HART

Bakken Shale

The Play Book

A supplement to

Oil and Gas Investor

E&P

PipeLine and Gas Technology

Bakken Shale: *The Play Book*

A supplement to *Oil and Gas Investor, E&P* and *Pipeline and Gas Technology*

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Cover photo courtesy of Sundance Energy Australia Ltd.

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Photos by Lowell Georgia

The Bakken

Horizontal drilling in North Dakota's enormous Bakken resource play is yielding astonishing volumes of oil.

By Peggy Williams,
Senior Exploration Editor,
Oil and Gas Investor

The first impression a newcomer has of North Dakota is the immensity of its white-blue sky. This is vast and open country, a land of bountiful wheat fields, wondrous badlands, and unbroken vistas.

And, beneath the wide plains of the Roughrider State lies a resource that displays the same grand scale. The Williston is the largest sedimentary basin onshore the US, and it contains the largest undeveloped oil play in the nation. The Bakken resource resides in a complex shale reservoir composed of interbedded sands, silts, dolomites, and limestones.

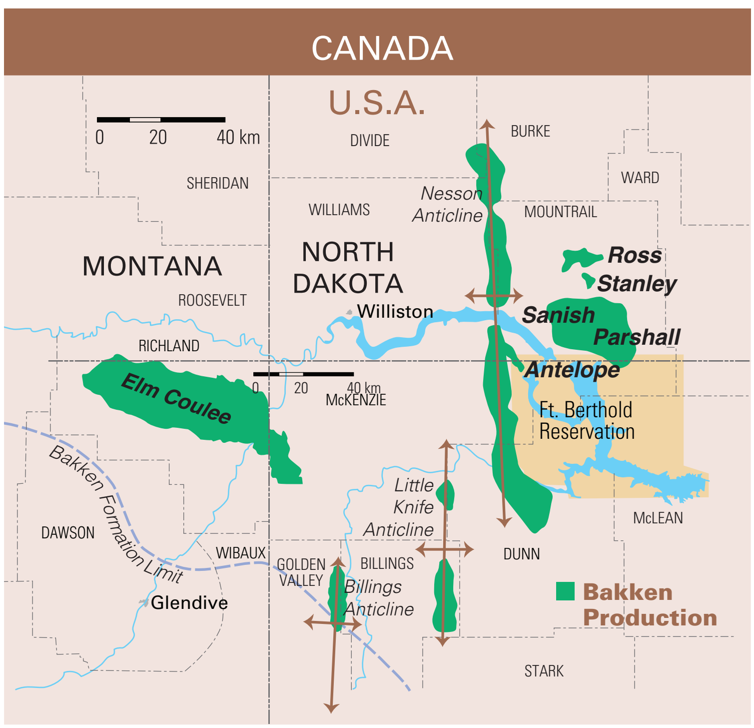
The extent of North Dakota's Bakken play is phenomenal — it stretches many miles across rolling prairie, from Columbus to Killdeer, and from Williston out past Stanley and down south of New Town. Indeed, the U.S. Geological Survey (USGS) recently estimated that the Bakken contains mean undiscovered volumes of 3.65 billion bbl of oil, 1.85 Tcf of gas and 148 million bbl of gas liquids. These are technically recoverable volumes, spread across a resource that covers some 25,000 sq miles, including portions of eastern Montana. In addition, southeastern Saskatchewan holds another 1.3 billion bbl of technically recoverable Bakken oil.

These days, big triple rigs punctuate the broad Dakota skies. The play is booming: more than 60 rigs are at work in North Dakota's Bakken play, and wells are being drilled and fractured, tanks are being set, gas plants are under construction, and pipelines are being laid. Yet, the wide spacing of the big horizontal wells — they stretch up to 9,000 ft laterally at vertical depths of some 10,000 ft — means that the activity is still dwarfed by the rolling grasslands.

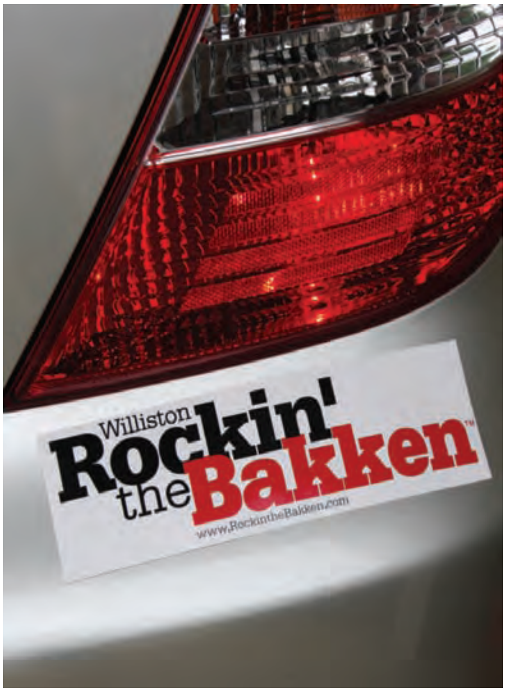
North Dakota had its first love affair with the Upper Devonian/Lower Mississippian Bakken shale in the early 1950s, when production on the crest of the great Nesson Anticline was discovered. This long, narrow structural feature collected Bakken-generated oil in several formations. Vertical wells at McKenzie County's Antelope Field produced strongly from fractured Bakken shale and underlying Sanish sand, but across most of the area the Bakken served mainly as a stand-in when other objectives faltered.

The next flirtation teased in the late 1980s when horizontal-drilling technology was tried in the Bakken shale. Drilling centered on the Billings Anticline, another regional structural feature that trends through Billings, Golden Valley, and McKenzie counties. Some 30 million bbl of oil were produced from horizontal wells in the upper, shaley member of the Bakken. The thin, organic-rich source rock appeared

Operators brought drilling and completion techniques that were successful in Montana to North Dakota's Bakken play.



Town officials in Williston, North Dakota, freely hand out bumper stickers promoting the Bakken boom.



A fresh-caught sample shows the high quality of Bakken crude.

to be a good target for horizontal wellbores, as the laterals could intersect natural fractures that provided conduits for oil.

These early horizontal Bakken wells didn't access enough crude, however, and the play withered when oil prices fell below US $20 per barrel. The natural fracture systems that supplied the Bakken's permeability were just not widespread enough or predictable enough to support a commercial play. Peak Bakken production rates reached 10,000 b/d in the early 1990s, and declined steadily thereafter.

The current blossoming of the Bakken began to unfurl in 2000. Near the southwestern edge of the shale's extent, in Richland County, Montana, operators began to drill horizontal wells. The core movers in the play were private firms, so the play stayed fairly quiet.

Lyco Energy Corp., based in Dallas, launched the Montana play. The company discovered a tremendous stratigraphic trap in the Middle Bakken dolomite, a 4-ft to 15-ft interval sandwiched between upper and lower shales. Initially, Lyco drilled vertical wells, but in 2000 it spudded its first horizontal.

That well, #36-2H Burning Tree State, was encouraging. Other private operators moved quickly to capitalize on the discovery: Headington Oil Co. and Petro-Hunt, both based in Dallas, and Slawson Exploration Co. of Wichita, Kansas, built positions. Public companies such as Denver-based Whiting Petroleum Corp. and St. Mary Land & Exploration, and Houston-based Burlington Resources and EOG Resources Inc. joined in.

To date, Elm Coulee has produced more than 69 million bbl of oil from more than 580 horizontal Bakken wells. A typical well can ultimately recover 450,000 boe, and the 500-sq-mile field will likely yield more than 300 million bbl of oil. The US Energy Information Administration ranks Elm Coulee as the fifteenth-largest oil field in the onshore Lower 48.

Building Out

Enid, Oklahoma-based operator Continental Resources Inc. moved into the Elm Coulee play in its infancy. The company was looking for oil, and it liked the opportunities it saw in the Rocky Mountain region. "We were interested in the Williston, Big Horn, and Powder River basins," said Harold Hamm, chairman and chief executive. "We think oil has more intrinsic value than natural gas, and we wanted to find large fields."

Continental was already a Williston producer when Lyco's Bakken play emerged. Continental worked the Red River in North Dakota's Slope and Bowman counties and South Dakota's Harding County. It had honed its horizontal-drilling expertise in Cedar Hill Field, which it developed entirely with horizontal wells beginning in 1995.

The company favored cutting-edge technology, and it hunted places where it could use horizontal drilling to its advantage. It came across the Bakken play in Montana as the earliest horizontals were being drilled.

"In 2001, when we saw the play was likely to work, we immediately began to lease," Hamm said. Land was available for $35 to $50 per acre, and it wound up with 125,000 acres in the burgeoning field. It drilled its first well in the field in 2003, and since then has drilled more than 140 producers.

Today, Continental makes 8,200 net boe/d from Bakken wells, and about 7,000 comes from Elm Coulee. It currently runs three rigs in the field, working on infill locations. The first well in a 1,280-acre spacing unit at Elm Coulee recovers about 450,000 bbl estimated ultimate recovery (EUR), and the second about the same volume.

Last year, Continental tested 320-acre spacing, and results were robust. The infill wells have recoveries approaching 400,000 boe, substantially higher than anticipated. "We're now drilling our Elm Coulee acreage down to 320-acre spacing, and we have about 60 locations left to go," Hamm said.

Elm Coulee's Bakken also offers a tremendous EOR target. This fall, Continental plans to install both a huff-and-puff CO_2 pilot and a waterflood pilot. It will bring in CO_2 for the pilot by rail.

But the future of the Bakken lies in North Dakota, believes Hamm.

Neighboring State

Emboldened by its success in Montana, Continental moved into North Dakota in 2003. It focused its efforts along the Nesson Anticline, where the Bakken is thick, has a history of vertical production, and is naturally fractured. Initially, it put 100,000 acres together and started horizontal drilling.

This incarnation of horizontal work in North Dakota wasn't notably successful. At Elm Coulee in Montana, operators drilled dual-leg laterals, left them openhole and fractured each leg separately. "We tried that same thing in North Dakota and it didn't work," said Jeff Hume, senior vice president, operations.

The problem was that North Dakota's Bakken had a higher frac gradient than Montana's Bakken. Fracs broke up into the Lodgepole in North Dakota, and the Bakken wasn't being as effectively stimulated. Continental shifted to single 9,000-ft laterals, and started to run uncemented casing and swell packers. "We've climbed the learning curve. We stage frac with the plug-perf method, with 10 separate stages per lateral, and have plans to increase the number of stages on future wells," Hume said.

Immediately, results improved 100%. At the same time, the company continued to lease all along the trend of the Nesson Anticline, accumulating more than 350,000 net acres.

"When we went public in the spring of 2007, the Bakken was out of favor," said Hamm. "But we started making some consistently good wells, and that turned perceptions around."

In 2007, the company drilled 27 Bakken wells in North Dakota that averaged 335,000 bbl EUR each. That included the good, bad, and ugly, and they tested acreage all along its 140-mile acreage position. This year, results have been even better: consistently, across its entire area, initial production rates suggest EURs could average more than 400,000 bbl per well.

Portentous Addition

As robust as the Bakken is proving to be, Continental added to that bounty with its #1-29H Bice, drilled into the Three Forks-Sanish in Dunn County. The Bice flowed 700 b/d for its first week of production. Moreover, Continental recently announced results of another major Three Forks-Sanish success. Its #1-35H Mathistad, in McKenzie County, came online at an average rate of 1,198 boe/d. That well is 23 miles north-northwest of the Bice.

Interest in the Three Forks-Sanish is extremely high across the basin, as the implications for future production and reserve additions are considerable.

"When we took this lease position, we looked at a lot of core data. And we could see staining as much as 50 ft into the Three Forks," said Hamm. The Lodgepole is such a great seal that oil generated in the Bakken has been forced into the top of the Three Forks-Sanish, a Devonian formation that lies just below the lower Bakken shale.

Indeed, the entire interval from some 150 ft into the Three Forks through the Bakken and into the base of the Lodgepole is thought by some workers to be a unified source system, and any porous zone within that interval will be charged with oil. What's so attractive about the Three Forks-Sanish is that it can have higher porosities and permeabilities that the Middle Bakken. That can add considerable matrix storage.

The Bice and Mathistad discoveries herald this huge additional potential: "We think that the Three Forks-Sanish could be a separate accumulation, in addition to the Bakken. It could double the Bakken resource."

Support for this concept also comes from the best well in the Bakken play. In the fall of 2006, Petro-Hunt LLC completed #2D-3-1H USA in Charlson Field, McKenzie County, for 729 bbl of oil and 785,000 cf/d of gas. It featured a single, openhole lateral that extended 3,200 ft into the Three Forks. According to state records, in the 18 months from October 2006 to March 2008, the well made 437,509 bbl of oil and 538.2 million cf of gas. It still makes some 700 b/d. "It's a horse of a well," said Hamm.

This year, Continental will spend $245 million and drill 41 net wells in the Bakken, including additional tests in the Three Forks-Sanish. The company has 15 rigs working in the Bakken, a dozen of which are in North Dakota. That includes a joint venture it has with ConocoPhillips that it entered in 2006.

"We were all taught that shales were impermeable source rocks. But breakthroughs in precision horizontal drilling and multistage, high-pressure fracs at high rates have made all the difference," said Hamm. "All that technology is responsible for allowing industry to harvest the shales, and it's been done by a small group of independents."

Certainly, the performance of the stocks of the 15 independents that focus on resource plays in multiple basins has increased exponentially. "The market is paying for the tremendous opportunities that this new technology has opened up. It's a great land rush – companies are nailing down positions in plays all over the country. And the Bakken is unique among the major resource plays because it produces oil."

Whopping Discovery

The hottest area in North Dakota's horizontal Bakken play is in the vicinity of EOG Resources Inc.'s Parshall Field, a gem discovered by the operator in the summer of 2006 in Mountrail County, east of the Nesson Anticline.

In two busy years, Parshall and contiguous Sanish Field have grown to some 50 horizontal wells that make more than 16,000 b/d. Extraordinarily good Bakken wells continue to expand the accumulation, which now covers nearly eight townships. Estimates of recoverable oil are 150 million bbl at its current size, but limits are not yet defined downdip or along strike.

The first discovery in the area was made at Ross Field, in north-central Mountrail County. Michael S. Johnson, independent geologist, and Henry H. Gordon, president of Strata Resources, both based in Denver, put together a 6,000-acre prospect at Ross.

"I looked at electric logs and completion cards, and noted that several wells had some noncommercial Bakken oil recoveries," said Johnson. "The Gulf Nelson Farms well, drilled in 1982, was a lookalike to Elm Coulee Field, and that's what drew me to the area." The duo sold the deal to a couple of private independents, who partnered with EOG Resources to drill a horizontal Bakken well in late 2005. A twin to the Gulf well, the #1-24H Nelson Farms, in Section 24-156n-92w, flowed 155 bbl of oil, 100,000 cf of gas and 102 bbl of water from a single 4,000-ft lateral.

The Ross discovery wasn't unusually fine, but it inspired the prospectors. About 25 miles south, Johnson and Gordon put together another idea, this one much larger in size. "Logs on a dry hole in this area also looked like logs in Elm Coulee," said Johnson.

The geologist was amazed that the acreage on his idea was unleased. "I couldn't fathom why it was all open. I used to walk around the block and wonder what was wrong with it – why didn't anyone own it?"

Tulsa-based geologist Bob Berry joined the pair and put up most of the leasing capital. The group acquired

38,000 acres, some of it for as little as $3 an acre.

Johnson showed the prospect to some 15 companies. A common critique was that the acreage wasn't fully within the Bakken's oil-generation window. Most explorers believed it was too edgy, bordering on thermally immature Bakken.

EOG eventually bought 75% of the deal, and Berry kept a quarter. In early 2006, EOG drilled its #1-36H Parshall. Pressures were so high – gradient of 0.7 psi – that the company was only able to take the lateral out 1,200 ft into the Middle Bakken before the well blew out. It was completed making 463 b/d.

EOG immediately began to drill offset wells, and results climbed as it fine-tuned its drilling techniques. (Berry sold his interest to Whiting Petroleum when the drilling flurry began.) These are monster producers: Wells with initial potentials of up to 3,630 boe/d have been completed in Parshall Field.

According to EOG, a typical single-lateral producer at Parshall has a measured depth of 15,000 ft, can be drilled for $5.25 million, and can tap gross reserves of 900,000 bbl of oil. Oil in place is 9 million bbl per section; the field is being developed on 640-acre spacing. The company orients its laterals at right angles to the regional fracture trend, which runs northeast-southwest. Stage fracs along the laterals are employed as well.

One of the truisms about resource plays is that they don't behave like conventional reservoirs. At Parshall, the boundary between thermally mature and immature Bakken forms part of the updip trap, said Johnson. "That's why we had so much trouble selling this. Parshall is different than any Bakken field in North Dakota."

Current thinking not yet universally embraced holds that Parshall's oil was generated in place and that the area is near the immature boundary. Parshall appears to be a new type of trap, and it has broad implications for explorers working in other areas and other resource plays. Fundamental concepts are being eagerly reevaluated by geologists.

"This Bakken play is the best thing that's happened to North Dakota's oil industry since discovery of the Nesson Anticline fields," said Johnson.

"WE WERE ALL TAUGHT that shales were impermeable source rocks. But breakthroughs in precision horizontal drilling and multistage, high-pressure fracs at high rates have made all the difference."

*—**Harold Hamm,** chairman and chief executive, Continental Resources Inc.*

Prime Location

Whiting Petroleum Corp. has an enviable position of some 96,000 net acres in the eastern Bakken play. Its 13,000 net acres in Parshall equate to an average 20% interest; in Sanish, its interests range from 80% to 100%.

"We were an early participant in the development of Elm Coulee in Montana's Bakken play, but we didn't have much acreage," said James Volker, president and chief executive. "So we put our people to work looking for similar geologic conditions, and areas where the Bakken was mature enough to have oil in the expulsion stage." The Sanish area stood out, thanks to an old well log that exhibited a thick section of high-resistivity rocks in the Middle Bakken.

Sanish is similar to Parshall, but not identical. Both the entire Bakken interval and the crucial Middle Bakken reservoir are thicker in Sanish, and the field is firmly in the oil-generation window. Wells in Sanish recover between 350,000 boe and 900,000 boe each. Initial rates on Whiting's wells can easily top 1,000 boe/d. Its best completion announced to date is its #11-27H Liffrig, which came onstream earlier this year at 2,530 boe/d.

The company has settled on a development plan of two single laterals, oriented northwest-southeast, on each 1,280-acre unit. A Sanish Field well costs $6 million, compared with 640-acre Parshall wells that run $5.2 million to $5.5 million apiece. Whiting saves $10.4 million to $11 million in drilling costs by using two vertical holes and long laterals on 1,280-acre units, versus four vertical holes and laterals on 640-acre units.

"Each field is unique and requires its own approach," said Volker. "Sanish has thicker Middle

Continental Resources swabs in its #1-32H Kermit, a Bakken producer in McKenzie County, North Dakota.

Bakken and more matrix storage than Parshall, and it's less intensely fractured."

For completions, Whiting runs an uncemented liner in its laterals, which typically extend nearly 10,000 ft across two sections. It uses swell packers and sliding sleeves. "It's a great mechanical advancement," said Jim Brown, senior vice president. "The external packers and sliding sleeves allow us to frac up to 11 zones in a 24-hour period." Per well, its stimulations consist of 2 million lb of sand and 20,000 bbl of low-concentration gel.

In 2007, Whiting drilled 33 Bakken wells. This year, it plans 56 wells in Sanish, of which it will operate 36, and it will participate in 50 to 60 wells in Parshall Field. Its North Dakota capex will be $302 million, 40% of its total 2008 budget.

At present, the company runs five rigs at Sanish. It will shortly ramp to seven rigs, and will finish the year at nine. "Each rig can drill about six wells a year, so over three years we'll operate 128 wells," said Volker. "In addition, we may drive another well bore between existing pairs to reduce spacing to 320 acres." Whiting's locations total 180 at two wells per 1,280-unit; infill drilling would naturally increase that inventory markedly.

Whiting emphasizes infrastructure, and it has been enhancing its ability to build gas-processing plants. The company is constructing a gas plant at Robinson Lake, south of Stanley. Initially, the plant is processing 3 million cf/d. By 1Q 2009, capacity will reach 33 million a day. Out of each million cubic ft, it will strip approximately 150 bbl of gas liquids.

"This is a great opportunity for us to process our own gas, and also process some gas for others." Additionally, the company is constructing pipelines to Stanley to take gas to Williston Basin Industries and oil to Enbridge.

"We want to eliminate flaring in the field. The day we frac, we want to be able to send our gas through to sales," said Brown.

The company's Bakken production is steeply inclining. In 1Q 2008, Whiting's net production from Middle Bakken in Sanish and Parshall totaled 3,344 boe/d, a 92% increase from 4Q 2007. Net production in March reached 4,153 boe/d, and more good news is expected in its 2Q results.

"We're very happy with our position in the Bakken," Volker said.

North Dakota Focus

Another firm tied strongly to the Bakken play is Austin, Texas-based Brigham Exploration Co. "We're very excited about the Bakken, and we feel very fortunate to be involved in it," said Bud Brigham, chief executive and president.

Brigham entered the play in 2005. "We came out of a board meeting with the charge to find unconventional plays that would complement our successful, but often choppy, conventional drilling program. Our goal was to bolt on a deep, predictable inventory to provide more consistent quarterly growth for our shareholders in both production and reserves," he said.

The company evaluated all the major unconventional plays in the US, and the Bakken rose to the top.

"We were attracted to the Bakken's potential economics and substantial resources in place, and the associated option value that it provided," Brigham said. "It became our first and most significant commitment to an unconventional project."

Brigham had been working in the Williston since the mid-1990s. It initially played Red River, and had enjoyed some success. It lined itself up with a consultant who had been involved in the early days of Elm Coulee, and purchased 45,000 net acres in Williams and McKenzie counties in western North Dakota. The main geological criterion was porosity development in the Middle Bakken.

In 2006, the company drilled three long laterals that ranged from 8,000 ft to 9,000 ft in length. "These were prior to the implementation of staged-frac technology in the play," said Brigham. A single frac was placed on each lateral.

Results were not sterling. Two of its wells came on at about 200 b/d. "We were disappointed in those early results, but production from those wells has held up better than we expected." Ultimately, each well should make between 100,000 boe and 165,000 boe.

The company pressed onward. It continued to aggressively add leases, and at present holds nearly 300,000 net acres. Its prime holdings are 88,000 net acres in Mountrail County, which it entered in 2007 through a 3,000-net-acre joint venture with Northern Oil & Gas Co.

Brigham segments its Mountrail holdings into three areas: Parshall/Austin area, with 8,700 net acres; Ross, with 27,000 net acres; and Stanley, with 5,800 net acres. It has one rig working continuously, and it will likely pick up a second rig later this year. Its 2008 program is currently set at seven operated wells, but if it takes on another rig, the figure will rise to 10 to 15. "We're not a first mover, but we were out there early. To a large degree, we're following the tried-and-true methods pioneered by other operators," said Brigham.

Its nonoperated activity has also accelerated dramatically. Its latest estimate is that it will be involved in 44 non-operated wells, typically with smaller working interests ranging up to 25% per well.

"In 2008, we could be involved in 56 wells, potentially proving up approximately 100 locations," Brigham said.

Meanwhile, the company has been acquiring acreage in eastern Montana, targeting Middle Bakken dolomite porosity and also Red River features. Brigham holds 100,000 net acres in Montana, and has drilled two consecutive Red River discoveries in that area.

Neither has it forgotten about its original play. The company recently added 48,000 acres west of the Nesson, which raised its total position in Williams and McKenzie counties to 99,000 net acres. It has reentered one of its original Bakken horizontals in that area. It sidetracked the hole and used swell packers and multiple stages to stimulate the lateral.

"We'll have some news to report on that soon, and we're optimistic that this will improve our results and make our acreage west of the Nesson economically viable," he said.

Brigham expects to be busy in the Williston for many years. Despite the fine wells operators are making, only 5% to 15% of the Bakken's in-place oil is being recovered. "We fully expect that improvements in technology — such as stimulations, refracs and secondary recovery — will allow us to get more of that oil out of the ground. There is a lot of option value over time."

Furthermore, the Williston is a multipay province. "We think the Three Forks is just one example, but may be the best example, of the kind of expansive potential that the basin offers," Brigham said. The company is in the planning stages for a consortium that will drill a Three Forks well in Mountrail County.

"We are a small company, but we have nearly 300,000 net acres in the Bakken. Relative to other public companies involved, we think we're the company most leveraged to the play. If investors like the play, they need to take a look at us."

Long-time Player

St. Mary Land & Exploration Co. was an early participant in Elm Coulee Field through its subsidiary, Nance Petroleum. St. Mary was quite pleased when XTO Energy Inc. recently purchased Headington Oil's interests in Elm Coulee and the Bakken play for $1.85 billion in cash and stock.

"Having XTO come into Elm Coulee as an operator is very valuable to us," said Jay Ottoson, St. Mary executive vice president and chief operating officer. "If we apply that valuation to our 113,000 net acres in the field, it's a really big number."

THE COMPANY'S BAKKEN PRODUCTION is steeply inclining. "We're very happy with our position in the Bakken."

James Volker, president and chief executive, Whiting Petroleum Corp.

Like other Elm Coulee operators, St. Mary moved into North Dakota several years ago to test the Bakken. "Our early results in North Dakota using Elm Coulee technology were not very good," he said.

The company currently holds 37,000 net acres in North Dakota, including 25,000 acres on the border of Mountrail and Burke counties in its Powers Lake and Stillwater areas, and 12,000 acres on the Nesson Anticline.

"We think that the technology that EOG brought into the basin has opened the Bakken up across a very large area. It makes our areas much more prospective," he said.

Outside of the Parshall area, St. Mary sees the Bakken as a cost-driven play. "The industry should be able to drill wells across wide areas if costs are reasonable."

This year, St. Mary plans to operate two to three horizontal Bakken wells in North Dakota. It's also taking its wells down to the Three Forks, which it believes could be present beneath its acreage, and it is participating in a number of non-operated wells.

Its first new-technology Bakken well is drilling in its Powers Lake project in Mountrail County. "We're going to spend the money to do everything we can to make a well," said Ottoson. It is a 640-acre test, and the company plans to use an external casing packer completion with sliding sleeves.

For 2008, it will keep that rig busy in the Bakken. "We'll ramp up next year if this year's program works. We see a lot of upside in the Bakken."

West of the Nesson

Another operator that's reconsidering its Bakken potential is American Oil & Gas. The Denver independent entered the play three years ago, and drilled a multi-lateral well in 2006 on the 90,000-gross-acre Goliath Block in Williams and Divide counties. The block is operated by Evertson Operating Co., a private firm based in Kimball, Nebraska. American owns 32,000 net acres; its other partners are Denver-based Teton Energy and Australian firm Sundance Energy.

"Like others, we brought over technologies that had been successful at Elm Coulee," said Andrew Calerich, president. The company made a producer, but the 160-barrel-per-day production rate was disappointing. The well had three laterals, and one of the fracs jumped into the Lodgepole.

"We're evaluating the geology on our acreage again. We want to figure out where to drill our next well." The block is directly west of the Nesson Anticline, and several operators, including Continental and Hess Corp., are active on adjacent blocks.

Happily, American and its partners have Red River potential at Goliath as well. It has participated with Whiting in successful Red River drilling, and it will drill a Red River target this summer on a prospective trend that runs north-south across its block.

A common conception holds that the Nesson Anticline was positive during Bakken deposition, and that it acted as a barrier to sand and reworked carbonate deposition. Bakken workers have believed that clastics were prevalent on the eastern side of the anticline, but that they were not deposited on its

In anticipation of continued success, Whiting has stockpiled pumping units at its Robinson Lake site in Mountrail County, North Dakota.

western side. That's crucial, because the sandy dolomitic facies comprises the main reservoir rock in the Middle Bakken. Where that's not present, basinal rocks are present that are not nearly as prolific.

"The Middle Bakken is very complex," said Peter Loeffler, American vice president, exploration and development. "It's a very fine-grained dolomitic siltstone, and we see evidence for that facies in our area. We think clastics did cross the anticline in Bakken time."

Completions are the key for making economic wells in the Goliath area, he said. "I'm confident that we do have reservoir in our area, and we think good completions will open up the Middle Bakken reservoirs that are not naturally fractured."

American and its partners expect to start drilling for Bakken by year-end.

Southern Reaches

The Bakken has even attracted foreign firms to North Dakota. Sundance Energy, formed in late 2003, holds approximately 16,000 net acres in the play, mainly concentrated in two areas.

In its South Antelope prospect, in McKenzie County south of Antelope Field, it holds some 4,000 net (25,000 gross) acres within an area of mutual interest with private New Orleans-based operator Helis Oil & Gas. Sundance's first four wells at South Antelope came on production recently, and it has an additional well working on completion and a sixth well drilling.

"We participate with Helis with everything they do in South Antelope," said Jayme McCoy, Sundance's Denver-based managing director. Sundance's interests range from 50% to 7%. "Helis has a rig under contract, and this will be a good driver for our activity in the near term."

In this area, Helis has drilled laterals in both the Middle Bakken and Three Forks-Sanish intervals. "We have one well that produces from dual laterals, and we've had good results in both zones," he said. Going forward, the partners plan single-lateral completions. Sundance's best well to date is #16-14H Jones, which had an initial potential of 971 b/d and produced an average of 400 b/d during its first 15 days onstream.

Adjacent to South Antelope, Sundance owns 100% of approximately 7,500 acres in its Phoenix prospect, in McKenzie County on the Fort Berthold native American reservation. This block lies on the southern end of the Nesson Anticline. Industry interest is quite high in this position: Field reports indicate that private operator Peak North Dakota LLC has achieved rates of around 1,000 boe/d at its #9-24H Tekakwitha, drilled about four miles northeast of Mandaree and within six miles of Sundance's Phoenix project.

Sundance has secured a permit on its #21-30H Chase and is building location on that well. "We'll operate this project ourselves," said McCoy. "Permitting has been very challenging, so we have started permitting on three additional wells to meet our 2008 drilling goals."

Each well on the reservation requires an environmental assessment, which slows the permitting processes. "Reservation land is overseen by the Bureau of Indian Affairs and Bureau of Land Management, so we're dealing with the federal layers of administration, in addition to the normal state requirements."

Services are also in short supply. Drilling rigs are difficult to come by, and tubulars, such as casing, tubing and liners, are expensive and not readily available. "The high oil prices are great, but this area is extremely competitive and it can be difficult being a small operator in this environment," McCoy said.

Nonetheless, the major hurdles appear to be behind Sundance, and it's looking forward to a 2008 drilling program of three to four operated wells at Phoenix, and 13 to 15 non-operated wells elsewhere in the basin.

Additionally, Sundance owns a 100% interest in its Manitou prospect in Mountrail County. That is in its formative stage; at present, more than a thousand acres have been acquired. Finally, it holds a 5% interest in the Goliath prospect, with partners Evertson, American Oil & Gas, and Teton Energy.

Sundance expects meaningful production volumes will begin to flow from its Bakken acreage this year.

Deep Background

Not all companies pursue operations, and one firm has built its Bakken strategy around well-positioned lease interests. Wayzata, Minnesota-based Northern Oil & Gas Co. holds more than 60,000 net acres in the heart of the play, with 25,000 in Mountrail County.

The company is led by chief executive Michael Reger, who hails from four generations of Williston Basin lease-brokers. "My family has been leasing land in the basin since the 1930s," said Reger. "It's safe to say that a Reger has leased nearly every acre in the Williston Basin at one time or another."

In 2005, Reger decided to take the business to the next level, and move it from lease brokering to E&P. In 2006, Northern began to lease in Mountrail County, on the heels of EOG's Parshall discovery.

The company focused on the core fairway, seeking exposure to drilling activity, and that strategy has worked exceedingly well. "We have been permitted into more than 75 wells with various operators, and our average working interest is about 10%," he said.

Currently, Northern is participating in 10 wells, and it has another dozen spudding within a month. If activity continues at its present pace, its entire acreage position could be drilled over in two years.

The company has about $15 million in cash, some $14 million in outstanding warrants, and no debt. "We have a nice war chest to meet our cash calls and feed our aggressive acreage acquisition budget," Reger said. "Our production is growing quickly."

Bakken Future

Lots of companies are working North Dakota's Bakken, and observers have speculated that the rig count could reach 100 by year-end. So far, operators using horizontal wells and multistage stimulations have been making excellent wells flung far across their holdings.

Still, although the Bakken is present and thermally mature over a marvelously large area, it's far from a homogenous formation. Many unknowns remain: the importance of local and regional tectonics, fracturing from oil generation, salt dissolution, overpressuring, and facies changes are among the immediately obvious questions.

What is clear is that the target is compelling. Unquestionably, enormous volumes of oil are held within the cryptic formation. Time will tell if the industry's best technologies can unlock a good part of the Bakken's potential.

Reprinted from **Oil and Gas Investor,** ***August 2008.***

Canadian Bakken

Saskatchewan's sizzling Bakken play is serving up 300 b/d, light-oil producers across an enormous area.

By Peggy Williams
Senior Exploration Editor
Oil and Gas Investor

Photos courtesy of Crescent Point Energy Trust

Saskatchewan's first horizontal well was drilled in 1987; through the end of 2007, more than 8,000 such wells had been drilled.

US firms have been energetically carving horizontal holes throughout western North Dakota in search of Bakken oil, and their Canadian compatriots have been doing the same in Saskatchewan. Both groups are working the savory Middle Bakken in the vast Williston Basin, a third of which lies within Canada, and a quarter within Saskatchewan.

The Bakken is steaming hot: Saskatchewan's production from Bakken alone has risen from 580 b/d in May 2004 to more than 32,000 a day in just four years, said Ed Dancsok, director, petroleum tenure branch, of the province's energy and resources ministry. As of August, Saskatchewan boasted 880 producing Bakken wells; there were merely 80 in 2004.

"We've had a real rush," he said. "Since 2004, we have generated about C $800 million for the province in sales of Bakken-prone lands; this year alone, we've already had more than $500 million in sales." The province's previous sale record was $250 million for an entire year, across all plays.

Migrated Oil

In Saskatchewan, the Bakken lies at depths from 2,200 ft to 7,700 ft and is normally pressured. The thermal kitchen, the area of mature source rock that generated the Bakken's fine, light, coffee-colored oil, resides in northeastern Montana and northwestern North Dakota. Only a smidgeon reaches into Canada.

That means Canadian oil migrated from the south. "Fracture trends extend from North Dakota and Montana into Saskatchewan, and provide a potential migration pathway into the province," said Dancsok. "Our Bakken play is a combination of a structural trend and stratigraphic pinch-out of the reservoir."

The Bakken has produced in Saskatchewan since 1956, from Roncott Field. This little accumulation, about 30 miles from the American border, made only minor volumes. A year later, a pool was discovered at Rocanville, at the formation's northeastern edge. The best wells made around 90 b/d. The two finds are 170 miles apart, and both are on little structures, said Dancsok.

The reservoir is a mixed carbonate-sand unit in the middle of the Middle Bakken member. This portion of the Bakken is in an aquifer system, so production requires conventional trapping situations.

Current Target

Today's drilling focuses on a siltstone member in the lower part of the Middle Bakken. This extremely dolomitic, coarse siltstone is widespread and remarkably persistent. Its thickness ranges from some 30 ft to 60 ft, and it displays average porosities of 12% and permeabilities of 0.4 to 0.6 md. Matrix storage is therefore significant.

The Bakken is thin and shallow at the play's northern end. Close to the American border, the formation deepens to 7,700 ft. The heart of present activity is at Viewfield, in the trend's center, halfway between the original pools. Here, the reservoir lies at 5,500 ft.

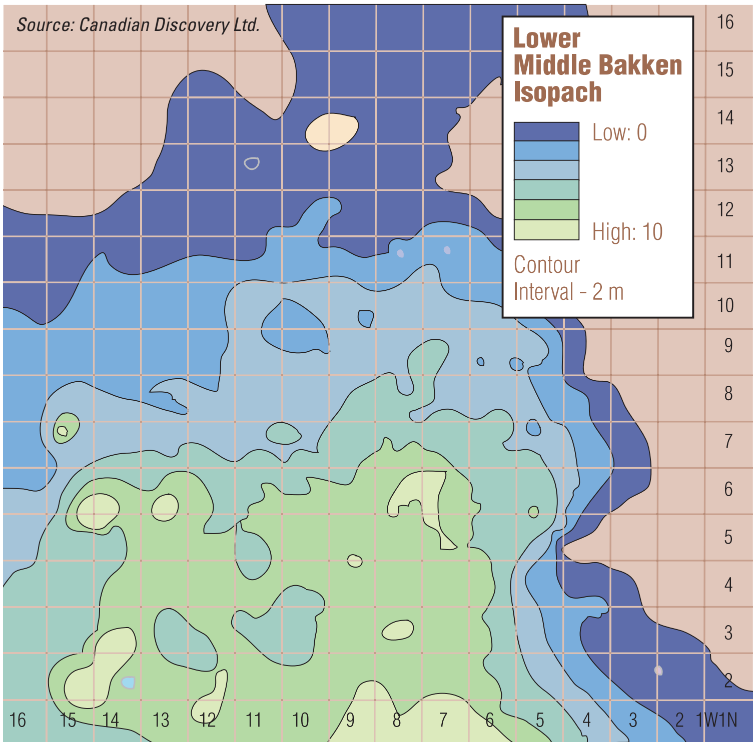
The siltstone play is an astonishingly large stratgigraphic trap, with interplay of petrophysics, hydrodynamics, and stratigraphy creating the accumulation. Generally, the Bakken reservoir wedges out on its northern edge; it thickens to the south, but is wet near the American border.

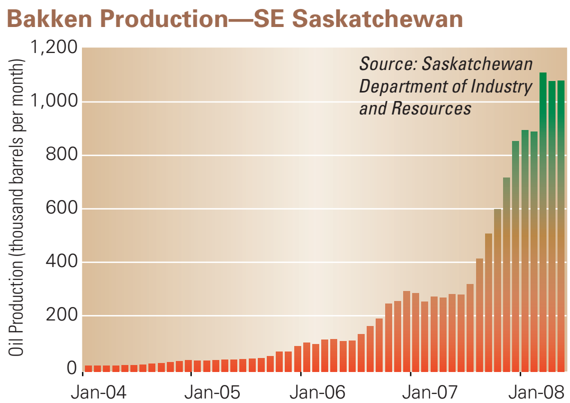
Calgary-based Canadian Discovery Ltd. has completed a massive, multiclient Bakken study in Saskatchewan that includes extensive reservoir characterization, petrophysics, hydrodynamics, and data from some 1,000 wells. "We consider Saskatchewan's Bakken an unconventional play, but not a resource play, because it's full of migrated oil," said David Hume, director of consulting services and multiclient studies.

