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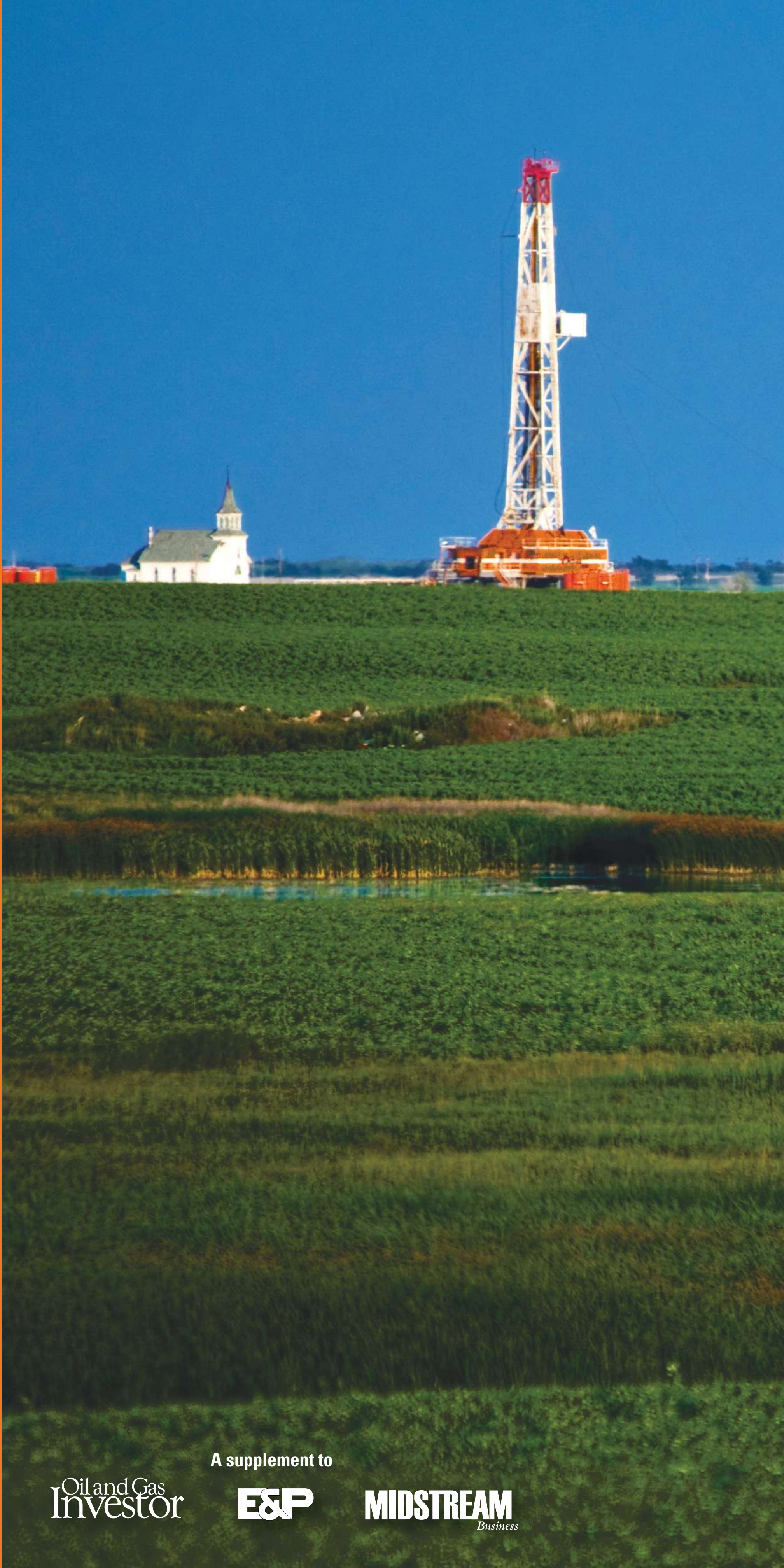
Bakken/Exshaw

The 2013 Playbook



A supplement to

Oil and Gas Investor

E&P

MIDSTREAM Business

UNCONVENTIONAL OIL & GAS CENTER

Bakken/Exshaw:
The Playbook

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

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Wellsite controls are so tight that even wells close to lakes pose no threat to water supplies. *(Photo courtesy of Kodiak Oil & Gas Corp.)*

Interest, Activity Continue in the Bakken

Operators are expanding the limits of the Alberta Bakken/Exshaw.

By Stephen A. Sonnenberg
Colorado School of Mines

The Alberta Bakken/Exshaw play of northwestern Montana and the Williston Basin Bakken play both have continued to generate interest from the industry. By far, the Williston Bakken play (both Bakken and Three Forks) has generated the most interest and most drilling activity. Current rig count in the US Williston Basin is more than 200 horizontal rigs (185 in North Dakota alone).

These plays will be described using a petroleum system approach. The simplest definition of a petroleum system is the source beds and all the genetically related hydrocarbon accumulations.

