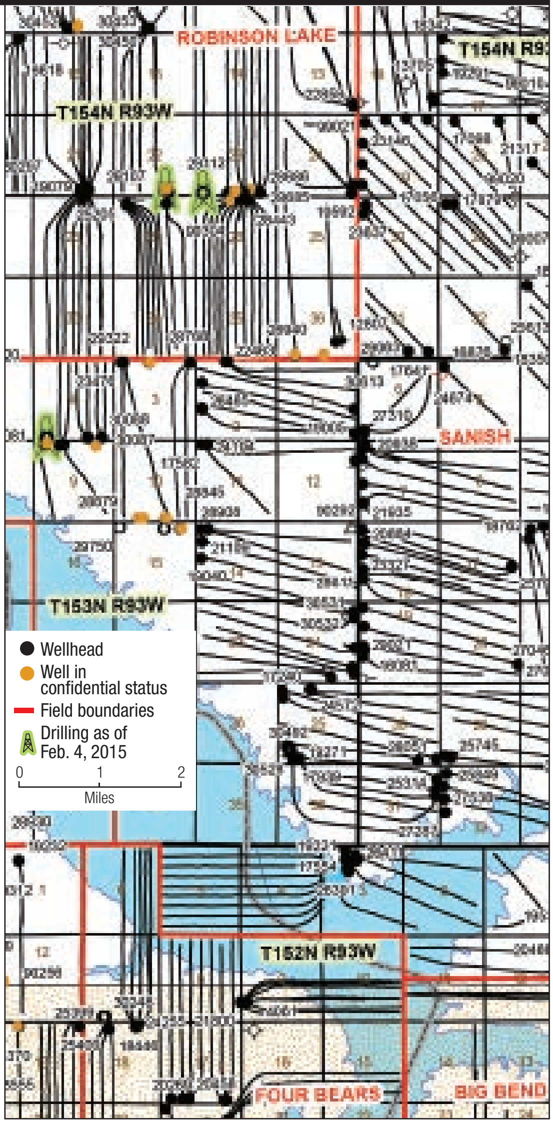
The rigs that will continue to work will drill in the sweetest spot—that is, Tier 1—of Hess' 613,000-net-acre position in the play. The company intends to keep its assembly line working. "You have to maintain that capability. As we talk to investors, the question is 'why not just cut the Bakken out?' Well, you lose capability."

Hess has been employing the "lean manufacturing" method in development of its Bakken position. "You have Bakken rigs on pads, so they 'walk.' But, if you have to move that rig

Less tapped to date, the Three Forks pay zone is demonstrating high-volume wells underlying the Bakken in the Williston Basin's center. Overleaf, Nabors Industries Ltd. drills for Whiting Petroleum Corp. in Sanish Field in Mountrail County in mid-January. Facing page, completion work on three Three Forks wells in Sanish Field.







Horizontals in Sanish Field and the area number as many as eight, at times, from a single pad, according to an early-February, North Dakota Department of Mineral Resources map. Additional well density is expected from downspacing in the Bakken and from landing a growing number of laterals in the underlying Three Forks.

and that fracturing operation to another pad, that takes about 1,000 truck loads," Hill said. "You have to remove any inefficiency in the logistics of doing that—trucks showing up when they shouldn't, equipment showing up late. You try to keep this line going with no waste.

"You can find a lot of waste in an inefficient flow of manpower, materials, equipment, supplies. We've been knocking out \$100,000 and \$200,000 a quarter consistently in our well costs just by attacking these things. There's not one thing you can point to; it's a lot of things that add up to big numbers."

Hess' first-quarter 2013 Bakken D&C cost per well averaged \$8.6 million; in fourth-quarter 2014, \$7.1 million. The company aims to preserve the operational gains. "Lean manufacturing depends on the supply chain cooperating with you. Let's say people gut their unconventional business. The restart costs are going to be significant."

Re-enlisting talented personnel may be most difficult for the industry, he added. "There are a lot of new people in this business who have never been through these downturns. Attracting them back could be difficult. And it happened so fast: There are people who had jobs in this industry on Thanksgiving Day; by Christmas, they didn't."

To defer or not to defer?

North Dakota's backlog of wells needing completion totaled 775 at the end of November, according to Helms' mid-January report. Warren Russell and Michael Cohen, analysts for Barclays Capital Inc., noted at press time that only 39 wells were completed in November compared with 272 in August, 193 in September and 145 in October. The November completions were about as few as in January 2014, when temperatures and wind prevented work during 15 days, according to DMR reports.