Despite its predictability and extent, the Bakken still poses challenges. Its uranium content is high, so it shows up as a shaley reservoir on logs, and its pyrite content is also high, which masks its resistivity response. "Another issue is that the play requires horizontal wells and sequential fracturing, but the overlying sandstone can be wet," said Hume. "Operators have to be very careful with fracs, or look for areas that don't have overlying water."

Based on volumetric methods, Hume and his group calculated primary and secondary recovery for Saskatchewan's unconventional play in the siltstone at 1.1 billion bbl, a recovery of 15% of original oil in place. "Some people have talked about enhanced recovery, which could raise recoveries to 25%. That would be almost 2 billion bbl of recoverable oil."

Source: Saskatchewan Department of Industry and Resources





LEFT: The Middle Bakken reservoir is a dolomite sandstone that thins to the north and east.

TOP RIGHT: Bakken production in Saskatchewan has surged in the past two years.

Constant Improvement

North Dakotan Bakken wells can be top-shelf producers, capable of making more than 2,000 boe/d. They are massive, overpressured, high-volume wonders. Saskatchewan wells are bread-and-butter, coming in at rates as high as 300 b/d.

But what Saskatchewan's Bakken gives up in prime rates, it gets back in consistency. "We view the US Bakken as being much more variable than in Saskatchewan," said Glenna Jones, vice president, Canadian energy equities for Calgary-based Ross Smith Energy. "Where the US play works, it really works, but there are places where it doesn't work. So far, geology and well results suggest that the Saskatchewan play is quite a bit more consistent to date."

And it's still growing: "We see continual and significant improvement, quarter after quarter, on rates. Wells are getting better all the time, although companies are starting to push the play's boundaries." Strong rates are being measured in the northern direction, and some wells quite far south – around Township 3 – have also delivered nice rates.

Furthermore, the play is far from mature. "Most companies in the fairway have four to five years of drilling inventory to get down to four wells a section, and there have been some long step-outs from the main core area that have been successful," Jones said.

Early Mover

A top operator in Saskatchewan's Bakken play is Petrobank Energy and Resources Ltd. It's running nine rigs and plans to drill 154 net Bakken wells this year. Its activity has heated up in the past two years. "We drilled half that number last year, and in 2006 we drilled four Bakken wells," said Gregg Smith, vice president, Canadian business unit. "We latched onto the play and got big in a hurry."

The Calgary-based firm currently makes 15,000 boe/d from Bakken wells, out of total Canadian business-unit daily production of 17,500 boe. Its position stretches across 141,000 net acres.

Petrobank is credited with bringing Packers Plus technology to the play, the innovation that broke it wide open. "Southeastern Saskatchewan was known for having Bakken potential for a long time, because wells always had shows while drilling through the Bakken. But, only a few wells produced from it and pools were localized and quite small."

In 2005, Starpoint Energy, at the time a small Calgary-based firm, was tracking Bakken activity in the US. Its first well was a farm-in on Petrobank land. "We had the opportunity to participate in the earliest wells in the play and watch how it developed," said Smith.

These inaugural horizontal wells were encouraging, but recovered oil volumes were small. Operators began experimenting with fracing and completions in the horizontals, and Petrobank held minor interests in these early tests. US techniques that were applied in the Bakken didn't work in Canada; increases in productive capabilities came with increases in water, as fracs broke into water-filled zones above the target reservoir.

Petrobank settled on Packers Plus downhole equipment to help frac the horizontals. "This technology allowed us to maintain a lower feed rate, so that we didn't clobber the zone with the fracs," he said. "The fracs were the same size, but they grew more slowly and stayed much more focused in the Bakken zone."

Results were phenomenal, but Petrobank kept them close. "When we realized how well the technology worked, we got aggressive at land sales and acquisitions," Smith added. The company tied up a tremendous land base, including bids of C $60 million in the April 2007 provincial sale.

That got everyone's attention. "Pretty quickly, the industry adopted our methods. Now, nearly all companies in the Bakken play in Canada use Packers Plus." Still, technologies are far from static. Petrobank continues to refine its wells, and is experimenting with shorter wells and more intense stimulations.

"The Bakken has fueled a huge increase in the productive capability of Petrobank. Our production is four times more than what it was 18 months ago," Smith said.

In the play's heart, around Viewfield, average wells begin producing at rates of 200 to 300 b/d. Recoverable reserves are 150,000 boe per well, on a 3P basis. "Every year, our reserve auditor has upgraded estimates of recoverable reserves per well," said Smith. Petrobank drills four parallel, horizontal wells per section, and each lateral is 5,000 ft. Legs are 1,300 ft apart, and each is fractured in eight stages. Fracs are staggered between offsetting well bores.

A typical Bakken well in Saskatchewan costs Petrobank C $1.6 million to $1.7 million to drill and complete, and another C $200,000 to fully equip. The firm has also invested heavily in infrastructure to move its volumes. It has three production facilities at present, and will add a fourth prior to year-end.

"At 150,000 bbl per well, we are only recovering 15% of original oil in place," said Smith. "We are looking for technologies to raise recoveries." Additionally, Petrobank is drilling exploratory wells to locate more Bakken areas to pursue, and to identify other reservoirs that might benefit from similar technical approaches.

Friendly Province

In 2002, Saskatchewan made a deliberate move to encourage horizontal drilling. A new, horizontally drilled Bakken well falls into a royalty category called fourth-tier oil. The category is a sliding-scale royalty structure sensitive to price and productivity. Higher oil prices mean higher royalty rates, and higher well productivity also denotes higher royalties. A typical Bakken well initially produces about 200 b/d which would translate into royalties of about 35%.

However, Saskatchewan has a drilling incentive that provides for a maximum royalty rate of 2.5% and a freehold production tax rate of 0% on the first 37,750 bbl of oil produced from a shallow horizontal oil well. That incentive is intended to offset some of the high, upfront costs associated with horizontal drilling. Once that volume is produced, the well is subject to normal fourth-tier, sliding-scale royalties.

"Our fiscal regime is very attractive," said Ed Dancsok, director, petroleum tenure branch, for the province's energy and resources ministry. "We have the incentives, the technology and the geology, and the companies are willing. It has generated a lot of interest in drilling for Bakken in Saskatchewan."

Aggressive Growth

Crescent Point Energy Trust is the prime producer of Canada's Bakken oil. Some 50% of the company's production flows from the play, said Trent Stangl, vice president. "We produce in the neighborhood of 16,000 boe/d in the Bakken, and our overall corporate production is about 37,000 boe/d.

"We estimate that the Bakken pool in southeastern Saskatchewan contains 5 billion boe of in-place resources. It's the largest oil find in western Canada in more than 50 years."

Calgary-based Crescent Point has been involved in the Bakken play since its inception. When it converted to a royalty trust, it spun out its exploratory

Crescent Point Energy Trust has 10 years of drilling inventory in the 1,100-sq-mile core area in Saskatchewan's Bakken. It runs 10 rigs in the play, along with its related entity Shelter Bay Energy Inc.

acreage into Starpoint Energy. That entity grew rapidly and also converted into a royalty trust. Starpoint then spun out its exploratory acreage to Mission Oil & Gas Inc., an early Bakken explorer. Crescent Point initially invested in Mission, and subsequently acquired the company.

"When we first approached Mission about a merger, we thought the Bakken was half a billion bbl of oil in place. It's 10 times that size now," said Stangl.

Crescent Point holds 288,000 net acres in the play. Additionally, the trust has investments in private company Shelter Bay Energy Inc. Due to government restrictions on equity growth in trusts between now and 2011, Crescent Point set up Shelter Bay to accelerate production from the trust's Bakken properties. Crescent Point owns 19% of Shelter Bay, which will merge into Crescent Point in the future. "Shelter Bay is entirely focused on the Bakken. It's private, so it's not subject to income-trust concerns and it can issue equity. That allows Crescent Point to augment its growth," said Stangl.

Shelter Bay produces another 3,500 boe/d, and holds 102,400 net acres. When that's added to Crescent Point's production, the collective entities make nearly 20,000 boe daily from the Bakken and hold 390,400 net acres in the play.

This year, Crescent Point will drill 110 gross Bakken horizontal wells, up from 79 in 2007. Shelter Bay will drill 75 Bakken wells this year. Average reserves are 145,000 boe and costs are C $2 million per well.

"We have 10 years of drilling inventory on the Crescent Point side, in the core Bakken area around Viewfield, which covers about 1,100 square miles," he said. "We also have considerable exploration acreage beyond that." Together, the entities run 10 rigs in the play. Shelter Bay's operations are handled by Crescent Point through a management and technical-services agreement. "We move the rigs based on what is most efficient," Stangl said.

Crescent Point is investigating methods to improve Bakken recovery. At a minimum, the play can be developed at four wells per section, at 15% recovery of in-place oil. The company has a small pilot that features eight wells per section. Results to date are agreeable, and match nicely with its detailed engineering simulations. "Eight wells per section should provide an additional 5% recovery," he added.

It also has a small waterflood study in progress. "The waterflood simulation suggests possibilities of additional 7% to 10% recoveries. On a pool this big, that is a massive volume of reserves."

From a tasty appetizer, the Canadian Bakken has already unfolded to a full-on feast. Served up next could be a sumptuous dessert course.

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Defined and Described

The Bakken, long recognized to be a world-class source rock, is coming into its own as a prolific producing reservoir.

By Peggy Williams
Senior Exploration Editor
Oil and Gas Investor

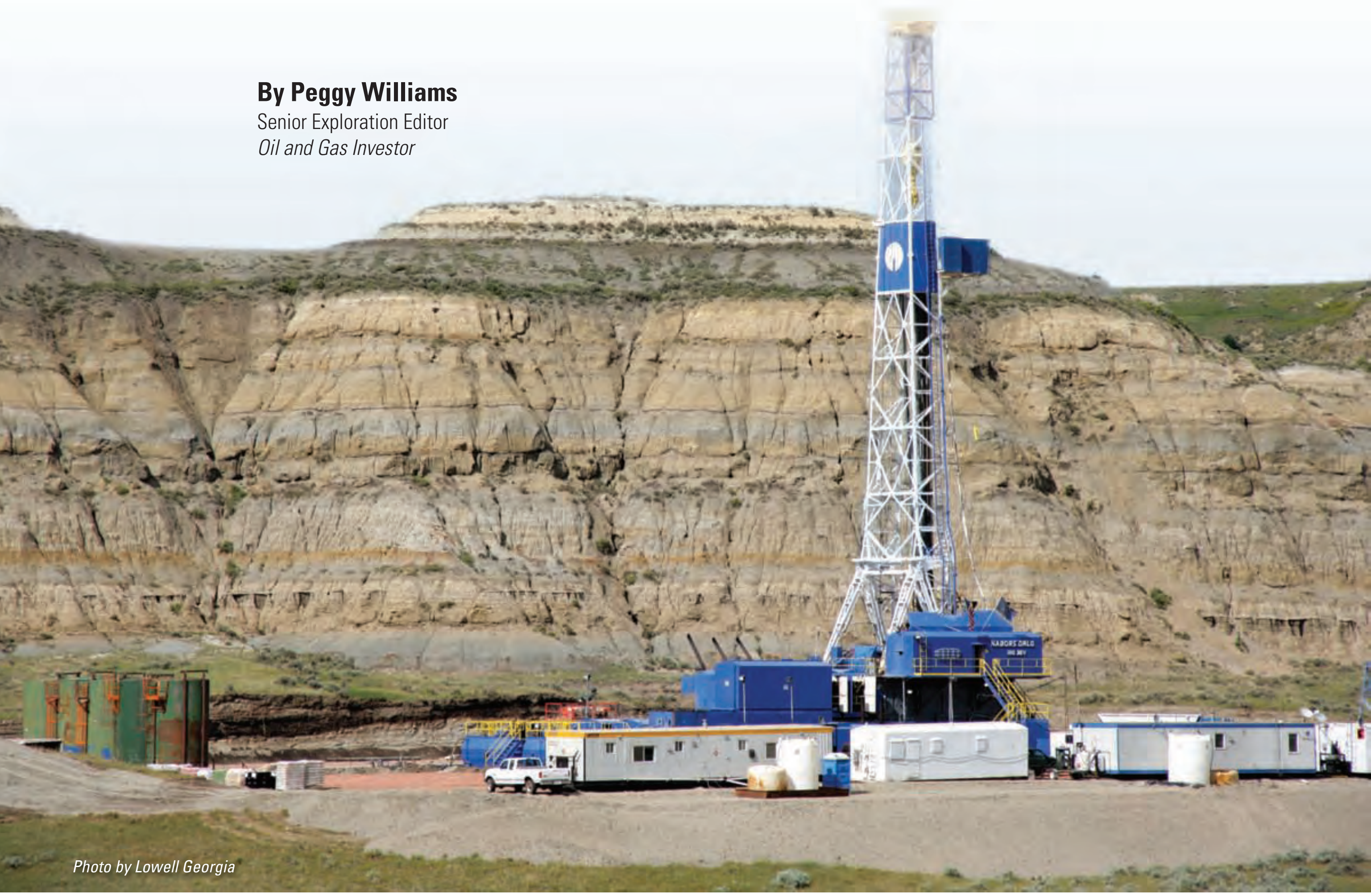


Photo by Lowell Georgia

Drilling activity has surged in the Williston Basin as the Bakken play has caught fire.

Before 1987, the Mississippian/Devonian Bakken produced from scattered fields in the Williston Basin, both in Canada and in the US.

Williston Basin is home to a series of major north-south trending structural features: the Nesson, Little Knife, and Billings anticlines. Additionally, the immense Cedar Creek runs northwest to southeast, from eastern Montana into the southwestern corner of North Dakota. Furthermore, the basin is crossed by several lineament trends, with a dominant group running N70E.

Historical Bakken production was from vertical wells, mainly on structures such as North Dakota's Nesson Anticline. Such legacy fields included Elkhorn Ranch, Hofflund, and West Tioga in North Dakota, and Ceylon, Hummingbird, Roncott, and Roncanville in Saskatchewan.

For the most part, the Bakken was not the primary objective in these fields; rather, the shale was a secondary target that was completed only after the main objective was not commercial, or had ceased commercial production.

In 1988, a boom of horizontal drilling swept through the Bakken. Operators, armed with early horizontal-drilling technology, went after the Upper Bakken shale along its depositional edge in western North Dakota, near the Montana line. The shale, between 4 ft and 10 ft thick, produced oil from horizontal wells that intersected sufficient fractures. The best well drilled in that period, which lasted until 1994, has made more than 600,000 bbl of oil. Many of these early horizontal Bakken continue to produce oil. Fields developed heavily in this era include Elkhorn Ranch and Bicentennial. Some 22 million bbl of oil and 50 Bcf of gas have been produced from these accumulations.

The next great surge of development occurred in 2000. That's when Elm Coulee Field was discovered in Richland County, Montana. This massive field has made nearly 75 million bbl of oil since its discovery. Activity persists, as operators continue infill drilling. To date, Elm Coulee has made more than 74 million bbl of oil. However, the play stayed on the Montana side of the basin for quite awhile before it finally broke east into North Dakota and north into Saskatchewan.

Today, four major areas are in development in the Bakken: Elm Coulee, in Richland County, Montana; Parshall Field in Mountrail County, North Dakota; the Nesson Anticline, in various North Dakota counties; and Viewfield, in Saskatchewan.

Stratigraphy and Lithology

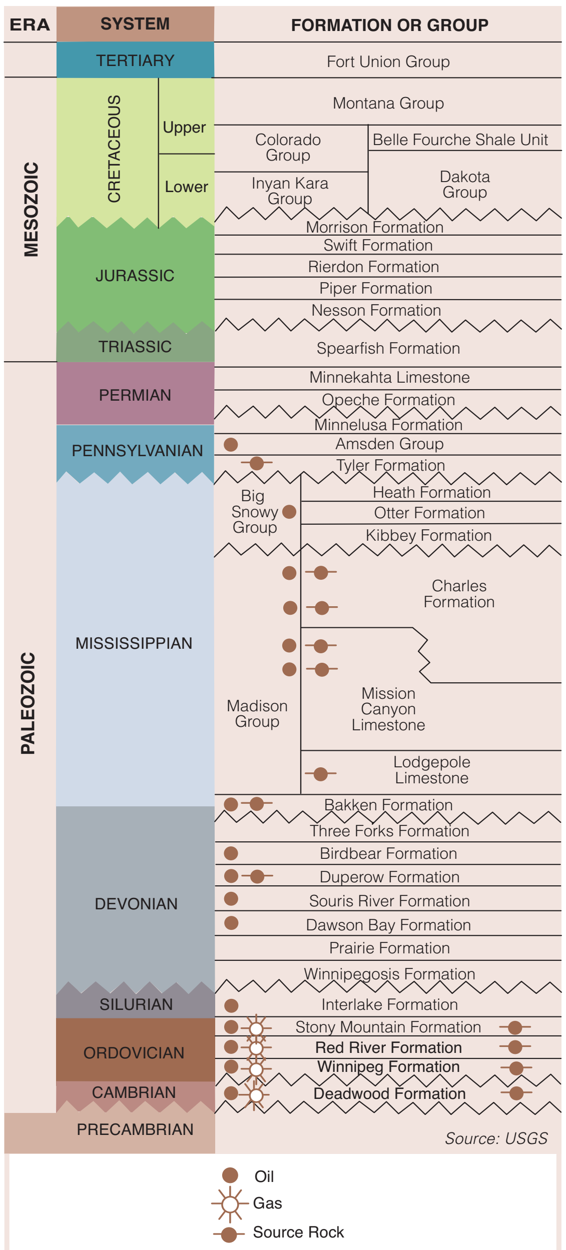
The Bakken is an immense layer of rock that covers some 200,000 sq miles of the Williston Basin. It stretches across eastern Montana, western North Dakota and southern Saskatchewan, and even reaches into far western Manitoba.

Until recent improvements in horizontal drilling and completion technologies, the Bakken was not an attractive reservoir. It has low porosities, averaging around 5%, and permeabilities are extremely low, averaging 0.04 md. The Bakken attains a maximum thickness of around 140 ft; its depocenter lies just east of the Nesson Anticline in western Mountrail County, North Dakota.

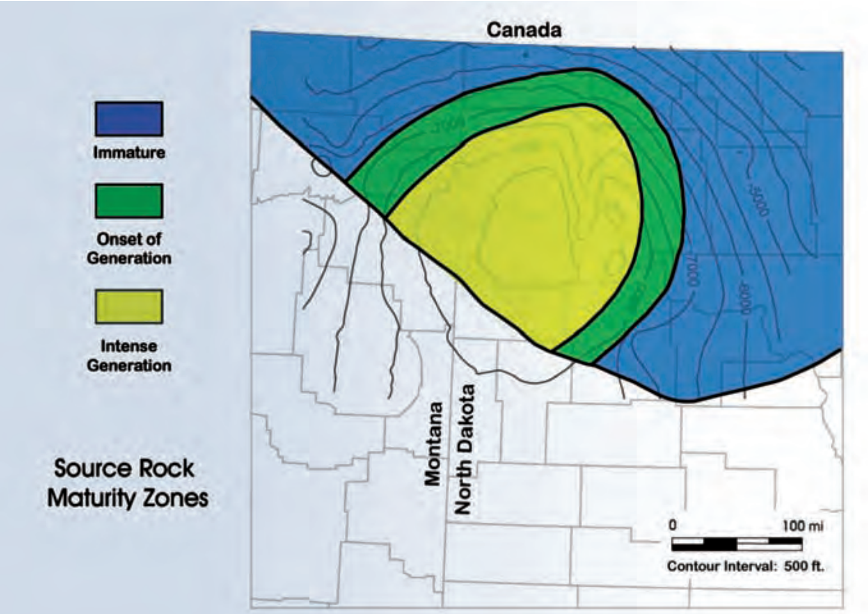
The Bakken is both source and reservoir, and is an unconventional resource play. The petroleum system is quite complex. Within the Bakken's thermal kitchen — the area of intense generation of hydrocarbons-there are areas where oil remains in place and has not migrated; Bakken oil has also migrated long distances. Fields in Saskatchewan, for instance, hold oil that's traveled across international borders.

A characteristic of the Bakken that contributes to its outstanding productivity is its strong overpressuring. The formation attains pressures of up to 0.7 psi/ft this is thought to be a result of hydrocarbon generation. The Bakken is conformably overlain by the dense Lodgepole limestone, which forms an effective top seal.

Williston Basin Stratigraphy



The Bakken is one of many producing intervals in the hydrocarbon-rich Williston Basin.



Source: Modified from Webster 1987

The Bakken's thermal kitchen resided in western North Dakota and eastern Montana, but did not extend into Canada.

The Bakken is also fractured, and this fracturing is thought to be related to tectonics, lineaments, and oil generation. Both horizontal and vertical fractures are present. In the thermal kitchen, vertical fractures are much more prevalent.

The formation is commonly divided into an upper shale, a middle mixed clastic and carbonate unit, and a lower shale.

The *Upper Bakken Shale* reaches 30 ft in thickness. Its total organic carbon (TOC) content averages 10%, which makes it an extremely rich source rock. It is a finely laminated, black mudstone. It contains illite clay minerals, quartz, feldspar, and carbonate grains. Pyrite can be abundant.

The *Middle Member* of the Bakken is a mixed carbonate/clastic sequence. At Elm Coulee, the middle member is a dolomitized carbonate-bar complex. It has relative low porosity, between 8% and 10%, and permeability of .05 md, according to investigators at the Colorado Energy Research Institute and Colorado School of Mines.

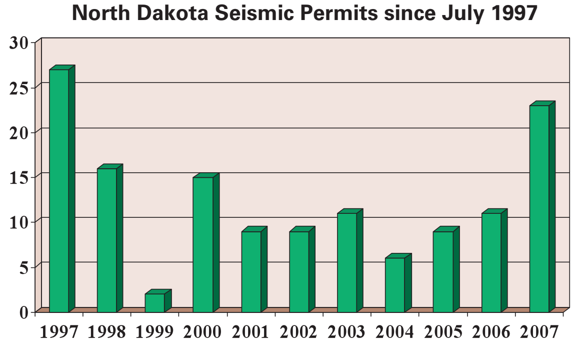
The Middle Member is the target of the current drilling campaigns. Many workers subdivide it into smaller units. Typically, one facies varies from fine- to medium-grained sandstone to siltstone. It is often cemented with calcite, and dolomitization is observed. Microfractures are common in core. Carbonate facies are also present, and these can range from silty limestone to calcareous siltstone to dolomitic limestone. It attains an average thickness of around 40 ft, but does reach up to 90 ft in the Elbow Subbasin in west-central Saskatchewan (Smith, 1996).

In North Dakota, the eastern side of the Nesson Anticline is rich in clastics, and the western side is sediment starved. It appears that great anticline acted as a barrier to clastics. While the northern and southern portions of the Nesson were high, the middle was low during Bakken deposition. Two shears were responsible for the downdropped portion of the anticline, and sediments were able to wash over this part.

The *Lower Bakken Shale* is black and rich in organics, much like the upper shale. Its TOC averages 8%. Calcite and pyrite grains are common, and microfractures can be observed in core. It is quite a

RIGHT: Seismic permits have jumped along with Bakken drilling in North Dakota. 3-D seismic is widely used in the horizontal play.

North Dakota Seismic Permits since July 1997



Source: North Dakota Department of Mineral Resources bit thicker than the upper unit, and can reach nearly 60 ft in the center of the North Dakota sub-basin (Smith and Bustin, 1996).

The *Three Forks* unit lies immediately below the Bakken. Included in the Three Forks is the Sanish sand. The source system reaches down 150 ft or so into the Three Forks, and the petroleum system also includes portions of the lower Lodgepole.

Antelope Field, discovered in 1953, is considered a Sanish pool. It had 52 wells, currently 12 wells produce. The reservoir has made 12.8 million bbl of oil and 10 Bcf of gas. There are three distinct zones: Bakken, Sanish, and Upper Three Forks. Decline curves for Antelope are not similar to other Bakken areas, likely for this reason.

Petro-Hunt's famous #2D-3-1H, in Section 2-153N-95W, McKenzie County, North Dakota, is the most prolific well to date in the play. It was completed in October 2006 and has already produced more than 600,000 bbl of oil. The well, drilled in Charlson Field, has tapped into a highly fractured area.

One reason that the Three Forks is so attractive to explorers is that it has good porosities, which means matrix storage.

In Manitoba's Sinclair Field, porosities range from 17% to 22%. The field produces from Middle Bakken plus two separate Three Forks intervals, 100 feet below the Bakken.

The Bakken/Three Forks contact is sometimes unconformable, and can be sharp or gradational. The Sanish sand is placed in the Three Forks, but to some workers appears to be related to the Bakken. It occurs erratically.

The Bakken is underlain by the Devonian *Prairie Salt*, an interval that tends to dissolve. Its dissolution greatly affects overlying rocks; the Bakken is marked by dissolution edges and holes.

In some areas, such as the Lodgepole area near Dickinson, the Bakken thickens over salt-collapse areas. At Elm Coulee Field in Richland County, Montana, the zero edge of the Prairie Salt lines up with the thick Middle Member of the Bakken.

Seismic Data

For decades, Bakken explorers have used seismic data to help their exploration and development efforts. In the early days of horizontal drilling in the late 1980s, operators employed 2-D data to help determine areas of fractured Bakken, either from salt dissolution or draping over structural features.

Today, 3-D seismic is widely used to fine-tune locations and resolve reservoir properties. Two immense surveys are in the works: CGG Veritas has permitted its Big Bakken shoot, an enormous 646-sq-mile 3-D survey that covers portions of Mountrail and Burke counties, North Dakota. The survey runs along the east side of the Nesson Anticline, from townships 154-163n, ranges 91-94w.

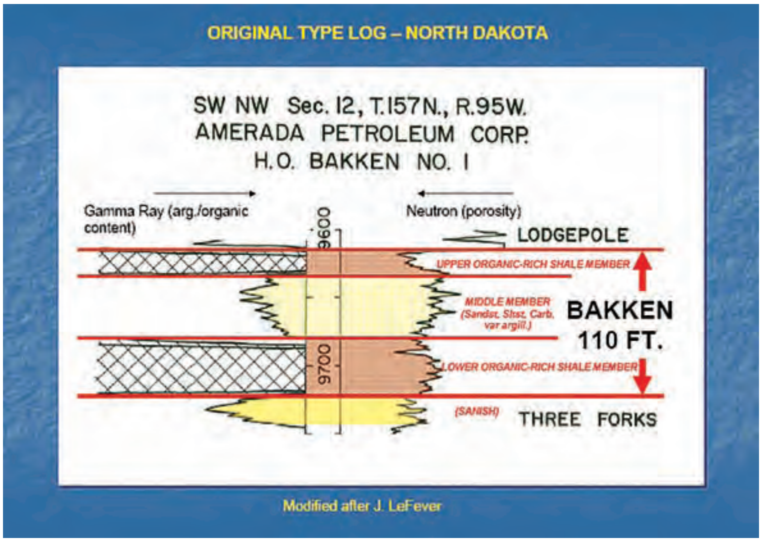
CGG Veritas has also permitted a 330-sq-mile survey in northern Divide County, North Dakota. According to IHS Inc., the geophysical company expects to complete the Blooming Prairie survey in early 2009. It will cover portions of townships 161-164n and ranges 96-100w. The area contains a number of Bakken fields, including Blooming Prairie, Ambrose, and Baukol-Noonan.

Through the end of October, 18 seismic surveys, both 2-D and 3-D, had been permitted in 2008 in North Dakota.

Seismic programs that have been permitted or shot recently include:

- A 33-sq-mile shoot in McKenzie County, North Dakota. This CGG effort, which abuts the Montana state line, will cover several fields, including Bakken production in Cartwright and Mon-Dak fields. The Cartwright 3-D survey will be shot across portion of townships 149-151n and range 104w.

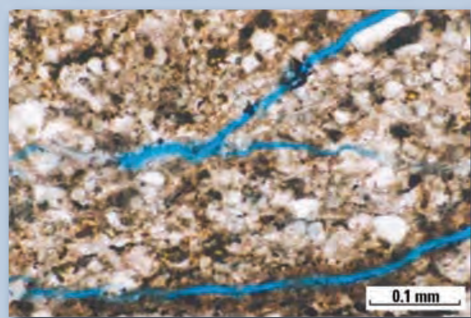
The type log for the Bakken shows its three members: the upper shale, middle clastic/carbonate interval, and lower shale.

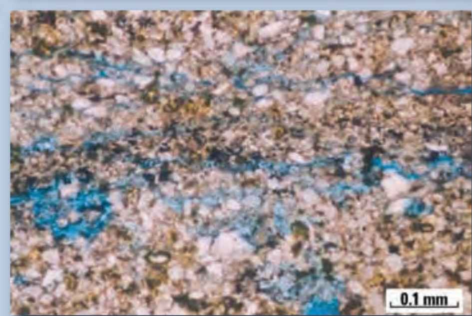


The middle member of the Bakken is the target of current horizontal drilling campaigns. RIGHT: Bakken drilling has dominated North Dakota activity of late.

Middle Member Bakken Porosity

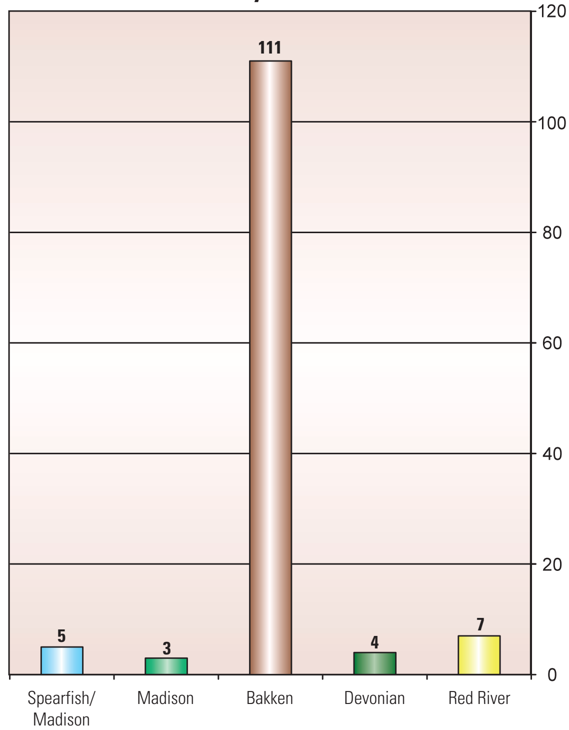
- Primary and secondary matrix porosity
- Fracture Porosity: related to regional and salt tectonics; related to hydrocarbon generation





Source: Adapted from LeFever, North Dakota Geological Survey

North Dakota 2007 Producing Wells Added by Formation



Source: North Dakota Department of Mineral Resources

- A 43-sq-mile survey in Williams County, North Dakota. Geokinetics USA's Cassandra shoot is running along the western side of the Nesson Anticline in townships 155-157n, ranges 96-97w. The area is a few miles west of Beaver Lodge Field, which is the site of Bakken activity by Hess Corp. Within the Cassandra survey, three Bakken wells have been drilled in Dollar Joe Field, currently operated by Whiting Petroleum. Since March 2006, the field has made some 54,000 bbl of Bakken oil.
- A 117-sq-mile survey in Mountrail County, North Dakota. PGS Onshore is acquiring this South Ross 3-D data for Brigham Exploration in townships 154-156n and ranges 91-94w.
- A 229-sq-mile survey in Mountrail County, North Dakota. Geokinetics is shooting this survey for Hess Corp. The Red Sky 3-D survey commenced in August 2008 in portions of townships 155-157n, ranges 89-91w. It covered the area where Continental Resources drilled its #1-35H Jean Nelson discovery, in Section 35-156n-91w. Hess has an active drilling program in the area.
- A 131-sq-mile survey in Mountrail County, North Dakota. Geokinetics completed the Shell Lake survey this spring for operator EOG Resources in townships 153-156n and ranges 88 to 90w.
- A 152-sq-mile 3-D survey for Petro-Hunt LLC in Williams and Divide counties. Global Geophysical Services Inc. completed the Bright Prospect survey in the first half of 2008 over an area where the independent has been drilling Bakken/Sanish tests. It covers portions of townships 159-161n and ranges 98-100w.
- A 110-sq-mile survey in Dunn and McKenzie counties, North Dakota. This effort, the North Mandaree 3-D, is being collected by CGG for Zenergy Inc. in townships 149-150n and ranges 93-94w.

The Bakken Tops the List for Potential

An overview of the play and key operators underscores the area's importance.

By Don Lyle
Contributing Editor

No play in the lower 48 US matches the Upper Devonian-Lower Mississippian Bakken for sheer volume of undiscovered but technically recoverable hydrocarbons.

That's a mean number of 3.65 billion bbl of oil, 1.85 Tcf of gas and 148 million bbl of natural gas liquids from the formation in Montana and North Dakota, according to a US Geological Survey (USGS) report issued in April 2008. The study said there was a 5% chance the Bakken held 4.3 billion bbl of oil, while it calculated a 95% chance that the shale contained 3 billion bbl of technically recoverable oil.

To put that in perspective, the government agency estimated total US technically recoverable oil reserves – not including the Bakken — at 174.67 billion bbl.

The Bakken makes up most of the 4.3 billion bbl of technically recoverable oil in the Williston Basin. Among other areas in the lower 48 states, the Western Gulf Basin holds 3.38 billion bbl, the East Texas/Louisiana/Mississippi Salt basins 2.76 billion bbl, the Permian Basin 1.26 billion bbl, and the Ventura Basin in California 1.06 billion bbl of undiscovered technically recoverable oil. No other basin in the lower 48 has 1 billion bbl.

Most of the US technically recoverable oil lies in Alaska, with 10.36 billion bbl in the Alaska National Wildlife Refuge, 3.98 billion bbl on the North Slope, and 10.56 billion bbl of undiscovered technically recoverable oil in the National Petroleum Reserve-Alaska.

Canada called the Bakken the hottest play in western Canada and estimated its own share of Bakken potential at 25 million bbl to 100 million bbl, probably based on numbers from the USGS survey.

That was a big surprise to most people in the oil and gas industry. A 1995 USGS report estimated

undiscovered technically recoverable Bakken hydrocarbons at 151 million bbl.

Another USGS estimate offered US in-place resources at 400 billion bbl of oil with probable recoveries less than 5% of that number.

A later estimate by Headington Oil Co., one of the two largest operators in the Elm Coulee field in Montana, which produces from Bakken, put in-place resources from that field alone at 5 million bbl per sq mile. Assuming average recoveries of 10%, reserves from that field alone would total 500 million bbl.

Those impressive numbers led to enthusiastic forecasts. "The future potential is enormous. It means we will be able to exploit this for the rest of the century," said Lynn Helms, director of the North Dakota Dept. of Mineral Resources.

One author went so far as to call the Bakken "the new Saudi Arabia."

Not all reports came in at that optimistic level. The USGS report estimated some 2.6 billion bbl of Bakken oil could be technically recoverable from North Dakota, but the state countered with an estimate of 2.1 billion bbl.

No one guessed at even the most pessimistic of those projections when Amerada Petroleum Corp., predecessor of Hess Corp., completed the H.O. Bakken No. 1 in Section 12-157n-95w on the Nesson Anticline in Williams County, N.D., on Henry Bakken's property in 1953.

The tight formation made minimal contributions to North Dakota's production until Meridian Oil Inc., a subsidiary of Burlington Northern Railroad, found and tested the benefits of horizontal drilling to cross natural fractures in the 8-ft-thick Upper Bakken shale.

It initially drilled the No. 33-11 MOI vertically and found the formation tight. It moved back up the hole to 9,782 ft and drilled horizontally with a 630-ft lateral. It completed the well in September 1987 for 258 b/d of oil and 299 Mcf/d of gas. The well produced 346,942 bbl of oil and 54,654 bbl of water through December 1998.

The well cost US $2 million to drill and took 57 days to complete. It also set off a burst of horizontal drilling to the naturally fractured Bakken until falling oil prices closed the play down a few years later.

LYCO Energy Inc., Headington Oil Co., and others renewed interest in the Bakken with vertical wells in Richland County, Mont., but the play really took off when LYCO drilled the first horizontal well into the middle Bakken in Elm Coulee field in 2000.

Since then, Elm Coulee field has produced more than 65 million bbl of the 105 million bbl of oil produced from the Bakken as the horizontal play burst through the Richland County boundaries into a wide area of North Dakota.

Characteristics

The Bakken consists of the Upper Bakken shale, the Lower Bakken shale, and the Middle Bakken. The Mississippian Lodgepole lies on top of the Upper Bakken and provides a reservoir for Bakken-sourced hydrocarbons. The Devonian Three Forks lies below the Lower Bakken. The Upper Bakken is about 23 ft thick, and the Lower Bakken is 50 ft thick through much of the North Dakota portion of the basin. The Middle Bakken is about 85 ft thick. Total organic content can reach 30%.

The Middle Bakken consists of five zones. Siltstone makes up the upper and lower zones. The middle layer is sandstone and the two intermediate layers are interbedded dark gray shale and buff silty sandstone, according to Julie A. LeFever with the North Dakota Geological Survey.

That Middle Bakken member has proved to be a prolific producer in both Montana and North Dakota. In North Dakota, the Bakken lies at about 10,000 ft reaching 11,000 ft at the depocenter in southwestern North Dakota.

The formation rises to 4,500 ft at the eastern edge of the Williston Basin and to about 3,100 ft at the Canadian border. The overpressured zone carries pressures between 5,500 and 5,800 psi and contains the huge volumes of oil described by the USGS. The Lodgepole above and the Three Forks below formed effective barriers to migration. As the shales matured, expansion of the kerogens in the shale produced macro and micro fractures, which can produce 39° to 46° gravity oil to well bores, particularly horizontal well bores.

Bottomhole temperatures are higher in North Dakota and pressures tend to be higher at .5 to .58 psi/ft of depth. The shale in North Dakota is unstable and argues against openhole completions.

Bakken Returns

The Bakken shale offers attractive returns at current oil prices and horizontal well costs.

WELL COST							Source: Jefferies & Co.
$6.25 million	47%	67%	90%	114%	138%	164%	190%
$5.25 million	63%	90%	118%	148%	180%	210%	242%
$4.25 million	89%	125%	162%	201%	240%	280%	110%
OIL PRICE	$50	$60	$70	$80	$90	$100	$110

Porosities generally sit in the 7% range with some areas tested as high as 10%. Permeabilities are in the .01 md area.

An Energy Information Administration report said, "The recent, highly productive oilfield discoveries within the Bakken formation did not come from venturing out into deep uncharted waters heretofore untapped by man, nor from blazing a trail into pristine environs never open to drilling before. Instead, success came from analysis of geologic data on a decades-old producing area, identification of untapped resources, and application of the new drilling and completion technology necessary to exploit them. In short, it came from using technology to convert unconventional resources into reserves."

In putting together the technically recoverable resource estimate released in April 2008, the USGS divided the Bakken into five assessment units (AUs).