The Bakken is a tight oil play characterized by low permeability and porosity. Porosities are generally less than 8% and permeabilities are less than 0.1 millidarcies (md). Fracturing (both natural and induced) plays a key role in getting these reservoirs to produce economically. Tight oil accumulations have the following characteristics:

- Pervasive hydrocarbon saturated accumulations;
- Not localized by buoyancy;
- Abnormally pressured (high or low);
- Commonly lack downdip water;
- Updip contact with regional water saturation;
- Low permeability and low matrix porosity reservoirs;
- Reservoirs may be single or vertically stacked;
- Commonly enhanced by fracturing;
- Associated with mature source rocks either actively generating or have recently ceased generation;
- Hydrocarbons of thermal origin;
- Fields have diffuse boundaries; and
- Inverted petroleum systems.

Pervasive hydrocarbon saturation is common in the deep parts of depositional basins where source beds are thermally mature. Little water is present in these parts of a basin because the force of expulsion has moved the water out or the water has been consumed in the bitumen/oil generation process. Thus the role of buoyancy associated with conventional accumulations is called into question in basin-center accumulations. Abnormally high pressure is created by hydrocarbon generation and can aid in reservoir deliverability to the wellbore. Basin-center systems generally lack downdip water but do have water updip. Reservoirs in the deep basin have been subjected to high amounts of diagenesis and have low porosity and permeability. Reservoirs in the basin center may be vertically stacked or just single layers. Because of hydrocarbon generation and regional stresses, natural fracturing is common in basin-center systems. The hydrocarbons present are of thermal origin (not biogenic). Fields in the basin center often are sweet spots (areas of higher production than surrounding areas). These sweet spots are usually related to fracturing and/or depositional environments. The producing areas (fields) have fuzzy boundaries; rarely are field boundaries sharp and well defined.

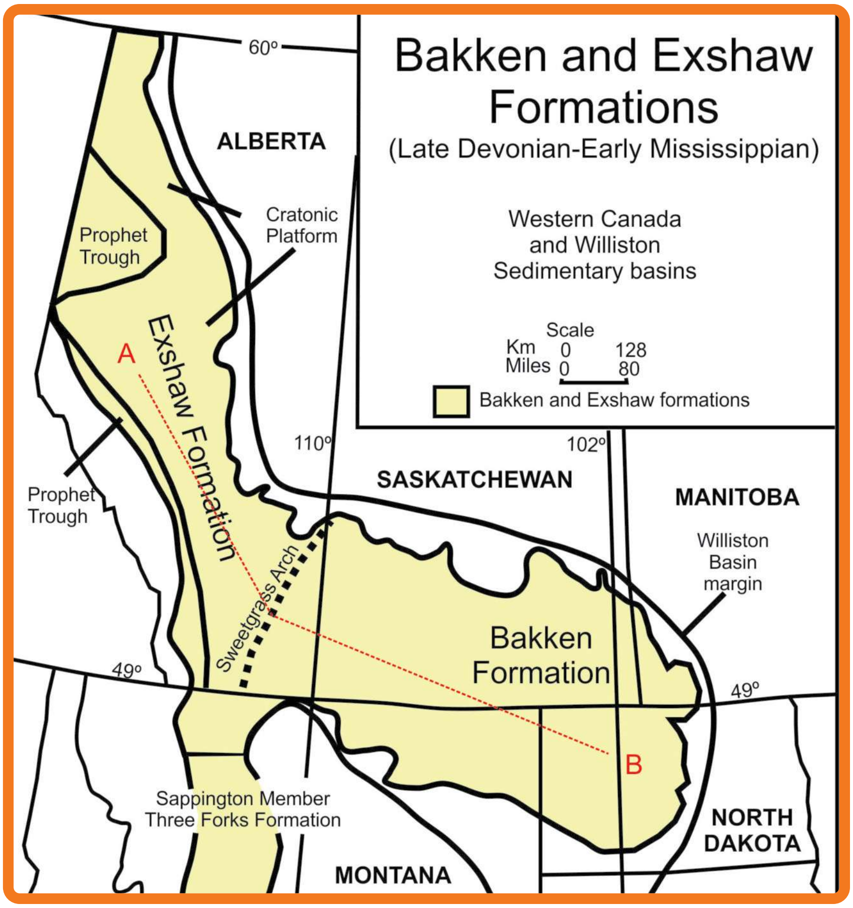
Many of the important shale plays of North America have inverted systems (e.g., Barnett, Austin Chalk, Eagle Ford, Niobrara, etc.). The situation in the Williston Basin is that the reservoir rocks never reach the gas window. Water exists updip from the pervasive oil accumulation but the system does not enter the gas window in the Williston Basin. The Bakken/Exshaw in the southern Alberta Basin of western Montana will most likely have both the oil and gas phases present. The same is true of the Exshaw of the Canadian part of the Alberta/Western Canada Basin.