Helms noted in January that there were 11 days in November of wind of greater than 35 mph, which is too strong for safe completions work, and seven days of temperatures below 10 degrees Fahrenheit, which is too cold to successfully move completion fluids.

The rig count had fallen by 25 since November, he added, to total 156, down from 191 in October.

"Oil price is by far the biggest driver behind the slowdown," Helms reported. As for completions, "operators report postponing completion work to avoid high initial oil production at very low prices" and while working to place gas-capture infrastructure to meet North Dakota's flaring-reduction rule.

Hess' Hill said that deferring completions—in the Bakken or elsewhere—makes no sense. "I've heard people talk about that. That's purely a cash-flow management kind of strategy. But you've already got half of the well's cost sunk. For it to sit there idle with no revenue doesn't make any sense from a return standpoint. You're much better off just completing it and getting it onto production."

While Hess won't defer completions, paring back drilling does add up. "[On] an unconventional well like in the Bakken, 70% of the NPV is generated in the first three years. Outside the core of the core, it just makes sense to defer until the price comes back up—and we believe it will come back up."

As for operators who are canceling rig contracts, Tudor, Pickering, Holt & Co. (TPH) analysts reported in late January that they were "still floored that [Helmerich & Payne Inc.]—the largest U.S. land driller and the land-drilling industry 'gold standard'—is guiding its first-quarter, U.S., land-revenue days down 25% quarter-over-quarter."

The analysts said they were revisiting their own "overall U.S.-land-rig-count decline—i.e., trajectory and magnitude—assumptions as well."

But the cost of canceling rig contracts may pay off in a \$45 WTI environment, they added. The fee for terminating the contracts is a small part of the well's total cost. "For example, on a Bakken well costing some \$10 million, even a rig with a high $20,000 dayrate only represents a little over 5% of the well cost," they reported.

"With low oil prices, why would an E&P obligate itself to spend the other [roughly] 90% of the well cost just because a rig is contracted? The … buyout is typically the remaining cash margin on a contract, so early terminations cost some $5 million per year of contract remaining for many rigs. [It's] not too onerous."

D&C

While Hess is working to lower its Bakken cost on the supply-chain management side, it is also working on improving well performance. It operates 1,150 Williston Basin wells and has a nonoperated interest in 914 others. "We know we are drilling some of the lowest-cost wells in the play," Hill said. "We also know our productivity is well above average for the industry, and that's not just due to geological position."

Hess is finding success with the use of sliding sleeves in its completions. "It is really conducive to lean-manufacturing techniques."

Also, it is advancing in geosteering the lateral. "The Bakken is about 45 feet thick on average, but there is a sweet spot within the zone. If you are able to keep your completion within that zone—and we have the data to prove it—your IP [initial production] and your EUR [estimated ultimate recovery] can be up to 20% better by geosteering.

"We're using seismic, MWD [measurement while drilling], all the tools we can to highly geosteer the well to make sure we are staying in the absolutely best part of the reservoir. It makes a huge difference to the productivity. We're the only ones doing that to this precision."

A six-TPH-analyst group, led by Matt Portillo, delivered a "There and Bakken Again" report in June, analyzing well performance, new completion techniques and what additional downspacing is possible in the play. They reported, "Even after more than 5,000 wells have been drilled in the basin, operators are still modifying completion designs … with a particular interest in slickwater fracks and large increases in smaller-mesh proppant."

As for density, they reported, "it is still relatively early days on many of these tests, but it increasingly feels like 10-plus wells per DSU [drilling-spacing unit] will work across a majority of the basin." Their estimated potential at the time was for four to 15 wells per two-section unit, including wells in the Middle Bakken and in the underlying Three Forks benches.

Hess was experimenting with coiled-tubing completions that include cemented liners and sliding sleeves in a couple of wells at press time. Hill said he found the technique intriguing, but it's early yet for Hess to convert to it. The technique has been cited as potentially troublesome when completing a lateral that deviates greatly.

Hill said, "It all works as long as everything goes well. The tensile strength of coiled tubing is not that high. If you have to pull on it hard,

Greg Hill, Hess Corp. president and COO, says the core of the Bakken core remains profitable at $45 WTI and is where the company will focus its oil-manufacturing operation for now. Below, artificial lift on the Mary Elizabeth 13-13 extended-lateral Three Forks well. The well has made some 141,000 barrels in its first 32 months online.

you're going to part it. As long as everything goes well, it's going to work, but we're going to have to get a lot more experience under our belt before we convert to it.