The Elm Coulee-Billings Nose AU in Montana and extending southeast into North Dakota, contains a mean 410 million bbl of oil, 208 Bcf of gas, and 17 million bbl of natural gas liquids (NGL), all undiscovered and technically recoverable.

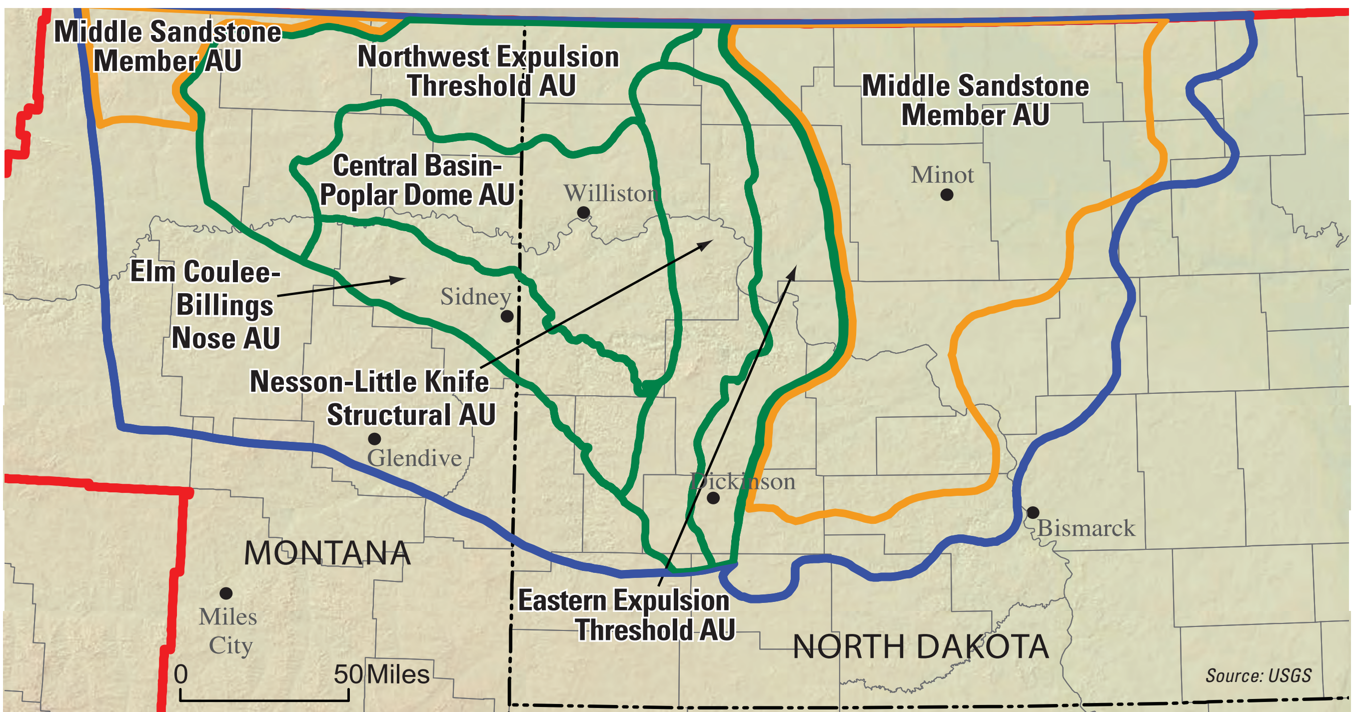
The Central Basin-Poplar Dome AU, also in Montana and North Dakota north of the Elm Coulee-Billings Nose AU, holds a mean 485 million bbl of oil, 246 Bcf of gas, and 20 million bbl of NGLs, undiscovered but technically recoverable.

The Nesson-Little Knife AU running north and south along the Nesson Anticline in in North Dakota contains an estimated mean undiscovered by technically recoverable 909 million bbl of oil, 461 Bcf of gas, and 37 million bbl of NGLs.

Immediately to the east, the Eastern Expulsion Threshold AU holds an estimated mean 973 million bbl of oil, 493 Bcf of gas, and 39 million bbl of NGLs in undiscovered and technically recoverable resources.

The final area is the Northwest Expulsion Threshold AU, generally north of the Central Basin-Poplar Dome AU to the border with Manitoba and

The blue outline shows the extent of the Bakken-Lodgepole total petroleum system, while the green outlines delineate assessment units. The yellow line shows conventional resources.




NATCO
CONNOR
SALES COMPANY, INC.
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SALES COMPANY, INC.

Bakken Resources

Source: USGS

	Total Petroleum System and Assessment Unit	Field Type	Total Undiscovered Resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
	Bakken-Lodgepole TPS													
Continuous Oil Resources	Elm Coulee–Billings Nose AU	Oil	374	410	450	410	118	198	332	208	8	16	29	17
Continuous Oil Resources	Central Basin–Poplar Dome AU	Oil	394	482	589	485	134	233	403	246	10	18	35	20
Continuous Oil Resources	Nesson–Little Knife Structural AU	Oil	818	908	1,007	909	260	438	738	461	19	34	64	37
Continuous Oil Resources	Eastern Expulsion Threshold AU	Oil	864	971	1,091	973	278	469	791	493	20	37	68	39
Continuous Oil Resources	Northwest Expulsion Threshold AU	Oil	613	851	1,182	868	224	411	754	440	16	32	64	35
Continuous Oil Resources	**Total Continuous Resources**					**3,645**				**1,848**				**148**
Conventional Oil Resources	Middle Sandstone Member AU	Oil	1	4	8	4	1	1	3	2	0	0	0	0
Conventional Oil Resources	**Total Conventional Resources**					**4**				**2**				**0**
	Total Undiscovered Oil Resources					**3,649**				**1,850**				**148**

The USGS assessment units show the distribution of undiscovered technically recoverable resources in the Bakken.

Saskatchewan. It holds mean estimated undiscovered and technically recoverable resources amounting to 868 million bbl of oil, 440 Bcf of gas, and 35 million bbl of NGLs.

At the end of 2007, the formation was producing some 200,000 b/d from 1,100 wells in North Dakota and Montana. North Dakota's portion of that was 70,000 b/d from 423 wells.

For contrast, the Canadian segment of the Bakken play produced 56,000 b/d of oil at the end of the same year.

Recovery Techniques

Operators have tried a variety of techniques to wring maximum production from the tight Bakken, but the number one ingredient in the recipe for success is horizontal drilling with as many a three laterals reaching out from the vertical well bore. Currently, about 95% of Bakken wells are horizontal.

The Bakken, particularly in North Dakota, is unstable in some areas and some wells require a liner to prevent the hole from collapsing.

According to the North Dakota Geological Survey's LeFever, earlier wells experienced formation damage from drilling muds, and companies found a cure in drilling with slightly underbalanced inverted mud systems.

The US Dept. of Energy agreed, saying, "Earlier drilling in the Bakken formation targeted the shale members. Success in these efforts hinged on connecting conventional vertical wellbores with an existing natural fracture system while not ruining the well bore in the process with introduced drilling fluids. The shale itself is highly reactive with water and swells when exposed to it, which can seal off a productive fracture system. Also, the Bakken formation contains iron pyrite within its sediments. This mineral forms an iron hydroxide precipitate when exposed to hydrochloric acid, and there are reported cases of this phenomenon causing irreparable well damage."

Current techniques call for the operator to determine the orientation of natural fractures and drill to intercept the maximum number of fractures.

The operator then fractures the well and produces it back through an uncemented pre-perforated liner.

Frac jobs require equipment stout enough to overcome pressures up to 5,800 psi. Once the formation is fractured, closing pressures can reach more than 8,000 psi. That often requires proppant with more resistance than common sand.

Marathon Oil Corp. drills to Middle Bakken dolomitic zone at about 10,000 ft true vertical depth and drills a 10,000-ft lateral.

It starts with 13 ½-in. surface casing, drops to 9 ⅝-in. casing at about 2,150 ft, then to 8 ⅝-in. and 7-in. casing at 11,000 ft. It sets 4 ½-in. liner at 20,000 ft.

EOG Resources Inc. completed the 1-07H Detienne horizontal well in its Parshall field, the most prolific Bakken field in North Dakota. It reached the Middle Bakken at 9,318 ft and reached TD in the same formation at 14,518 ft. It conducted open perforations in the Bakken from 9,660 ft to 14,348 ft and fractured with 819,500 gallons of water and 1.98 million lb of sand. The well showed an initial production of 824 b/d of oil, 369 Mcf/d of gas, and 2,074 bbl of water, according to IHS Inc.

Financial Aspects

Financial returns on Bakken wells bring smiles to faces of board members, company managers, and investors. Jefferies & Co. Inc., in its June 2008 Resource Chronicles, using figures from the North Dakota Industrial Commission, company reports, and its own information, demonstrated why the Bakken is so popular.

A well with a completed cost of $5.25 million should return 242% to the operator with an oil price of $110/bbl. Even at $50/bbl, the return is 63%.

Those figures assume 600,000 bbl of reserves in the well, a first-month average production of 600 b/d, a fixed cost of $4,000 a month, variable costs of $6/bbl, a 5% severance tax, and a net royalty interest of 80%.

According to EOG, the Bakken gives it the highest returns in its portfolio, which includes the Barnett shale.

The average per-acre bid for Bakken properties in the April 2008 North Dakota auction reached $516. The high per-acre average bid in those auctions was $825 in late 2007.

The high bid reached $33,000 during the November 2007 sale when Sinclair Oil & Gas Co. offered $16,500 an acre for a half interest in 320 acres in Mountrail County. EOG's Parshall field is in that county.

Companies operating in the US/Canada Bakken shale play are profiled on the following pages.

US Key Players

American Oil & Gas

American Oil & Gas targets oil and gas opportunities in the Rocky Mountains, and the Bakken shale offers one of those opportunities within a stack of possible pay zones in the Williston Basin in Williams and Dunn counties in North Dakota.

It calls its North Dakota properties on the western edge of the Nesson Anticline its Goliath Project, where it holds some 88,000 gross (50% interest in 167,000 acres) of properties. Teton Petroleum Co. holds the other half.

An early entrant into the modern Bakken play, American Oil & Gas acquired a 75% working interest in 33,000 acres in the Goliath area in 2005 for US $2.97 million and 675,000 shares of common stock.

It previously owned some Bakken properties in Richland County, Mont., as a non-operating partner.

According to Pat O'Brien, chief executive officer, "This new acreage position will greatly expand our exposure to additional Bakken potential. In addition to the Bakken formation, we see opportunity for exploration in the Mission Canyon, Nisku, Birdbear, Duperow, Interlake, and Red River formations."

At that time, he listed horizontal wells to the Middle Bakken as the prime target and said other operators nearby had drilled Bakken wells with initial test rates of 460 b/d and 568 b/d from single lateral well bores.

In a 2Q report, the company said the Champion 1-25 trilateral well drilled on the Goliath properties was producing and had been drilled and completed differently from current standard completion methods. It later said the well was not a commercial success. It showed an initial potential of 180 boe/d, but production dropped quickly to 55 boe/d.

American Oil & Gas calls the Middle Bakken its primary target within that area, but its current production comes from the deeper Red River formation. It held an 11.9% non-operated interest in the Solberg 32-2 well drilled to 14,400 ft in the Red River in 2007. That discovery tested for 2.1 Mcf/d of gas and 408 b/d of condensate. That interested the joint interest partners enough that they contracted a 10 ½-sq-mile 3-D seismic survey around the well.

It also planned the follow-up Machette 30-1 well to 14,400 ft to test the Stonewall, Red River, and Winnipeg formations with continuing assessment to the Bakken as a primary target and the Madison, Duperow, Nisku, and Interlake formations as secondary objectives.

American Oil & Gas anticipates drilling more Bakken wells late in 2008. It said the acreage had the potential for 100 gross wells.

Anschutz Exploration Co.

Anschutz Exploration Co. entered the Bakken early, got off to a big start, and then took a break to examine its strategy in the North Dakota section of the Bakken play in the Williston Basin.

The private company ran up to three rigs in the play at one time when it worked the play under the Ansbro name, but it pulled all the properties into the Anschutz umbrella in mid-2008.

During a May 2006 presentation, Schlumberger named Ansbro's Miller 44-31H Willmen in Dunn County one of the top 150 Bakken wells with a production rate of 334 b/d. It drilled that 10,780-ft vertical well horizontally to a total depth of 16,101 ft.

Now, it has reawakened activity in southern Dunn County after a lapse of about a year, concentrating on the area around Russian Creek, St. Anthony, and Murphy Creek fields.

According to the *bakkenshale.blogspot.com* Web site, the company asked North Dakota authorities for 1,280-acre spacing in 84 sections of land that it wants to include in either the Russian Creek or St. Anthony field.

In July 2008, Anschutz planned a horizontal well, the 24-7H Scott, some two miles south-southeast of the southern-most producing well in Murphy Creek field. That Marathon Oil Corp. well tested for 327 b/d of oil, 171 Mcf/d of gas, and 92 b/d of water from an openhole lateral from a vertical depth of 10,778 ft north to a total depth of 19,720 ft.

One wildcat well completed under the Ansbro Petroleum Co. name tried to maximize production with four laterals. That well, the 12-8H Griggs, is in Dunn County. It tested at only 73 b/d of oil, 19 Mcf/d of gas, and 214 b/d of water, according to IHS Inc.

Subsequently, the company discontinued its dual-lateral program in favor of a single 5,000-ft lateral to hold costs down.

Behm Energy Inc.

Privately held Behm Energy Inc., a longtime Williston Basin producer, has taken an active interest in the Bakken shale play with several wells permitted and an outside chance of investment money from Holland.

A RedOrbit report on the 2008 Williston Basin Petroleum Conference & Expo quoted Gerry Van Dijk, a banking and investment attorney from Amsterdam, who said, "I read about North Dakota's oil in an article in the *New York Times* in December." He came to take a closer look representing a pool of private investors from Holland looking for investment opportunities.

"We'd like to make a first investment of US $100 million and then see how it goes," he added. He has set up an association with Lenny Behm, president of Behm Energy, but Behm said they were just friends.

Behm has Bakken leases in Mountrail County, N.D., in the prolific Parshall field area, and additional leases in other areas, including Ward County, also in North Dakota, where it is working its Bakken Carbondale Project.

Northern Oil & Gas has taken a 3% interest in Behm's Edwards 1-30 BH and Moen 1-29 BH horizontal wells, both in Mountrail County. Drilling dates haven't yet been set. In all, Northern has interests in four drilling units in Parshall field with Behm.

Early in 2008, the North Dakota Industrial Commission issued seven drilling permits in Osloe and Spring Coulee townships in Mountrail County to Behm. All of the wells were classed as tight holes.

Brigham Exploration Co.

Brigham Exploration Co. is on an acquisition and drilling binge as it executes an aggressive plan to make a mark in the Bakken play in the Williston Basin as a major operator and participant.

On the acquisition side, the company had 95,600 acres of leases in the Williston Basin in McKenzie and Williams counties. By the beginning of March 2008, the company held almost 240,000 acres of prospective Bakken leases.

The company added 48,000 Bakken acres west of the Nesson Anticline in North Dakota to bring its holdings to 287,000 net acres by the end of 2Q 2008. That acquisition raised holdings to 199,000 net acres west of the Nesson Anticline in North Dakota and Montana and 88,000 acres east of the anticline in Mountrail County, the most prolific Bakken county in North Dakota.

"We expect the improved drilling and completion techniques we're utilizing east of the Nesson Anticline to positively impact the economics of our acreage in the western portions of the basin," said Bud Brigham, chairman, president, and chief executive officer.

In addition, "Given continued drilling successes and accelerating activity by EOG and other operators in the Parshall/Austin area, we expect to participate in a significant number of non-operated wells during the second half of 2008 and into 2009," he said.

By the end of July 2008, Brigham raised its land position to 293,000 acres.

Drilling produced results, as well. At the end of 2007, Brigham had five net proved locations. By the end of 2008, it plans to have 35 proved locations, assuming all permits go through.

As a bonus, all of the company's properties have potential to produce from the Three Forks and Sanish (upper Three Forks) zones immediately below the hydrocarbon-generating Lower Bakken shale.

Other potential targetzs include Red River and the shallower Lodgepole and Mission Canyon formations.

POSITION: Most of Brigham's drilling, and most of its growth, took place in Mountrail County where it controls some 40,300 net acres. About 7,000 of those net acres adjoin giant Parshall field and EOG Resources' prolific Austin field. It also has some 26,000 net acres in its Ross area west of Parshall field between that field and the Nesson Anticline.

Another 7,300 net acres in Mountrail County are in Brigham's North Stanley area, about 15 miles northwest of EOG's Austin wells and 12 miles north of Brigham's Bakke 23-1H discovery. It also holds 48,000 acres in an extensional area east of the Nesson Anticline.

West of the anticline, it holds some 51,000 net acres in McKenzie and Williams counties and roughly 100,000 acres in Sheridan and Roosevelt counties in Montana. The Montana acreage has the Red River as a primary target, but it also has Bakken potential.

Among the company's producing wells at the end of 2Q 2008, the Mrachek 15-22 1H, west of the Nessons Anticline flowed at an early production rate of 727 boe/d.

Its Hallingstad 27-1 flowed at an early rate of 450 boe/d. The Bakke 23-1H, in which the company has a 76% working interest, tested at 310 boe/d on pump, the Hyanek 2-1H at 142 boe/d on pump, and the Bergstrom Family Trust 26-1H at 119 boe/d on pump. All were in Mountrail County.

Brigham had one rig under contract in August 2008 working east of the anticline but planned to add another rig by the end of September.

Currently, operators work on 640-acre spacing in the area around Parshall field, but spacing will likely drop to 320 acres before long, the company's president said.

Brigham added, "This year, we expect to drill or participate in the drilling of at least 17 gross wells, or six net, in the play in at least four different areas. The 40,300 net acres in Mountrail County give the company the potential to drill 137 to 274 net wells, depending on spacing.

At the end of July, Brigham reported its best well in the Bakken play. Its Carkuff 22-1H in the Ross area tested flowing 1,110 b/d of oil and 500 Mcf/d of gas, and it was completing two more wells, the Kvamme 2-1H and the Pyara 1-21H (operated by Slawson Co.) in the Parshall/Austin area.

Its Johnson 33-1H flowed 618 boe/d in the North Stanley area, and the Manitou State 36-1H in the Ross area tested at 272 bo/d. Brigham's Ross acreage could support up to 84 net wells on 320-acre spacing.

It also has interests in the EOG-operated Austin 25-35 1H and the Austin Wayzetta 13-01H wells in the preparation stages. The 25-35 1H well is a south offset to EOG's 3,060-b/d Austin 8-26H well.

Those completions increased the company's overall production from 100 b/d of oil in December 2007 to 500 b/d in June 2008 and 1,500 b/d of oil by September 2008. Brigham could drill up to 27 net wells on its 8,700 acres in the Parshall/Austin area.

On July 15, Brigham raised its capital expenditure plans for 2008 to US $174.8 million, a $54-million increase from its February budget. Some 80% of those funds will go into drilling with the rest marked for land and seismic acquisition. Approximately $109 million, or 63% of the total, will go to the Williston Basin. The company has 85 people working on acreage acquisitions.

That Williston Basin money will finance 12 operated Bakken-Three Forks and two Red River wells and numerous non-operated wells.

Brigham plans a further expansion in 2009, according to the company's September presentation at a Lehman Brothers conference.

The expansion potential with the company's current holdings offers 298 locations east of the Nesson anticline and 617 locations west of the anticline on 320-acre spacing.

COMPLETION TECHNIQUES: Over the years, Brigham has changed its completion techniques, moving to horizontal wells with single laterals. The trend leans to longer laterals with more staged fracture treatments.

West of the Nesson Anticline, its Field and Erickson wells in 2006 came in at 200 b/d of oil and stabilized between 50 b/d and 90 b/d with estimated ultimate recoveries from 100,000 b/d to 165,000 b/d with a single frac job and no isolated stimulations.

Its Mrachek re-entry in 2008 tested at 727 boe/d from seven isolated fracture intervals, and two wells spudded in August will have 20 to 25 isolated fracture intervals.

East of the anticline in the Ross area of Mountrail County, the company used 10 fracture stages in the Johnson 33-1H well to get 618 boe/d, 12 frac stages in its 1,100 boe/d Carkuff well, and seven frac stages in its 380 boe/d Bakke well.

Fractures have a great deal to do with success. Laterals on the Field and Erikson wells were 7,584 ft and 8,799 ft, respectively, but the Mracheck well in the same area with a 5,332-ft lateral and more frac treatments produced at a much higher rate.

Laterals in the Bakke and Carkuff wells east of the anticline were 4,707 ft and 5,454 ft, respectively. A company must balance production potential with treatments. The earlier wells with one frac treatment costs $5.8 million. The Mracheck well cost $6.8 million with seven staged treatments. The Bakke well cost $4.9 million with seven stages, and the Carkuff, with 13 staged frac treatments, cost $6.6 million for production of 1,100 b/d.

Liners have evolved from pre-perforated uncemented designs in 2006 to uncemented with swell packers in 2008. Fracture stages have increased from one to 13 currently with 22 to 24 stages planned for the future.

Brigham's Johnson 33-1H in Mountrail County aims for Bakken pay.

Photo courtesy of Brigham Exploration Co.

Williston Basin Resource Inventory

Currently 85 field Landmen acquiring additional BEXP leasehold

			Bakken		Three Forks		Total	
		Net Acres	Locations	Reserves	Locations	Reserves	Locations	Reserves
Most Data	Parshall/Austin Area	8,500	26	15 Mmbo	26	15 Mmbo	52	30 Mmbo
	Other Mountrail County	35,900	112	28 Mmbo	112	28 Mmbo	224	56 Mmbo
	Total Mountrail County	44,400	138	43 Mmbo	138	43 Mmbo	276	86 Mmbo
	Williams/McKenzie Co's	95,800	299	70 Mmbo	299	70 Mmbo	598	140 Mmbo
	E. NessonExt. Areas	51,100	159	39 Mmbo	159	39 Mmbo	318	78 Mmbo
Least Data	Eastern Montana	101,700	317	78 Mmbo	317	78 Mmbo	634	156 Mmbo
	TOTAL	293,000	913	230 Mmbo	913	230 Mmbo	1,826	460 Mmbo

** Unrisked potential locations and reserves Assumptions include two laterals per section for both Bakken and Three Forks Also assuming 300 000 Bo/well for both Bakken & Three Forks except Parshall/Austin Area where 700,000 Bo/well is assumed. NRI s assumed at 82% except Williams and McKenzie Co s ND where 78% NRI was assumed. Numbers may not add up due to rounding.*

Graphic courtesy of Brigham Exploration Co.

Brigham's acreage could generate 913 Bakken and 913 Three Forks locations with potential reserves of 230 million bbl of oil in each of the plays.

Fracture treatments have changed from cross-linked gel with 500,000 lb of sand in 2006 to a current norm of slick water with cross-linked gel and 2 million lb of sand. Future treatments anticipate slick water with cross-linked gel and 3.5 million lb of sand.

FINANCIAL ASPECTS: Using state-of-the-art drilling and completion techniques, Brigham considers its breakeven point a well that will produce 153,000 boe. That's based on the New York Mercantile Exchange strip prices on July 28, 2008, a drilling and completion cost of \$5.638 million, and operating expenses of \$8,397 a month.

That spells profits when probable per-well reserves in the Ross area range from 200,000 boe to 400,000 boe and probable reserves in a Parshall-Austin area well range from 400,000 boe to 1 million boe.

On the low side, the company figures a 200,000-boe Ross area well will cost \$5.87/Mcfe to drill and complete, give back a net present value discounted at 10% a year of \$1.87 million and offer a 19.1% rate of return.

On the high side, a 1-million boe Parshall-Austin well will cost \$1.17/Mcfe to complete, give back a net present value of \$36.57, and offer a return of nearly 200%.

BTA Oil Producers

Midland, Texas-based BTA Oil Producers has worked the stacked pay formations in the Williston Basin for years on both the Montana and North Dakota sides. It still works the shallower zones, including the Pierre.

Details about the privately owned company's Bakken activities are scarce, but it took out permits earlier this year for the 20411 JV-P Nelson and 20411 JV-P Gohrick 43-17 Bakken wells in Williams County, N.D.

Schlumberger's Walt Korziel, in a May 2006 presentation titled "North Dakota Completion Considerations," also named BTA in his list of best Bakken completions in North Dakota to that time. The company's 20411 JV-P Melgaard in Stoneview field in Divide County showed an initial potential of 190 b/d of oil.

It produced from a single lateral with a vertical depth of 8,887 ft and a total measured depth of 15,625 ft.

CNX Gas Corp.

CNX Gas Corp. is a major coalbed methane and gas shale operator in the Appalachian Basin, and its experience there persuaded the company to take a cautious look at the Bakken oil shale play in North Dakota.

It joined the Bakken play by planning to participate with Marathon Oil Corp. in several Bakken wells in 2008. Marathon is the operator. "For the first time in our history, we contributed acreage and invested working interests in the Bakken shale," said Nicholas J. Deluliis, president and chief executive officer of CNX.

Neither company publicly delineated the wells or

A ConocoPhilips pumpjack in the Williston Basin pumps Bakken fluids.

properties in the alliance or the amount of money that would go into the program.

CNX has allocated US $46 million for its shale exploration programs, but that money also includes major commitments to the Chattanooga shale in Tennessee, the Huron, the New Albany, and the Marcellus shales.

In all, CNX has 842,000 acres of shale properties in the Appalachian and Illinois basins with estimated recoverable resources of at least 5.2 Tcf of gas.

Marathon holds 320,000 acres with Bakken potential in North Dakota and plans more than 300 wells in the next five years to reach 20,000 boe/d by the end of 2012.

Concho Resources

The Bakken shale in North Dakota lies far from Concho Resources' core properties in the Permian Basin of West Texas and southwestern New Mexico, but the company counts the Bakken as an emerging play.

It holds 42,362 gross acres (11,069 net) in the Bakken and two wells have been drilled on the property by operating partner Newfield Exploration Co. Most of its properties are in Mountrail and McKenzie counties in North Dakota. It attributed proved reserves of 400 MMcfe to the play.

According to Newfield, its Westberg Prospect area consists of 18,000 gross acres (8,050 net to Newfield) and is prospective for Bakken and the Sanish/Three Forks formation immediately below the Lower Bakken shale. Newfield and Concho each have a half interest in the Westberg area.

"Based on initial encouraging results, Newfield expects to drill five to seven wells in the Westberg Prospect area in 2008," Newfield said. It has more than 20 locations identified in the Westberg area and plans a two-rig drilling program there through 2009.

Concho didn't identify its properties by name, but it said it owned approximately 22,935 gross (2,818 net) acres of leases in Mountrail County and participated in two new wells in 2008. It anticipated increased activity in the area.

Concho said it had participated in eight horizontal Bakken wells by the end of 2007. At that time, four were producing and three awaiting completion. The other was drilling.

The company owned 19,427 gross (8,250 net) acres in McKenzie County with an interest in one producing well at the end of 2007. At that time, it was participating as non-operator in two additional wells, one of which was drilling. That probably was in the Newfield partnership.

In its 1Q 2008 report, Concho said, "We are increasing the amount of capital devoted to the Bakken in North Dakota due to the early success we have seen on the drilling projects we participated in thus far."

ConocoPhillips Inc.

ConocoPhillips Inc. fell into the Bakken play in North Dakota through its involvement in the Red River play acquired in its 2006 acquisition of Burlington Resources in the Williston Basin in the southwestern part of the state.

It does have a substantial position with Bakken potential. At that time, it was North Dakota's largest oil producer with daily production of 40,000 b/d of the state's 119,000 b/d total.

Most of that oil came from its interest in the Cedar Hills operating unit, which it operates with Continental Resources Inc.

Continental said it entered an agreement with ConocoPhillips in June 2006 to form an area of mutual interest in Dunn, McKenzie, Mountrail, and Williams counties in North Dakota to test production from the Bakken. Continental's share of that area was 97,000 net acres. Under the agreement, each of the companies had the right to acquire a half interest in the exploration block acreage owned by the other company for US $500 an acre.

In October 2007, each company had three drilling rigs working within the area of mutual interest.

In a 2Q 2008 conference call in July, Continental said that rig count held steady. The companies expanded their use of multistage frac treatments and increased productivity of wells compared with 2007 drilling.

In a fact sheet, ConocoPhillips said it concentrated its activities on the Bakken and on its Red River waterflood in Cedar Hills South and the East Lookout Butte units. Its land position with Bakken potential covered 160,000 net acres.

Continental also said it was broadening its Bakken play by drilling to the Three Forks/Sanish formation immediately below the Lower Bakken. If that effort is successful, ConocoPhillips undoubtedly will follow suit. Continental said the Three Forks/Sanish could provide substantial incremental production to the Bakken program.

ConocoPhillips also has Barnett shale operations in Texas and a position in the Black Warrior Basin of Alabama with shale potential.

Continental Resources

Continental Resources picked the Bakken shale as one of its core oil and gas areas, a decision that helped move the company into the top landholder position in the play and to the second-largest oil producer in the Rocky Mountains, second only to ConocoPhillips.

The company prides itself on its selection of unconventional resources as a key competency and has drilled more than 600 horizontal wells to back its know-how in unconventional oil and gas. Some 82% of its proved reserves and 76% of its production come from unconventional reservoirs where it holds approximately 1 million net undeveloped acres of leases.

That emphasis paid off as Continental posted record oil and gas production, revenues, and income in 2Q 2008. Income for the quarter reached $127 million, up from $44 million in the same quarter a year earlier on a pro-forma basis.

Harold Hamm, chairman and chief executive officer, said, "Over the past six months, our 2008 cash flow outlook has increased significantly, and as a result the board of directors has approved a $267 million increase in 2008 capital expenditures for drilling, land and seismic, raising our total capex budget to $883 million."

Some $100 million of that increase will go into additional drilling in the Bakken, the Woodford shale in the Arkoma Basin and the company's Appalachian gas shale plays. Another $122 million of the increase will go into seismic and lease acquistion in the Bakken, Haynesville, Marcellus, and Huron shales.

That increased drilling, along with a response from the company's Red River secondary recovery units on the Cedar Creek Anticline should increase year-end production

N.D. Bakken and Arkoma Woodford

Reserve potential	ND Bakken	Arkoma Woodford	Totals
Net reserves/well	325,000 boe	2,400 MMcf	
Net potential unbooked locations	546	541	1,087
Reserve potential	177 MMboe	1.3 Tcf	387 MMboe
Net boe/well	325,000 boe	400,000 boe	
Estimated avg. D&C	$5.8MM	$5.0MM	
Pre-tax IRRs			
@$60/bbl & $6/Mcf	20%	34%	
@$80/bbl & $8/Mcf	40%	69%	
@$100/bbl & $10/Mcf	69%	122%	

1. CLR internal economic model, based on gross reserves per well of 400,000 boe for ND Bakken and 3,000 MMcf for Woodford
2. Assumes 1 well per section for ND Bakken and 8 wells per section for Arkoma Woodford

Table courtesy of Continental Resources Inc.

The Bakken is a hot play for Continental Resources but the Woodford shale in the Arkoma Basin of Oklahoma generates higher returns.

to 43,000 boe/d, up 30% from the end of 2Q of 2008.

Drilling will increase during the remainder of the year as the company expects to raise its operated rig count from 26 at mid-year 2008 to 35 rigs by the end of the year.

POSITION: Continental holds 577,000 acres of land in its Bakken shale leases in Montana and North Dakota and it's one of the company's biggest growth areas. It is currently participating in approximately 20% of the wells drilling in the Bakken today.

Of its total capital expenditures in 2008, approximately $245 million will go into drilling in the Bakken where it produced an average of 8,445 boe/d during 2Q representing 27% of the corporate total from all operations.

Some 82% of the company's total 134.6 million boe of proved reserves are from unconventional reservoirs and approximately 74% of those reserves are proved developed producing, and 25% of those reserves are in the Bakken.

At the end of the half, it was operating 13 drilling rigs in the Bakken and plans to raise that number to 16 by year-end, three in Montana and the rest in North Dakota. At mid-year, ConocoPhillips had three rigs working in an area of mutual interest in which Continental owns approximately 100,000 net acres in North Dakota.

Continental had 546 net potential unbooked Bakken drilling locations in North Dakota spotted at mid-year, based on 640-acre spacing.

The Montana Bakken acreage continues to add approximately 300,000 gross bbl of reserves per well with 320-acre infield drilling and trilateral, field extension wells.

Among notable Montana Bakken wells, the Finnicum 1-25 trilateral well on 640-acre spacing, in which Continental has a 48% working interest, came in at 228 boe/d. The LeaJoe 1-1H single lateral, in which the company holds a 63% working interest, showed an initial potential of 609 boe/d and the Swenseid 3-9H single lateral, in which the company holds 95%, produced 336 boe/d.

On the North Dakota side of the play, Continental completed 13 gross wells in 1Q and 33 in 2Q.

It also drilled the Bice 1-29H in Dunn County for a gross 693 boe/d and the Mathistad 1-35H in McKenzie County for a gross 1,260 boe/d. Neither of those wells produced from Middle Bakken, but the play opened as a result of Middle Bakken activity. Continental completed those two wells in the Three Forks/Sanish formation immediately below the Lower Bakken and some 50 ft to 75 ft below the Upper Bakken. Due to the separation between producing formations, the company believes they may be separate reservoirs, and the combination could sharply increase reserves for the company by simply drilling wells a short distance deeper.

“This is every bit as good as what we have encountered in the Middle Bakken," Jack Stark, Continental's senior vice president for exploration, told the *Daily Oklahoman.* "And if it proves to be separate production, we think it would quantitatively add to our reserves in the field."

COMPLETION TECHNIQUES: Continental logged bonus recoveries from its North Dakota Bakken wells with improved completions. The seven-day average initial production rates for wells completed in 2Q was 513 boe/d, up 13% from the average in the previous quarter.

“These improved production rates and increased consistency show the significant advances we've made in our completion techniques. We've gained valuable experience in the play in the past 18 months. We are now fracture stimulating wells in 10 segments and plan to test the impact of 12 or more segments,” Hamm said.

FINANCIAL ASPECTS: With net reserves per well of 325,000 boe, and 546 net potential unbooked locations, and unbooked reserve potential of 177 million boe, Continental has attractive returns from its North Dakota Bakken play. Figuring $5.8 million to drill and complete a well, the company can get a 20% return with oil priced at $60/bbl and gas prices at $6/Mcf. The internal rate of return doubles with oil at $80 and gas at $8, and the returns climb to 69% with oil at $100 and gas at $10. That assumes 400,000 boe in gross reserves per well and one well per section in the Bakken.

Still, the Bakken offers room for improved returns. The infrastructure is tight, and more pipeline capacity could lower costs. During a US Senate Appropriations Subcommittee meeting in North Dakota in early September, Hamm testified that his company currently ships about 3,000 b/d of Bakken production by rail because of the lack of pipeline capacity. That adds several dollars to the delivery cost of those barrels.

Crusader

Crusader Energy Group, formed early in 2008 when Westside Energy Corp. acquired Crusader and changed the name of the combined company to Crusader, claims the bulk of its assets in the Midcontinent and Permian Basin, and it has one of its seven rigs running in the Bakken shale play and may add more.

The company concentrates on unconventional resources plays, horizontal drilling, and multistage fracture techniques.

At the end of 2007, it had 130 Bcfge of proved reserves and 715,000 gross (248,000 net) acres of leases and 4,800 identified drilling sites.

Within that picture, it holds 37,760 gross (24,550 net) acres of Bakken leases and 300 MMcfge in proved reserves in the shale. It also has 118 potential drilling locations along the Cedar Creek Anticline in southeastern Montana and southwestern North Dakota. It plans six wells on its properties in 2008 with the first well planned to spud in 2Q.

One of those Crusader-operated wells is the Oilers 1H-10 in Richland County, Mont. Northern Oil & Gas holds a 7.5% interest in that well.

The company plans to keep one rig operating through 2009 and may add more.

For comparison, it has 125.4 Bcfge in proved reserves and 17.18 MMcfe/d in production in the Anadarko Basin and 26 Bcfge in proved reserves and 46 MMcfge/d of production from the Barnett shale in the Fort Worth Basin of Texas.

Encore Acquisition Co.

Encore Acquisition Co. is looking for a combination, possibly a sale, to extract full value for the company's assets, but it's not waiting passively for fortune to strike. It is working an aggressive expansion program and increasing earnings.

In the quarter ended June 30, 2008, revenues reached US $354.8 million, up from $180.7 million a year earlier. "We are pleased to see improving results from our two largest areas of capital deployment: the Bakken/Sanish in the Williston Basin and the West Texas JV [joint venture] in the Permian Basin. These areas were already working well, but now they are even better. We previously announced the Charlson 11-16H Sanish well, which [showed an initial potential of] 1,100 boe/d and averaged 843 boe/d over the first seven days," said Jon S. Brumley, chief executive officer and president, in the company's 2Q report.

POSITION: That Sanish well is part of the company's Bakken-Sanish program in North Dakota. The Sanish lies immediately below the Lower Bakken.

The company's success in the Bakken encouraged it to add a third drilling rig to its program to begin drilling the company's Almond Prospect in Mountrail and Ward counties in North Dakota. Encore owns 53,000 acres in that prospect.

In a presentation at a Lehman Brothers conference in September 2008, the company said it set out in 2006 to increase its exposure to "exciting new plays." Those plays included the Bakken.

At the end of the first half of 2008, company-wide production reached 38,205 boe/d and it had a reserve/production ratio of 17 years. Some 80% of its reserves were in oil and it had proved reserves of 239,401 boe.

The Bakken, with first half production of 1,261 boe/d was near the bottom of the production column among its properties. Its lowest area under production was the Tuscaloosa marine shale at 48 boe/d.

Still, Encore likes oil plays, and the Bakken was 88% oil. The company has 6.8 million boe in proved reserves, and 80.6 million boe in proved, probable, and possible reserves.

It had 34,000 net acres in the play in April 2007 and 82,000 acres of Bakken land at the end of 3Q 2007. That grew to 155,000 acres by the end of the 4Q, 178,000 net acres at the end of the 1Q 2008, and 260,800 acres by the end of 2Q 2008.

It planned to grow its Bakken program from three rigs at mid-year 2008 to six rigs. Encore said it could raise its production to about 5,500 boe/d by the end of 2010 with four to six rigs running.

Encore has two primary targets in its Bakken play, the Middle Bakken, which gets its oil from the upper and lower Bakken formations, and the Sanish, which gets oil from the Lower Bakken and is prospective in most of the company's active areas. In those areas, the Bakken lies at depths from 9,300 ft to 11,400 ft, while the Sanish lies below at 9,400 ft to 11,600 ft.

Encore has 103 gross proved wells in its Bakken/Sanish program, with another 563 gross prob-

An EOG Resources' rig works the Bakken play in North Dakota

able wells (268 of those on the company's re-frac program) and 53 gross possible wells, for a total potential production from 719 wells.