Screening criteria for unconventional tight oil systems include the following items:

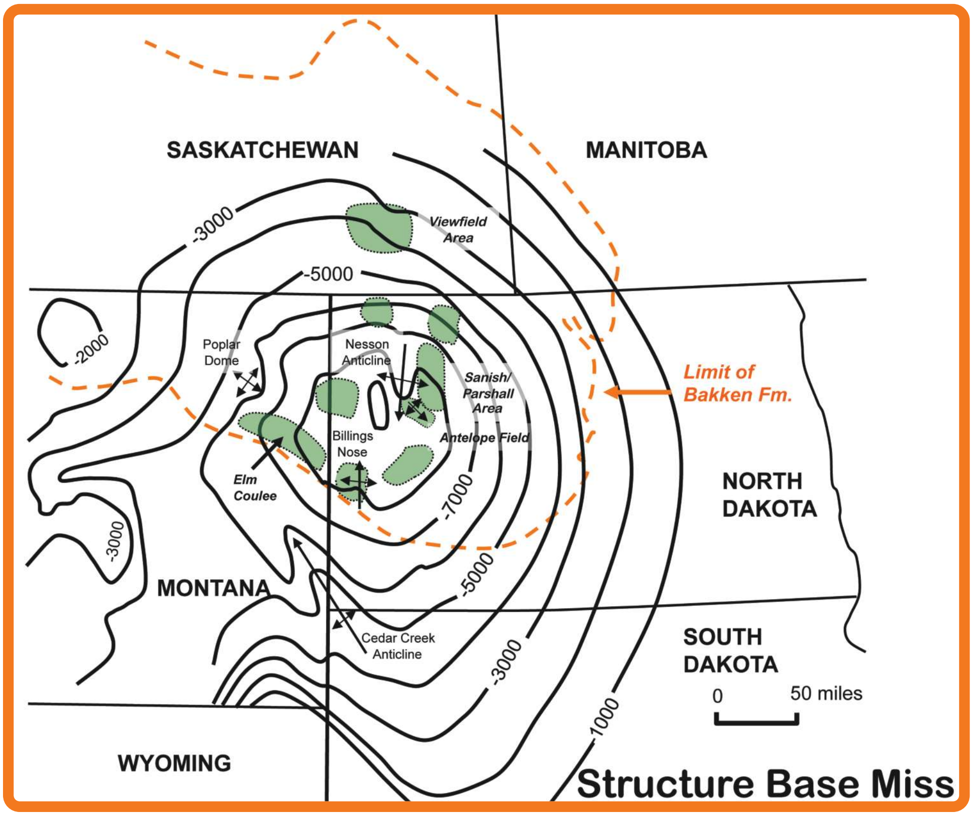
- Total organic content (TOC) > 2.5 weight (wt.) %;
- Net thickness: > 50 ft;
- Ro: 0.5 – 1.3;
- Type I or Type II kerogen (sapropelic);
- Mineralogy (< 40% clay);
- Hybrid lithologies; and
- Shows.

This list is modified from one used by the US Geological Survey in their worldwide assessment of tight oil systems. The TOC of greater than 2.5 wt.% is necessary for effective source rocks. Generally a thickness of 50 ft or greater is ideal for a good oil source rock. The oil window is defined by vitrinite reflectance values of 0.5 to 1.3. The mineralogy of brittle shales generally consists of either high carbonate or silica content. The silica and carbonate can be either detrital or biogenic. Too much clay will make the shales too ductile. Source beds located in close proximity with reservoir rocks (hybrid lithologies) generally make the best producers (e.g., the middle Bakken siltstones, sandstones, and dolostones and Three Forks dolostones are in close proximity to the Bakken shales). Shows are always the best clue to a potential tight oil play.

The Bakken-Exshaw is a widespread unit that was deposited in Late Devonian and Early Mississippian. The unit consists of an upper and lower organic-rich shale (TOC > 10 wt.%) and a middle member of mixed lithology (silty dolostone, dolomitic siltstone, limestone, sandstone, etc.). The Bakken name changes to Exshaw outside the Williston Basin. The Bakken was named for subsurface occurrences in the HO Bakken Well in 1953 by J.W. Nordquist. The formation was named after Henry Bakken, a farmer in Tioga, N.D., who owned the land where the formation was initially discovered and described from a well. The Bakken is an entirely subsurface unit in the Williston Basin. The Exshaw was named for outcrops at Jura Creek north of Exshaw, Alberta, by P.S. Warren in 1937. The Exshaw terminology is used outside the Williston Basin but is equivalent



Map illustrating the extent of the Bakken/Exshaw/Sappington formations. The Bakken terminology is generally restricted to the Williston Basin; the Exshaw terminology is used in Alberta and western Montana; the Sappington terminology is used in southwest Montana. All of these units are related to each other and quite similar lithologically. (Modified from Smith and Bustin, 2000)



Structure map base Mississippian, Williston Basin. Limit of the Bakken Formation shown by orange line. Areas of development activity and new fields shown by green pattern. *(Source: Images by Stephen A. Sonnenberg)*

and very similar lithology-wise to the Williston Bakken. Those within the industry tend to use the terms interchangeably.