"If it's a breakthrough, then we're going to go for it. That's all part of lean manufacturing as well—looking for the next breakthrough."

Coiled-tubing fracks

Whiting Petroleum Corp. has reported success with its trials of the coiled-tubing technique. In June 2014, it fracture-stimulated Waldock-Federal 14-4-3XH in Sanish Field in Mountrail County with coiled tubing—in 93 stages—with 4.12 million pounds of 20/40 sand and 96,503 barrels of water, at up to 21 barrels a minute and up to 4,634 psi in the roughly 9,000-foot lateral.

A 24-hour test on a 26/64-inch choke produced a modest 365 barrels from the Middle Bakken member. Cumulative production in the well's first 123 days was 68,543 barrels, however, or an average of 558 bbl/d, according to state files. (Whiting hosted this month's cover shoot but it and many other operators were unable to comment as they had not yet released 2015 guidance by press time.)

Oil and Gas Investor reported of the Waldock well, "All 93 stages were fractured in a single, continuous operation without tripping the frack-isolation assembly out of the hole."

Whiting revealed the Waldock results in late July, adding that "a key benefit of coiled-tubing fracks is cycle-time efficiencies in high-well-density areas. Without the need to drill out the plugs, we have been able to accelerate production by five to seven days per pad where we have tested it in the Williston Basin."

In October, it reported trials in McKenzie County southwest of Sanish Field. Designated as Twin Valley Field by the state, Whiting refers to the area as its Tarpon Field. Four of its five wells that were landed in Bakken there in 2012 IPed between 4,400 and 5,000 barrels of oil. It returned to the field in 2014 with five more wells with four of these landed in Three Forks. Two IPed between 4,500 and 5,000 barrels. Cumulative production in these wells' first five months online was 161,000 barrels and 194,000 barrels.

However, the other three—Flatland Federal 11-4HR in the Middle Bakken, 11-4TFH in the upper Three Forks and 11-4TFHU in the Three Forks' second bench—came on with 7,120 barrels of oil equivalent (boe), 7,824 boe and 5,930 boe. (The figures are from a Whiting press release; the Flatland well files were on "confidential status" with the state at press time.)

The Middle Bakken well was completed with a cemented liner and coiled tubing in 94 stages on Oct. 11. The second, with cemented liner and coiled tubing in 104 stages the following day. The third, the next day, with plug-and-perf and five frack clusters per 30 stages, for 150 frack points.

A Google Maps satellite image of the area in late January happened to have been shot during the frack job. Awaiting the anticipated oil was a battery of 28 tanks.

Completed cost

The completed wells' cost is roughly the same—between \$8- and \$8.5 million—Jim Volker, Whiting chairman, CEO and president, said in an October earnings call, according to a SeekingAlpha.com transcript. An analyst asked if the coiled-tubing technique works in every field. "I mean, some of those wells are just huge," he said.

Mark Williams, Whiting senior vice president, exploration and development, said it varies with geology.

Far west, the company varied completion techniques in three new Skov-lease wells in Richland County, Montana, in early 2014. Two of these employed a cemented liner and IPed 1,072 and 1,219 barrels. A third well was fracked in 85 stages using a cemented liner and coiled tubing; it IPed 1,607 barrels. Whiting reported that it also employed more sand—between 50% and 100%—in the wells than the roughly 2 million pounds used in a 2013 Skov-series well, which IPed 927 boe.

Volker said in a May call that the coiled-tubing process, coupled with the cemented liner, provides an understanding of the effectiveness of where the hole is being stimulated. "It's empirical because it can only go out one … place. When you open that port up, it has to go out there. You've got cement behind the pipe. There's nowhere else it can go but out into the formation.

"Microseismic is a great tool for being able to tell us the overall area that we're affecting by our fracks but … we can tell by our pump schedule, essentially, exactly how much frack volume is going out in each … of those perforations. So there's no guesswork involved. It's pretty direct."

The tubing also allows for fluid circulation, so premature screen-outs can be resolved quickly, according to Warren Williford, marketing director for the method's developer, NCS Multistage LLC. "The coiled tubing also serves as a dead string," he told *Investor*. "The completion team can see real-time pressure at the target zone and adjust flow-rate and proppant concentration on the fly to optimize proppant placement."