FINANCIAL ASPECTS: Under current planning, Encore would spend $69.1 million to develop its proved reserves, $1.2 billion to develop probable reserves, and $162.2 million on possible reserves for a total $1.39 billion. In return, it would get a net present value, discounted at 10% a year (PV10), of $272.6 million for proved reserves, $2.1 billion for probable reserves, and $60.6 million for possible reserves for a total $2.48 billion.

In its presentation at the Lehman Brothers conference, Encore said it planned 53 Bakken wells, 16 operated and 39 non-operated, during 2008.

Cumulatively, Encore has drilled 12 operated wells in the Middle Bakken with a seven-day average initial production rate of 400 boe/d. Historically, its drilling cost has come in under $4 million for a single lateral well on 640-acre spacing. Encore has focused its North Dakota activities in eight specific areas with the largest, its Cherry Prospect area, at 68,700 acres.

Encore offered statistics to show analysts why it likes the Bakken. It has 616 potential drilling locations and 268 re-frac locations. It incurs lease operating costs of $6,720 per well per month. It holds an average 75% working interest in its wells and an average 62% net revenue interest.

It pays production taxes in North Dakota of 7% in the first 18 months of production and 11.5% after that, and it sells its oil at a 12% discount to the New York Mercantile Exchange price.

With that base, and with oil at $115/bbl, it would cash in a PV10 of $7.5 million on a well with 350,000 boe of reserves, $6 million on a 300,000 boe well, and $4.5 million on a 250,000 boe well.

Stated another way, it would get a 101% return on a 350,000 boe well, a 78% return on a 300,000 boe well, a 57% return on a 250,000 boe well, and a 39% return on a 200,000 boe well. Obviously, the bigger the well, the better the economics. Its finding cost on a 200,000 boe well comes in at $25/boe, drops to $20/boe on a 250,000 boe well, $16.67 on a 300,000 boe well, and $14.29 on a 350,000 boe well.

Encore's pioneering re-fracturing program also has yielded results good enough to encourage other operators in the basin to follow its lead.

The company conducted five re-fracs at its Murphy Creek area. Production at the Rogne 11-35 rose to 200 boe/d from 55 boe/d, and production on the Kulish 24-2H increased to 185 boe/d from 45 boe/d. Those were the two best wells in the program.

On average, the re-fracs have added 60 boe/d in incremental production and 80,000 boe in incremental reserves. They offer a finding and development cost of $8/boe and a 100% rate of return.

Enerplus Resources

Arguably, the modern Bakken play began when geologist Richard Findley convinced executives at Lyco Energy that operators missed a rich pocket of oil when they drilled through the Middle Bakken zone.

As the story goes, Lyco brought in Halliburton for expertise in horizontal drilling and fracturing and they put Montana's Elm Coulee Bakken field on the map. That field has produced more than 70 million boe.

Lyco later consolidated its holdings into the Sleeping Giant project in Richland County, Mont., and, in 2005, sold that property to Enerplus Resources Fund, Canada's oldest and second-largest energy income trust, for US $421 million.

The field represented the trust's single-largest producing property with 8% of the company's proved and probable reserves and 11% of its production. Since it bought the properties, it replaced some 9 million boe of produced hydrocarbons and raised reserves by 4 million boe, increasing the field's proved and probable reserves to 42 million boe.

The company invested $106 million to drill 39 gross wells (23.7 net wells) in 2007 and increased production to 11,132 boe/d.

Now, it's fine-tuning the properties, currently working on a third well per section in the drilling program with attractive results but lower than the company had hoped.

Meanwhile, refractures on older wells added an average 50 boe/d in production and 77,000 boe in reserves per well. It planned to spend $60 million in 2008, largely on production optimization with automated pump controls, fluid-level management, and reduction of system downtime. It also planned to test production potential by drilling a fourth well per section and looking for additional properties outside its core area.

With those activities, the company planned to hold production at around 11,000 boe.

"The problem is not finding the oil, it's being able to recover it commercially," said Garry Tanner, chief operating officer, in an article in the *Calgary Herald*.

It met that production target with 11,346 boe/d average in 2Q 2008 after drilling four gross (29 net) wells, according to Gordon J. Kerr, president and chief executive officer.

In an Enercom conference presentation in August 2008, Kerr said the company assumed an 18% recovery in booking reserves, and it was tapping resources of 200 million boe of oil in place. That translated into some $280 million of future development potential.

EOG Resources

EOG Resources Inc. generates big numbers in its earnings, production, reserves, and potential, and it counts the Bakken shale in North Dakota as the play with the company's highest returns.

That's a strong statement, since the company is involved in some of the strongest plays in the US. For example, in 2007 it drilled 293 net wells in the Barnett shale in the Fort Worth Basin to increase production to 271 MMcf/d of gas and 2,200 b/d of condensate and gas liquids. It expected to significantly increase that production in 2008.

At the end of 2007, it had net proved reserves of 6.67 Bcf of gas and 179 million bbl with two-thirds of its production in the US and additional operations in Canada and Trinidad and Tobago.

POSITION: Also in 2007, EOG solidified its position as the second-largest leaseholder in the Bakken play with approximately 320,000 net acres. It increased estimated reserves 80 million boe, net, up from 60 million boe at the end of the previous year. Only 21 million boe of those reserves were proved.

Three reasons for the company's strong results from the Bakken are location, location, and location. Its Parshall field in Mountrail County, N.D., is the most prolific Bakken producer in the state. Most other operators in the area support the strength of their Bakken plays by their distance from Parshall field.

At a mid-year presentation, EOG offered some convincing figures. It had 38 operated wells on sales and another eight operated wells awaiting completion. The average initial potential of its most recent 10 wells averaged 1,700 b/d.

The company figured its properties contained 9 million bbl in place per section and it could attain a recovery factor of 10%. For EOG, that meant 350,000 boe to 700,000 boe in net reserves per well. The 80 million boe in estimated net reserves only count Parshall field, not additional potential in surrounding areas.

During 2008, the company planned step-out wells to expand the field. It currently is drilling on 640-acre spacing, but it's experimenting with 320-acre spacing. If that proves profitable, it could significantly increase well locations and reserves. The company also is looking at the potential for secondary recovery in Parshall field.

During the company's 2Q 2008 conference call, Mark Papa, chairman and chief executive officer, said, "We are currently drilling with eight rigs. Seven of these are drilling in the core and one rig is testing areas on the periphery of the core.

"We continue to make great wells in the core. Three examples this quarter are the Austin No. 5-14H, No. 24-33H, and No. 9-11H, which had peak rates of 3,744 b/d, 1,880 b/d, and 3,225 b/d, gross, respectively."

Papa said, "During the first half of 2008, our average IP (initial production) rate for all wells drilled was 1,732 b/d and our direct after-tax reinvestment rate of return exceeded 100%. I think a 1,732 b/d average initial rate allows us to deem these as oil monster wells."

Those wells were drilled directionally on 640-acre spacing. The technique works well enough that the company hasn't changed its completion strategy of the past in the first six months of 2008.

Timothy K. Driggers, vice president and chief financial officer, said, "I think, whatever we're doing, it seems to be much better than most other companies out there in terms of initial rate and, we think, also in reserves." There's still more. Around the core Parshall area, "We believe there's an extension area where wells are still very economic with 250,000 bo to 450,000 bo of oil growth reserves per well. Not as prolific as the core area, but still very good wells," he said.

It drilled in that extension area during 2Q and liked what it found.

Those strong Bakken results convinced the company to drill 80 gross wells in 2008 and at least 100 gross wells the following year.

Driggers said EOG wants to drill more wells in the extension area to get the same feel for recovery factors and and reserves that it has in the core area. Probably, he said, it will work like the company's Barnett play in Johnson County, Texas. There, the company set an initial recovery and reserve estimate and added to that figure as it obtained more information.

Some companies working the Bakken in North Dakota have reported outstanding results by drilling through the Bakken to the Three Forks/Sanish immediately below the Lower Bakken. In some cases, those companies have said that formation could equal Bakken reserves.

EOG has tested the Sanish in Parshall field, but it's spotty and not a particularly quality reservoir. The company will continue to look for opportunities in that lower zone. Those tests have been run on some wells within a 100,000-acre boundary, and may not apply to the company's full 320,000 acres.

The good news just kept coming. According to EOG's 3Q report, the company had seven rigs drilling in Parshall field and another drilling step-out wells.

Its most prolific wells for the quarter are the Austin 21-28H at 2,847 b/d, the Austin 18-21H at 3,029 b/d, and the Austin 10-34H at 3,477 b/d.

Evertson Energy Partners LLC

Privately owned Evertson Energy Partners LLC has standing interests in the Williston Basin, including the Bakken play.

In 2006, Evertson owned a 25% interest and American Oil & Gas Inc. a 75% interest in the Goliath Project in Dunn, Williams, McKenzie, and Mountrail counties on land prospective for Bakken and other formations. The companies were actively acquiring leases.

That year, Teton Energy Corp. bought in for a fourth interest from American in the area of mutual interest.

Evertson then signed an agreement assigning a 5% interest, or one-fifth of its 25% interest, in the Goliath Project to Sundance Energy of Australia. The area of mutual interest covers some 142,000 acres, and the Goliath partners own 87,081 gross acres, or 63,687.5 net acres.

Evertson was named operator of the project. The properties are prospective for Bakken, but the Mission Canyon, Duperow, Nisku, and Red River also are targets with potential. When Whiting Petroleum completed the Solberg 32-5 Red River discovery immediately north of the Goliath properties for 408 b/d and 2.1 MMcf/d, the Goliath partners shot 12 ½ sq miles of 3-D seismic around the Solberg well and decided to test the Red River.

That doesn't mean they've abandoned the Bakken. In August 2008, Evertson applied for a 1,280-acre spacing unit covering Sections 24 and 25-156n-98w in Williams County to drill a horizontal Bakken well.

Fidelity

Fidelity Exploration & Production Co., the largest gas producer in Montana, moved into the Bakken play in North Dakota with an aggressive drilling program.

The company has operations around the country and produced 77 Bcfge in 2007 from reserves of 707 Bcfge on 860,000 acres of land with up to 2,000 future drilling sites in its existing producing fields. It plans 300 wells in 2008.

The subsidiary of North Dakota's MDU Resources utility drilled its first operated well in the Bakken in 2007 and built on that effort with further operated and non-operated wells, according to Fidelity President Darwin Subart.

After successes in the Bakken zone, Fidelity drilled its first operated well into the Three Forks/Sanish formation immediately below the Lower Bakken and sourced by the Lower Bakken. After a frac treatment, the Domaskin 11-29H well's average production over its first five days online was 634 b/d. Fidelity has a 58% working interest in the well. That well was in Mountrail County, N.D., home to that state's most prolific Bakken wells.

"If the Three Forks/Sanish formation proves to be a separate reservoir from the Middle Bakken, this will provide additional opportunities to grow reserves and production within our leasehold position," said Terry D. Hildestad, president and chief executive officer of MDU Resources. That lease position has reached 65,000 aces in Mountrail and Burke counties.

By mid-year 2008, the company had spudded 14 wells aimed at the Middle Bakken in the two counties and had three drilling rigs working the area. It planned to participate in 50 to 60 wells in the Bakken and about half of them were set up as operated wells.

MDU spotted an addition profit opportunity in the area. Development of the Bakken play is smothered by the lack of pipelines from the area, and the utility company is considering building the Bakken Pipeline, a new gas pipeline that would take gas from the Bakken sweet spot to a new connection with the Alliance Pipeline. If MDU goes through with those plans, the line would have an initial capacity of 100 MMcf/d of gas with the ability to double that capacity with additional compression.

GeoResources Inc.

GeoResources Inc. found a new growth area for its northern division with an aggressive participation program in the Bakken shale.

The company holds 10% to 15% interests in some 26,000 acres in Mountrail County, N.D., considered the heart of the North Dakota portion of the Bakken play. It also is participating in horizontal Bakken shale wells through a joint venture with Slawson Exploration, which worked one drilling rig full time during 2008 and added another rig in late 2008 for continuous operation through 2009.

Among successful wells, GeoResources held a 5.1% working interest in the Pathfinder 1-9H, with an initial production of 1,463 boe/d but limited by pipeline capacity to 600 boe/d, and a 6.1% interest in the Prowler 1-16H, with an initial test rate of 908 boe/d.

It has a 5.1% interest in the Prospector 1-36H and a 6% interest in the Payara 1-21H, both awaiting completion at press time. Slawson planned to being drilling the Voyager 1-28H, in which GeoResources held an 8.9% working interest, after the Payara well.

When the second rig begins working, it will start with the Goldeneye 1-2H (4.1% interest), with the Peacemaker 1-8H (3.8% interest), Bandit 1-29H (10% interest), and Nightcrawler 1-17H (4.5% interest) next in line.

With previously completed wells, the company is involved in nine gross wells with another eight wells scheduled. It is planning and permitting additional Bakken wells.

GeoResources has budgeted US $9 million for its participation in the Bakken in 2008 and 2009. At mid-year 2008, it has 740,000 boe in unproved potential reserves in the Bakken. That number included 10 budgeted wells east of the Nesson Anticline in Mountrail County and one well in Montana. It could expand or contract the program based on drilling results.

It also is participating is a lease acquisition program with Slawson.

According to the company, its association with Slawson allows it to compile a large database of information about the Bakken play while gaining understanding of the technical and operations aspects of the play.

Helis Oil & Gas Inc.

Helis Oil & Gas Inc. has expanded its Williston Basin activities as it operates for itself and other companies in exploring the Bakken shale.

Both Helis and Sundance Energy Inc., an Australian company with extensive operations in the US, have applied to the North Dakota Industrial Commission for permission to extend the boundaries of Hess Corp.'s Blue Buttes field to allow them to drill Bakken wells on 640-acre and 1,280-acre spacing to the south.

Helis also has proved to be an aggressive proponent of the Bakken as it submitted the highest per-acre bid during the June 2008, US Bureau of Land Management land sale on the Fort Berthold Indian Reservation. It bid US $4,600 an acre for a 200-acre parcel in McKenzie County, N.D.

Late in 2007, Helis signed a farm-in agreement to act as operator on part of Sundance Energy's Phoenix Prospect on the reservation. That parcel later was split off as the South Antelope Prospect.

The companies still are working that property as an area of mutual interest as Sundance has the option of taking interests from 7% to 50% in any well drilled by Helis.

Helis is a privately owned company and doesn't publish its results, but an August presentation by Sundance said the South Antelope prospect consists of 25,000 gross, or 4,000 net, acres. It has five producing wells and four more were awaiting completion at the time of the presentation.

Sundance held onto a 100% interest in the remainder of the Phoenix prospect.

Hess Corp.

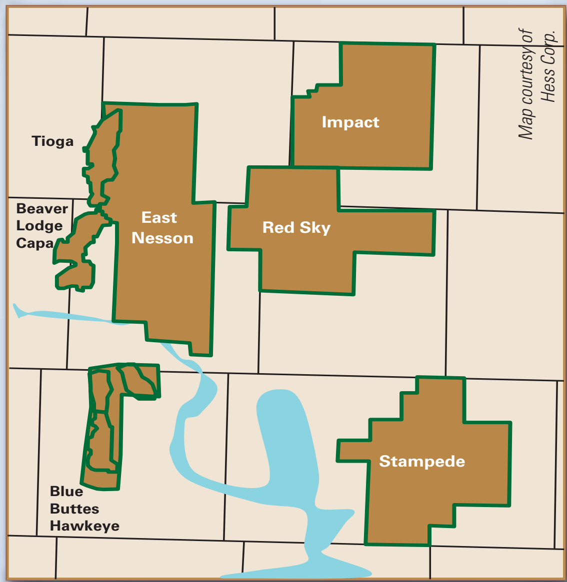
Amerada Oil Corp. drilled the first commercial oil well in North Dakota on the Clarence Iverson farm near Tioga in Williams County. That April 4, 1951, discovery at 10,500 ft put the Williston Basin on the oil country map. It had to drill through the Bakken to reach the Silurian dolomite producing zone.

By May 20, the industry had leased 30 million acres of North Dakota's 44.8 million acres of land, but the real play focused on Billings, Bottineau, Burke, McKenzie, Mountrail, and Williams counties.

Hess Corp., successor to Amerada Oil still operates the Tioga and Beaver Lodge fields surrounding the Clarence Iverson No. 1 well.

Hess has even closer ties to the Bakken. The year after its Iverson discovery, it drilled a well on the Henry O. Bakken farm, picked the shale out of the drilling cuttings, and named the formation after the farm's owner. It still owns a lot of production and a lot of leases in the basin, and it's deeply involved in the new boom in the Bakken shale.

Hess Corp. is larger than the old Amerada Oil. It



Some 500,000 acres of Hess Bakken properties lie north and south of Lake Sakakawea in North Dakota.

pulled in more that US $1 billion in after-tax income fromits exploration and production activities in the quarter ended June 30, 2008, and it produced 393,000 boe/d during the quarter, up from 378,000 boe/d in the same quarter a year earlier. That size is one reason the company isn't accelerating its Bakken property development faster than it already is.

The company's strategy calls for 3% to 5% growth in production and 5% to 8% growth in reserves a year, and that planned growth strategy already has major projects lined up in front of the Bakken play. For example, this year it's concentrating on production from the Joint Development Area in the Gulf of Thailand, a project with the largest reserves in its portfolio. Hess, the operator, holds a 50% interest. During Phase 1, that project will project 120 MMcf/d of gas. Phase 2 will double that figure. The ramp up of Snohvit, where it holds a minority interest, also is in the works. In 2009, its Shenzi project in the Gulf of Mexico will go online. The tension leg platform already is on the way.

The Bakken shale is on the list as a major contributor in 2010.

POSITION: That doesn't mean Hess has ignored the Bakken. The company held 325,000 acres in the Bakken area at the end of 3Q 2007, according to Jefferies & Co.'s June 2008 "Resource Chronicles."

That position climbed to 400,000 acres by the end of the year, to 411,000 acres in the first half of 2008, and stood at 500,000 acres in August 2008.

According to the company, "In North Dakota we are the leading oil and natural gas producer. Following many years of maintaining production levels at several large company-operated units, including Beaver Lodge and Tioga Madison, our North Dakota asset is growing again with the development of our Bakken drilling program. Adjacent to the Williston Basin in western North Dakota, the Bakken Shale represents a new growth opportunity for Hess."

Hess had seven rigs working the play early in 2008 and planned to add another in 4Q. It will raise its rig count to 10 in 2009.

During the company's 2Q conference call, Chairman John Hess said he was more confident about the Bakken in 2008 than he was the previous year, and that showed by the acreage acquisition. Drilling so far has produced wells averaging between 250 boe/d and 300 boe/d and per-well reserves of 600,000 boe. "We're very pleased with what we're seeing," he added.

The company's wells produced a net 8,000 boe/d at the end of the first half of 2008.

During an August 2008 presentation, Hess outlined five high-impact Bakken areas in North Dakota. Its East Nesson area included its Beaver Lodge, Tioga, and Capa fields in Williams County; the Blue Buttes and Hawkeye fields are in McKenzie County; its Stampede area in Mountrail and Ward counties; and its Red Sky area lies north of Stampede. Blue Buttes primarily produces from the shallower Mission Canyon formation, but Hess has received 1,280-acre Bakken spacing authorization and drilled to Bakken in the field. That field also has potential from the Red River formation. The company's activities in the Bakken will gain from its widespread infrastructure already in place in North Dakota.

Still another bonus may lie in the wings. US Department of Energy reports have identified the company's Beaver Lodge field as a potential storage field for carbon dioxide. That potential also could enhance the company's Bakken activities. EOG Resources is testing carbon dioxide tertiary recovery potential in its Parshall field wells.

Hess also has carbon dioxide recovery experience at its Seminole-San Andres Unit in the Permian Basin.

Kodiak Oil & Gas Co.

Kodiak Oil & Gas Co. concentrates its activities on the Vermillion Basin in Wyoming and the Williston Basin in North Dakota and Montana as it seeks plays with stacked play potential.

Working an aggressive acquisition campaign along with tight cost controls, the company increased its

Bakken properties on the Fort Berthold Indian Reservation to 54,000 gross, 38,000 net, acres by the end of June in 2008. That was an increase from the 38,686 gross, 28,957 net, acres it held three months earlier.

It operates all but 7,000 net acres on the reservation. It participates on wells operated by another producer on those leases.

At the end of 2Q, the company had built the site for its first Bakken well on the reservation, the Tall Bear No. 16-15H. The company is the operator on that well with a 70% interest. It planned to drill the horizontal well to a total depth of 15,600 ft. Kodiak planned to spud the well with the delivery of a newbuild drilling rig. It also secured drill pipe for that well and six additional horizontal wells.

Kodiak also received drilling permits for two more horizontal wells, and it expects delivery of a second rig in March 2009.

According to Lynn Peterson, president and chief executive officer, "During the year we re-evaluated our exploration strategy in the Bakken shale play. Based, in part, on the announced drilling and production results of other operators in the immediate area of our Bakken shale acreage in the west central North Dakota counties of Mountrail, Dunn, and McKenzie, we revised our capital expenditure budget. Our previously announced capital expenditure budget included selling down our working interest in our Bakken leasehold in order to fund a portion of our 2008 drilling program. As we continued to evaluate the Bakken play, we revised our strategy and now intend to continue acquiring acreage, while maintaining a high working interest."

The company invested US $6.3 million in the first half, primarily to acquire leases and seismic data and for the workover and completion program. Prior to the initial drilling, the company worked on maximizing production while lowering costs by working over and recompleting Bakken wells in the Mon-Dak field.

At the end of the first half, Kodiak had working interests in 23 gross, 14.7 net, wells and operated 16 gross, 11.2 net, wells.

Lario Oil & Gas

Privately owned Lario Oil & Gas likes to minimize its risk. That's one reason the company set its sights on the Barnett shale in Texas, the Woodford shale in Oklahoma, the Mississippian chert in Mississippi and Alabama, and the Bakken shale in the Williston Basin.

Following the discovery of the giant Elm Coulee Bakken field in Montana, it picked up high working interests in that area. Following that plan, it followed the discovery of the giant Parshall Bakken field in North Dakota by assembling acreage in that area in the fall of 2007.

According to the company's Web site, it now has more than 30,000 gross, 12,000 net, acres in the core area. Lario has participated in 12 oil discoveries, three additional wells are currently drilling, and several non-operated locations have been staked on company acreage.

"We have staked five additional locations which will be operated by Lario," the Web site reported. "Based on two wells per section, Lario will be exposed to 280 locations."

The *bakkenstocks.com* Web site listed five Lario sites from the North Dakota Oil & Gas Commission records in June 2008.

All five wells were in Township 155n-92w. The Strobeck 1-35H is in Section 35, the Lund 1-10H in Section 9, the State 1-16H in Section 15, and the Sorenson 1-9H, also is in Section 9.

Marathon Oil Corp.

Marathon Oil Corp. is big business. As a big business – the fourth-largest US-based integrated oil and gas company – it talks to analysts, and when it makes predictions, it makes sure those predictions become facts.

During its September 2008 presentation to analysts at a Lehman Brothers conference, the company said it was assured of production growth through 2012. Some 70% of the company's 2012 production already is onstream and Marathon is on track to increase production by 8.8% a year through 2012.

A big chunk of that growth will come from its established and growing projects offshore Equatorial Guinea, in the North Sea, and in Libya, along with anticipated plays offshore Indonesia, Angola, and the Ukraine.

Another big chunk will come from its US-based resource activity. The building blocks in that activity are the tight Mesaverde channel sands in the Piceance Basin in Garfield County, Colo., where Marathon plans 700 wells to reach 900 Bcfg in reserves; coalbed methane in the Powder River Basin of Wyoming, and the Bakken play in Montana and North Dakota.

Emerging resource plays also include 260,000 net acres with coal seam gas potential in the UK.

In the US, it includes 40,000 net acres in the Marc-ellus shale in Pennsylvania and West Virginia and it planned to reach 100,000 acres by the end of 2008, as well as

25,000 net acres in the Haynesville shale in Texas and Louisiana, some Barnett shales properties, and 30,000 net acres in the Woodford shale in Oklahoma.

Altogether, those US resource plays offer the company approximately 285 million boe of potential net resources and an estimated peak net daily production of more than 50,000 boe/d by 2011.

POSITION: Marathon currently controls 320,000 net acres in the Bakken oil play in Montana and North Dakota, and it plans to reach peak production in the play at 18,000 boe/d to 20,000 boe/d in 2012, according to Clarence Cazelot Jr., president and chief executive officer. It achieved a significant increase with the acquisition of 72,000 net acres from Petroleum Development Corp.

To put that production into perspective, Marathon expects year-end 2008 production of 380,000 boe/d to 400,000 boe/d worldwide.

At mid-year 2007, it had 200,000 net acres of leases.

Those properties lie in Richland County, heartland of Bakken production in Montana, and in Billings, Divide, Dunn, McKenzie, Mountrail, and Williams counties in North Dakota.

Marathon started drilling in the area in May 2006 and began producing in August of that year.

It produced 700 b/d of oil and 100 b/d of natural gas liquids and from its properties by the end the first half of 2007 for a total 800 boe/d of production.

By September 2008, it increased its Bakken production to 6,000 boe/d from about 50 wells. About 90% of that production comes from its Hector/Ajax area in Dunn County, according to a report from Jefferies and Co. in its June 2008 "Resources Chronicles."

During the company's 2Q 2008 conference call, David E. Roberts Jr., executive vice president, Upstream, said the wells were coming on stream with a 30-day average initial potential of 250 b/d to 300 b/d. "A lot of what is going on in the Bakken has to do with how the wells are staggered and when they come on, and you have got to be very careful about how you add up production. But we are not seeing any declination where our expectations are," he added in a recording of the call by *seekingalpha.com*.

In 2008, it boosted its rig count to seven rigs with plans to drill 65 Bakken wells during the year. That's just one piece of the 400 gross wells it plans during the next four to five years. It acreage covers potential net risked resources of approximately 100 million boe.

"The company draws upon its extensive experience in reservoir characterization, horizontal drilling, well stimulation, and commercial and marketing expertise in the Rocky Mountain basins to leverage this substantial position in the Bakken formation," according to the company.

Marathon also opened a regional office in Dickinson, N.D., to manage the Bakken activity.

Murex Petroleum Corp.

Murex Petroleum Corp. is a long-time fan of the Williston Basin and one of the early companies to sink a drill bit into the Bakken shale in the latest revival of the play.

Not all of its wells are in the Bakken. It has operations in Wyoming, South Dakota, and Montana; some of its 120 wells in North Dakota look for other pay. In Renville County, it's working a waterflood in Mouse River Park field. It has another waterflood in the Davis Buttes Tyler unit in Stark County.

The company put its drilling know-how to work not only on its own Bakken properties on the Nesson Anticline in Williams County, N.D., but on farm-ins with others, notably Northern Oil & Gas Inc., which owns a lot of Bakken land but lets others drill the wells.

The Associated Press talked with Murex Vice President Donald Kessel, who said the company started drilling the Bakken in 2005 and, in April 2008, had 21 producing wells. Of those wells, only four produced below expectations.

"Sure, we're making money, but every 45 days we're putting US $5 million back into a new well. Every dollar we get goes back into the ground drilling, and there aren't any guarantees," he said.

Kessel was born in Belfield, N.D., and started looking at potential production from North Dakota in the late 1990s. The company likes to name its wells with the first and middle names of company employees.

For example, in an April application to the North Dakota Industrial Commission (NDIC), it asked for an order allowing production and to permit gas flaring from its Jacob Daniel 25-36H, with a surface location in Section 36-154n-91w in Mountrail County, an area that has been very good for Murex.

In the same area, on Northern Oil & Gas land, it completed the Rick Clair 25-36H in April 2008. Northern retained a 6.25% interest in the well.

According to the *bakkenstocks.com* rig report in June, the Red Hawk 351 rig was working for Murex at the MRP 18-1 well, the Cyclone 20 rig was working for the company on the Shannon Duane 11-2H, and the

Ensign 71 rig was working on the Linda Gail 30-31H.

On August 28, the same source said the Red Hawk 351 rig was drilling the MRP-19-1, and the Cyclone 20 rig was drilling the Chandler James 25-36H.

In February 2008, the company asked the NDIC for field rules for the Midway-Bakken pool and the Temple-Bakken pool, both in Williams County. It also asked for an order pooling interests in a spacing unit for the West Capa-Bakken pool in Williams County. That field is in Sections 27 and 34-155n-962.

At the same time, it asked for temporary spacing to develop a pool discovered by the Jacob Daniel 25-36H in Mountrail County.

In July 2008, Northern told its shareholders that the Rick Clair well, in the same section as the Jacob Daniel well, showed an initial potential of 1,400 boe/d. It also said a township away, in Section 36-155n-91w in Mountrail County, Murex had permitted the Chad Allen 25-36H.

Newfield Exploration Co.

Newfield Exploration Co. counts major US shale plays as prime territory for its expertise, and it grows the company on the back of its shales, tight sands, Gulf of Mexico, and international operations.

Among its onshore US holdings, Newfield holds a dominant position in the Woodford/Caney shale play in Oklahoma as well as substantial positions in the Lafayette shale in Arkansas, in Monument Butte field in Utah, and Jonah and Pinedale fields in southwestern Wyoming.

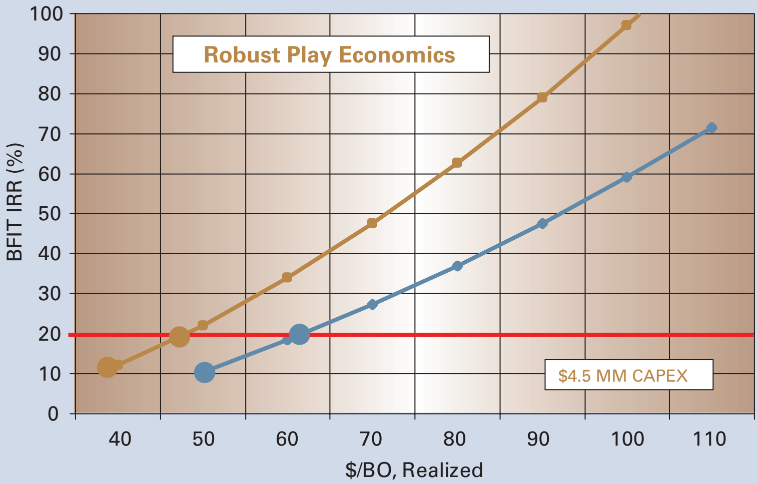
POSITION: Among Newfield's major exploration and production plays, production and development of the Bakken is near the bottom of the list, but the potential is high.

In a September 2008 presentation, Gary D. Packer, vice president, Rocky Mountains, said Newfield has 473,000 net acres in the Bakken play with additional Sanish/Three Forks potential in the same area immediately below the Bakken.

He classified 170,000 net acres in the development and exploitation category and 303,000 net acres as exploratory.

It runs a two-drilling-rig program in the Williston Basin

Bakken/Sanish Wells ROR vs. Realized Oil Price



Graphic courtesy of Newfield Exploration Co.

Newfield sees attractive economics in its Bakken shale play with a breakeven point at US $38/bbl of oil before income taxes, assuming an industry average 350,000 bbl of oil per well.

with a potential 11 wells scheduled for 2008. That level of activity warrants a US $49 million capital budget, or 14% of planned spending in the Rocky Mountain region. That drilling includes seven to 10 wells in the Bakken and one to the Sanish/Three Forks.

Among its holdings in the Williston Basin, it is operator of the Big Valley area with 51,600 net acres. It is a partner with Concho Petroleum in the 8,050-net-acre Westberg prospect where the companies plan five wells this year.

Newfield also is the operator in the Cartwright prospect with 14,400 acres. It has a net 4,000 acres in the Aquarium joint venture with Whiting Petroleum as operator.

It plans five wells as operator in the Lost Bear prospect with 7,700 net acres and operates Watford South with 7,800 net acres.

In Montana, it operates 54,000 net acres within the giant Elm Coulee field.

It plans to ramp up its Bakken/Sanish/Three Forks activity to between 20 and 40 wells in 2009.

Packer said the company has completed three Bakken wells in 2008, with initial potentials above industry averages. The Olson 1-30H tested at 329 boe/d, the Larsen 1-16H at 710 boe/d, and the Jorgensen 1-10H at 911 boe/d.

Newfield drilled two of those wells, the Olson and Larsen, in its Westberg area; it is completing the Rolfsrud 1-32H; and it plans two more wells in that area before the end of 2008.

Westberg also is a focus area for 2009 with plans set for 18 wells.

Hess, ConocoPhillips (former Burlington Resources), and Petro-Hunt all are drilling nearby with Bakken wells reaching an initial potential of 480 boe/d and Petro-Hunt's Sanish/Three Forks well coming in at 852 boe/d.

Lost Bear also will receive special attention. Newfield drilled its Jorgenson well there and is completing the follow-up Jorgenson 1-4H. It will drill three more wells through the rest of 2008, including its operated Jorgenson 1-15H to the Sanish/Three Forks.

Newfield plans three more wells in 2009, with more Sanish/Three Forks wells pending results from its first well in the area.

Among nearby wells, the Bakken has produced initial potentials as high as 570 boe/d for Encore and the Sanish/Three Forks potentials as high as 1,095 boe/d for Continental Resources.

COMPLETION TECHNIQUES: While it drills its horizontal wells, it continues to add to its knowledge of completion optimization. It's testing fracture sleeves as opposed to plugging and perforating and it's working on fracture monitoring and zonal isolation between frac treatments.

FINANCIAL ASPECTS: Newfield's Williston development and exploitation properties represent an unrisked resource potential of more than 100 million boe, while its exploration properties have an unrisked potential of 240 million boe.

Risked potential in the development and exploitation area involves 240 drilling locations with 52 million to 67 million boe broken down into 52% Bakken acreage and 41% Sanish/Three Forks acreage.

Risked potential in the exploration area includes 192 locations with 24 million boe to 30 million boe potential.

Assuming below-average wells with 271,000 boe in reserves per well, the company will get a 20% rate of return on an oil price of $62/bbl. Its breakeven point with a 10% before income tax rate of return is $50/bbl of oil.

If wells meet the industry reserve average of 350,000 boe, Newfield will get a 20% return at an oil price of $48/bbl of oil and the breakeven point drops to $38/bbl.

Northern Oil & Gas Inc.

Northern Oil & Gas Inc. is one of the most active companies in the Bakken shale play on the North Dakota side of the Williston Basin, and it hasn't drilled a well.

Northern's ace in the hole was the foresight to recognize an opportunity and buy leases in prime locations in the sweet spot of the emerging Bakken play.

That strategy helped the company post a US $283,465 profit in 2Q 2008 with plans to finish the year with 1,100 b/d of gross oil production.

Other companies may be drilling the wells this year, but the company said it can operate wells on some of its

60,000 net acres of Bakken properties in 2009, and it expects the full acreage position will be developed by the end of 2011 with approximately 90 net wells, based on 640-acre spacing, with potential to give the company 45 million bbl of oil. That's just the Bakken. That doesn't count the underlying Sanish/Three Forks, enhanced oil recovery or tighter well spacing.

By Aug. 5, 2008, the company had a working interest in 26 drilled or drilling gross wells with a 2008 success rate of 100%. More than 70 drilling permits were issued or pending.

"We are very pleased to move into profitability at this early stage. We believe our low fixed overhead will translate into increasing net profit margins as we accelerate development of our Bakken and Three Forks/Sanish acreage positions," said Michael Reger, chief executive officer. The company's production expenses average $1.25/bbl in 2Q.

As an example of successes, Brigham Exploration drilled the Johnson 33 1H on Northern property in Mountrail County north of EOG's Parshall field for an initial potential of 650 boe/d and sustained production of 560 boe/d. Northern has a 16.5% working interest in the well and controls some 10,000 acres near the site.

That wasn't even its best well. The Whiting Oil & Gas-operated Braaflat 11-11H in Mountrail County offered an initial production rate of 1,600 boe/d, and the Murex Rick Clair 25-36H turned in a 1,400 boe/d initial rate.

Other companies working Northern properties include Sinclair Oil, EOG Resources, Slawson Exploration, ConocoPhillips (on land acquired with Burlington Resources), Windsor Energy, Trapper Resources, XTO-Headington Oil, Encore Operating, Samson Oil, Crusader Energy, St. Mary Oil & Gas, Hess Corp., and Kodiak Oil & Gas.

Oasis Petroleum North America LLC

The Oasis Petroleum North America LLC management wastes no time. It hit the ground over the Bakken shale running and it hasn't stopped.

A group of former senior managers of Burlington Resources formed Oasis after ConocoPhillips bought their former employer. They secured initial financing from EnCap Investments LP in 2007, and, at this point, the company has a handful of wells on tight-hole status in North Dakota, and a deal to drill more Bakken wells in a partnership with MDU Resources, a North Dakota pipeline and utility company with its own exploration and production arm called Fidelity Exploration & Production Co.

Among wells on the confidential list are the Federal 41-15H in Section 15-150n-104w, the Erie 44-19H in Section 19-157n-92w, the Laumb 11-22H in Section 11-160n-93w, the Colson 11-20H in Section 20-161n-93w, the Mess 44-21H in Section 21-156n-93w, the Loki Johnson 11-35H in 35-156n-93w, the Rulson 11-30 in Section 30-156n-92w, the Erie 44-18H in Section 18-157n-92w, and the Uran 11-11H in Section 11-153n-93w. Although some of the wells are clustered, the group of wells covers a broad area.

The Loki Johnson well is listed as a development well in Alger field in Mountrail County by state records. Other wells are in Williams and Burke counties.

In 2Q 2008, Oasis got a new infusion of acreage to explore. During MDU's 2Q 2008 conference call it said MDU's acreage position after the Oasis deal was more than 65,000 net acres. The company expected to participate in 50 to 60 Bakken wells in 2008 and about half of those would be operated by Fidelity, according to a recording of the meeting on *www.seekingalpha.com*.

Answering questions by analysts, Steven L. Bietz, president and chief executive officer of WBI Holdings Inc., the pipeline and energy services arm of MDU, said the 65,000 acres was a drop of some 10,000 acres from previous reports, and that reflected the Oasis acreage and some additional acreage the company leased.

Oasis provided some cash and drilling commitments to the agreement and agreed to bring in its own drilling rigs.

Oasis wasted no time. It got a rig on site and began drilling in 3Q 2008.

Peak North Dakota LLC

Peak North Dakota LLC picked up a drillbit and went to work in the Bakken shale play in North Dakota hitting a strong first well and continuing to do good work on subsequent efforts.

In early 2008, the Denver company drilled the Takakwitha 9-24H Section 9-149n-93w on the Fort Berthold Reservation in Dunn County about 15 miles southwest of the prolific Parshall field.