Williston Basin Bakken-Three Forks play

The Williston Basin and Western Canada Basin were connected during parts of the Late Devonian and Early Mississippian. The stratigraphy is similar across both areas but the names of the stratigraphic units change. The Sweetgrass Arch separates areas in which the Bakken terminology is used from areas where the Exshaw terminology is used. To complicate things a little further, in southwestern Montana, the Exshaw term is replaced with the Sappington term.

The primary targets of exploration are the middle member of the Bakken or Exshaw and the upper to middle Three Forks. The upper and lower organic-rich shales are "world-class" source rocks across the entire area.

The Williston Basin is a large, intracratonic sedimentary basin that occupies parts of North Dakota, Montana, South Dakota, Saskatchewan, and Manitoba. The basin, however, probably originated as a craton-margin basin and evolved to an intracratonic basin during the Cordilleran orogen. Sedimentation occurred throughout much of the Phanerozoic, and the thickness of the stratigraphic section in the Williston Basin is approximately 16,000 ft. Many unconformities are described in the stratigraphic section, but rocks of all of Phanerozoic time periods are represented by some deposits. Paleozoic strata consist mainly of cyclic carbonate deposits; the Mesozoic and Cenozoic strata consist mainly of siliciclastics.

During the Late Devonian and Early Mississippian, the basin was an area of active subsidence in a broad shelf area that existed along the western margin of North America. The proto-Williston Basin was an extension of the Devonian Western Canada or Elk Point Basin and situated in tropical regions near the equator.

Three Precambrian provinces underlie the Williston Basin: Superior craton, the Trans-Hudson orogenic belt, and the Wyoming craton. These provinces trend north-south and structures associated with them have strongly influenced later sedimentation and structural features. Notable structural features with a north grain in the Williston Basin include the Nesson, Billings, Little Knife, and Tree Top anticlines. Northwest-trending prominent structural feature include the Cedar Creek, Antelope, and Poplar anticlines. Periodically these structural features reactivated through time.

Bakken Formation, Williston Basin

The Bakken Formation regionally in the Williston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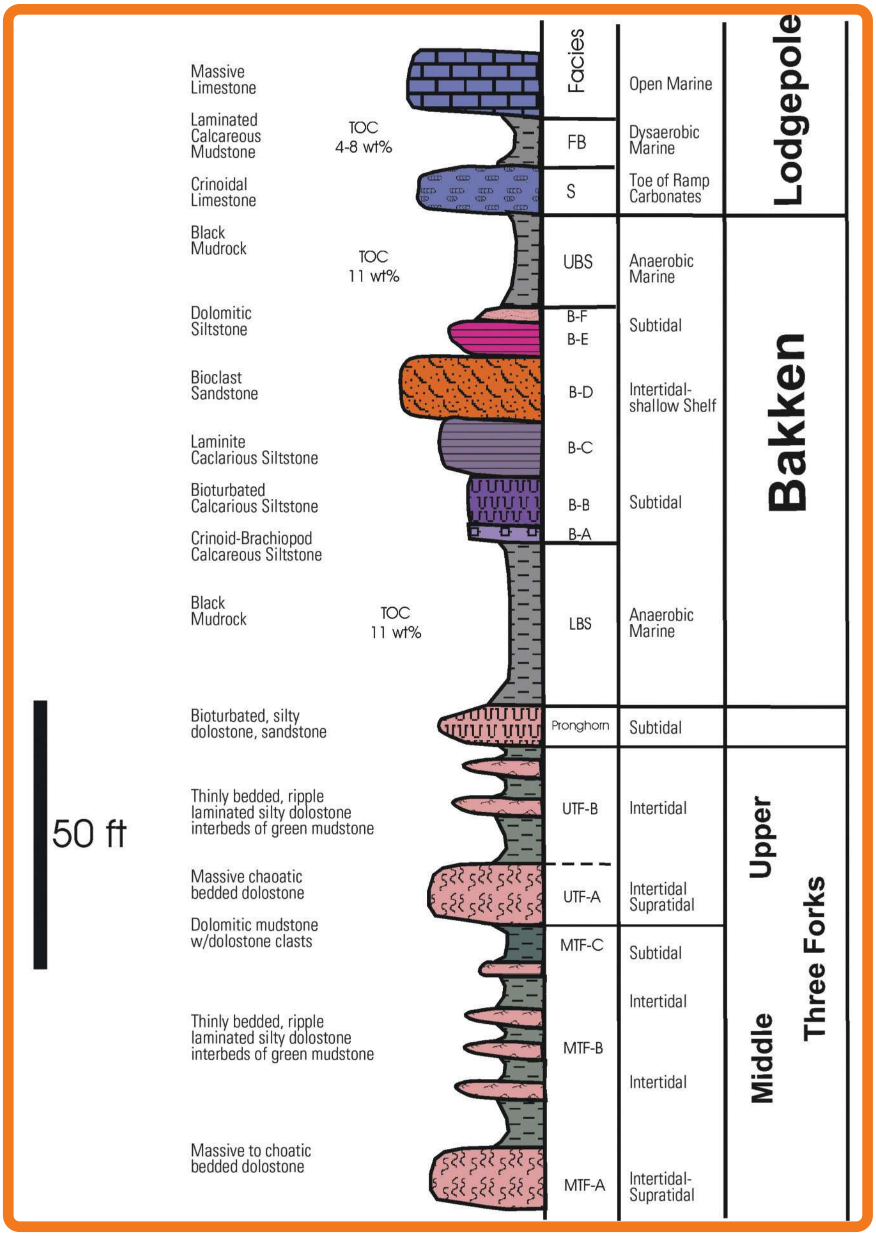