The current depth limitation for the system is that reels of coiled tubing are about 20,000 feet. With the Bakken at more than 10,000 feet in the basin's center, a reel might be shy of reaching the toe of a two-section lateral, which is up to an additional 10,000 feet. For these, operators have used an NCS hybrid system of cemented ball-shift sleeves placed beyond the tubing's reach.

The system is fast, though, he said. *The Bakken* magazine cites September remarks by a

Facing page, the view of the Missouri River and Fort Berthold Reservation at the New Town river crossing on State Highway 23. Drilling in the distance was Cyclone Drilling Inc. Rig 14 for Continental Resources Inc. in Antelope Field, McKenzie County.

Above and at right, workers at a zipper-frack job for Whiting at a three-well pad in a hollow in Sanish Field. Discovered by Whiting in April 2006, Sanish Field produced 103 million barrels of oil through November.

Whiting operations manager, Monte Madsen, to North Dakota Petroleum Council members in an annual meeting. The system doesn't use pumped-down balls or plugs, so "there is nothing to run in the well between fracks. [There is] nothing left in the well and nothing to drill out. [It's] just an open, production-ready wellbore," Madsen said.

Flex, flaring, conditioning

Hess' Bakken spend will be 38% of its 2015 capex budget and it expects 2015 production of between 95,000 and 105,000 net barrels daily, compared with a 2014 exit of 102,000 a day. Hill said its manufacturing program in North Dakota balances its long-lead-time commitments in the deepwater Gulf of Mexico.

"You have these onshore businesses you can dial back in a lower-price environment and these offshore assets that generate a huge amount of cash flow. The offshore assets are really what carry you through the lean times."

The company's several-year Tubular Bells development in the Gulf commenced production in November and is expected to produce between 30,000 and 35,000 net boe a day this year—the equivalent of about a third of Hess' net production from its 2,064 operated and nonop Bakken wells. Hess is operator of Tubular Bells with a 57.1% working interest.

"What I like about unconventional is just what we're doing today," Hill said. "I can scale it up and I can scale it back. That's different than an offshore asset. Once you commit to those, they're not going to stop. You're in. If you're overextended, that can put a lot of stress on your balance sheet.

"The unconventionals provide that flex in the portfolio."

He added that Hess is advantaged in the Bakken by having gas-capture infrastructure. Beginning in 2012, the company has spent some $1.5 billion on gas takeaway and on a processing plant in Tioga "so, from a flaring standpoint, we're in great shape."

The company expects it will be flaring no more than 10% of Bakken and Three Forks

wells' associated gas by 2017. The plant can process up to 250 million cubic feet a day, producing about 35,000 bbl/d of NGLs. Among the products, Hess is selling the ethane to Nova Chemicals Corp. in Sarnia, Ontario. "For everyone else [in the Bakken], that ethane is shipped down the pipe," Hill said. "We're extracting it, so we're getting additional value out of the lighter end of the gas barrel as well."

The contract with Nova has a price floor, "so we will never reject ethane. It's pretty much just an all-upside contract."

North Dakota adopted a new oil-conditioning rule in December to reduce the volatility of the crude the state produces. The rule is to take effect April 1. (Helms' office did not reply by press time to a request for a statement on whether the oil-conditioning rule would be postponed. A Bakken producer said in Houston in mid-January that, with this rule and the existing, increasingly strict, gas-flaring rule, "they really shot themselves in the foot.")

Hill said it isn't an issue for Hess. "There have been multiple industry studies that show Bakken crude is similar to other light crudes produced in the U.S.; therefore, you really don't need further stabilization as long as you operate well. We believe we can meet these guidelines just through normal operating procedures.

"You have to run your heater treaters at the right temperature and pressure. Crude-stabilization facilities—not necessary."

Whiting's Barb W., Earl T and JB 11-6 wells were each landed in Three Forks in Sanish Field near the intersection of Lake Robinson Field.

At top, Unit Corp.'s Boss Rig 404 drills for Whiting in Williams County along State Highway 2 northeast of Williston. Whiting gained the lease in its acquisition of Kodiak Oil & Gas Corp. in December. Randy King, a managing director of Anderson King Energy Advisors LLC, expects, at least, creeping consolidation in the Williston Basin at $50 oil.

Netbacks

Hess uses both pipe and rail in getting its crude to markets. Genscape, publisher of *Petro-Rail*, reported in mid-January that Bakken oil was getting $47.81 at EOG Resources Inc.'s rail terminal near Cushing, Oklahoma. Meanwhile, Bakken was getting $49.17 at Anacortes, Washington; $52.14 at St. James, Louisiana; $52.42 at Albany, New York; and $53.27 at Yorktown, Virginia.