The well also was about a mile south of Mandaree field, a field with a Bakken history. According to the *Rocky Mountain Oil Journal*, the well came in at about 1,000 b/d of oil. It's listed by North Dakota as part of Mandaree field.

Shell drilled the the Packineau BIA 12-17 in Section 17-149n-93w. The well went to the Cambrian Deadwood, but the company plugged the well back to the Bakken to log the discovery well for the field. It was not Shell's finest well. It tested for 35 b/d of oil, 27 Mcf/d of gas, and 153 b/d of water. Shell plugged the well in 1983 after producing 803 bbl of oil, 35 Mcf of gas, and the same 153 bbl of water.

Peak North Dakota continued to post good results. It has drilled at least nine wells. In the November 2008 hearing meetings before the state's oil and gas commission, it asked for spacing rules to develop its Fredericks 5-11H wildcat in Section 5-148n-92w and for its 24-21H Voigt in Section 24-248n-94w, both in Dunn County.

Penn Virginia Corp.

When it comes to unconventional resources, Penn Virginia Corp. is no shrinking violet. It has coalbed methane properties in Appalachia and Oklahoma and works the Marcellus and Lower Huron shales in Appalachia. It's active in the Haynesville shale in east Texas and the Woodford shale in the Arkoma and Anadarko basins of Oklahoma. It plays the Fayetteville shale in Arkansas and the Selma Chalk in Mississippi.

It also likes the Bakken shale play in North Dakota with its high potential pay in the dolomite section between the upper and lower shales.

At mid-year, the company held some 37,000 net acres in Dunn and McKenzie counties that it operated with a 35% interest with an unnamed partner and had just completed its first horizontal well, the Sickler 22-1H in Dunn County, and committed to another, according to Jefferies & Co.'s June 2008 "Resources Chronicles."

The nearest Bakken production was about six miles away, and that well turned in a non-commercial 50 boe/d.

The second operated well tested for an initial potential of 666 boe/d, and its third well, operated by another producer, tested for 544 boe/d. By early September, the company had 51,000 net prospective acres, according to a presentation at a Lehman Brothers conference.

"That's very exciting. It's very exciting for people that are looking for oil, and that's why we're here," said Jan Brethren, land manager for Penn Virginia Oil and Gas, in a CBN News report.

During the company's 2Q conference call earlier, Jim Dear Love, president and chief executive officer said, "We've got about 57,000 acres in the Bakken, just to put it in perspective, and I'm going to say that 60% of that we would consider to be prospective, and the other is to be determined, but we were not holding out a hell of a lot of hope for it."

Baird Whitehead, executive vice president, clarified further, saying, "We think that probably more than 60% is prospective; I can say either probably out of the 29,000 we have based on one well we drilled that didn't perform, it's probably only 4,000 or 5,000 net acres that we'd say probably have been condemned. So that leaves 24,000 to 25,000 net acres that still could be prospective in the Bakken in that overall area, which is more than the 60% of course, but we have got to get more wells drilled and we just approached this conservatively at this point in time as far as locations we feel real strong about."

It planned to participate in six Bakken wells, 3.9 net wells during 2008.

Penn Virginia estimated its unasterisked exploratory potential in the Bakken at 80 Bcfge.

The Raynor, Pa., company is no newcomer to North Dakota activity. As early as 2005 it hooked up with Bill Barrett Corp. in an agreement to test potential from the Radcliffe and Bakken formations in Montana and North Dakota. In 1Q 2006, it acquired a 100% interest in 22,000 net acres in Dunn County, N.D.

Petro-Hunt LLC

Oil country legend H.L. Hunt jumped in with ready money to buy the Daisy Bradford No. 3 and land surrounding that well after Columbus Marion "Dad" Joiner brought in the discovery of the supergiant East Texas field. He knew a good thing when he saw it, a trait that runs in the family. One of his sons, William Herbert Hunt, used that same foresight to set up operations in the Williston Basin. His trust estate's Petro-Hunt LLC is one of the larger privately held independent oil and gas companies in the world.

The company is no stranger to technology. Its Otto Boss 18-1 in Williams County, N.D., was the first dual whipstock re-entry out of 5 ½-in. casing in North Dakota. At 7,172 ft, it was the longest lateral drilled out of a re-entry well by April 1998. And it was the first four-lateral well ever drilled in North Dakota.

Petro-Hunt bought Chevron's properties in the Williston Basin for US $48 million in 1992 and bought Texaco's properties for $22 million in 1995.

It has drilled a lot of wells in North Dakota, and it's still drilling aggressively, but it's most remarkable well probably is the USA 2D 3-1H in Section 2-153n-95w in Charlson field about 25 miles from giant Parshall Bakken field in McKenzie County.

The Petro-Hunt well didn't stop at the Bakken; it went straight through to the next lower formation, the Sanish/Three Forks. When Petro-Hunt discovered the well in October 2006, it tested for 729 b/d of oil, 785 Mcf/d of gas, and almost no water, according to the *bakkenshale.blogspot.com* Web site. The well probably paid for itself in six months.

Petro-Hunt calls the well a Bakken well, but it might be a Sanish/Three Forks well.

In July 2007, the company completed the USA 11B-2-2H well to the south in Section 11 for 700 b/d of oil, 850 Mcf/d of gas and no water.

The original well acted as inspiration for at least one company. In mid-2008, Encore Acquisition said, "Encore recently finished its first well in the Sanish formation, the Charlson 11-16H, and plans to complete the well in July. This well is approximately four miles northwest of the best Sanish well drilled to date in North Dakota, the Petro-Hunt USA 2D 3-1H, which produced over 560,000 boe in 19 months."

Not all the company's wells meet that high standard. According to the April 28, 2008, well report, its Torgerson 15B-2-2H in Mountrail County tested for 117 b/d of oil, and the Feb. 11, 2008, well reports said its Wold 31D-4-3H in Burke County showed an initial potential of 187 b/d.

The June 18, 2008, list of tight holes, as reported by *bakkenstocks.com*, showed the company with seven wells drilled in the Bakken on which completion information had not yet been released.

Questar Corp.

Questar Corp. is a US $11 billion integrated company with activities in exploration and production, pipelines and utility services, but company information talks about its emphasis on exploration and production when it says, "Questar E&P is one of the fastest-growing independent E&P companies in the United States."

It backs the statement with facts. Between 1997 and 2008, the company's reserves grew from less than 500 Bcfge to 2.16 Tcfge and production climbed from 60 Bcfge to nearly 170 Bcfge.

It proved its capabilities with substantial positions in unconventional resources plays on the Pinedale Anticline in Wyoming, the Uinta Basin in Utah, the granite wash in Texas, the Woodford shale in western Oklahoma, and the Hosston/Cotton Valley/Haynesville shale in Texas and Louisiana.

Now, it's turning its focus toward the Bakken shale in North Dakota.

In a presentation at a Lehman Brothers conference in September, Chief Operating Officer Charles B. Stanley said the company acquired 62,000 net acres in the Bakken play. Most of the properties are in Lake Sakakawea and along the north shore with some properties along the southern coastline. The property is on the Fort Berthold Indian reservation.

Whiting Petroleum's Sanish field, with initial potentials between 500 boe/d and 2,500 boe/d, lies about 25 miles north-northeast. EOG's Parshall field, with initial potentials from 750 boe/d to 3,000 boe/d and estimated ultimate recoveries as high as 700,000 boe, is about 12 miles to the north. Marathon's Bailey field with initial potentials of 500 boe/d to 1,000 boe/d, is southwest about 10 miles.

Questar didn't plan to drill its first Bakken well until 4Q 2008. Planned location for that well is in SEction18-150n-90w in McLean County. The company estimates possible reserves of 200 Bcfge on its property.

"The game plan here is to have several well permits in hand before we move a drilling rig in," said Keith Rattie, chairman and chief executive officer, during the company's 2Q conference call in July 2008.

The company previously participated with a 25% non-operated net revenue interest in a Bakken well in Parshall field. That well showed an initial potential of 1,800 boe/d. That helped convince the company the play deserved further investigation.

Its current bank of properties gives it 88 possible horizontal drilling locations on 640-acre and 1,280-acre spacing with average gross estimated ultimate recoveries from 537,000 boe to 800,000 boe per location.

Chuck Stanley, president and chief executive officer of Questar's market resources group, said, "… we chose that location based on proximity to some old vertical wells that give us some reasonable subsurface control on the presence of the porous Middle Bakken interval, as well as the maturity of the Bakken source rock, the upper and lower Bakken shales that encase that porous Middle Bakken interval."

Samson Oil & Gas

Perth, Australia's Samson Oil & Gas chose North Dakota's Bakken play along with other resource plays for the US arm of its activities.

Samson drilled one well in the Williston Basin, which was a horizontal well that reached 100 b/d of oil from the Bluell formation in North Harstad field.

Working off the success of that well, the leaseholder on the property asked Samson Oil & Gas to drill a Bakken well in the field.

The companies decided to drill the well to the Middle Bakken at 11,335 ft, plug the well back, and drill horizontally for 4,800 ft. After drilling, the Australian company will stimulate the well along the horizontal section.

Under the agreement, Samson Oil & Gas has a half interest in the well and may try to farm out enough of the well to retain a 31.25% interest. Whether Samson participates in the well depends on whether it successfully farms out that share, according to the company's 6k filing with the US Securities and Exchange Commission.

In July, Northern Oil & Gas, said Samson would drill the Gustafson 29-161-92 H in Section 29-161n-92w in Burke County, N.D. Samson holds a 25% interest in the well, which it planned to spud in August 2008.

The Australian company said a leading service company studied the North Harstad area, found it could contain a contingent recoverable 7.7 million bbl of oil from the Bakken and Samson's share of that could be 3.2 million bbl net to Samson.

Samson Resources Co.

Samson Resources Co. of Tulsa, Okla., mounted an active drilling campaign in the Williston Basin as it reached for high pay rates in an outlying portion of the Bakken play.

The privately owned company doesn't release much information about its position in the play, but information from state records helps fill in the blanks.

In North Dakota, a company can declare a well confidential, or a tight hole, and hold information about the well for two years.

Samson Resources has been an active driller in the play long enough that some of those wells have emerged from the tight-hole period.

Two wells came off confidential status in April 2008. One well was the Hanisch 28-163-98H in Section 28-163n-98w in Divide County. That well tested for 58 b/d of oil and 58 b/d of water. The other well, the Sparks 4-162-98H in Section 4-162n-98w, also in Divide County, came in at 197 b/d of oil and 47 b/d of water.

In January 2008, the company said its Haugland 31-163-98H in Section 31-163n-98w, in Divide County, tested for 261 b/d of oil and 104 b/d of water.

One indication of the volume of activity shows up in the North Dakota Department of Mineral Resources' confidential well reports.

Those records show the company has 10 wells still on confidential status in an area that includes townships 161n to 164n, ranges 92w to 99w.

Sinclair Oil & Gas

Sinclair Oil & Gas may not be able to match land positions or drilling volumes with the big boys in the Bakken shale play, but it wants to make a solid contribution to the play by proving up technology that could increase production throughout the basin.

Simultaneous fracture treatments of adjacent wells have increased gas shale productions in the Barnett shale in the Fort Worth Basin of Texas and the Fayetteville shale in the Arkoma Basin in Arkansas, but operators haven't tested the technique to increase oil production in the Bakken.

Sinclair wants to change that. In May 2008, it asked the North Dakota Industrial Commission for authorization to conduct a simultaneous fracture treatment on two parallel horizontal wells, both in the same 1,280-acre spacing unit in Whiting's Sanish field in Mountrail County, N.D., with the help of US $600,000 in state funding. The wells would cost an estimated $11.6 million to complete, and the two operators in the test would each assume an equal share of the costs.

Currently, operators typically drill one long-reach, single-lateral horizontal well bore in a 1,280-acre unit and use multistage fracture treatments.

Sanish field has a lot of wells, and Sinclair and Whiting Oil & Gas have results from nearby wells to determine if the simultaneous frac job works in the Bakken and whether the results match predrill expectations.

Under the proposal, Whiting, as operator, will drill one well from a surface location in NW NW 24-153n-91w and drill to a bottomhole location in SE SW 25-153n-91w. After completing that well in about 50 days, it will drill the second well from NW NE 24-153n-91w to SE SW 25-153n-91w, both with laterals in the Middle Bakken zone.

In both wells, it would set 13 1/2-in. surface casing at 2,100 ft and drill an 8 3/4-in. hole to a kickoff point at 8,750 ft, build angle at 14º degrees per 100 ft.

It would run 7-in. casing to 9,400 ft at a 90º angle and cement the casing in place. Whiting would drill the lateral to approximately 19,000 ft and run 4 1/2-in. liner to TD with seven swell packer and eight sliding sleeve subs hung back to the 7-in. pipe.

If the wells test all right to that point, the companies would build tank batteries at the surface locations, move in frac trucks at both locations, and use the sliding sleeves to direct frac fluids to the most distant segment of the well. After fracturing that stage, it would drop ball to seal off that stage, move up hole and repeat the process through eight stages in each well.

Frac treatments would consist of slickwater fracs with 20/40 sand in cross-linked gel.

Following the treatments, the companies would shut in the wells overnight then let the wells flow back while measuring flow rates and pressures.

Later, the companies would add a packer and set 2 7/8-in. tubing to produce the wells.

It would measure performance of the simultaneously fractured well pair against five offset wells in the field, the Weflen 11-15H, Locken 11-22H, Liffrig 11-27H, Locken 14-28H, and Braaflat 11-11H.

The Braaflat well gives the companies some big barrels to fill. That well, drilled by Whiting on a Northern Oil & Gas lease, came in with in initial potential of 1,600 b/d of oil.

Under the original proposal, the wells should begin flowing by the end of September, but it would take a minimum of three months of production to establish an estimated ultimate recovery.

Sinclair has additional Bakken wells in Mountrail County, including the Nelson 1-26H, drilled on Northern Oil & Gas land on Section 26-155n-90w and completed for 750 b/d of oil.

The company also has two Bakken wells in Richland County, Mont., that came in at initial potentials of more than 300 boe/d.

Slawson Exploration Co.

Slawson Exploration Co., an operator since 1957 with more than 3,500 wells in 10 states and a history of more than 25 years in the Williston Basin, has a sweet tooth for the Bakken. It satisfies its craving with one of the more active drilling programs in the basin.

In early September 2008, it had 27 wells drilled or pending on the North Dakota Industrial Commission's tight-hole list.

Also in early September, the company was adding new wells to the list at nearly one a day, including wells in the play's hottest field, Parshall, in nearby Ross field a wildcat near Ross, all in Mountrail County, N.D.

Many of those wells are on Northern Oil & Gas property. For example, the Pathfinder 1-9H in Mountrail County offered an initial production rate of 1,500 b/d of oil. Northern retained a 3% working interest in the horizontal well.

Also on Northern property, Slawson completed the Prowler 1-16H in Mountrail County with initial production of 950 b/d of oil. Northern kept a 3.5% interest in that well.

In all, Slawson had 11 wells in various stages of awaiting rigs, drilling, or completed on Northern property. Northern retained working interests ranging from 3% to 27% in the wells. The wells are in townships 151, 152, 157, and 158 north, ranges 89, 90, 91, and 92 west. Other Slawson wells are in areas farther from the sweet spot, as far south of the Parshall area as 139n, and as far west as 103w.

St. Mary Land & Exploration Co.

St. Mary Land & Exploration Co. may be more than 100 years old, but age hasn't slowed this operator a bit. It's one of the more aggressive drillers in the Bakken play in Montana and it raised its capital expenditure budget for 2008 to increase that activity.

Throughout the US, St. Mary increased its exploration and development budget by US $98 million to a new level of $758 million.

The increase will go into the company's key growth areas, the Woodford shale in Oklahoma, the Cotton Valley and Haynesville shale in the Ark-La-Tex, Wolfberry (Wolfcamp-Spraberry) tight oil, and the Bakken in North Dakota.

It calls the Haynesville, the Pearsall shale in southwest Texas, and the Bakken its resource plays for future growth.

It will spend $130 million of its exploration and production budget in the Rocky Mountains and $24 million will go into coalbed methane in the Hanging Woman Basin on the Wyoming-Montana border. "In the Rockies, the majority of the capital increase relates to funding additional activity in North Dakota focused on horizontal Bakken wells. St. Mary is allocating more capital to its operated Bakken program," the company said.

St. Mary holds 74,000 net acres in the new Bakken area in North Dakota with Bakken and Sanish/Three Forks drilling on and around that acreage, according to a September 2008 presentation at a Lehman Brothers conference. Those properties are in Divide and Burke counties, on the eastern flank of the Nesson Anticline north of giant Parshall field, and its Bear Den prospect south of the Nesson Anticline, all in North Dakota.

It also holds 108,000 acres in the traditional Bakken dolomite area, which includes properties in the Bakken dolomite fairway, a part of the Elm Coulee field trend in

Montana, and properties that follow that fairway into North Dakota.

It is drilling or completing its first three company-operated horizontal wells in Mountrail County, considered the heart of the Bakken play in North Dakota, and has 26 permitted locations.

Throughout its North Dakota properties, it has permitted at least 40 locations. That's a big advantage in the Bakken play, where permitting is moving slowly.

Summit Resources Inc.

Paramount Petroleum Ltd. of Canada works big plays from the Liard Plateau to the Mackenzie Delta in Canada, and it's no surprise the company decided to test the Bakken.

Paramount entered the Bakken play in North Dakota in 2002 and currently operates there through its Summit Resources Inc. subsidiary.

Summit works the company's 75,000 net acres with September 2008 production of about 1,000 boe/d.

The company had a US $60 million budget in 2008 to drill approximately 20 net wells, and it had two drilling rigs, Paramount 1 and 2, commissioned by the parent company. Those rigs arrived in July 2007.

The active program targets the Bakken and Birdbear formations on more than 90 development drilling locations, principally around Medora in Billings County, N.D.

The company's internal work assumes a horizontal well cost of $4.5 million to reach a well with 300,000 boe in reserves and 200 b/d initial potential production.

According to mid-June state reports, Summit planned to drill the Summit Fee 1-19H with the Paramount 1 rig and the Roosevelt Federal 2-4H with the Paramount 2.

In August, the state said Summit planned to use the Paramount 1 rig to drill the Gap Federal 3-8H and the Paramount 2 was scheduled for the Summit Fee 1-9H.

The North Dakota Industrial Commission, in April, said Summit had completed the Summit Federal 1-25H from the Birdbear formation in Section 25-143n-103w in Golden Valley County near the Montana border for 185 b/d of oil and 270 b/d of water.

Sundance Energy Ltd.

Australia's Sundance Energy Ltd. made a big jump into the Bakken shale play in North Dakota with participating interests in two projects with other operators and two project areas it will operate with a 100% interest.

Sundance controls some 210,000 gross acres in plays across the US, and more than half that gross acreage, 106,000 acres sits in North Dakota, and the Bakken play. Net acreage is another story. It holds 66,000 net acres in the states and only 16,000 net acres in the Bakken, but the company continues to lease in the area.

Its most advanced project is South Antelope, in which Helis Oil & Gas Co. is the operator. Sundance has 25,000 gross, 4,000 net acres in this project. Helis drilled and completed five wells by late July 2008 and had four more in various stages of drilling or completion. Sundance plans to continue its program with Helis at least through 2009.

One well in the area, completed before the 2008 campaign began, was the Levang 3-22H. The well flowed more than 30,000 bbl through the end of May, and the companies now plan to install a pumpjack to increase production.

The first well in the South Antelope area under the agreement, the Jones 4-23H, had produced more than 12,000 bbl of oil by the end of May and also was scheduled to go on pump. Sundance had a 45% interest in that well and has interests ranging from 7% to 50% on wells in the program.

A follow-up well, the Jones 16-14H, was the best well to date in South Antelope in McKenzie County. It showed an initial potential of 971 b/d of oil and produced an average 400 b/d of oil during its first 15 days online.

The companies plan eight to 10 South Antelope wells this year and could double that number next year if results are good.

The Phoenix area is immediately east of South Antelope on the Fort Berthold Indian reservation. Sundance places net reserve potential at 39 million boe.

That project started out under Helis 100% ownership and that company operated an area on the west side of the Phoenix tract, also in McKenzie County and adjacent to South Antelope. Phoenix later shifted to full ownership by Sundance. "This agreement allows Sundance and its shareholders to leverage upon the operating expertise of Helis while retaining a strong interest in its high-potential oil and gas assets," said Jayme McCoy, managing director of Sundance.

Sundance holds 10,874 gross, 7,574 net, acres in Phoenix.

The Phoenix area had only one well on it, and that well produced 20 b/d to 30 b/d of oil from the Mission Canyon formation. Sundance has moved a rig into the area and is drilling the Chase 21-30H to Bakken as operator on its first well in the Williston Basin.

Phoenix is south of the giant Parshall field.

Sundance's third project, Goliath, is northwest of Parshall in Williams County. Sundance holds a 5% interest in that 64,223-acre tract, or 3,211 net acres. American Energy has a half interest, Teton Energy a 25% share, and Evertson Energy Co., the operator, has the remaining 20%. The area is prospective for Madison, Duperow, Nisku, and Interlake production as well as Bakken and Red River.

The companies have conducted 3-D seismic in the Goliath area and spudded the first well. Sundance said it has 20 drilling locations, net to Sundance, on the prospect area.

The final prospect area is Manitou. It lies north of Parshall field and east of Goliath in Mountrail County.

Sundance holds 100% of this 5,680-gross, 1,048-net, acre prospect area. That area still is the emerging phase with more preparatory work needed before the company chooses drilling locations.

Teton Energy

Teton Energy bought into the Goliath prospect in 2006. It's beginning to reap some of the rewards for the play and anticipates more in the coming years.

American Oil & Gas holds a half interest in the prospect at the northeastern end of the Nesson Anticline in North Dakota. Teton holds a 25% interest it bought from American. Evertson Energy Partners, with a 20% share is the operator on the property, and Australia's Sundance Oil & Gas holds the remaining 5%.

The company says the Bakken is the primary target, but the acreage also holds potential for production from Red River, Madison, Duperow, Nisku, and Interlake.

In the first half of 2008, Teton participated in four gross wells and currently holds non-operated interests in seven wells, six Bakken wells, and one Red River well. Three additional wells, were awaiting permits or equipment.

In an August presentation at an Enercom conference in Denver, President and Chief Executive Officer Karl Arleth said the company holds 88,472 gross, 16,435 net, acres in Goliath, and he said the play was in the proof-of-concept stage.

For its share, Teton has proved reserves of 100 MMcfge, probable and possible reserves of 600 MMcfge, and potential reserves of 49.2 Bcfge.

Originally, the company planned to spend US $4.4 million on eight gross wells in the play, but by July, it had backed off to $1.2 million in spite of increasing overall capital spending plans to $49.2 million from $43.3 million.

It increased spending on operated properties on the Central Kansas Uplift, non-operated properties in the Piceance Basin of northwestern Colorado, and operated and non-operated wells in the Denver-Julesburg Basin of northeastern Colorado.

Now, Arleth said, the Williston is in the discretionary cash flow stage. It should graduate to the free-cash-flow, or financial returns, stage in 2011 or 2012.

Executive Vice President and Chief Operating Officer Dominic Bazile said the company's four new wells are in Dunn and Mountrail counties. The company holds a 1.5% working interest in the wells with production from two wells reaching a net 10 boe/d in the first half of 2008.

The company also had a 5.65% interest in the Whiting Petroleum operated Solberg 32-2, a Red River well on Goliath property that tested for 4.1 MMcf/d of gas and 408 b/d of oil. That well still produced 2 MMcf/d of gas and 108 b/d of oil at the end of May.

The company anticipates a Red River test north of the Solberg well, and the group has permitted the Vaill 30-1 for drilling before the end of 2008.

According to Teton, an average Bakken well will provide an estimated ultimate recovery of 250,000 boe at a drilling cost of $3.8 million. Initial potentials average 275 boe on 640-acre spacing for horizontal wells, and an operator can expect a well to return cash flow for 33 years. The average monthly lease operating cost per well is $4,600.

One of the wells in which Teton holds an interest is the Champion 1-25H in Williams County, N.D. It came onstream in January 2007, producing from two of three horizontal laterals drilled to the Middle Bakken. That well had produced at rates as high as 250 b/d of oil, but it had slipped to 25 b/d of oil and 50 Mcf/d of gas by the end of 3Q 2007.

Tracker Resources Development LLC

Tracker Resources Development LLC found a home in the Bakken play in North Dakota and has an active program in the works to prove up its portion of the play.

The company holds 68,000 net acres in the Middle Bakken play on leases with more than 300 million bbl of oil in place. Those assets are held in joint venture with Red Arrow Exploration. Tracker is the operator.

In July 2008, Tracker asked the North Dakota Industrial Commission to add 80 sections to Little Knife field. The commission reduced that number to about 68 and approved the request.

In August, it asked the commission for temporary spacing authorization to develop a pool its Tracker Resource Development II LLC discovered with the Rohde 2-1H well in Section 2-144n-93w in Dunn County.

In September, it asked the commission for an order extending field boundaries for the Murphy Creek

Bakken pool to add eight 1,280-acre spacing units in Sections 5 and 8, 6 and 7, 17 and 20, 18 and 19, 27 and 34, 28 and 33, 29 and 32, and 30 and 31 in Township 143n-93w. It also asked for authorization to drill one horizontal well on each spacing unit.

The commission also released well information that credited Tracker with drilling the Trampe 1-1H in Section 1-144n-97w in Dunn County with an initial production rate of 163 b/d of oil and 269 b/d of water from the Bakken formation.

Five months later, it reported Tracker drilled the Trampe 26-1H in Section 26 of the same township for 202 b/d of oil and 408 b/d of water.

Tracker drills some of its wells on Northern Oil & Gas properties. Northern said the company planned to drill the Knutson 4-1H in Section 4-143n-94w. Northern said it would keep an 8% interest in the well.

Whiting Petroleum Corp.

Whiting Petroleum Corp.'s statistics in the Bakken shale play in North Dakota looks like production from an earlier time, an offshore field, or another country with initial potentials well above the 1,000-boe mark in a prolific resource play.

Since its inception in 1980, Whiting's game plan directed the company to build a strong asset base and grow through acquisitions, development, and exploration. It put that philosophy to work in the Rocky Mountains.

The company claims 25% of its total reserves in the Rocky Mountain states, and 51% of its proved reserves in the Rockies are in North Dakota. Those Rocky Mountain reserves include 42.2 million bbl of oil and 1,169 Bcf of gas. Its September 2008 production of 23,100 boe/d was higher than its operations in the Permian Basin, the Gulf Coast, the Mid-Continent, or Michigan.

POSITION: Whiting started its aggressive leasing program, focused in Mountail County, in 2005. The following year, it offered an assessment of its Bakken play, saying, "To date, we have drilled and completed two exploratory wells. We are encouraged by our Bartleson State 44-1H well, which is currently flowing oil and appears to be an economic well. We are currently drilling our third well and conducting a 98-sq-mile 3-D seismic survey in order to assist in our selection of future drilling locations."

At that point, the company had only seen a shadow of the potential of what was to turn into the biggest lower-48, onshore oil campaign in the US.

Whiting's major Bakken properties are Sanish and Parshall fields. It holds 191,361 gross, 98,292 net, acres in the two fields where estimated ultimate recoveries average approximately 900,000 boe/well and drilling and completion costs run between $4.5 million and $7 million.

The company drilled 33 wells in 2007, according to a September 2008 presentation at a Lehman Brothers conference. It plans another 36 operated and 20 non-operated wells in Sanish field for 2008. It plans to see between 60 and 70 non-operated wells in Parshall field in 2008.

By early September, it had 27 wells producing from its 2008 drilling campaign in Sanish field and 60 more in Parshall field. It was completing four more wells in Sanish and 11 more wells in Parshall. It was drilling seven wells in Sanish and 5 wells in Parshall, and it had approved authorities for expenditure for 17 Sanish wells and five Parshall wells.

The Denver-based company tallied its best initial potential at the Behr 11-34H. That well showed initial production of 3,245 boe/d. It produced an average 1,335 boe/d during its first 30 days online.

Honors for the best continuing production go to the Braaflat 11-11H. That well offered an initial potential production of 2,997 boe/d, but it produced an average 1,505 boe/d in its first 30 days. It still averaged 1,271 boe/d for its first 60 days online.

Combining its 14 best Sanish field wells, Whiting came up with an average initial potential of 2,184 boe/d and an average production of 1,020 boe/d for the first 30 days.

Capital expenditures for 2008 included $247 million for operations in Sanish field and $82 million for operations in Parshall for a total $329 million in the Bakken play. Whiting's company-wide capital expenditure budget for all operations totaled $850 million.

Far from slowing down, in addition to the 36 gross, 29.6 net, wells planned for Sanish field in 2008, the company plans 59 gross, 39.4 net, wells in 2009, and 33 gross, 20.9 net, wells in 2010, for a total of 128 gross, 89.9 net, operated wells. It also anticipates 52 gross, 12 net, non-operated wells.

Those figures don't include the possibility of 60 operated and 42 non-operated wells that could be drilled on downspaced locations.

COMPLETION TECHNIQUES: Among its better wells, it completed the Liffrig 11-27H well flowing 2,247 b/d of oil and 1.7 MMcf/d of gas (2,530 boe/d). It drilled the well to a true vertical depth of 9,920 ft and ran its 24-hour initial potential test on a 17/64-in. choke with 1,300 psi of flowing casing pressure. It completed the well on 1,280-acre spacing in the Middle Bakken with a single 7,720-ft lateral. Some earlier wells in the field had been completed as trilateral wells.

Whiting completed the Locken 11-22H about two miles north of the Liffrig well to the same depth with a 7,625-ft lateral. That well produced an average 818 bbl/d of oil and 828 Mcf/d of gas, on average, in its first 30 days online.

Sanish field gas contains a lot of natural gas liquids with 1,700 Btu/cu ft of gas. To take advantage of favorable liquids prices, Whiting built a gas processing plant to strip out the liquids and prepare it for pipeline transportation. That plant had an initial capacity of 3 MMcf/d of gas and Whiting plans to push that capacity to as much as 33 MMcf/d of gas in 4Q 2008. The plant should produce 150 to 170 bbl of natural gas liquids in every 1 MMcf of gas.

FINANCIAL INFORMATION: Sanish and Parshall wells give Whiting estimated ultimate recoveries between 400,000 boe and 900,000 boe per well at a completed well cost of $5.5 million to $6 million.

Windsor Bakken LLC

Windsor Bakken LLC started collecting acreage early in the Bakken play in North Dakota and Montana. At the same time, it began collecting investors to launch its drilling program. It started drilling in September 2007.

One investor, Gulfport Energy Corp., bought a 20% ownership interest in Windsor Bakken. That company invested US $2.5 million by September 2007 and said it was participating in 11 planned wells with capital expenditures estimated at approximately $1 million.

According to Gulfport, Windsor Bakken owned 64,100 net acres in Bakken-favorable leases and had bids out for another 45,700 net acres. By December 2007, Gulfport said it was participating in 13 Bakken wells with an average interest of 1.74% per well.

Windsor's Whitmore 1-6H started drilling at the end of May 2008. That well is about a mile from EOG's Austin 4-09H, a Parshall field well that showed an initial production potential of 1,519 b/d of oil.

At least some of Windsor Bakken's wells lie on leases held by Northern Oil & Gas. For example, Windsor Bakken's Wolf 1-4H well in Section 4-151n-92w in Mountrail County, N.D., was scheduled to spud on Sept. 1, 2008. Northern retained a 16% interest in the well.

Windsor Bakken has one drilling rig contracted.

XTO Energy Inc.

XTO Energy Inc., one of the nation's biggest independent companies and a major unconventional resource player across the US, closed a deal in July 2008, that made it one of the biggest producers, acreage holders, and reserve owners in the Bakken play in Montana and North Dakota.

Since oil constitutes most of the production from the Bakken, this purchase won't contribute a great deal to the company's goal of becoming the nation's biggest gas producer by 2011.

That plan calls for XTO to double gas production from 1.8 Bcf/d in 2007 to 3.6 Bcfe by 2011. Some US $10.6 billion in acquisitions in 2008 will help fuel that drive.

Many of those acquisitions are bolt-on additions to existing properties in the Barnett shale in Texas, the Fayetteville shale in Arkansas, and the Woodford shale in Oklahoma, in addition to what XTO calls "$1.3 billion in miscellaneous acquisitions in East Texas and the San Juan Basin (New Mexico and Colorado)."

The 2008 purchases added 2.3 Tcf of proved gas reserves and 420 MMcf/d of production.

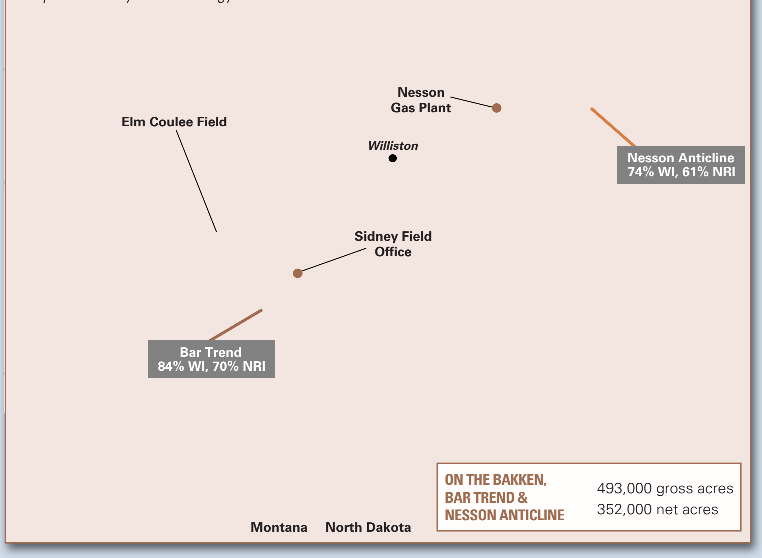
Gas reserves and production contributed a large part of the company's "Year of Acquisitions," but it made major additions to oil reserves and production as well with its Bakken purchases.

POSITION: XTO has more acreage in the Bakken than any of its shale plays. It holds 380,000 acres in the Fayetteville shale, 280,000 each in the Marcellus and Barnett, and 100,000 acres in the Haynesville.

In July 2008, XTO closed its purchase of Bakken producing properties and leases from Headington Oil Co. for $1.8 billion in cash and stock. That gave XTO 493,000 gross, 352,000 net, acres of Bakken leases in Montana and North Dakota. Headington was a major acreage holder in the giant Elm Coulee Bakken field in Montana.

Acreage Position

Graphic courtesy of XTO Energy Inc.



XTO's Headington acquisition gave the company major holdings in two of the highest-producing Bakken shale areas.

XTO engineers estimated proved reserves on the properties at 68 million boe, with 60% of those in the proved developed category. That acquisition added some 10,000 b/d of oil production.

Two months later, XTO completed a merger with Hunt Petroleum Corp. and associated companies into a wholly owned subsidiary for approximately $4.2 billion in cash and stock. That acquisition added properties in Texas, New Mexico, Arkansas, Oklahoma, Kansas, Wyoming, Colorado, Alaska, Utah, Louisiana, Mississippi, and West Virginia to the XTO portfolio. It also added another 100,000 acres of Bakken leases and 400 b/d of oil production.

"With these deals, XTO now becomes a leading operator in perhaps the largest oil resource play in the nation with more than 450,000 net acres. As with our other acquisitions, our objective is to more than double the proved reserves through the application of cutting-edge technology.

"Given the opportunities in the Bakken through horizontal drilling, multiple stimulations, and enhanced recovery, we anticipate the potential for even more," said Keith A. Hutton, president.

"Currently, our team has four drilling rigs at work with plans to increase the activity to six rigs during the first half of 2009," he added. "Early well results are encouraging with a recent producer, completed in the Middle Bakken, flowing at a rate of 650 b/d. At the same time, we have expansive coverage of the emerging Sanish/Three Forks play as established by production rates on offsetting acreage. XTO will soon spud its first horizontal well into this interval."

Following the Headington acquisition, XTO said the 325,000 net acres included 215,000 undeveloped net acres with 3-D seismic shot over most of the properties.

Those properties were split into two groups. One group included the Bakken Bar trend from Elm Coulee field in Montana on the northwest and moving southeast into North Dakota. The other group included properties along the Nesson Anticline in North Dakota, host of some of the best Bakken wells in that state. Those properties include potential not only from Upper, Middle, and Lower Bakken shales and siltstone but from the Sanish/Three Forks. One company said Sanish/Three Forks production on its holdings could match its potential from the Bakken.

To put the two acquisition into perspective within XTO, the company produced 51,300 b/d of oil in 2Q 2008, before the acquisitions. That was an increase from 46,100 b/d of oil in the same quarter a year earlier. The Bakken acquisitions alone should raise production at the end of 3Q to 61,400 b/d of oil.

The Williston Basin acquisitions also offer some upside potential. The central Bakken oil area is surrounded by properties with tight gas potential.

It plans to increase its 2009 production levels by 22% during its "Year of the Drill Bit," a year dedicated to developing legacy properties and properties acquired in 2008 with the help of $4.6 billion in capital expenditures for development and 120 drilling rigs working full time.

FINANCIAL ASPECTS: On its Headington properties, XTO said reserves ranged from 300,000 boe/d to 500,000 boe/d with initial potential production of 300 boe/d to 600 boe/d. Drilling costs ranged from $3 million to $5.5 million per horizontal well.

The company also offered a close-up view of potential profits. It would spend about $3/bbl on production expenses and another $9 to $11/bbl on production taxes and gathering. Bakken oil sells at a $5/bbl price differential to New York Mercantile Exchange quoted prices for West Texas Intermediate oil.

With those numbers as background, XTO expects $300 million in annual cash flow from its Bakken properties with an oil price of $100/bbl. With oil at $115/bbl, cash flow rises to $355 million, and a $130/bbl oil price raises cash flow to $410 million a year.

Canada: Key Players

Crescent Point Energy Trust

Crescent Point Energy Trust claims the title of the biggest Bakken producer in Canada and the biggest oil producer in southern Saskatchewan, and it's using enviable economics to continue its growth.

Some 80% of the company's production comes from southern Saskatchewan, and aggressive growth in its Viewfield Bakken property will fuel that growth.

The Bakken pool in southeast Saskatchewan contains an estimated 4 billion boe to 5 billion boe in place consisting of light oil, gas, and liquids. It's the largest oil find in western Canada in more than 50 years.

POSITION: Crescent Point controls production of more than 14,000 boe/d, holds 380 net sections, 243,200 net acres, of undeveloped land, and 1,050 net development drilling locations. Only 358 of those locations are booked as reserves.

Crescent Point acquired some US $940,000 in assets, largely in the Bakken play. That included the $587 million acquisition of Mission Oil & Gas Inc. in February 2007, the acquisition of Innova Exploration Ltd for $374 million in October 2007, and the acquisition of Pilot Energy Ltd. in January 2008 for $71 million.