Stratigraphic column for the Bakken Petroleum System showing the various facies which are recognized in core. Targets for horizontal drilling are Middle Bakken facies B, C, D, and E and all facies in the Middle and Upper Three Forks. (Resistivity lines drawn from Hester and Schmoker, 1985)

Basin consists of four members: upper and lower organic-rich black shale, a middle member (silty dolostone or limestone to sandstone lithology), and the Pronghorn. The Bakken Formation ranges in thickness from a wedge edge to more than 140 ft, with the thickest area in the Bakken located in northwest North Dakota east of the Nesson Anticline. The members of the Bakken thin and converge toward the margins of the Williston Basin and have an onlapping relationship with the underlying Three Forks. The contact between the Bakken and Three Forks is probably conformable in the deeper parts of the basin and unconformable along the basin flanks. The Bakken is conformably overlain by the Lodgepole. The four members may represent two regressive-transgressive cycles of sedimentation. Following Three Forks deposition, major uplift and erosion occurred along the margins of the Williston Basin. With a subsequent relative sea-level rise and low-energy transgression, the Pronghorn and lower Bakken shales were deposited. Another regressive event resulted in the middle Bakken being deposited, followed by the next transgressive event which deposits the Upper Bakken Shale.

The upper shale ranges in thickness from 0 ft to approximately 30 ft. It is the primary source bed for the Elm Coulee area as the lower shale thins dramatically in the area.

The isopach for the lower shale shows considerable variation compared to the upper shale isopach. The thickest lower shale occurs east of the Nesson Anticline in the general Sanish Field area. The thick appears to be controlled by the Nesson Anticline paleostructure.

Both pyrolysis and resistivity data can be used as a proxy of thermal maturity. Resistivities greater than 100 ohm-m indicate oil-wet shales and thermally mature areas. The area of thermal maturity is extensive across the Williston Basin, which has enabled this play to cover such a large area.

The upper and lower shale members are potential source rocks and are lithologically similar throughout much of the basin. The shales are potential source beds for the Bakken, Three Forks, Lodgepole, and Mission Canyon formations. The shales are dark-gray to black, hard, siliceous, slightly cal-