Hill said pipe-only takeaway would limit the price Hess gets to what that geographically fixed end-market will pay. Rail has allowed the company to ship to the East, West and Gulf coasts. "We've always believed a flexible infrastructure is a better infrastructure. We wanted the ability to get our crude oil to the best markets."

Overall, the company produces higher Williston Basin netbacks via its use of rail and its extraction of ethane from the associated gas. "So we've got the lowest cost in the industry, some of the best productivity and we have netback advantages. Those three reasons are why we're pretty darned confident we have the highest returns in the play."

Simmons & Co. International Inc. equity analyst Guy Baber wrote prior to Hess' earnings report that it was "a relative favorite within our coverage universe versus comparable North America-levered E&Ps." Hess' portfolio-wide, $4.7-billion capex plan is an out-spend of its 2015 estimated cash flow.

"On the more positive side, Hess has a rock-solid balance sheet … which should help the company navigate the current environment," Baber concluded.

Hill said, "We've been able to cut our D&C cost 47% over a three-year period while drilling and completing wells that are twice as complex, with sliding sleeves, the way we geosteer our laterals and other technology components."

Most essential has been its work toward lean manufacturing, however, he said.

Basin consolidation

Hess' year-end 2014 cash on hand was $2.44 billion; debt, $5.99 billion; and debt-to-capitalization, 21.2%. With its fiscal strength and operational expertise, would it participate in basin consolidation?

"Obviously, the adage is 'buy low, sell high.' We're always looking at opportunities," Hill said. "Clearly, multiples are coming down and some companies are getting stressed. That's going to open opportunities to us, but whatever it is has to make sense, from a financial standpoint, and it has to strengthen our portfolio."

That same day, Randy King had time to talk about basin consolidation. Managing director and co-founder of Anderson King Energy Advisors LLC, the 35-year-plus M&A advisor noted that deal-making had gone dark in the midst of a three-year strip in the $50s.

But he saw a light. "This is a pause that refreshes. It might be too optimistic to say, but you're going to have some real benefits with cost structure that come out of this," he said. "The whole administration of the business—land, the back-office work—is running months behind on some of these plays. You've got to catch up."

Slowing down may enable improvements in well performance, he added. "You're going to

Steve and Sarah operate the popular Red Hot Chuckwagon oasis at the intersection of Bureau of Indian Affairs roads 12 and 14 on the reservation in Dunn County, east of Mandaree. It's the best—and only—food on BIA 14, Steve noted.

get more light shed on the type curves on some of these plays. Slowing down, you'll see more individual-well performance and maybe make better economic judgments going forward.

"We're focused more on the pain now, but I think companies come out of this in a stronger position, knowing where and how to best exploit their assets."

In terms of Bakken transactions, in particular, King expected "creeping consolidation" of fragmented, nonoperated interests. These interest-owners "are going to be challenged to keep up with [the spend by] the larger operators in this time frame. You may grow your position just by picking up non-consents, expired leases, tactical things, and not necessarily with massive mergers.

"There are ways to pick up additional interest here by being a little more well-heeled on the capital side."

The opportunity might be brief, though, according to Richard Forrest, global lead partner, energy, for consulting firm A.T. Kearney Inc. The firm reported in late January that "analysis and discussions with industry executives revealed the likely onset of a new wave of mergers and acquisitions across the value chain in the next six to 12 months."

Forrest added, however, that "the window of opportunity may be shorter than expected and will be driven by oil-price expectations."

King knew in January of several mergers that would make sense, but the ones that are most likely are mergers of equals, he said. "These are no-premium deals. It's hard for companies to come around to these, but you're merging for when the upturn occurs. You will be in a better position. There are folks who ought to be considering this, particularly smaller guys that have good assets and can live longer and have better liquidity down the road if they could consolidate."

But, he added, "that requires a maturity and self awareness that is hard to come by in this marketplace."

Debt markets

Should this cycle continue into the summer, might some publicly held operators be compelled to merge?

"If you're in a situation with bank debt, you're under the gun with redeterminations," King said.

Meanwhile, an advantage many operators have currently is that they accessed high-yield debt with favorable terms. In 2011, 97% of E&Ps' new bond issuances were over 50% call protected; this past summer, 93% were under 50%, according to a KeyBanc Capital Markets Inc. analysis. Eight-year bonds were commonly carrying at least a three-year call protection.