Mission assets produced about 5,000 boe/d in 2007. Innova added 2,800 boe/d. The Pilot acquisition added another 1,000 boe/d.

Those acquisitions increased undeveloped Bakken holdings by more than 150% from 143 net sections to 363 net sections. The company acquired another 115 net sections of undeveloped land from open market purchases and purchases of Crown properties.

Crescent Point also agreed to farm out 22 net sections, or 6% of its undeveloped Bakken land to Shelter Bay Energy Inc. to accelerate production from the trust's Bakken properties. Crescent Point agreed to invest up to $56.1 million in Shelter Bay for a 20% interest in that company.

The trust expects Shelter Bay to drill 40 gross Bakken horizontal wells in 2008 and the same number again in 2009. Crescent Point will hold up to a half interest in each well. The company also said it expected to merge Shelter Bay into Crescent Point in the future.

In another part of that agreement, Crescent Bay agreed to buy the non-Bakken assets of Landex Petroleum Corp. for $74.8 million. At the same time, Shelter Bay would acquire the Landex Bakken assets for $215 million.

An already good position improved by the end of 2Q 2008. During 2Q, when drilling resumed after the spring breakup in May, Crescent Point participated in 24 gross, 19.1 net, horizontal Bakken wells at Viewfield. It also fractured 28 gross, 25.6 net, Bakken wells. Those activities added more than 1,600 boe/d in production.

In addition, Shelter Bay drilled seven Bakken wells on the farmout land, giving Crescent Point another 3.5 net wells. The trust's share of production from those wells averaged 300 boe/d for the quarter. Shelter Bay assumed all capital costs on those wells.

Crescent Bay also completed design work on a gas plant at Viewfield and ordered equipment for an expansion to 15 MMcf/d of gas from 9 MMcf/d. That will accommodate up to 110 gross, 93.4 net, Bakken wells the company will drill in 2008 and wells planned by Shelter Bay. Further design work is in the works to take plant capacity to 30 MMcf/d by mid-year 2009 to handle additional production. The company also added more Crown land to bring its total undeveloped Bakken holdings to 386 net sections.

For all of 2008, the company will drill 110 gross, 93.4 net, Bakken horizontal wells, up from 79 gross, 65.5 net, wells in 2007. It also will fracture up to 130 gross, 114.4 net, Bakken wells during the year from the 150 wells awaiting frac jobs. That activity should help the company finish the year with production of 37,500 boe/d.

RECOVERY TECHNIQUES: So far, Crescent Point has recovered .3% of the Viewfield resources, and independent engineers have projected a recovery of 3.9% at the end of 2007. The company's internal technical team anticipates a 15% primary recovery over time. Internal simulations suggest it can reach 19% recovery at eight wells per section. If the company achieves that 15% recovery, it will add another 165 million bbl in proved and probable reserves, or US $3.74 billion in added value.

The trust drilled 88 gross, 60 net, Bakken horizontal wells during 2007, including 11 step-out wells, and conducted frac treatments of 46 of the wells. Improved frac treatments raised reserves by 17%, doubled initial production rates to an average 200 boe/d, and more than tripled the net present value of each well.

The improved completion techniques and step-out drilling allowed Crescent Point to raise its oil-in-place estimate to 4 billion boe from the previous level of 1 billion boe with reserve additions of 35.7 million boe proved and probable and 20.8 million boe proved.

FINANCIAL ASPECTS: During 2007, Crescent Point's finding and development cost was approximately $11.60 per proved and probable barrel of oil equivalent. That gave the company an 2007 Bakken netback of $54.31/boe. Those numbers improved sharply by the end of 2Q of 2008.

Company-wide netback, after realized financial instruments for the first quarter of 2008 rose to $57.11/boe, up from $35.96/boe in 2007, largely from higher market prices for oil and lower operating costs.

"Many of the factors driving the higher operating netback are associated with the Viewfield Bakken resource plan, which realizes narrow differentials, low royalty rates, and operating costs," the company said.

Netback from the Bakken play in 2Q was $87.97/boe.

Crown Point Ventures Ltd.

Crown Point Ventures Ltd. put its first Bakken well on line in southeastern Saskatchewan in late September, effectively expanding the popular play to an area the company said has overlooked Bakken potential.

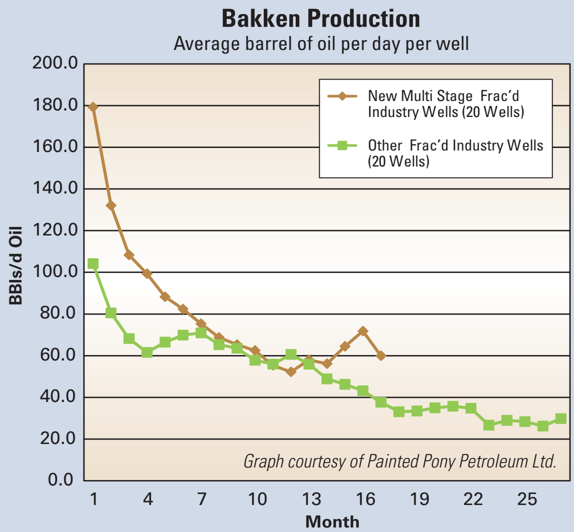
The company isn't releasing information about the well, but it has drilled a second well and is adding a pumpjack to put it into production as well. Those successes persuaded the company and its partners to obtain drilling and production rights on another 640 acres of land in the same area to raise their acreage position to 6.640 gross, more than 5,640 net, acres. The properties are northwest of Moosomin on the Trans-Canada Highway near Wapella.

Crown Point has a 47.5% working interest in the project and plans a fall-winter drilling campaign in the field. Its total cost in the first two wells is US $371,891 (Cdn $384,000) and will be financed with cash flow.

The operator is Interwest Enterprises Ltd. It anticipated drilling the first two wells in four days each.

Crown Point is not a newcomer to the Bakken play. In early September, 2008, it agreed to sell its working interest in Sinclair field in southwestern Manitoba for US $6.15 million. That field produced from Bakken and Lodgepole. Crown Point said it would use the proceeds to expand its Saskatchewan drilling play and for obligations in its El Valle field in Argentina's San Jorge Basin.

Gordon Kettleson, president and chief executive officer



Wells drilled with Packers Plus multi-stage frac jobs perform noticeably better than earlier wells with standard stimulation treatments.

of Crown Point, also is president and chief executive officer of Interwest, while Hal Kettleson, founder of Interwest, was president and chairman of Crown Point and now is chief financial officer.

Painted Pony Petroleum Ltd.

Painted Pony Petroleum Ltd. went public on May 23, 2007, and it already has 100 Bakken drilling locations and is working a 40-well drilling program in 2008.

By September 2008, it had drilled 11 gross, 3.74 net, horizontal operated wells in the Bakken play in southern Saskatchewan with a 100% success rate. It also drilled a step-out to the stratigraphic play. Since its inception, the company drilled 19 gross, 7.35 net, operated Bakken wells. It also added to its Bakken potential with two farm-ins.

Netbacks at the field level from its operations reached US $74.96 (Cdn $69.60) a barrel.

By the end of 2Q, Painted Pony managed to increase its production 433% from 1Q, a company record 789 boe/d. It drilled 10 gross, 4.5 net, Bakken wells in 2Q to raise its six-month total to 22 gross, 9.3 net, wells with a 95% success rate. At the end of June, it had 53,000 acres of option land in southeastern Saskatchewan and added another 7,100 acres in August.

Prices climbed enough that the company's netback for Bakken oil rose to US $85.17/bbl. By the end of 2Q, Painted Pony accumulated an inventory of 250 horizontal wells to the Bakken and other formations in southeast Saskat-chewan, either through owned leases or through farm-ins.

Not only can the company take advantage of Bakken returns, but the Saskatchewan government offers a horizontal well royalty incentive of a 2.5% royalty rate on the first 37,000 bbl of oil on Crown land and a freehold mineral tax holiday on the first 37,000 bbl.

In addition, deep wells below 5,578 ft (1,700 m) also get an incentive of a 2.5% royalty rate on Crown land and no freehold mineral tax on the first 106,000 bbl of oil.

Painted Pony improved its completion treatments to a Packers Plus multistage frac technique, which improved production, reduced water production, increased recoverable reserves, and improved well economics.

The company also increased its working program with plans to drill up to 40 gross, 18 net, Bakken horizontal wells in the second half of the year. It has Bakken potential in it Kisbey, Weyburn, and Midale field properties.

Petrobank Energy and Resources Ltd.

Petrobank Energy and Resources Ltd. drills more wells in the Bakken play in southeastern Saskatchewan than any other operator.

The company started its position in the shale-siltstone play in 2001 with the acquisition of Barrington Petroleum Ltd. That total rose to 62,448 gross, 49,105 net, acres at the end of 2006. It subsequently built its position to 156,000 gross, 141,000 net acres, according to a company presentation in September 2008. It produced 13,000 boe/d at the end of 2Q and raised that to 17,500 boe/d by early August. It is working from a base of proved, probable, and possible reserves totaling 68.5 million boe.

Petrobank drilled 75 Bakken horizontal wells in the first half of 2008 and plans to drill 154 wells for the full year from a drilling inventory of 577 wells figuring four wells per section.

An assessment on a 150,000-boe well by the Sproule Associates consulting company suggested an initial potential of 200 boe/d with a decline to 150 boe/d after the first 10,000 boe of production. Typical wells should further decline to about 100 boe after production of 19,000 boe and to 50 boe/d after 30,000 boe of production. Thereafter, production declines should be shallow through the remaining life of the wells.

According to the company, "Petrobank's strong presence in the Bakken stems from an aggressive strategy of identifying undeveloped areas, applying, and refining advanced technologies and quietly acquiring an extensive land position."

The company's land position in the Bakken in Saskatchewan and Manitoba includes substantial blocks of non-expiring fee simple lands.

Technology plays a big part in Petrobank's success. "Through the use of existing fracture stimulation technology but modifying its application, we achieved production results that exceeded expectations by a wide margin," according to the company Web site.

"This approach involves sequential fracturing in isolated high-quality portions of the reservoir and allows improved concentration and containment of the frac within the formations. Previous frac techniques frequently went out of zone causing an immediate influx of water from surrounding formations leading to a rapid decline in oil rates and ultimate recoveries.

"Many of our wells now produce at an initial rate in excess of 250 b/d and average 90 b/d over the first year. Our reserve evaluator (Sproule) currently estimates that, with the new completion technique, recovery rates will now be between 10 and 15% of oil in place, which has increased the recoverable reserves up to 240,000 bbl of oil per section of land."

COMPLETION TECHNIQUES: The company offered a closer look at those completions. It drills four parallel horizontal wells per section. After drilling to the kickoff point, it drills 4,922 ft laterally and perpendicular to the natural fractures. Each well is offset 1,312 ft from its neighbors.

The company conducts eight isolated and unique fracture treatments in each horizontal section with packers isolating each interval.

The company opens frac ports individually during the sequential fracturing from the toe to the heel of the horizontal section. It also uses slow frac fluid injection to keep the fractures within the Bakken zone and avoid excessive water invasion.In addition, the company staggers fractured sections between adjacent wells to open more channels to oil flow.

FINANCIAL ASPECTS: Processing of gas and natural gas liquids (NGLs) makes a big difference in the economics of a typical Petrobank well.

Without conservation of gas and NGLs the cost of drilling, completing, and hooking a well to production is US $1.78 million (Cdn $1.9 million). The company figures proved, probable, and possible reserves (3P) at 150,000 boe with finding and development costs of US $12.06/bbl and an average first-year production average of 94 boe/d.

Petrobank figures a net present value before taxes at $2.98 million with a West Texas Intermediate oil price of $80, an NPV10 of $4.31 at $100/bbl WTI oil, and $5.53 million with WTI at $120/bbl.

It would get a 169% internal rate of return at $80 WTI, 341% at $100 WTI, and more than 500% at $120 oil.

Life-of-reserves netbacks would be $55.30 at $80 oil,

$72.27 at $100 oil, and $89.12 at $120 oil.

Using the same process and conserving gas and NGLs, the well cost rises to $1.85 million, the 3P reserves climb to 185,000 boe, and finding and development costs drop to $10.12/bbl. Average first-year production grows to 105 boe/d.

Under those circumstances NPV10 at $80 WTI oil is $3,729, increases to $5,205 at $100/bbl oil, and rises to $6,681 with $120 oil. Meanwhile internal rates of return increase to 234% with $80 oil, 483% with $100 oil, and more than 500% with oil at $120/bbl.

Netbacks over the reserve life of the well average $53.58 with $80 oil, $69.39 with $100 oil, and $85.19 with $120 oil. Economics also spill over to the local community, according to an August 2008 article in the *Toronto National Post* about Weyburn, Saskatchewan.

The article said, "Older houses in Weyburn that were vacant or asking $30,000 two years ago are now trading for $150,000 or more," according to Doug Maurer, local manager for Petrobank.

The article continued, "In the last fiscal year, Saskatchewan earned a record $419 million in Crown land oil drilling rights sales, more than double the previous record, including $132 million along spent by Petrobank and other players in the southeast."

Reece Energy Exploration Corp.

Reece Energy Exploration Corp. started operating with a goal of positioning itself in resources plays in Saskatchewan because it wanted an operation that would allow the company to drill a lot of wells with reasonably predictable results.

It also wanted a play that allowed it to spread its upfront investment in geology, land acquisitions, and facilities over many wells and long production.

The company assembled interests in fields that produce light oil from the Midale, Frobisher, Kisbey, Alida, Tilston, and Souris Valley that match Reece requirements. The Bakken in Saskatchewan also fits those parameters.

"While not usually productive in vertical wells, it (Bakken) has proven to be a great resource play now that horizontal drilling and multistaged fracturing techniques have come of age. Reece has an interest in over 55 sections, net 27.7, of mineral rights with Bakken potential in southeast Saskatchewan," the company said.

The company and its joint venture partners have started drilling in their area of mutual interest and plan 10 wells, five net, to Reece, in 2008. "With success, development drilling will begin in earnest in 2009," Reece said. Ten more prospects are waiting in the wings anticipating that success.

The companies completed their first well in May and started production without a fracture treatment.

The joint venture's area of mutual interest lies north of Weyburn and northwest of Viewfield, and Reece has committed US $20.44 (Cdn $22) million, or 33% of its 2008 capital expenditure budget, to the Bakken.

That first exploratory well was a success, and the company planned a frac job before the end of the 3Q 2008. The second well was not economic. It was testing the third well in late September and started drilling the fourth well.

Ryland Oil Corp.

Few companies focus on the Bakken play as precisely as Ryland Oil Corp. It saw the success of the giant Elm Coulee Bakken field in Montana and found experts to try to match that success.

Two members of the company's senior management team were directly involved in the exploration and development of the Elm Coulee field. Dick Findley, the company's chairman, was credited with the discovery of the Elm Coulee field. (In recognition of his work, Findley was named Outstanding Explorer of the Year by the American Association of Petroleum Geologists in 2006.) Tom Lantern, vice president, engineering, oversaw the initial development of Elm Coulee while employed as asset manager for Halliburton Energy Services, the company said.

In a September 2008 report, the company reported it had started a two-rig 13-well drilling program on its 345,000 gross and net acres in southeastern Saskatchewan. Among those 13 wells, it plans five horizontal Bakken tests by the end of March 2009. While it is testing several unconventional reservoirs in the program it is evaluating the Bakken throughout its acreage position. That evaluation includes core sampling from the Bakken over two widely separated areas and production tests in vertical wells to test the Bakken's production potential.

"Based on this data, as part of the current program, Ryland has drilled the Roncott 4-36 well as its first horizontal Bakken middle member well. The Roncott 4-36 is in the final stages of completion following a fracture stimulation of the horizontally drilled Bakken middle member. The company is encouraged by the fluid rate and oil cut from the completion testing and is completing installation of surface facilities and preparing to put the well on pump by mid-September," Ryland said.

It added, "Based on the initial results, an offset horizontal Bakken well, Roncott 4-1, was spudded this week approximately one mile north of the previous location. The company has permitted four additional Bakken locations on the surrounding leasehold. In addition, the company is continuing to evaluate shallower objectives in the area as part of its overall exploration program. As previously announced, Ryland intends to drill three more horizontal Bakken wells to further test the southeastern portion of its acreage holdings."

Ryland also drilled the Lake Alma 4-8 well in the central area of its holdings in Saskatchewan. Although the prime objective was a shallower formation, it also took a Bakken core sample. The results are encouraging, and Ryland is conducting a full analysis of the Bakken's commercial potential in the area.

Shelter Bay Energy Ltd.

Shelter Bay Energy Ltd. started operations in January 2008, with a mandate to explore and develop Bakken properties in southeastern Saskatchewan.

Crescent Point Energy Trust, the biggest producer (and Bakken producer) in the area, is a trust dedicated to distributing a high percentage of earnings to its investors. It organized Shelter Bay to do the exploration and development work in its 1,000-sq-mile Viewfield area in southeastern Saskatchewan, an area with an estimate of more than 4 billion bbl of Bakken oil in place and the largest oil discovery in Canada since the early 1950s. Crescent Point already has more than 260 net Bakken wells in the area.

To help the fledgling company along, Crescent Point farmed out 22 net sections, or 6%, of its undeveloped Bakken holdings to Shelter Bay and invested US $52.46 million (C $56.1 million) for a 20% interest in the company.

Shelter Bay is now the third-largest producer in the Viewfield area with more than 100 gross operated sections of land in its inventory.

In March, Riverstone Holdings LLC, Kelso & Co., Goldman Sachs, and Trafelet & Co. added their money to get Shelter Bay well on its way to raising US $584.5 million.

That money allowed Shelter Bay to buy Landex Petroleum for $289.9 million. Crescent Point then acquired all of the non-Bakken assets of Landex, about 1,500 boe/d, for $74.8 million, and Shelter Bay kept the Bakken assets, which produce more than 3,000 boe/d.

Crescent Point said it expected Shelter Bay to drill 40 gross horizontal wells to the Bakken in 2008 and another 40 gross wells in 2009. Since they will be on farm-out land, Crescent Point will hold a 50% interest in each of the wells in addition to its ownership interest in Shelter Bay, which slipped to 19% when Shelter Bay issued some stock for its acquisitions.

Shelter Bay drilled seven Bakken wells on the farm-out lands, giving Shelter Bay and Crescent Point new production of 300 boe/d each for the quarter. Under the farm-out agreement, Shelter Bay paid all of the capital costs of the seven wells. Shelter Bay also drilled another six Bakken wells outside of the farm-out area.

Talisman Energy Inc.

Talisman Energy Inc. modified its corporate strategy in May 2008 aiming at longer-term growth; a focus on fewer, more material assets; healthy returns with sustainable growth and improved delivery with achievable targets.

That sounds like a tailor-made strategy to reserve a place in the corporate portfolio for a significant Bakken play, and Talisman is doing that.

In a September presentation, Talisman said it accumulated 430,000 gross, 340,000 net, acres in the Bakken-prone area of southeastern Saskatchewan.

For perspective, it has 460,000 net acres in the Montney shale/tight sand, 310,000 net acres in the Outer Foothills of Alberta, 760,000 net acres in the Quebec shale of Quebec and New York, 640,000 net acres in the Marcellus shale in New York and Pennsylvania, and a combined 108,000 net acres in an arrangement with Hallwood Resources in the Barnett shale in West Texas and the Lafayette shale in Arkansas.

Its Bakken properties hold some 10 Tcfge, or 1.67 billion boe, of hydrocarbons in place. That's 3.4 million to 4.5 million boe in place per section.

Talisman completed its reservoir characterization work in the play in 2007. It still is working on pilot programs, but it started development work in mid-2008.

A horizontal well costs US $1.59 million (Cdn $1.7 million) to drill and complete. The company can drill four to eight wells per section and expects ultimate recoveries of 100,000 to 120,000 boe per well.

Talisman's land lies throughout much of southeastern Saskatchewan, and the core area sits in a general oval, widening to the east that is about 36 miles long east-to-west and nearly that at its widest point north-to-south.

In general, wells show an initial potential of about 180 boe/d, drop to around 100 boe/d after six months, decline further to 50 boe/d at around 15 months, and then follow a shallow decline curve for the remainder of the life of the well.

The company identified about 200 well locations in which it holds a 75% interest in its 2008 program.

It originally planned to drill 22 horizontal Bakken wells in 2008, but it revised its 2008 plan to drill 56 wells for the year. By the end of 2Q, with three drilling rigs at work, it had drilled 11 wells. Four of those wells came online at production rates averaging 190 boe/d.

To meet the higher well target, it raised capital expenditures for the Bakken to between $107.5 million and $112.2 million for 2008. It previously planned to spend $56.1 million to $65.4 million in 2008 and 2009, but will spend additional funds on infrastructure in 2009. That spending should raise production to between 800 boe/d and 900 boe/d in 2008 and to 2,900 boe/d to 3,000 boe/d in 2009.

Fatter budgets and higher production aren't the company's only goals. It also plans to hold finding and development costs between $16.82 /boe and $19.63/boe.

When it accomplishes those goals, the reward is high-quality, light, sweet crude with fast recycle times and high netbacks. It also gets liquid-rich associated gas production.

TriStar Oil & Gas Ltd.

TriStar Oil & Gas Ltd., already one of the major producers in the Bakken play in southeastern Saskatchewan, continues to build its land inventory and potential for success in Canada's hottest light oil resource play.

By the end of 2Q 2008, the independent increased its holdings to 220 gross, 145 net, sections through acquisitions, Crown land auctions, and farm-in agreements with other operators. That land position gave the company 797 gross, or 531 net, drilling locations. Of the 531 net locations, only 36 net locations were booked for reserves at the end of 2007.

At the same time, TriStar increased its company-wide capital expenditure program to US 341.5 million (Cdn $365 million) from the previous level of $280.6 million ($300 million). The Bakken play will use $187.2 million ($200 million) of that budget. "The increase in expenditures is expected to be allocated entirely to the company's southeast Saskatchewan core area, primarily to the Bakken play. The majority of the increase will be directed towards facilities and infrastructure construction along with continued Bakken undeveloped land acquisition and drilling activity,"the company said in its 2Q report.

Those facilities include the construction of two more central processing plants and additional oil pipelines and gas gathering systems, "all to position TriStar to continued growth of the Bakken resources play."

With the help of more drilling and the additional facilities, TriStar intended to leave 2008 with production of 23,000 boe/d from all of its activities, up from 20,332 boe/d from 2Q.

During 2Q, it drilled 15 gross, 8.1 net, Bakken horizontal wells and expanded production boundaries to the north, east and south.

It continued work to improve initial production rates with better fracture treatments, saying, "TriStar believes that advancements in technology and improvements in the techniques employed will ultimately lead to higher primary recovery factors and reserves per well than are currently forecast in its booked reserves." Those booked reserves amount to only about 1.2% of the 580 million boe of hydrocarbons in place. If it can raise the recovery factor to 12% using four wells per section and current average reserve bookings, it would get 62 million boe, net to TriStar, more than currently booked reserves.

The company planned to drill another 84 gross, 52.5 net, Bakken wells in the second half of the year. That represents substantial growth since, at a $100 West Texas Intermediate oil price, each new well adds US $4.02 million in net present value.

"With these attractive economics and TriStar's sizable Bakken development drilling inventory, the Bakken play will continue to be a focus of TriStar for the remainder of 2008 and beyond,"the company said.

An article prepared for the August 16, 2008, Reginia Leader-Post by Kevin Johnston of ScotiaMcLeod, said, "TriStar's land is in very close proximity to other major land holders in the Bakken, including Talisman, Petrobank, and Crescent Point. I believe we will see a consolidation of the Bakken plays in the next 12 months."

The pace of TriStar's growth in the Bakken appeared in the company's 2007 4Q report when it said its Bakken production in August 2007 was less than 30 boe/d. By the end of the year, it had climbed to more than 1,100 boe/d. At that time, the company had used better fracturing techniques to raise average initial production rates to between 150 and 200 boe/d , or double its earlier rates. At the same time, it reduced water cut by 50% to 75% to approximately 25% of total fluids production.

By the end of 2Q 2008, production had more than doubled to more than 2,750 boe/d. An independent analysis estimated proven and probable reserves at 125,000 boe/well.

FIGURE 1. Experienced mountaineers carefully position remote FireFly sensor packages in rugged terrain that would prove extremely challenging for conventional cabled sensor networks.

Photo courtesy of ION

Inspiration, Innovation Unlock Bakken Pay

Thanks to some creative thinking and plain hard work, the Bakken is giving up its prize. As usual, technology is leading the way.

By Dick Ghiselin
Contributing Editor

The current Bakken Shale play is somewhat of a misnomer. Most of today's wells target the porous and permeable middle Bakken, which is anything but shale.

The Bakken spans Eastern Montana, the Western Dakotas and on up into Southern Manitoba and Saskatchewan, and is the most significant oil play in the Western US. The play comprises three members: an upper and a lower shale member – both of which are described as organic-rich marine shales of fairly consistent lithology – and a mixed siliciclastic carbonate middle member consisting principally of sandstone and dolomite. The upper and lower shale members are the petroleum source rocks for the Bakken and part of the continuous reservoir for hydrocarbons produced from the formation. The middle sandstone-dolomite member varies in thickness from a few feet to as much as 80 ft at depths of about 10,000 ft and exhibits variable lithologic and petrophysical properties. Geologically, the Bakken sediments are believed to have been laid down in a shallow ocean environment. The Bakken has been explored for many years, but never as aggressively as it is being probed today. As many as 50 separate US companies hold interests in the play, with additional development activity accelerating in Canada.

Taking a macro-view of the Bakken play, two adjacent features deserve notice. The Lodgepole formation lies just above the Bakken upper shale member and the Three-Forks formation lies beneath the lower Bakken shale. These factor into many of the well design and completion decisions as will be discussed subsequently.

The pay zone is extremely heterogeneous with lithology changing abruptly both vertically and laterally. Most of the anomalies are subseismic, so early exploratory success was the result of more luck than skill. As a result, a wide variety of techniques has been tried to identify and exploit the sweet spot, which is characterized as a layer of relatively high reservoir quality that meanders through the middle Bakken. Swarms of natural fractures exist, which may contribute to reservoir conductivity, or not. In some cases they create a path of least resistance that swallows up stimulation treatments intended to open up adjacent tight zones. In others, they serve as the natural conduit for effective reservoir drainage. Most of the natural fractures have very narrow apertures, so treatments often seek to widen the fractures, then prop them open.

During the early days, there appeared to be no magic formula for success in the Bakken, but today, companies are taking a more systematic approach to create sustainable models that serve as cumulative knowledge bases from which theories can be postulated and tested. These techniques are facilitated by powerful computers using the latest software applications. One such technique builds 3-D static models of target reservoirs using Petrel software, which is capable of accepting and integrating a wide variety of inputs from offset well data, seismic surveys, drilling data, and production data. In addition to modeling porosity, permeability, and geomechanics parameters, the software is capable of exporting to the powerful ECLIPSE reservoir simulator. This allows engineers and geoscientists to explore a variety of "What if?" scenarios to help operators choose between drilling, completion, and production, alternatives. Economic and risk software can be used to evaluate alternatives with relation to the operators' individual business models.

There is little doubt that a one-size-fits-all approach will fail in the Bakken. Reservoir heterogeneity and lithologic complexity demand that each well be treated as an individual challenge to be optimized in each phase of its construction and ultimate completion. Data from various sources cannot be collected in a vacuum, but must be integrated in 3D static and dynamic models that address production controls. What may work in a neighboring well may yield disappointing results in your well.

The following sections describe recently introduced technology and techniques that are already making progress in Bakken development or those that have addressed similar challenges elsewhere and appear to have potential to deliver positive results in Bakken wells. Although individual solutions may bring benefits, most experts agree that a holistic approach starting with careful planning that involves the effective integration of all solutions will ultimately yield the best reservoir life and overall profitability.

Exploration

High-quality seismic data are indispensable to defining optimal well sites and designing drilling programs capable of guiding well bores through the hearts of Bakken formation pays. Yet the complex geology of the play and mountainous topography of the northern US Rockies present formidable impediments to accurately imaging the subsurface. Perhaps no other exploratory play in the US better illustrates the shortcomings of conventional cable-based land seismic acquisition systems and the advantages of emerging cableless land seismic acquisition technology, both on the surface and below ground.

The rugged surface topography overlying the Bakken play can present problems for conventional land seismic systems because the cables linking receivers can limit the flexibility of a survey designer to deal with surface anomalies. Surface features such as rivers, thick woods, cliff faces, buildings, or difficult-to-access areas such as public or tribal lands, within a survey boundary, can make optimal placement of receivers in a cable system difficult, if not impossible. Cable systems are also restrictive as to scalability for large, densely sampled surveys given limitations around bandwidth and the increased level of troubleshooting required.

By contrast, cableless seismic systems can be configured in whatever design best achieves a producer's

Williston Bakken FRAC ISOLATION

Overview

SWELLFIX's Frac Isolation Packer is a simple and effective zonal isolation solution for your compartmentalized frac application. **SWELL**FIX has developed and tested a specific swelling packer for your Williston Bakken needs.

Run in brine or oil base environment, this particular packer makes contact with the open hole in three days. The packer achieves a full pressure seal in less than nine days. This standard Williston Bakken packer will hold 6,000 psi in either a 6.000" or 6.125" open hole.

The Williston Standard:

- **Base Pipe: 4.500" 11.6 ppf P110**
- **Thread: LT&C or Buttress pin x pin**
- **Element OD: 5.500" to 5.750" depending on hole size**
- **Element: 5 Swelling Bands**
- **Total Length: Approximately 16 ft (includes 4 ft of tong room on top and 2 ft on bottom)**
- **Pressure Rating: 6,000 psi @ 240° F**

Full Scale Testing

In September 2008, a full scale test was performed on **SWELL**FIX's Williston Bakken Frac Isolation Packer. The test utilized a 4.500" X 5.625" OD water swelling packer setting inside of a 6.000" ID test fixture. After fresh water was placed in the fixture, the temperature was raised and held at 240° F for the duration of the test. Initial element contact was noted at day three of the test. At day nine, a pressure differential was applied to the packer. The pressure was increased incrementally until a pressure of 7,500 psi was achieved.

SWELLFIX
zonal isolation

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Leaders in **Swelling Packer** Technology

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imaging objectives. The flexibility and freedom allowed by this acquisition technology means cableless systems are extremely well-suited for economically acquiring the kind of densely sampled, wide-azimuth, long-offset, seismic data required for advanced processing techniques. This data enables explorationists to locate fractures in Bakken sandstone-dolomite pay zones and to determine the orientation of the fractures.

The potential benefits of using cableless seismic technology in the Bakken shale play recently were demonstrated in the rugged mountains of northwestern Colorado, where one of the world's most advanced land seismic acquisition systems acquired high-density, full-wave data over a 30-sq-mile survey area to support redevelopment of a fractured shale reservoir. The FireFly cableless land acquisition system, developed by Houston-based ION Geophysical, completed the acquisition in a schedule so condensed that many of the seismic contractors invited to bid on the project doubted the work could be completed within the given time-window with conventional cable-based acquisition technology.

Heightened Bakken Interest

Interest in the prospectivity of the 25,000-sq-mile Upper Devonian–Lower Mississippian Bakken formation jumped appreciably after the U.S. Geological Survey (USGS) in April 2008 released a report that estimated the mean volume of undiscovered Bakken proven reserves in Montana and North Dakota, at about 3.65 billion bbl of oil, 1.85 Tcf of associated natural gas, and 148 million bbl of natural gas liquids — about 25 times the volume of a 1995 USGS estimate.

Each succeeding member is of greater geographic extent than the underlying member, and USGS concluded that most of the undiscovered Bakken oil resides within a continuous composite reservoir distributed across the entire area and including all members of the formation.

Hopes are high for the Bakken shale play, but only a few wells have produced from the formation to date. Consequently, companies participating in the expanding play still have a lot to learn about the formation, as well as the exploration, drilling, and production methods best-suited to optimize recovery. One of the most favored strategies is to drill a well vertically to a depth of about 10,000 ft to penetrate the thin sandstone-dolomite Bakken pay, then drill horizontally for an equal distance to access as much of the formation as possible to the well bore. Some operators complete horizontal Bakken wells by fracturing segments of the horizontal section in stages, as opposed to fracturing the entire horizontal section at once.

Fracture stimulating horizontal Bakken wells has been shown to improve oil recovery, but it is crucially important that the well bore penetrate as many naturally occurring fractures as possible to optimize the reservoir's productivity. Full-wave acquisition techniques, such as high-density, wide-azimuth, long-offset designs provide the most effective means available to pinpoint both the locations and orientation of naturally occurring fractures in the Bakken shale.

Full-wave acquisition enables users to capture converted wave data, which contains the information needed to image both fracture density and fracture orientation, as well as lithology. These properties are extremely important in achieving the level of understanding in shale plays that is required to optimize drilling plans. That means drilling only the wells that are needed to intersect available fracture systems and to allow an operator to position the horizontal section of the well bore in the sweet spot of the reservoir to achieve maximum connectivity and to recover as much oil as possible for as long as possible.

Fractured Shale in Colorado

To image the fractured shale reservoir for the so-called Durham Ranch survey in northwestern Colorado, crews deployed more than 6,000 FireFly field station units (FSUs) incorporating ION VectorSeis multicomponent receivers and acquired more than 10,500 receiver points, detonating nearly 7,000 dynamite shot points in just 20 days of shooting.

"This was a very challenging acquisition project in terms of the timeline and topography, not to mention our need to minimize the operational footprint in a sensitive area that includes wildlife, numerous ranches, and access restrictions to public lands," said Marty Williams, geoscience manager of East Resources Inc., an independent E&P company and the primary underwriter of the Durham Ranch survey. "In addition, we needed to acquire

Horizontal Open Hole Logging in the Bakken Shale

Saving Rig Time and Improving Log Quality

Historically, an operator had used drill pipe conveyance to conduct logging operations on their horizontal wells in the Bakken Shale. Wells drilled in this area typically have long horizontal sections upwards of 9,000 ft. Formation compressive strengths approaching 40 kpsi have generally yielded favorable hole conditions for open hole (OH) Well Tractor® technology.

The operator has changed their intervention strategy and now uses the Well Tractor® to perform logging operations. With this technology, logging tools can be conveyed to the logging point in a matter of minutes compared to several hours using drill pipe methods.

Benefits

- 18 successful OH wells logged (as of October 2008)
- Rig time reduced by 16 hours per well
- One day of logging services saved per well
- Estimated cost savings $80,000 per well
- Improved OH log data obtained
- Positive HSE impact by eliminating drill-pipe conveyed logging

For more information, please go to welltec.com.

Wireline Well Tractor®

The wireline Well Tractor® is a unique technology that enables intervention tools to reach the end of the horizontal or highly deviated well without employing drill pipe or coiled tubing conveyance methods.
Instead, the Well Tractor® is a wireline deployed self-propelled device that pushes wireline tool strings out to the end of the wellbore.

Coiled Tubing Well Tractor®

The fluid driven Coiled Tubing Well Tractor® extends coiled tubing's lateral reach in horizontal multi-stage completions.

The built-in fail-safe function in all Well Tractors reduces the risk of tools becoming stuck in the well.

Welltec®

densely sampled, full-wave data to better characterize a fractured shale reservoir that East Resources plans to re-develop.

"I've seen some of the early traces, and the seismic data look to be of the highest quality. We couldn't have completed this project without FireFly. Matching a game-changing technology with an experienced contractor provided a unique solution to the operational and imaging challenges we faced on this project," he concluded.

Densely sampled data were delivered within a specified 45-day time period and under budget from the remote, environmentally sensitive area, various parts of which were habitat to numerous species of wildlife, on public lands, and hosted extensive farming and ranching operations. Topography within the survey area was so extreme that climbing crews were hired to deploy tilt-insensitive VectorSeis sensors on the faces of shear rock cliffs by gluing them in place with a biodegradable epoxy (Figure 1).

At a time when conventional cable seismic acquisition systems are used to acquiring seismic surveys with approximately 20 to 40 folds of data, the nominal fold of the Durham Ranch survey was 240-fold.

Architecture Highlights

Each FSU consists of a small box containing 4 gigabytes of flash memory, a battery for power, and multiple communication protocols, including Bluetooth and VHF radio. Each FSU is connected to a VectorSeis sensor by a short wire, which transmits seismic signals to the FSU's flash memory (Figure 2).

FireFly architecture allows surveys to be designed virtually during operational pre-planning with modeling software that enables placement of each receiver and each source point in the x, y, and z coordinates. This enables crews in the field to deploy each FSU-sensor pair stakelessly by using GPS technology to determine horizontal position and digital elevation models to determine vertical positioning.

ION's Connex navigation tool enables the ability to monitor and track crew movements during deployment, as well as review the path taken by crews after the fact. In addition to helping ensure the safety of seismic crews and helping minimize environmental disruption, Connex helps enable many of FireFly's unique features and ensures the accuracy and integrity of seismic data acquired.

Each FSU communicates with the observer in the field by way of a full duplex, or two-way, radio communication system. In addition to sending commands by radio link, two-way communication enables the remote units to receive responses from the ground equipment, which provides the observers with the ability to monitor the status of the hardware or geophysical attributes.

FireFly radio communications occur on the 150 MHz band, a frequency at which the FCC allows a signal to be transmitted with up to 50 watts of effective radiated power. Communicating on the 150 MHz band helps minimize the amount of radio infrastructure needed on a project. The lower frequency also can better penetrate foliage and other obstacles without affecting its ability to operate.

Well Design

A variety of well designs have been attempted over the years. Today, most operators are drilling horizontal wells to develop the middle Bakken. Single and multiple laterals have been drilled in an attempt to maximize reservoir contact. Many operators preface their development drilling with a vertical pilot hole. The objective of this probe is to gather relevant lithology and geomechanics information on the target zone to help design and execute the subsequent lateral(s). Laterals vary in length from 3,000 ft to 10,000 ft.

Wireline logs are run in the pilot holes with the objective of answering the following questions:

- Where should the horizontal well be landed within the middle Bakken target zone to achieve the best production?
- At which azimuth should lateral wells be drilled to meet stimulation and reservoir drainage objectives?
- Are natural fractures present in the lateral, and if so, how will they impact fracture initiation and the post frac drainage pattern?
- Are stress variations present in the lateral, and if so, how will they impact fracture initiation and coverage?
- What should be the correct well spacing to optimize production from the reservoir?
- Where should fracture stage depths be located to achieve the best frac coverage?

- Can a fracture treatment be selected and implemented to frac from the Bakken down into the Three-Forks formation (or vice versa) to maximize recovery?
- How should the frac treatment be designed to avoid fracturing up into the Lodgepole formation?