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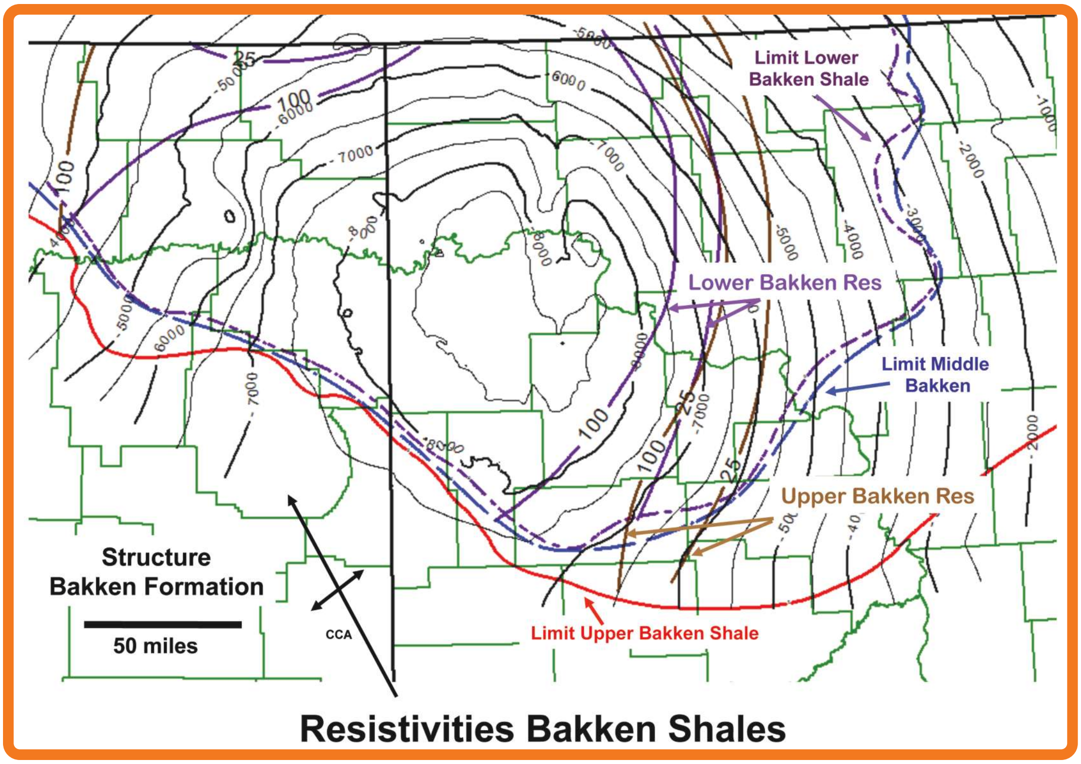
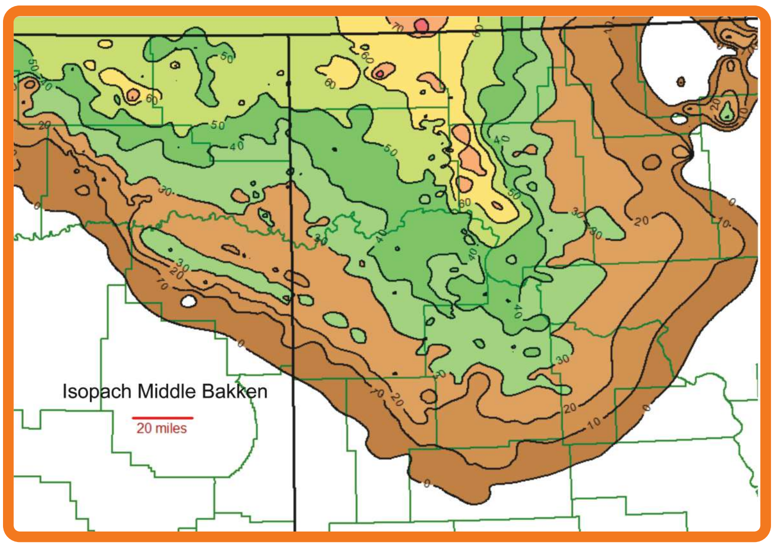


Resistivities in the Bakken Shales can be used as a proxy of thermal maturity. Resistivities greater than 100 ohm-m indicate thermally mature areas. The area of mature source rocks is extensive resulting the a very large producing area for the Bakken Petroleum System. *(Source: Stephen A. Sonnenberg; resistivity lines from Hester and Schmoker, 1985)*



Isopach map of Middle Bakken, Williston Basin. Thickness ranges from wedge edge to approximately 70 ft. *(Source: Stephen A. Sonnenberg)*

careous, pyritic, massive to fissile, and generally either break along horizontal fractures or with conchoidal fractures. The shales contain radiolaria, conodonts, ostracodes, small cephalopods, small brachiopods, and Tasmanites (algae) fossil. The TOC of the Bakken shales averages 11%.

The Middle Bakken can be subdivided into multiple facies. All the facies are thought to be related to deposition in a marine shelf setting (shallow epeiric sea) and appear to represent a shallowing upward sequence followed by a water deepening event. The facies in ascending order are: A, a fossiliferous calcareous siltstone; B, bioturbated calcareous clay-rich siltstone to very fine-grained sandstone; C is a thinly bedded to laminated calcareous very fine-grained sandstone; D is the highest energy facies and consists of fine-grained sandstone to carbonate grainstones; E represents the start of the water deepening and consists of thinly bedded, occasionally microbial laminated, to parallel laminated siltstone; and F consists of fossiliferous dolomitic to calcitic siltstone. The facies are widespread across the Williston Basin with some exceptions. Facies D is only locally developed; the amount of dolomite changes from area to area; production is associated with matrix development in facies C, D, and E and microfracturing. Facies B and C produce at Elm Coulee (Facies D is not present) whereas facies C, D, and E produce in the Sanish and Parshall areas.

The thickness of the Middle Bakken varies from a wedge edge to more than 70 ft. A depositional thick area coincides with the Elm Coulee area and the Sanish Parshall area. Basement tectonics and salt dissolution play roles in creating accommodation space for the middle Bakken. At the Sanish and Parshall fields several of the middle Bakken

facies pinch out in the field area. Interestingly, the source beds also transition from mature to immature in this same area. The trap at Sanish and Parshall fields is thought to be a stratigraphic-maturity trap. Stratigraphic trapping also occurs in the Elm Coulee area.

Pronghorn Interval, Williston Basin

In the North Dakota portion of the Williston Basin, the Pronghorn member of the Bakken Formation produces hydrocarbons in Sanish, Parshall, and Billings Nose fields. In other areas of the basin, the Pronghorn is not present, unproductive, or untested.