King said, "So they're not under near-term pressure to refinance those. It's a blessing in weathering the downturn."

But it is also a curse, he added. "It's a bit of a poison pill for doing consolidations because, in a consolidation, the survivor takes on the full measure of the obligation."

TPH analysts reported in late January, "Operators with positions in high-cost basins and/or [having] highly levered balance sheets have seen yields expand on the margin over the last few weeks with some bonds trading at 35 to 40 cents on the dollar. [We're] watching yield spreads as E&Ps slash budgets closer to cash flow."

King said, "Prices for high-yield notes are starting to weaken quite a bit. The most clever thing to do is, if you have a target, buy their notes at a heavy discount and use that as your leverage to do a transaction. But it's a rare event."

Operators themselves would be hard pressed to try it, considering that what cash on hand they are able to continue to generate must most likely be devoted to keeping production up. Instead, King said, "you really need the help of the distressed-debt experts. Potentially, they may come along beside you as a partner to facilitate that kind of transaction. I think we're

A traveling fireworks stand is parked in Mandaree for the off-season. Far right, pipelaying where BIA 12 ends at the Missouri River. At right, steel-toe oilfield boots top fence posts along State Highway 1804 east of Williston.

going to see some of this. That's true financial engineering in a positive way in this marketplace."

May private-equity funds join in buying debt on sale too? "It's a great entry point and it takes some courage: You have rights and obligations, but you're not in control of the board. You're not an equity-holder; you're a passive creditor.

"But it can be a great investment. Also, if the distress continues longer than anticipated, it puts you in a position to be able to help with a positive restructuring. I love the idea. I suspect there is a lot of work being done to identify targets along those lines. It's really interesting times."

How long?

Another leading Bakken operator, ConocoPhillips Co., reported in early January that, overall, its annualized net-income sensitivity is \$35- to \$40 million per \$1 change in WTI and WCS and \$80- to \$90 million per \$1 change in Brent. In late January, it reported plans for 33% less capex spend in 2015 than in 2014. Its new budget: \$11.5 billion. The portion for U.S. onshore was cut to \$3.6 billion from the \$5 billion of 2014. Its Lower 48 rig count was pared from 34 to 13.

Among those, six will drill the Eagle Ford; three, Bakken; and four, Permian. The drilling is primarily "aimed at maintaining leasehold and upholding contract commitments," TPH analysts reported. Jefferies LLC analysts Jason Gammel and Marc Kofler noted that the E&P's major projects elsewhere—offshore and abroad—require a 2015 spend of \$2.5 billion. Some \$2 billion of this will become available for its unconventional programs in 2016.

ConocoPhillips' North American average wellhead breakeven price in its unconventional plays—from South Texas to western Canada—is under \$40 a barrel, it reported. It also cited its North American unconventionals as producing its highest-margin full-cycle project returns. However, these also produce its highest decline rate, it added.

King noted that he has seen many shale-play decline curves while advising in E&P transactions. "They fall off very rapidly." In the Bakken and Three Forks, for example, among the 8,640 producing wells in November, the average production was 130 bbl/d. This includes wells ranging from Whiting's that IPed more than 7,000 bbl/d in October and, for example, EOG's 2006 Parshall Field discovery well, Parshall 1-36H, that was producing 45 a day in November.

King said, "If the industry does slow down materially with reduced cash flow and a lack of fresh capital from the markets, the supply side of this does heal itself pretty quickly."

Once the new supply that is already under way is worked off, "and that is the \$64,000 question when that occurs, I think the base decline in the U.S. is probably 20% to 25%. So it does heal itself pretty quickly."

But do operators just push that production number right back up to 9 million a day? A Jefferies LLC estimate this past summer was that a sampling of just 12 onshore-U.S. operators alone had inventory of between 7,900 and 66,000 well locations.

King said, "There is a risk of that. But you have to have capital to do that. This cycle will impact capital availability for a while."

Equity and debt markets will reopen to U.S. producers at some time in the future. "It won't be instantaneous, but we have inventory and skillsets that are more manufacturing in nature and can be restarted, so it's not without future volatility."

Some weeding may be good for the business, though. "If we were to stay in this price in all of 2015—which seems like a long time—we would probably position ourselves to come back even stronger. The marketplace will realize you need a robust industry to keep oil production up in the U.S.; it falls fast without it." □