Other operators target the middle Bakken right away with a horizontal well, then mill a window or two uphole in the vertical section to kick-off laterals. Obviously, the wells and lateral branches are designed to intersect as much of the sweet spot layer in the middle Bakken as possible. This layer may vary in thickness from 7 ft to 12 ft and represents the very best reservoir quality rock from a drilling perspective. Since Bakken wells will be fractured anyway, reservoir contact is not the principle goal of geosteering. Drilling efficiency is, and the so-called sweet spot offers high penetration rates and easy drilling. Accordingly, the objective is to achieve as much "coverage" in the sweet spot as possible. Coverage is defined as the ratio of footage drilled in the sweet spot versus the total drilled lateral length. Logs are used to determine the orientation of maximum regional stress and laterals are drilled with this in mind. Laterals drilled parallel to the maximum principle stress orientation will produce highly prolific longitudinal fractures when stimulated. Laterals drilled at an angle to the maximum principle stress orientation will produce transverse fractures. In general, these will require a much more aggressive stimulation treatment to produce high formation conductivity.

Well Construction

In North Dakota, the middle Bakken target zone is located between 9,500-ft and 11,000 ft true vertical depth (TVD). In Montana, the target is a high-permeability limestone or dolomite formation located at approximately 10,000-ft TVD. Generally, Bakken wells are drilled in two phases. The wells are drilled and landed in the middle Bakken target zone using oil based mud (OBM). They are cased and cemented using 7-in. casing. Directional drilling is performed using oriented mud motors because for the most part the rigs do not have sufficient horsepower to handle rotary steerable systems. Most of the time, the OBM is reversed out and replaced by oilfield brine for drilling the horizontal sections. Previously, the horizontal sections were drilled with a 6-in bit using mud motors and steered using conventional Gamma Ray measurement-while-drilling (MWD) equipment. However, this technique produced sub-optimal results. Average coverage in the Bakken sweet spot was about 36%, and this placed the completion engineers at a disadvantage. Steering with Gamma Ray resulted in several trial-and-error sidetracks and extreme dog-legs that made it difficult to land the completion string. Essentially, the Gamma Ray tool only told the directional driller when the tool drilled out of the target formation, it did not give any clues of which way to steer to get back into the pay zone and often the only solution was to pull back and attempt a side track. In addition, the lower Bakken shale is notoriously difficult to drill, and operators want to avoid drilling into it if possible. With conventional MWD techniques, it was nearly impossible to avoid because the target zone, although fairly

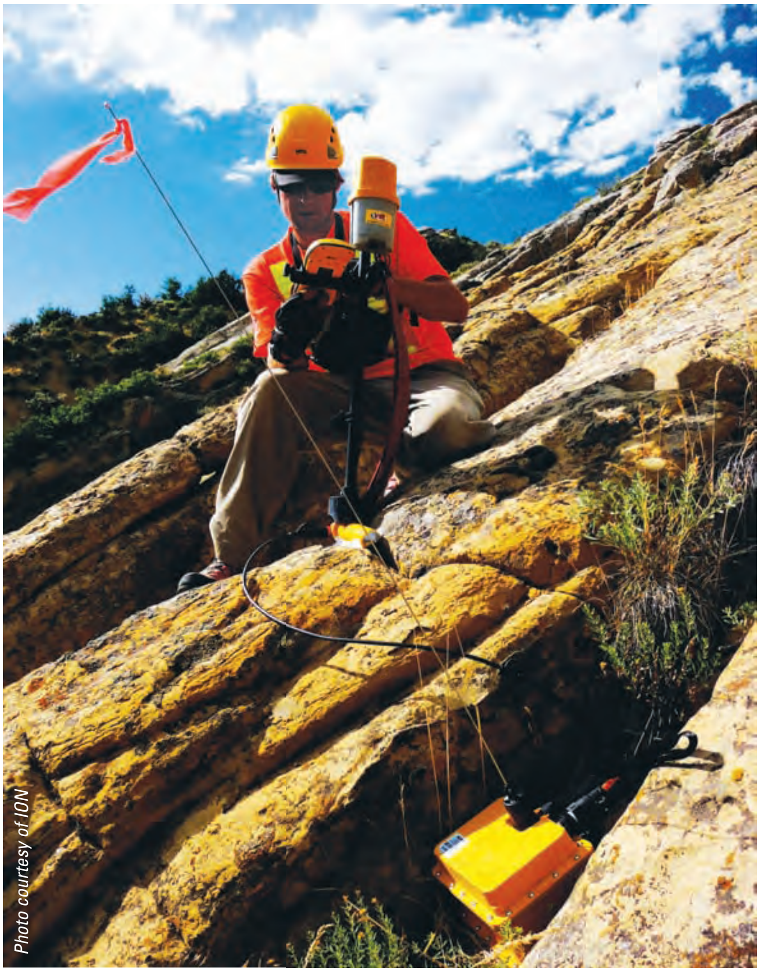


Photo courtesy of ION

FIGURE 2. Remote sensor packages contain triaxial VectorSeis solid-state geophones and a two-way radio transceiver with GPS capability.

thick, contained sub-seismic undulations and faults. By the time it was recognized that the bit had drilled out of zone, there was a 50-50 chance that a steering decision made to remedy the situation would be wrong and result in the well trajectory departing even farther out of the zone of interest. When this resulted in drilling into the lower Bakken shale, severe hole integrity problems could ensue.

Predictive Geosteering

The recent introduction of the PeriScope directional boundary mapping logging-while-drilling (LWD) service, has combined state-of-the-art hardware, software and experienced well placement engineers to make a step-change in directional accuracy and drilling efficiency. Instead of the reactive steering previously described, operators were able to employ predictive steering. With this new technology, coverage in the middle Bakken sweet spot has jumped to 96%, and wells can be steered to avoid drilling hazards while minimizing dog-leg severity (DLS). The new tool measures the distance and direction to an approaching boundary and provides ample warning to the directional driller so the bit can usually be steered away from the hazard. It also measures dip changes and reversals in the highly undulating strata. The average regional dip is fairly well known, but many times there are variations in local dip that can cause drilling out of zone unless a predictive technique is being used. Incidents of accidentally drilling into the lower Bakken shale have all but disappeared for those using the service.

FIGURE 3. A typical "curtain" plot illustrates the real-time display that helps the directional driller steer the well trajectory to maximum coverage in the target formation.

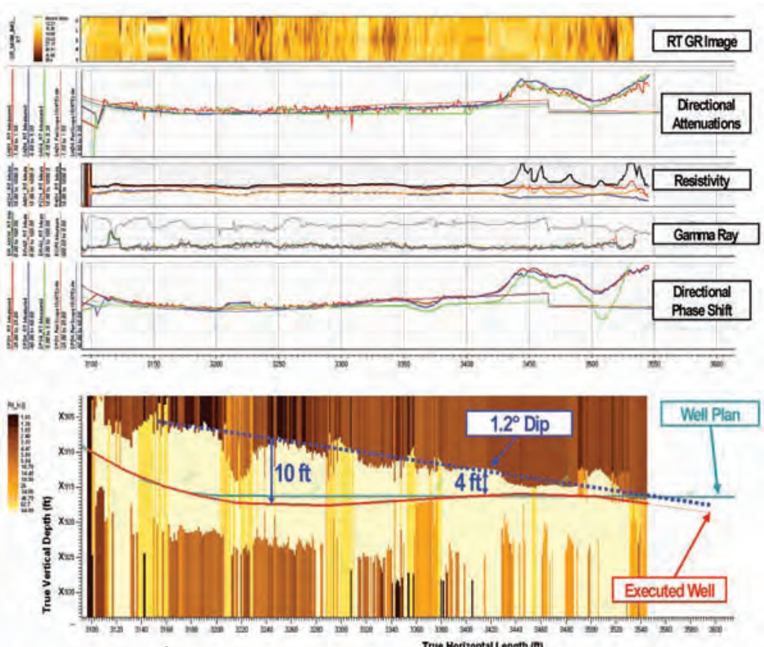


Photo courtesy of Schlumberger

The new tool is steered using real-time telemetry that gives the rigsite engineer a clear picture of drilling progress relative to the target formation (Figure 3). The information is simultaneously transmitted via very small aperture satellite transmission to the customer's office and the Operation Support Center in Denver. The system allows all stakeholders time to consider and approve steering recommendations before drilling out of zone. Real-time quality assurance is provided by the service contractor's well placement experts who may access the data screens from any secure Internet terminal worldwide (Figure 4). Other LWD systems run in conjunction with the boundary mapping tool provide porosity measurements and electronic caliper data that indicated borehole ovality or washouts. This information helps the completion engineers design where to place their zonal isolation devices for best results during subsequent stimulation services.

Additional information acquired while drilling is being used to improve overall drilling efficiency in the Bakken. Recorded data like vibration of the bottomhole assembly can be analyzed to allow optimization of bit runs by adjusting such parameters as weight-on-bit, drillstring and/or motor rotational speed and mud weight.

An alternative technique used by some operators is to let the well trajectory migrate in the middle Bakken, then measure the stress and fracture variations and stage the fracture treatment accordingly. Both techniques provide good solutions depending on the operator's needs.

Understanding Stress

A great deal of effort has been devoted to improving the understanding of fracture orientation. It is well-known that most hydraulically induced fractures propagate in the direction of the maximum principle formation stress. Accordingly, if a lateral is drilled parallel to the maximum principle stress, when it is stimulated, a longitudinal fracture will be formed. Conversely, if the lateral penetrates the stress field at an angle, it is likely that a transverse fracture will form when the formation is treated (Figure 5).

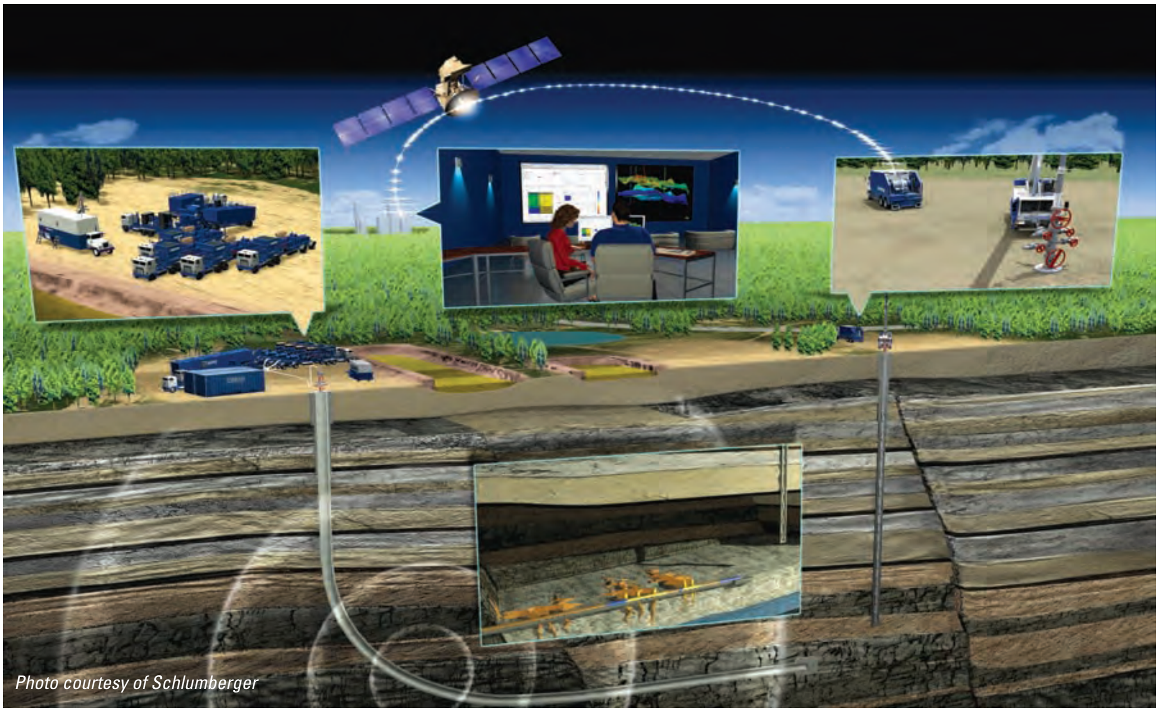


FIGURE 4. Schematic of communications network used during well logging and stimulation services to help all stakeholders make fully informed decisions.

Understanding the implications of stress orientation to Bakken completions is the subject of a paper (SPE 110679) presented at the 2007 SPE Annual Technical Conference and Exhibition held in Anaheim, Calif. The paper was co-authored by representatives of Hohn Engineering, Nance Petroleum Corp., and Pinnacle technologies. According to the authors, fracture orientation relative to the trajectory of the lateral plays a key role in treatment design. This has been long-understood in vertical wells that traditionally intersect a pay zone at right angles thus imposing considerable flow convergence as formation fluids flow radially to the well bore. No matter how deeply any fracture has propagated, the flow convergence factor can limit overall conductivity. Accordingly, any treatment which can widen the fracture aperture and supply a highly-permeable proppant pack will prove beneficial. Horizontal completions are another story altogether.

Longitudinal fractures occur when the lateral trajectory is parallel to the maximum principle stress orientation (Figure 6). In these cases, there is high conductivity even from a fairly shallow-propagating fracture, and the authors conclude that there is little advantage to using high compressive strength ceramic proppants. However, it may be advisable to use resin-coated proppants to reduce proppant flowback during the clean-up period. This is particularly advisable where cemented liners are used with communication through perforations, which create a form of flow convergence themselves.

However, the vast majority of fractures are of the transverse variety because of the lack of lateral orientation with the maximum principle stress (Figure 7). In these cases, say the authors, everything matters. Every measure must be taken to ensure that the right proppant is used, along with clean fluids and superior implementation. Accordingly, stimulation design takes on a whole new perspective where transverse fractures may result.

A recently introduced technique that has had success in the Barnett Shale play of North Central Texas is real-time monitoring of fracture propagation using microseismic methods. The technique has been introduced on several wells in the Bakken play. Briefly, arrays of seismic sensors are deployed in an offset well. They pick up the microseisms that occur as the rock fails and can track the propagation of the fracture (Figure 8). The long sensor arrays deployed in horizontal offsets allow simultaneous imaging of both the toe and the heel of the well being treated with results available onsite in 15 to 30 seconds. Not only does this allow the stimulation service provider to steer the fracture by altering the pumping schedule or by deploying diverters, but the

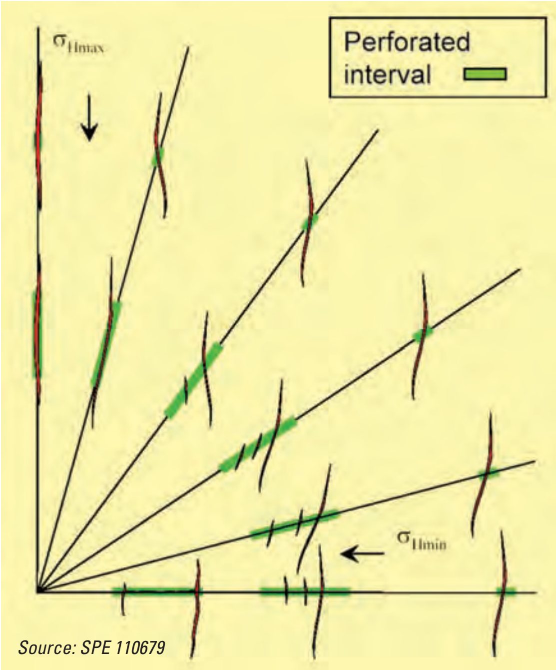


FIGURE 5. Longitudinal fractures result when lateral well bores are drilled in the direction of maximum principle stress. All others result in transverse fractures.

resulting fracture map is indicative of the way subsequent fractures may propagate, either from subsequent stages in the well being treated or in nearby offset wells. Moreover, the technique helps the operator understand the fracture geometry that is likely to dominate in the area of his lease.

Guesswork Produces Stressful Results

The value of foreknowledge of fracture orientation cannot be overestimated. A significant number of observations made during Bakken stimulations emphasize the danger of basing fracture design on guesswork or assumptions. The heterogeneous nature of the Bakken structure and lithology gives fractures a "life of their own." In two cases, despite extra effort to orient the lateral to minimize transverse fracture propagation, cross-linked sand laden slurry was pumped into offset wells 2,200 ft away in a transverse direction from the well being treated. Two other companies reported slurry pumped to surface in offset wells as much as 1,500 ft away. Often, increased water cut has been observed in offset wells following treatment of a well in the vicinity. And conclusive proof is obtained when radioactive tracers are pumped in the slurry. If a transverse fracture has resulted, the radioactive tracers are concentrated in a small section of the lateral rather than being evenly distributed along its length. Incidence of transverse fracture propagation in other fields in North America shows conclusively that an overwhelmingly high percentage of all horizontal wells treated result in transverse fractures. It is reasonable to assume that these conditions will prevail in the Bakken as well.

The authors postulate that a short, properly-treated transverse fracture is better than a long inadequately-treated one. They suggest that if short, high-conductivity transverse fractures can be produced reliably, operators may not have to drill such long laterals to achieve maximum producibility from their wells. They conclude that an investment in fracture planning and design, correct proppant selection and flawless implementation will pay off in better producers, reduced drilling costs and longer well-lives. As evidence, they provide production data from the Valhall Field in the North Sea (Figure 9). Because the oil velocities at Valhall are much lower than those in the Bakken play the authors believe that the resulting improvement from properly designed fractures at Bakken will be even more pronounced.

Finally, proppant flowback from poorly constructed fractures in the Bakken has plagued operators there for some time. Since Bakken wells must be put on some form of artificial lift fairly early in their lives, proppant flowback issues manifest themselves in premature pump failures along with severe collateral damage to tubulars and valves. So far, according to the authors, none of the wells treated with ceramic proppant have experienced flowback problems, even when the ceramic proppant is not pre-coated with resin.

Well Completions

A good deal of science has been applied to completion design in the Bakken. Unlike the Barnett, where one operator reckoned the most effective stimulation technique was to pump and pray, service providers have devoted considerable effort and expertise toward identifying the most effective treatment scenarios on an individual well basis. Since the principle objective of hydraulic fracturing is achieving maximum reservoir contact, the most effective designs involve effective the use of all data in the knowledge base. This includes everything from seismic to production data from previously drilled wells. Most recently, it has incorporated geomechanics data including detailed stress analyses. These parameters are invaluable in deciding where to locate zonal isolation devices and how to pump each stage of a multistage fracture treatment, such as that provided by Packers Plus, where each stage is treated individually using zonal isolation packers and sliding sleeve valves that are controlled by pumping successively larger balls as the treatment is being performed (Figure 10).

In this technique, zonal isolation is assured by a series of staged openhole packers that are inflated by pumping well fluid. The packers are strategically located along the completion interval and are used to isolate different zones so they can be stimulated individually according to each zone's requirements. Once the packers are set the lowermost zone is treated. Then a ball is pumped that closes the treated zone and shifts a sliding sleeve that opens up the next zone for treatment, and so on. Up to six stages can be treated on a single trip into the well. Alternatively, swell-packers can be used for zonal isolation, but these require several hours to fully seal off the annulus. When all zones have been treated, the pressure is released and the balls are produced to surface where they are caught in a ball-catcher basket. The beauty of this system is that each zone's treatment can be customized according to its requirements with different proppants, different treatment fluids, and different pumping schedules.

In the Bakken, the frac initiation pressure changes depending on where the treatment is being applied in the well bore. It has a high relationship to the presence of the natural fractures. For this reason, stimulation engineers make valuable use of log data during the completion and treatment design phases. For example, it is desirable to include the swarms of natural fractures between the zonal isolation devices, whether they are conventional packers or swell-packers. This will ensure that the treatment goes into the fractures to improve their conductivity. The aperture width of the natural fractures is quite narrow and one objective of stimulation is to widen these. By treating each zone individually, the overall performance of the stimulation treatment is optimized. Since the treatment is going to follow the path of least resistance, it is critically important to understand where the natural fracture swarms are located, as well as the formation hoop stress in the unfractured areas. This allows engineers to isolate the fractured zones and treat them separately from the unfractured zones. When they do this, they have all the options available such as proppant and frac fluid design, pumping schedule, volumes and pressures to optimize the treatments on a zone-by-zone basis. The latest diverters that include dissolvable fibers have been used. These can be very effective in helping to ensure a large portion of the sweet spot is treated. The fibers dissolve within 24 hours to 36 hours at 250°F after they are deployed, making it a particularly effective diversion technique in this complex environment. It is also possible to use oriented perforation to get past the hoop stress as well as to lower the required fracture initiation pressure. The logs tell the best direction to orient the perforations.

Schlumberger's Bob Welty, manager, US West Wireline Business Development, explained. The importance of isolating individual stages in the Bakken has become better understood recently as the variability of the reservoir quality in the laterals became better known. How to best isolate between stages is still evolving. The trend is toward more rigorous isolation methods and different ways to control the fracture initiation process to overcome the variable hoop stress in the laterals. The evolution has seen a move from openhole completions with large fracs using diversion methods like StimMORE for well coverage to swell-packers or cemented liners to provide isolation. Schlumberger has been studying the fracture initiation process compared to the wellbore characterization and has found variations from one area to another making it difficult to have a universal approach. Each has tradeoffs. Swell-packers are commonly used as one form of stage isolation and have the benefits of not requiring cementing, but also have the disadvantage of having to be strategically placed immediately after drilling the well, without the ben-

Source: SPE 110679

FIGURE 6 (top image). Longitudinal fractures provide the best communication with the well bore with high conductivity and require minimal proppant specifications.

FIGURE 7. Transverse fractures provide minimum wellbore contact and often are conductivity limited regardless of their height and depth.

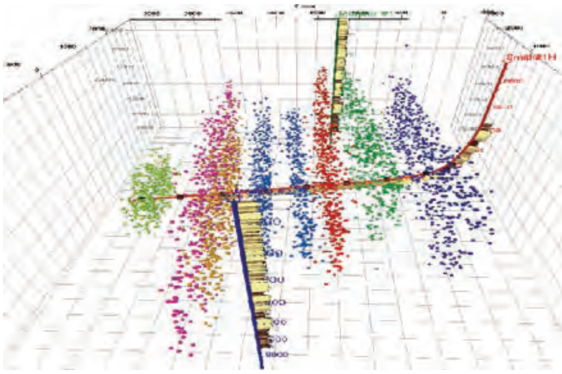


FIGURE 8. StimMAP Live plot illustrates how seismic technology can track fracture propagation in near-real time.

Image courtesy of Schlumberger

efit of much reservoir data in many cases. Many packers are simply placed at even increments that may include high stress unfractured and lower stress fractured intervals in the same section. Hoop stress can cause longitudinal frac initiation events in the near wellbore environment that can bypass the swell-packer in some cases. On the other hand, cementing provides the operator with time to evaluate the reservoir in a cased hole environment and then use this information to optimize the stages. The tradeoff here is achieving effective isolation on the low side of the hole and understanding where isolation does not exist and using this in their perforating and staging decisions. Even the phasing of the perforating matters for frac initiation as treating pressure can vary with the perforation orientation.

Although most Bakken completions are open hole, a few have been attempted in cased laterals. These situations are minimal because operators fear that cement will plug off the natural fractures they depend on for reservoir conductivity. However, in the cases where cemented pipe is used, a new Isolation Scanner tool from Schlumberger has provided excellent information on cement distribution and hydraulic integrity of the cement, both at the casing/cement interface and at the cement/formation interface. In addition, by understanding precisely the distribution of cement around the entire circumference of the casing, zonal isolation can be mapped leading to optimized perforation and stimulation treatments.

Canadian Treatment

In Southern Saskatchewan, the Bakken is considerably shallower than it is in the US. The sweet spot is thinner as well. Generally the Bakken can be found at a depth of about 4,920 ft to 5,412 ft in Canada, with the Middle Bakken sandstone varying between 16 ft and 33 ft in thickness. Porosity varies from 5% to 12% with water saturation averaging 50%. Permeability is low, ranging from 0.01 md to 0.5 md. The upper and lower shales are thinner as well, so only about 16 ft to 26 ft of shale separates the middle Bakken from the water-bearing Lodgepole formation above, or the Torquay formation (called Three Forks in the US) beneath. This creates a challenge for stimulation because there is a real risk of fracturing up into the wet Lodgepole. Historically, the play was developed using vertical wells without much success.

BJ Services, through the combined efforts of its Canadian region and the Tomball (Texas) Technology Center, has made a major study of the Bakken reservoir in Canada, pulling in data from operators and government sources as well as performing their own measurements on whole cores, and completing extensive modeling. These studies have shown that if the Middle Bakken could be drilled horizontally, particularly if it were drilled perpendicular to the maximum principle stress field, it could be completed and fractured to achieve good reservoir contact while ensuring limited fracture height growth.

Three technological initiatives have proved useful in successfully treating the Middle Bakken: performing detailed reservoir characterization, accurately predicting fracture dimensions, and using robust fracturing fluids. Possibly the most significant advancement in the exploitation of this reservoir is the ability to drill horizontal wells in a narrow window and mechanically isolate up to 13 discrete intervals within the openhole section. "This zonal isolation technique solved about 50% of the problem," said Brad Rieb, region technical manager, BJ Services, Canada. "But it was up to us to solve the other half of the puzzle."

The company was able to use applied chemistry to overcome several challenges. First it developed a crosslinked fracturing fluid and sophisticated breaker system that would perform reliably at low reservoir and treatment fluid temperatures—the Bakken reservoir in Saskatchewan is barely 160°F (70°C) – and extended pumping times. Second, treatment optimization required low pumping rates (about 5.0 bbl/min to 8 bbl/min) to ensure limited height growth and avoid subsequent fracturing up into the wet Lodgepole formation. It takes an average of 55 minutes to 65 minutes to pump 17,600 lb of 20/40 Ottawa sand, which is the typical size for a fracturing stage. Accordingly, both gels and breaker technology had to perform at low temperatures and low pump rates. The company's proprietary Vistar fluid and unique breaker system solved the problem; it has been pumped on 60% to 70% of the 5,200 stages treated to date.

"We believe that 90% of the fractures are transverse, which is consistent with our exploitation model," said Rieb. "The key is being able to place sequential, isolated toe-to-heel treatments slowly and predictably."

Results have confirmed the technique. The horizontal multistage fracture stimulated wells on average perform 10 times better than offset vertical wells. "Now that we have the pre-job analysis and treating technique down, we have been able to work on improving efficiency," Rieb said. "As a result, over the past 30 months, we have treated 650 wells averaging eight stages each – that's 20 wells per week."

Complementing BJ Services' rigorous on-site quality control, the company transmits job data in real time using a secure Internet link to their engineering department and client offices. The data is also accessible by clients from their homes or remote laptop computers 24/7 by logging in using a password. This allows full control of the real-time fracturing operation, which in turn permits immediate response to any change in the observed rate-pressure response. With several hundred zones successfully treated to date and with wells exhibiting excellent post-treatment performance, it's rare to see a client at the job site anymore.

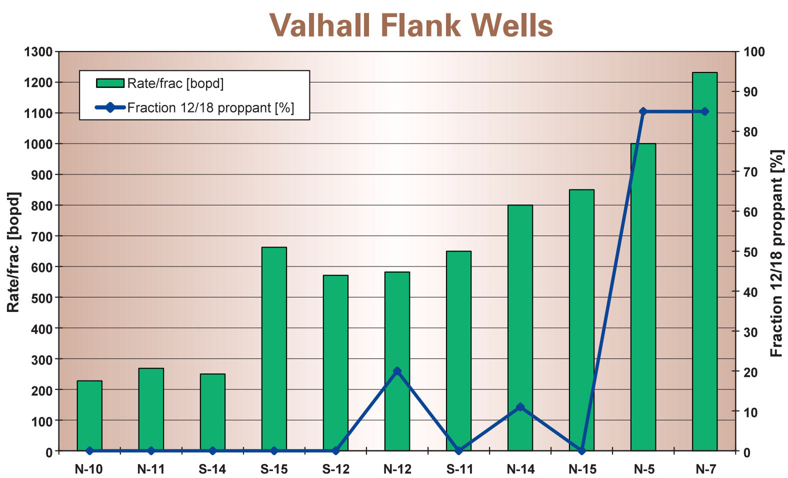
In addition to the improvements in zonal isolation, treatment chemistry and pumping techniques, BJ Services has addressed an extremely vexing problem affecting Western Canada – low water supplies. Often, there is insufficient fresh water available. Accordingly, the company has modified its chemistry so it can treat using produced water of variable salinity. Forty percent of the Bakken wells treated in Saskatchewan today are treated using produced water, much to the delight of local farmers and municipalities. BJ Services recently formalized its leadership role by establishing a Global Shale Technology Team based in Tomball, Texas. Randy LaFollette, manager of Shale Technology, said, "We have focused our efforts on understanding and engineering best practices and new technologies to meet shale completion challenges. It starts with a commitment to our 'Understand the Reservoir First' studies," he said.

Production

Bakken production is typified by high initial flowrates but also rapid pressure decline curves. As a result, most completions must include plans for artificial lift. Techniques vary all the way from traditional rod-pumped wells, to gas lift, to electrical submersible pumps (ESP). Production logging has been suggested as a way to help optimize production decisions, and one service that has had success in the Barnett is the FlowScan Imager tool from Schlumberger. The device measures multiphase flow across the vertical diameter of the lateral completion, providing vital insight of the source of each type of production along the entire well bore as well as quantifying its flow rate. One has been run in a Bakken well, and the results are being analyzed. One caveat is that the well must be flowing naturally when the log is run. Often Bakken wells die before they can be logged, so the decision to evaluate flow in the laterals using a production logging device must be made as part of the completion decision phase. By understanding how the well is producing under natural conditions, engineers can improve the effectiveness of artificial lift designs.

An important consideration in artificial lift design in the Bakken play is that reservoir parame-

FIGURE 9. Production from transverse fractures in the Valhall Field improved through the use of advanced proppant to create higher conductivity and wider apertures.



Source: SPE 110679

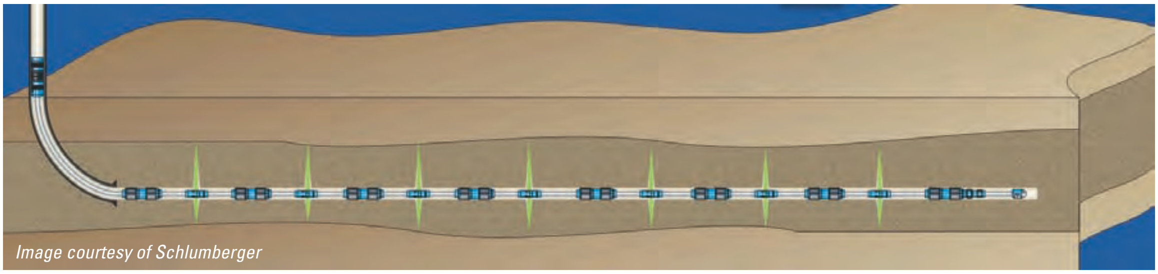


FIGURE 10. Multi-stage treatments using isolating packers and ball-operated valves achieve excellent results in the Bakken.

ters can change very quickly during production. Wells are produced using a variety of techniques from rod pumps to ESPs. Many of the wells are equipped with surface or downhole monitoring devices so well performance can be monitored 24/7 and production can be maintained at optimum levels for as long as possible. These devices are connected to a remote operations center that performs surveillance on hundreds of wells. When a well in the network falls below predetermined norms, an alarm alerts the center engineers who can use the data record to analyze the problem and determine its cause. Often, remedial action can be taken immediately to alleviate the condition, or the well can be shut in to minimize collateral damage to the well or its production equipment. The sophistication of the monitoring system is in direct proportion to the financial risk of a premature failure of well equipment or the cost of deferred production. Some of the best is used in conjunction with ESPs. Not only are many of these equipped to record and transmit well production data, but most can monitor the condition of the downhole equipment. Such parameters as vibration, power consumption intake and output pressures and temperatures, and motor winding temperature and flow rates prove valuable in diagnosing off-trending, and frequently result in repair initiatives being taken before the problem becomes serious enough to affect profitability.

New technology with direct application to Bakken production conditions is making its appearance just in time for the current drilling boom. An advanced gas handling device allows ESP pumping of flows with as much as 45% gas volume fraction (GVF), and the Poseidon multiphase ESP gas handling system has been introduced that has the capability to produce efficiently a well that is under slug flow regime, or one that has a GVF as high as 75%. It can produce multiphase flow from wells with gas/oil ratios from 8,500 to 12,000 scf/bbl. This type equipment, coupled with the downhole monitoring systems can be operated in a different manner in order for the ESP to be able to ride through the gas slugs without detrimental effects on the motor. Web-based remote monitoring, surveillance, and control are ideal for the Bakken play, where most operators' offices are many miles away.

Recompletions/Refracturing

According to the aforementioned SPE paper, several authors have addressed the issue of refracture stimulation to revive Bakken wells. They postulate that refracs are deemed necessary for a variety of reasons:

- To achieve increased diversion for improved lateral coverage;
- To reorient existing fractures;
- To correct insufficient or inadequate initial fractures;
- To replace lost conductivity caused by inadequate proppant strength (i.e. proppant crushing); and
- To replace conductivity lost due to proppant flowback.

Unfortunately, not all attempts at refracturing the Bakken laterals have been successful from an economic standpoint. The design and implementation process must ensure precise placement of the refracture in the depleted zone. This is easier said than done. The authors suggest that a more effective technique may be to design the initial stimulation taking all factors into account. Often, the problem has been identified as either closure of initial fractures subsequent to treatment due to high closure stresses in the area and/or excessive proppant flowback during the clean-up phase.

A thorough stress analysis should identify zones where high closure stress could be an issue. In these cases substitution of high-strength proppant, such as ceramic beads can supply the necessary compressive strength to the proppant pack to resist closure. Another possibility is poor proppant distribution within the fracture. To solve this problem, the authors recommend doping the proppant radioactive tracer elements so subsequent logs can determine actual proppant distribution. In multistage jobs, different tracer elements are used so the effect of each stage can be evaluated by performing a spectral analysis of the radioactive signature. If the results suggest that only a small portion of the lateral has actually received proppant, a refracturing attempt could be justified perhaps using a modified zonal isolation scheme. The benefit of this technique is that the refrac could be attempted immediately following the logging run and the problem resolved while the stimulation spread is still on-site.

An example where a thorough understanding of formation stresses is valuable is in cases where the operator would like to frac downward into the Three Forks pay and co-produce it along with the Bakken. With extremely high closure stresses in the lower Bakken between 9,000 psi and 10,000 psi, the operator must be assured that the fracture can be propagated all the way to the Three Forks and also that it can be kept open. High-strength ceramic proppant can do the job, but the entire treatment must be designed with the end-objective in mind. This example underscores the need for developing a comprehensive database on each well beforehand. It may be impractical or impossible to gather requite information after the fact.

A Stitch in Time

Notwithstanding the above, the authors pointed out that in most wells treated with ceramic proppant to date it has not been necessary to re-treat due to premature closure or excessive proppant flowback.

It has become increasingly evident that production optimization in the Bakken play will not result from application of a single cure-all technology. An integrated approach ensures that all knowledge is captured and used to model each well as well as the reservoir itself. This approach has led to greatly improved decision-making. Welty noted that data taken during logging runs in pilot holes or even in the horizontal well bores themselves may have application much later during well completion, stimulation, or even production.

Schlumberger is currently using several key wireline technologies to aid in well targeting and completion decisions. Two commonly run services provided in logging the pilot holes involve microresistivity imagers or acoustic scanning services to determine the azimuth of principle stress. Operators need this azimuth to orient the lateral according to the stress to control hydraulic fracture behavior and need the answer very quickly. Drilling perpendicular to the principle horizontal stress results in transverse hydraulic frac geometry, while drilling parallel to the principle stress, will create longitudinal frac geometry. This decision affects frac staging decisions and ultimately the drainage pattern and optimum spacing of the wells.

In the vertical holes, nuclear magnetic resonance (NMR) logs provide a matrix independent porosity and permeability to help select the best location to place the lateral. These are run on the same pass with services that provide resistivity, density, and neutron information and, in many cases, elemental capture spectrometry that gives elemental yields to determine how the complex lithology varies vertically and areally. The combinable NMR device provides the shortest echo spacing in the industry, which permits quantification of the smallest pore sizes, something critical in the complex Bakken lithology. Placing the lateral in the best permeability rock can be very helpful, and it has a positive effect on completion decisions and ultimate well performance.

Micro-imaging resistivity tools are used to characterize natural fractures and stress events in the lateral and vertical holes respectfully in both water- and oil-based muds. Natural fractures are important in the Bakken as they augment drainage and will affect the hydraulic fracture initiation process as they extend past the near wellbore hoop stress. Controlling the hydraulic fracture treatment to create maximum contact area requires a thorough understanding of the *in situ* hoop and far field stresses.

The Sonic Scanner service provides several key benefits that help operators better place and complete wells. It can determine the principle stress azimuth even when the anisotropy is less than 1.0%, something that could not be done previously and is critical, since the orientation of the lateral is selected based on this stress azimuth. The tool uses a new broad range frequency "Shaker" source for radial profiling that employs low frequencies to probe the far field stress and higher frequencies to look near the well bore. By seeing how the shear measurement changes in the near and far fields, engineers are able to ensure that the correct slownesses are measured and characterize hoop stress, something critical to the frac initiation pressures and the creation of Mechanical Earth Models for predicting wellbore stability. This behavior of near and far field shear also allows determination of the cause of the anisotropy, which is useful in determining if planar or complex hydraulic fracture behavior will exist. This in turn affects the fluid and diversion designs of the fracture treatment. The tool's design also provides a "slick" tool that improves the Stoneley measurement since the tool-effect is minimal and well understood. The improved Stoneley measurement allows measurement of the horizontal rock properties, allowing the plotting of accurate stress profiles even in layered rocks like the Bakken and shale reservoirs. The tool also can measure both horizontal and vertical rock properties to determine the true barrier strength in the laminated upper and lower Bakken shales. This 3-D rock mechanics is very useful in understanding the true stress gradient in the lower Bakken shale. This means the stimulation can be intelligently designed to either keep containment or to create height to frac into offsetting oil-bearing zones such as the Three Forks formation by design.

In horizontal wells, the Sonic Scanner and Formation Micro Imager have proven to be very valuable in selecting stage intervals based on the natural fracture and stress distribution along the lateral. Understanding the reservoir variability is critical since these sometimes subtle changes affect the hydraulic fracture initiation process that facilitates creating maximum contact area on the frac and even drainage of reserves.

Lithology also plays an important role in Bakken reservoir quality. The elemental capture spectroscopy (ECS) service uses activation to detect various elemental yields of the formation, which is used among other things to separate the volumes of dolomite from limestone and to better determine the clay content in the reservoir. In addition to the ECS service, Schlumberger's 1 11/16-in.-diameter Reservoir Saturation Tool can be pumped down through the drillpipe to determine lithology, porosity, and Sigma variations along the lateral for use in stage selection or swell-packer placement based on relationships back to the pilot hole logs.