The Pronghorn occurs on top of the Three Forks and below the Lower Bakken Shale. Facies in the Pronghorn in ascending order consist of: 1) heavily burrowed, well-sorted, angular to sub-rounded very fine to fine-grained sandstone; 2) interlaminated and burrowed dolomitic siltstone; 3) fossiliferous lime mudstone; 4) shale and thin interlaminated siltstone and very fine to fine-grained sandstone. The sandstone facies in the Pronghorn is equivalent to the Sanish Sand of North Dakota.

The Pronghorn was deposited in an overall deepening sea-level cycle.

The Pronghorn is probably equivalent to the Trident member of the Three Forks in western Montana.

Three Forks Formation, Williston Basin

The Upper Three Forks is evolving into a significant resource play in the Williston Basin. Although Three Forks production was established in Antelope Field in 1953, the play has re-emerged because of the horizontal drilling and multistage fracturing technologies. The Upper Three Forks can be subdivided into three main facies: massive bedded dolostone, chaotic/brecciated dolostone, and interbedded dolostone with green mudstones. These facies are thought to represent deposition in an intertidal to supratidal epeiric-sea setting. The brecciated intervals are caused by storm events (tempestites, i.e., storm deposits), evaporite dissolution, and possible sediment dewatering. Similar facies are found in the Middle Three Forks.

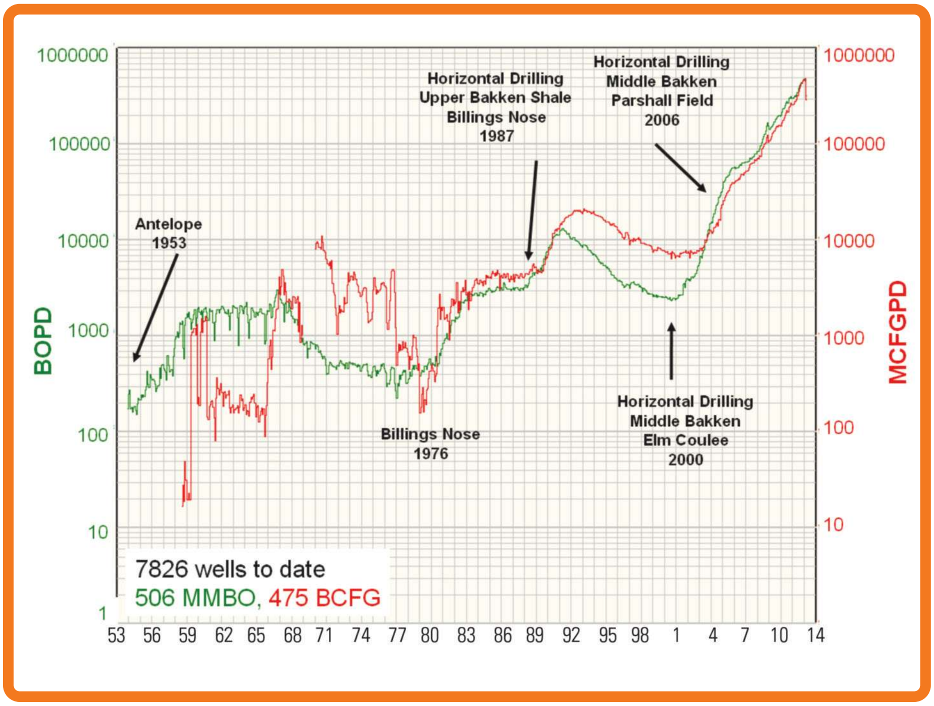
The Upper Three Forks has poor reservoir quality with low porosities (generally less than 8%) and low permeabilities (less than 0.1 md). The reservoirs require fracture stimulation to produce economically. Sweet spot areas are related to favorable facies development, natural fractures, and mature Bakken source rocks. The main source rock for the Three Forks is the Lower Bakken Shale. Where the lower and middle Bakken members thin in the southern part of the Williston Basin, the primary source rock becomes the Upper Bakken Shale. The Three Forks is overpressured, which is related to hydrocarbon generation.

The Upper Three Forks does not appear to be in communication with the overlying middle Bakken reservoirs where the Lower Bakken shales are sufficiently thick to form a barrier between the producing units. The Three Forks resource potential is estimated to be 2 Bbbl of recoverable oil. The Three Forks play coincides with the Bakken play, which adds significantly to the reserves across the basin.

The best reservoir potential appears to be in the Upper Three Forks. Recent development success illustrates that the middle Three Forks also has reservoir potential. The Middle and Lower Three Forks are being tested by several operators in the basin. On the west side of the Nesson Anticline, Continental Resources has established production in the middle member of the Three Forks. These results are very encouraging for adding additional reservoirs to the Bakken Petroleum System.