At the Bottom Line

Perhaps the most valuable aspect of the integrated model-building approach is that it allows operators to get a sense of the real potential of their wells. In the not so distant past, an operator would complete a well and test it. The well would clean up and make, say, 1,000 b/d, and the operator would think, "This is a successful well."

The problem is that using this methodology, all subsequent wells would be judged based on the performance of this first well. But there's a problem. What if the true potential of the first well was 3,000 b/d? Because the operator didn't know this, it may be possible to proceed to develop an entire field of under-performing wells. By building an integrated model, then testing it using an interactive simulator, and validating it with each new piece of data that comes in as the well is drilled, tested, and completed, an infinitely more accurate picture of the well's potential evolves.

Previously, when wells were stimulated to improve conductivity, it was not unusual for the operator to be satisfied with the improved production and never question whether it represented the well's true potential. On the other hand, the model doesn't play favorites. If the well has undeveloped potential, the model will tell you. Its ability to reveal the well's true potential is a function of the amount of accurate, timely, and relevant input data that has been provided.

This is why leading operators participating in the current wave of Bakken development are acquiring new seismic, running more and better logging programs and building comprehensive 3-D reservoir models. It also explains why they are able to implement production monitoring and surveillance programs to reduce risk and protect their investment. They can do so because they have carefully built a robust model on which to base their predictions. They have a good idea how their wells are supposed to perform, and now they can measure the wells' performance and compare it to realistic norms.

The benefits accrue to all players: successful wells produce to their full potential, and unsuccessful wells reveal their inadequacies early so no more money is wasted on a hopeless cause.

Bakken Play Spurs New Pipelines

Operators are working to insure that transportation capacity is available for growing oil and gas production.

By Bruce Beaubouef, Ph.D.,
Editor, *PipeLine and Gas Technology*

Development of the Bakken oil and gas shale play in northwestern North Dakota and northeastern Montana is spurring development of several new pipeline systems, as operators are working to insure that transportation infrastructure will meet the region's future oil and gas transportation needs.

These projects include expansion of existing facilities and as well as plans for brand new oil and gas gathering systems, gas transmission systems, and crude oil trunk lines. To keep the gas flowing, new compressor stations will be built and horsepower will be added at existing stations.

In addition, new gas processing facilities are being planned and existing plants are being expanded to monetize the growing amount of marketable natural gas liquids (NGLs) being produced in association with the Bakken crude oil and natural gas.

Crude Oil Pipelines

The Bakken shale play has received significant publicity as the next major crude oil resource for the North American market. And, with expected increases in crude output, officials are tracking production rates and measuring them against pipeline capacity to insure that the region's transportation infrastructure can meet future needs.

According to North Dakota's Pipeline Authority, crude oil transportation capacity is scheduled to expand by 86% through 2010, as measured against a 43% projected growth in the state's crude oil production. In 2007, pipeline and refining capacity totaled 230,000 b/d, slightly ahead of peak petroleum production of 229,403 b/d. The 229,403 b/d is Williston Basin production, which includes crude oil from North Dakota, South Dakota, and eastern Montana. This year, capacity has increased to 327,000 b/d, and by 2010, total crude petroleum transport capacity will increase to 378,000 b/d. That is 50,000 b/d ahead of projected peak production of 328,000 b/d.

"We at the Oil and Gas Division have worked with the governor's office, Industrial Commission, and private industry to make sure that our energy has outlets to find its way to market," said Oil and Gas Division Director Lynn Helms. "That has meant increasing not only pipeline and rail capacity, but also working to enhance processing and refining facilities to help capture these valuable resources."

Officials are very aware of price and pipeline capacity issues, which, if unresolved, could hinder continued acceleration in the development of the Bakken Formation. As production in Montana and North Dakota increases, the existing transportation system is becoming something of a bottleneck. The existing pipeline system for the Williston Basin area, which is also used for movement of imported Canadian tar sand oil, is fully utilized. Rather than sell oil at a discounted price to get it into the pipeline, some US operators have announced shut-ins and postponements of drilling.

The states of Montana and North Dakota are both actively working with operators and pipeline companies to address the issue of capacity shortages. In May 2006, Governor John Hoeven of North Dakota hosted a summit with legislators, oil industry officials from both the US and Canada, pipeline

Photo courtesy MDU Resources Group Inc.

MDU Resources is planning an expansion of its existing Grasslands pipeline system to accommodate growing gas production from the Bakken Formation.

companies, producers, and railroad officials to help address the challenge of increasing oil pipeline capacity in western North Dakota. "We're producing more oil, and we need to be able to get it to market so our producers and mineral owners do not suffer unfair discounts," Hoeven said. "We're developing more pipeline capacity and taking other steps to solve the problem." These other steps include investigating transportation via railroad tank cars. "More supply is also how we get the price down at the pump to help consumers," Hoeven added.

Operators are making plans to expand these gathering pipelines to tie Bakken production to processing and transmission systems.

Crude oil shipped from the Williston Basin in North Dakota and Montana has incurred discounts because of competition for pipeline space. Reduced capacity is attributed to an increase in production, combined with limited pipeline space and a temporary reduction in refinery capacity. In April 2006, the pipeline system was about 15,000 b/d short of needed capacity in western North Dakota. As of May 2006, about 6,000 b/d were restricted by capacity. That's one reason why North Dakota Petroleum Council President Ron Ness recently told state legislators that even while crude oil pipelines are already being expanded to send more North Dakota oil to market, still more new lines will be needed. "We're going to need another major outlet for crude oil before we're done," Ness said.

On Sept. 21, 2006, the North Dakota Public Service Commission approved the site of a 52-mile oil pipeline that parallels a stretch of existing oil pipeline in Williams County in northwestern North Dakota. Enbridge Pipelines North Dakota LLC already has approval to install larger pumps along the existing line. Enbridge wants to increase its pipeline carrying capacity in the region by at least 30,000 b/d, and these new facilities may be able to take up to 45,000 extra barrels daily.

Other planned pipeline expansions include:

- Enbridge Phase V, which will increase capacity from 80,000 b/d to 110,000 b/d in January 2008; and
- Enbridge's Phase VI, which will increase capacity by 51,600 b/d to a total of 161,600 b/d by 1Q 2010.

Enbridge is also actively exploring the best proposal for additional expansion, including a link between North Dakota and Canada. The proposal has received positive feedback from shippers, and is only one of the options Enbridge is currently exploring.

Other notable pipeline-related projects include:

- Butte Pipeline will introduce a drag-reducing agent in its pipeline system to Guernsey, Wyoming, which should increase export capacity by 10,000 to 12,000 b/d, to be completed before year-end; and
- TransCanada's Keystone pipeline project and its related expansion, which involves the construction of a major international system that will cross through eastern North Dakota (Keystone pipeline, 480,000 b/d) and eastern Montana (Keystone XL, 500,000 b/d). These projects will relieve Canadian oil sands pressure on the Guernsey, Wyoming, hub and can be tapped into to carry Williston Basin crude oil.

Natural Gas Transmission

While the Bakken shale play has gained publicity as a crude oil-bearing formation, the growing amount of drilling efforts there are leading to the development of new gas transmission lines, and the expansion of existing gas transmission facilities, to get the gas production to market. MDU Resources Group Inc., one of the key players in the region, has announced two new major pipeline projects that are designed to increase natural gas transportation capacity from the Bakken shale play.

In May 2008, Williston Basin Interstate Pipeline Co., the wholly owned natural gas transmission pipeline subsidiary of MDU Resources Group, announced plans to build a new natural gas pipeline to transport gas from the Bakken play to a new pipeline interconnect with Alliance Pipeline system. The proposed Bakken pipeline will consist of about 100 miles of 16-in. pipeline, compression, and associated facilities. It will begin at an interconnect with Williston Basin's existing pipeline system in Mountrail County, North Dakota, and will run northeasterly to a new pipeline interconnect with Alliance Pipeline in Bottineau County, North Dakota. The Bakken Pipeline is anticipated to have an initial capacity of about 100 MMcfd, with the flexibility to expand capacity to 200 MMcfd. The company said the pipeline is projected to be in service in mid-2010, subject to shipper commitment and regulatory approval.

Williston Basin Interstate Pipeline Co. has also announced plans to expand its existing Grasslands pipeline system, to add further natural gas transportation capacity. Placed in service in December 2003, the 253-mile, 16-in. Grasslands pipeline runs from the Powder River basin in northeastern Wyoming to western North Dakota, where it connects with the Northern Border pipeline system. The Grasslands expansion will include the construction of two new compressor stations; one will be in western North Dakota near Golva, the other in the far corner of southeastern Montana near the Wyoming border. Additional horsepower also will be added to an existing compressor station near Manning, North Dakota. The expansion project will add an additional 75 MMcfd to the system's existing capacity of 138 MMcfd.

In July 2008, Williston Basin conducted an open season on the Grasslands expansion project seeking customer commitment for additional transportation capacity. Strong customer demand for the pipeline capacity pushed the project to full capacity of 213 MMcfd. The project cost is expected to be about US $28 million and the targeted in-service date is August 2009, pending timely receipt of the necessary regulatory approvals.

> **WHILE THE BAKKEN SHALE PLAY** has gained publicity as a crude oil-bearing formation, the growing amount of drilling efforts there are leading to the development of new gas transmission lines and the expansion of existing gas transmission facilities…

"We built the Grasslands Pipeline with future expansion in mind, and we are more than pleased to have reached full capacity on the pipeline in just over five years," said Terry D. Hildestad, president and chief executive officer of MDU Resources. The Grasslands pipeline held an initial capacity of 80 MMcfd when it was placed in service in late 2003. Since installation, the pipeline has been incrementally expanded, bringing the firm pipeline transportation capacity on that segment to its current total of 138 MMcfd. "Our interstate pipeline system runs through the heart of several active energy production regions, including the newly developing Bakken Play, and we are playing a role in getting this energy to the marketplace," Hildestad said.

In fact, MDU Resources said it is making a number of long-term investments in the development of the Bakken's energy resources, including oil and natural gas, through three of its subsidiaries: Fidelity Exploration and Production Co.; Bitter Creek Pipelines, LLC; and Williston Basin Interstate Pipeline Co. Fidelity, an oil and natural gas production business, expects to participate in approximately 50 to 60 Bakken wells in 2008, of which about one-half will be drilled and operated by the company. Meanwhile, Bitter Creek is reviewing plans to build gathering pipeline infrastructure in the Bakken to gather natural gas produced

Bakken formation wells have spurred the planning and construction of several new gas processing plants in North Dakota.

in conjunction with the oil to move it to larger pipelines for transport to final destinations. The subsidiary is also actively investigating participation in the construction of natural gas processing facilities in the Bakken.

Gas Processing Facilities

With the increase in natural gas production, there is also a growing amount of associated natural gas liquids being produced in the Bakken play. These NGLs include naturally occurring propane, butane, and several others that have great value in the marketplace. The need to treat the gas and separate these NGLs into marketable products, in turn, has led to the planning and construction of several new gas processing facilities and the expansion of existing plants.

In particular, the Bakken formation wells drilled in Williams and Mountraill County, North Dakota, have spurred the planning and construction of four gas processing plants there. The four new gas plants – all roughly between Ray and Stanley – join eight existing plants in the western-most counties that are already processing oil-related natural gas. The gathering lines that collect the gas at the wells and take it to new processing plants are in place, but the challenge now is building transmission-size lines to take those products to locations where they can enter major natural gas lines, such as the Canadian-originating Alliance pipeline system. This pipeline enters northwest North Dakota in Renville County and exits in Richland County. Officials with the North Dakota Pipeline Authority have said that while several companies are planning those gas transmission lines, none are beyond the proposal stage. In the meantime, trucks and rail cars are taking the natural gas and other byproducts to market.

State officials believe that there is bound to be an increasing amount of gas byproduct in the coming months, because Whiting Petroleum, which has two of the new gas plants, is expecting to drill 50 to 60 more Bakken Formation oil wells in the Sanish and Parshall areas, and seven more into the Red River Formation this year. Other companies building new gas plants include EOG Resources and Nesson Gas Service, and these operators are planning to drill a combined 20 or more oil wells in the same Ray-Stanley-Parshall area. In the fall of 2008, EOG had nine rigs drilling and a tenth being shipped into the area. Nesson says it plans to keep drilling eight to 10 new wells per year.

In North Dakota, both natural gas pipelines and processing facilities have expanded, and industry leaders project further expansions in the future. Natural gas processing capacity will increase by more than 126%, including four new processing facilities and three major expansions. The resulting 513 MMcfd is enough natural gas energy to fuel 1.87 million homes a year. At the same time, natural gas pipeline capacity has increased by 122 MMcfd, and an additional 228 MMcfd has been proposed. Much of this gas was formerly flared off, so there is an environmental benefit, as well as an energy benefit to capturing the gas.

Significant natural gas processing plant facilities and expansions include:

- Whiting – a new 33 MMcfd Robinson Lake Processing Plant was expected to connect to Williston Basin on Oct. 1, 2008;
- Whiting – a new 10 MMcfd Ray, North Dakota, processing plant is now in operation;
- EOG – a new 20 MMcfd Stanley, North Dakota, processing plant was scheduled to come online in October 2008;
- Nesson Gas Services – a new 10 MMcfd processing plant near Ray, North Dakota, came online December 2008;
- Bearpaw's Grassland Plant – an expansion from 63 MMcfd to 100 MMcfd was completed in 2008;
- Hiland Partners' Bowman Plant – an expansion from 4 MMcfd to 40 MMcfd in Bowman County was completed in 2008; and
- Hess Tioga Plant – an expansion from 120 MMcfd to 250 MMcfd is currently in the planning phase.

In terms of natural gas pipelines, Alliance Pipeline filed with FERC in September 2008 to enable Pecan Pipeline to transport rich Bakken gas from the Mountrail County area to markets in Chicago. The project is scheduled to begin shipping 20 MMcfd to 40 MMcfd in 2009 and increase to 80 MMcfd in 2010.

Gas Gathering

Of course, gas gathering pipelines are needed to connect gas production to processing and transmission systems, and operators are making plans to expand these facilities as well. To help meet these needs, Oklahoma-based Hiland Partners says it has agreed to construct and operate gathering pipelines and related facilities in the Bakken Shale play in northwestern North Dakota for Continental Resources. Continental has dedicated 129,000 gross acres to the partnership. Hiland and Continental are both based in Enid. Continental has 10 rigs working in the Bakken and expects to add three additional rigs by the end of 2008.

The initial term of the agreement is 10 years, and grants the partnership the right to process natural gas and share in the sales proceeds of the natural gas liquids and residue gas. The partnership plans to make an initial capital investment of $10 million. The capital investment over the next three years is expected to total $27 million to build processing and treating facilities and install field gathering, compression and associated equipment. The first phase of the project is expected to begin operations by 2Q 2009. "We continue to build upon the success we have experienced with our existing Bakken plant in Montana," said Joseph L. Griffin, president and chief executive officer of Hiland Partners.

Conclusion

As drilling efforts in the Bakken have continued to ramp up, state officials and industry leaders have continued to coordinate plans for increasing transportation capacity. In September 2008, North Dakota Governor John Hoeven was joined by petroleum and pipeline industry leaders, Oil and Gas Division Director Lynn Helms, and Pipeline Authority Director Justin Kringstad to outline current and scheduled progress in expanding the state's oil and gas production and processing infrastructure. Also joining Hoeven were Kevin Hatfield of Enbridge Pipeline Inc., Tad True of True Pipeline Companies, Wayne Biberdorf of Hess, and John Berger, manager of Tesoro Refinery in Mandan. "We are working to ensure that our infrastructure keeps pace with our growing production of oil and gas," Hoeven said. "We have made sustained progress in both the transportation and processing of our petroleum resources, and we are working to keep pace with growing production in the future."

The Bakken Attraction

Despite the decline in oil prices, activity in the Bakken Shale and the emerging Three Forks/Sanish remains at robust levels. Why? Because the plays work at US $50 oil.

By Steve Berman
Senior Research Analyst
Pritchard Capital Partners

The Williston Basin contains the largest oil accumulation, the Bakken Shale, in the lower 48 states. The Basin is spread across the states of South Dakota, North Dakota, Montana, and the Canadian provinces of Saskatchewan and Manitoba. An April 2008 US Geological Survey (USGS) report estimated that in North Dakota and Montana alone there are about 3.65 billion bbl of oil, 1.85 Tcf of natural gas, and 148 million bbl of natural gas liquids recoverable in the Bakken formation, which is 25 times greater than the prior assessment done in the mid-1990s.

The Bakken is an unconventional oil play located at depths of approximately 8,500 ft to 10,500 ft and is a late Devonian, early Mississippian rock composed of three members – the upper shale, middle dolomite, and lower shale. The middle dolomite, commonly referred to as the Middle Bakken, is the primary oil reservoir with average porosity of 5%, low permeability of 0.04 md, and thickness up to 140 ft. Total thickness of the three members generally ranges from 150 ft to 200 ft. Drill and complete costs are running in the US $5 million to $6 million range. Current production from the Bakken is approximately 95,000 b/d. Laterals are being drilled as long as 10,000 ft. Primary objectives in addition to the Bakken are the Red River and the newly discovered Three Forks/Sanish (TFS). Currently there are approximately 100 rigs at work in the US part of the Williston Basin.

ACREAGE POSITIONS OF THE LARGER PLAYS IN THE BAKKEN SHALE

Company	Ticker	Acres
Continental Resources Inc.	CLR	604,000
Hess Corp.	HES	500,000
XTO Energy Inc.	XTO	450,000
EOG Resources Inc.	EOG	370,000
Whiting Petroleum Corp.	WLL	323,295
Encore Acquisition Co.	EAC	300,000
Marathon Oil Corp.	MRO	320,000
Brigham Exploration Co.	BEXP	293,000
St. Mary Land & Exploration Co.	SM	182,000
Newfield Exploration Co.	NFX	170,000
Northern Oil & Gas Inc.	NOG	65,000
Questar Corp.	STR	62,000
Penn Virginia Corp.	PVA	51,000
Kodiak Oil & Gas Corp.	KOG	36,000
American Oil & Gas Inc.	AEZ	32,500
Gulfport Energy Corp.	GPOR	17,660

Source: Company Reports

Bakken operators are still in the process of establishing how far the heart of the play extends. The first vertical Bakken well was drilled back in the early 1950s. The first major Bakken developed field, Elm Coulee, is in Eastern Montana. Through 2007, approximately 65 million bbl of oil out of the 105 million bbl produced from the Bakken came out of the Elm Coulee Field, which started major development in 2000. In 2006, EOG Resources Inc. drilled a well in the Parshall Field in North Dakota that, based on initial production, was expected to have an estimated ultimate recovery (EUR) of 700,000 boe. The strength of this well result, along with a temporary North Dakota tax break, catalyzed a land rush in the Parshall area.

The Parshall/Austin/Sanish area, in Mountrail County, North Dakota, has been the shining star of

Photo courtesy Sundance Energy Australia Ltd.

Newer rigs, sharper crews, and better economics make the Bakken one of the most profitable plays in the nation.

the Bakken, where drilling to date has been close to 100% successful with very high production rates. Wells here have generally come online at rates ranging from 500 boe/d to 1,000 boe/d, although most of late have been substantially higher, including several more than 3,000 boe/d. A typical single-lateral producer at Parshall has a measured depth of 15,000 ft, can be drilled for approximately \$5.25 million (higher as the lateral length increases), and can hold gross reserves of 900,000 boe. Oil-in-place is 9 million bbl per section, implying a low recovery rate of about 10%. Although we are still in the early stages of primary recovery in the Williston, these low rates make the play a prime candidate for secondary (waterflood) and tertiary (CO_2) recovery down the road. In other words, we should we hearing about the Williston Basin for decades to come.

Whiting Petroleum Corp. has announced that one of its Bakken wells in the Sanish field, the Richardson Federal 11-9H, which was completed on October 22, IP'd at 4,570 boe/d. This is the highest

THE WILLISTON BASIN CONTINUES TO attract capital in the current lower price environment because the play works at $50 oil, maybe even down to the mid $40s. EOG sees a non-core area 250 MBO EUR well at $65 flat oil still yielding a 30% direct after-tax unlevered rate of return, while the core area (850 MBO EUR) still generates a 100% direct after-tax unlevered ROR at $65 oil.

—***Steve Berman,*** Senior Research Analyst, *Pritchard Capital Partners*

initial production rate reported to date from a Bakken well, according to the North Dakota Industrial Commission. Whiting has completed a dozen wells in the Sanish field since July 1, 2008, with an average IP rate of about 2,300 boe/d — very impressive to say the least. EOG's last 10 completions in the Parshall Field had an average IP rate of 1,900 boe/d.

Largely untapped, and potentially as big as the Bakken, are the Three Forks and Sanish formations. The Three Forks is a dolamitic rock located 20 ft to 30 ft below the base of the Lower Bakken, while the Sanish is sandstone that is sporadically wedged between the Three Forks dolomite and the Lower Bakken shale. BEXP believes its entire Williston Basin acreage position could be prospective for the Three Forks formation. The Sanish sandstone, less prevalent in the Williston, is most prominent in the Antelope Field, at the southern end of the Nesson Anticline. Average distances between the middle of the Three Forks and the Middle Bakken range up to 100 ft.

A number of key Three Forks/Sanish wells have recently been drilled. On the western edge of the Ross Area at the Nesson Anticline, Encore Acquisition Co. announced in late July that its first Sanish well, the Charlson 11-16H, was brought online on July 23 at an IP rate of 1,106 boe/d and averaged 843 boe/d during its first seven days of production. Even better was the November announcement of a 1,750 IP rate TFS well in the same area by XTO Energy Inc. XTO got into the Williston this year in a big way through its acquisition of Headington Oil Co.

Continental Resources Inc. has completed nine operated TFS wells, which IP'd at an average 852 boe/d. The average on six of these wells in the southern part of the acreage was close to 1,000 boe/d. Year-to-date in 2008, Continental has actually had better results from its operated TFS wells than its operated Bakken wells (average IP rate 573 boe/d).

One of the best TFS wells drilled by anyone to date was in McKenzie County, North Dakota. In the fall of 2006, Petro-Hunt LLC completed the #2D-3-1H USA in the Charlson Field. The well came on at 729 boe/d and 785,000 cf/d. It featured a single, openhole lateral that extended 3,200 ft into the Three Forks. According to state records, through August 2008, the well made 577,000 bbl of oil and 721 million cu ft of gas, and still makes approximately 1,000 boe/d.

The Williston Basin continues to attract capital in the current lower price environment because the play works at $50 oil, maybe even down to the mid $40s. EOG sees a non-core area 250 MBO EUR well at $65 flat oil still yielding a 30% direct after-tax unlevered rate of return, while the core area (850 MBO EUR) still generates a 100% direct after-tax unlevered ROR at $65 oil. Declining costs are starting to help the economics — Brigham Exploration Co., for example, sees costs coming down by 20% to 33% over the next three to six months. Almost every company we have spoken with or heard feels the Bakken/TFS is economical at $50 oil, and at even lower prices in some of the sweet spots on and east of the Nesson Anticline. We have run low price assumptions through a well economics model and come to the same conclusions.

Operational enhancements have been and should continue to dramatically improve the economics of the play. Brigham, for example, in increasing the average number of frac stages from 7.7/well to 10.3/well, saw a 92% increase in average EURs at an average cost increase of only 4%. The company is currently drilling several 20 frac stage wells and expects to see continuing positive cost/benefit results.

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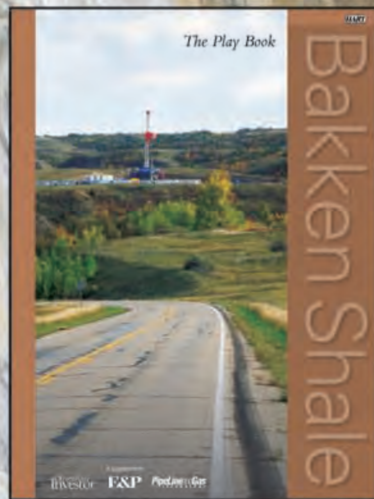

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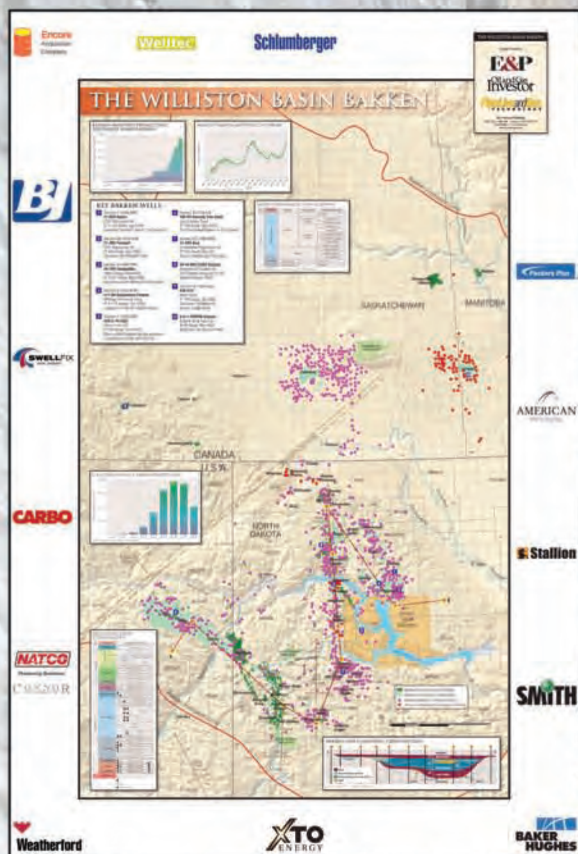

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Hefty Potential

The Bakken play has all the elements needed for a long and lustrous future.

By Peggy Williams
Senior Exploration Editor, *Oil and Gas Investor*

The Williston Basin's amazing Bakken play continues to grow. Developments to date, as impressive as they are, seem to be just the beginning.

The size of the prize is astonishing: The Bakken formation is estimated to contain between 200 million bbl and 400 million bbl of oil in place. This is self-sourced oil, generated within the world-class source rock.

In 1995 the US Geological Survey (USGS) estimated that the Bakken contained 150 million bbl of recoverable oil. Once horizontal drilling and multistage fracturing unlocked the oil trapped in the formation, the estimates of the in-place oil that could be recovered skyrocketed.

The most recent USGS study concluded that the formation contains mean undiscovered volumes of 3.65 billion bbl of oil, 1.85 trillion cf of gas, and 148 million bbl of natural gas liquids.

The survey assessed the geologic elements of the Bakken petroleum system, including distribution of the source rock, its thickness, organic richness, maturation, petroleum generation capabilities, and migration. It also looked at the type of reservoir rocks, their distribution and quality, and the character of traps and time of their formation.

The estimate represents undiscovered, technically recoverable oil and associated gas resources. The calculations do not consider the volumes that could be economically recovered from the Bakken,

Photo courtesy of Lowell Georgia

Recent Prolific North Dakota Bakken Wells

OPERATOR	WELL NAME	COMPLETION DATE	SEC-TWP-RANGE	COUNTY	CUM BBL OF OIL TO SEPT-08
Petro-Hunt	USA 2D-3-1H	Oct-08	2-153N-95W	McKenzie	601,970
EOG	Austin 2-03H	Nov-07	3-154N-90W	Mountrail	267,103
Encore	Morgan Draw Federal C 5	Nov-04*	11-143N-103W	Golden Valley	265,103
EOG	Austin 4-09H	Dec-07	9-154N-90W	Mountrail	261,000
EOG	Patten 1-02H	Mar-07	2-152N-90w	Mountrail	250,894
EOG	Ehlert 1-35H	Apr-07	35-153N-90W	Mountrail	245,519
EOG	Bartelson 1-3H	Nov-06	3-152N-90W	Mountrail	244,687
EOG	Austin 1-02H	Oct-07	2-154W-90W	Mountrail	241,552
EOG	Austin 8-26H	Feb-08	26-154N-90W	Mountrail	238,081
EOG	Austin 6-15H	Apr-08	15-154N90W	Mountrail	220,438
EOG	Zacher 1-24H	Jun-07	24-153N-90W	Mountrail	212,857
EOG	Hoff 1-10H	Jun-07	10-152N-90W	Mountrail	210,212
EOG	Warberg 1-25H	Jan-07	25-153N-90W	Mountrail	208,376
St Mary	Federal 21-14HR	Nov-04*	14-146N-102W	McKenzie	198,066
EOG	C & B 1-31H	May-07	31-153N-89W	Mountrail	195,389
EOG	N&D 1-05H	Jul-07	5-152N-90W	Mountrail	194,944
EOG	Wenco 1-30H	Sep-07	30-153N-89W	Mountrail	194,445
Murex	Stacey-Lynne 1-12H	Mar-05	1-156N-96W	Williams	171,801
EOG	Parshall 2-36H	Sep-06	36-153N-90W	Mountrail	168,161
Hess	Ferguson Smith 1-30H	Jul-06	10-155N-95W	Williams	164,050

**Horizontal reentry of existing well; completion date is for reentry. Source: North Dakota Industrial Commission*

however. Instead, it lays out the scale of the formation's potential.

In general, the USGS concluded that undiscovered resources in the Bakken are in a continuous reservoir that includes all three members and that's present throughout the entire oil-generation window; an area that covers roughly 20,000 sq miles in northeastern Montana and northwestern North Dakota.

Additionally, great volumes of oil have been expelled from the thermal kitchen and migrated through the Bakken siltstones and sandstones into areas in Saskatchewan and Manitoba.

North Dakota

North Dakota is the epicenter of Bakken action today. According to the North Dakota Industrial Commission, there are some 650 active Bakken permits and confidential wells within the state. Drilling activity stretches across Mountrail County and along the entire length of the great Nesson Anticline. Operators are probing many townships between the Nesson and the Montana state line. Both the north and south sides of the Fort Berthold Indian Reservation are extremely active, and drilling is underway on the reservation itself.

In North Dakota, the Bakken's tremendous productivity is related to its overpressuring. The high pressures are a result of hydrocarbon generation. The formation is laced with microfractures, created during the oil-generation process, and also with fractures caused by regional tectonic stresses. Another geologic situation that contributes to fractures in the Bakken is dissolution in the underlying Devonian Prairie salt. In areas where this occurs, the Bakken responds accordingly.

Certainly the most successful area to date has been Parshall Field. Wells in this accumulation, which occurs at the boundary of mature and immature Bakken sediments, are phenomenal. Bakken wells can make prodigious volumes of oil; quite a

Recent North Dakota horizontal Bakken completions deliver astonishing volumes of oil.

Manitoba Bakken Stratigraphy

ERA	PERIOD	GROUP	FORMATION	MEMBER/FACIES
Paleozoic	Mississippian	Madison	Charles	
			Lodgepole (Upper)	Flossie Lake
				Whitewater Lake
			Lodgepole (Lower)	Upper Daly
				Lower Daly
				Cruickshank Shale
				Cruickshank Crinoidal
				Cromer Shale
				Basal Limestone
		Bakken		Upper Bakken
				Middle Bakken
	Devonian			Lower Bakken
		Qu'Appelle	Three Forks	
		Saskatchewan	Birdbear	

Source: Manitoba Science, Technology, Energy and Mines

ELM COULEE FIELD: BAKKEN PRODUCTION

Year	Bbls Oil
2000	21,164
2001	277,784
2002	798,075
2003	2,765,074
2004	7,769,572
2005	15,905,525
2006	18,928,023
2007	18,109,024
2008*	10,119,686
	Total: 74,693,927

**Partial year data. Source: Montana Board of Oil & Gas*

ABOVE: In Manitoba, operators are tapping reserves in the Bakken's Middle Member and in underlying Three Forks sediments.

RIGHT: Montana's Elm Coulee Field should ultimately recover some 250 million bbl of oil and 300 billion cf of gas.

few wells have exceeded production of 100,000 bbl of oil in less than a year's time. Results of this magnitude are driving the play forward.

Furthermore, in North Dakota, the Bakken is underlain by sandstones that are part of its petroleum system. In North Dakota, excellent wells are being made in the Sanish sand and Three Forks formation. The Bakken petroleum source system actually extends 150 ft into the Three Forks, through the Bakken, and into the base of the Lodgepole formation. Any reservoir rock within this interval will be charged with oil and associated gas.

An exciting aspect of the Three Forks is that it appears to behave as a separate reservoir from the Bakken, so Three Forks development could be additive to the Bakken.

Montana's Elm Coulee Field

Montana's Bakken field, Elm Coulee, is the fifteenth-largest onshore US field, according to the Energy Information Administration.

The reservoir at Elm Coulee is a fractured, silty dolomite. It occurs from 8,500 ft to 10,500 ft deep, and attains a vertical thickness of 8 ft to 14 ft. The porosity range is typically 8% to 10%, and permeability is 0.05 md. Oil saturations are 75%.

Initially, the Bakken was developed on 1,280-acre spacing, and then second wells were drilled to bring spacing down to 640 acres. Initial per-well production rates range from 200 b/d to 1,900 b/d.

Oil in place per section has been estimated at 5 million bbl at Elm Coulee. Primary recovery is expected to be between 10% and 18%. A well drilled on 640-acre spacing can recover as much as 500,000 bbl.

Elm Coulee is a massive field, covering some 530 sq miles. It will ultimately recover some 250 million bbl and 300 billion cf of gas. To date, it has made 75 million bbl.

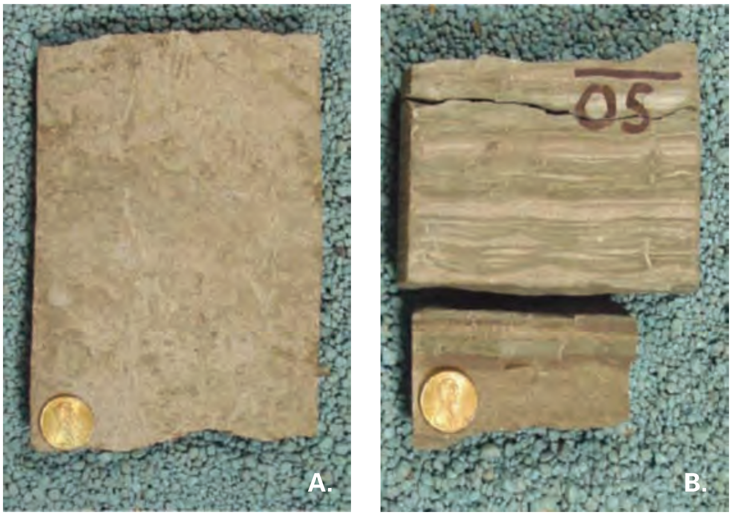
Going forward, operators are looking at further infill drilling and enhanced recovery technologies. Work is also in progress to push the edges of the field outward.

Canada's Bakken and Torquay

About 25% of the Williston Basin is within Saskatchewan. The successful application of new technology has cracked open the Bakken light oil play in Canada.

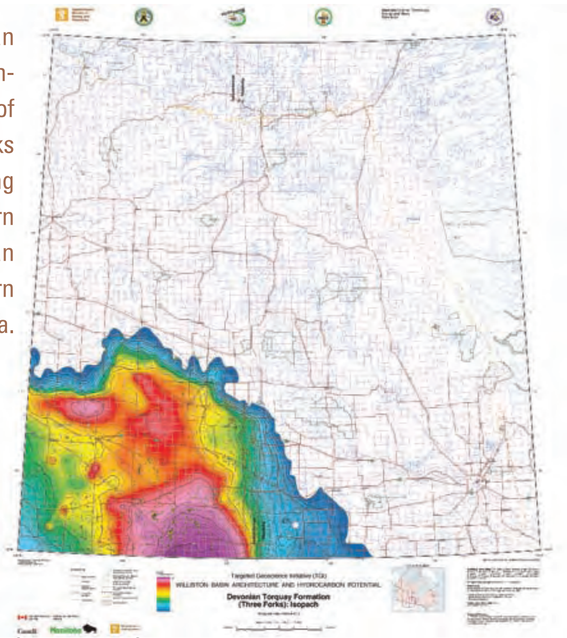
Canada's Middle Bakken reservoirs produce oil that was generated in the Bakken source kitchen in the US portion of the Williston Basin. The Bakken shales in Canada are every bit rich enough to generate oil, but they were never subjected to sufficient heat. They are thermally immature. The play is normally pressured, so flow rates are not as stout as in North Dakota. But, drilling depths to the silty, fine-grained Middle Bakken sandstone are less than in the US slice of the play, and costs are considerably lower.

Thanks to the Bakken, oil production has increased exponentially in Saskatchewan in the last couple of years, from less than 600 b/d in May 2004 to more than 34,000 b/d in May 2008. The sale of oil and gas drilling rights has gener-



Sanish Sandstone: Core photographs representative of "Sanish" sandstone from the Raymond T. Duncan #1 Rose (Section 2-153n-94w). A: Medium-brown, highly burrowed siltstone to very fine-grained sandstone characteristic of the "Sanish" sand (depth – 10,601.3 ft). B: Characteristic apple green and tan interbedded sequence of the Three Forks Formation (depth – 10,605 ft). Adapted from LeFever & Nordeng, North Dakota Geological Survey, Bakken core short course, July 7-8, Denver, Colo.

The Devolian Torquay formation, part of the Three Forks group, is a drilling target in eastern Saskatchewan and western Manitoba.



Source: Targeted Geoscience Initiative

ated record revenues for the province, in 2007 and so far in 2008.

The most recent Crown sale in October 2008 pushed the province's annual total past the C $1 billion mark for the first time. Operators are very bullish on the play: the Weyburn-Estevan area again attracted the most bids with sales of more than $191 million. Pioneer Enviro Group Ltd. paid more than $3 million for a 65-hectare parcel of deeper rights in southeast Saskatchewan. The highest single-parcel price paid was just under $33.9 million. Standard Land Co. Inc. acquired this 1,554-hectare exploration license of deeper rights, located 28 km east of Estevan.

Canada also has a reservoir beneath its Bakken formation that is hosting a lively play, and one related to the Three Forks targets that are generating high interest on the US side of the Williston Basin.

In an area along the Saskatchewan-Manitoba border, Maple Leaf operators are busily developing the Upper Devonian Torquay, a formation that is part of the Three Forks group that underlies the Bakken. The Torquay is composed of dolomitic mudstones and siltstones. It's a weathered, brecciated formation with good reservoir characteristics. In places where the Lower Bakken shale is absent and the Torquay onlaps the Middle Bakken, the Torquay has been charged with Bakken oil.

Initially, operators drilled vertical wells into the formation. The focus has recently shifted to horizontal drilling.

Fairborne Energy Ltd., an active participant, reported that it is currently interpreting data from a 42-sq-mile 3-D survey that it shot in the Sinclair area. It recently drilled 10 horizontal wells that have average production of about 65 boe/d.

So, the future of the Bakken across its broad extent is splendid. From overpressured to normal pressured areas, in-place to migrated oil, resource plays to more conventional accumulations, there are still considerable volumes of oil to be produced.

Bakken Reference Guide

For sources and more information on the Bakken shale, visit *www.EPmag.com.*

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