Bakken exploration, history of basin

The Bakken Formation of the Williston Basin has seen several cycles of exploration and development since the 1950s. The earliest discovery occurred in the Antelope Field of North Dakota in 1953 and development continued into the 1960s. Wells targeted the Bakken and Upper Three Forks on a tightly folded structure. The Bakken and Upper Three Forks are low permeability, fracture-enhanced reservoirs in Antelope with fracturing related to the tight fold. The wells were drilled vertically and after a sand-oil fracture stimulation treatment were capable of producing an average of 209 b/d of oil. Antelope Field has produced 11 MMbbl of oil and 20 bcf of gas from the Three Forks Bakken interval. Average cumulative production per Three Forks well is 550 Mbbl of oil and 1.4 bcfg. Following the Ante-



Production curve for Bakken Petroleum System (Bakken and Three Forks). Several cycles are noted on the plot: Antelope field development, Billings Nose vertical wells, Billings Nose horizontal wells, and the middle Bakken development cycle (includes Elm Coulee, Parshall, Sanish, and many other new fields). *(Source: Stephen A. Sonnenberg; production data from IHS)*

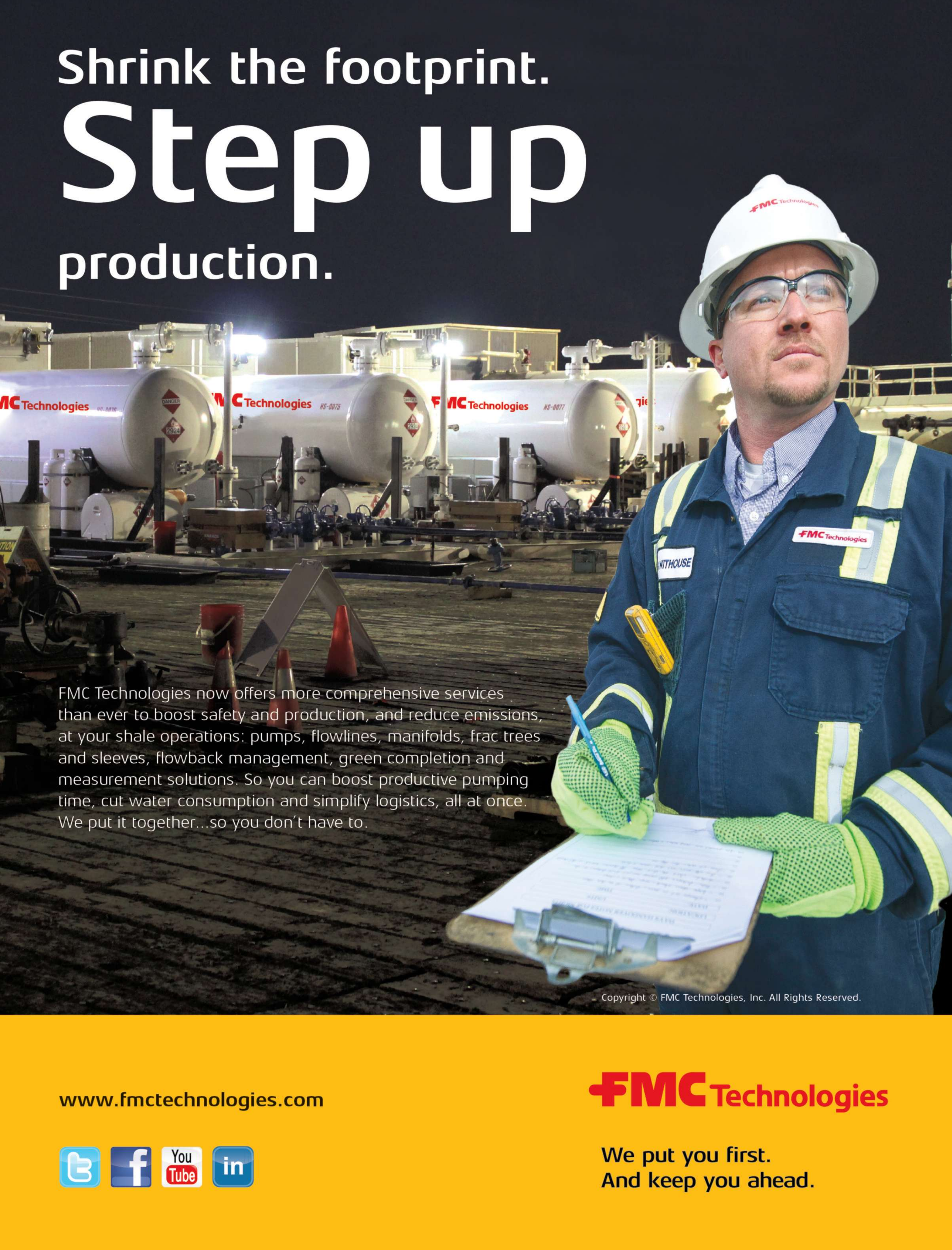
lope discovery, exploration proceeded slowly. All four members of the Bakken and the Upper Three Forks were perforated in Antelope and production established these formations as petroleum reservoirs in the basin.

The next significant discovery in the Bakken was by Shell in the Elkhorn Ranch Field in 1961. The Upper Bakken Shale was completed in the well as a secondary objective after the deeper primary objective, the Red River zone (Ordovician), was not successful. The Elkhorn Ranch well was very significant in that it showed significant reserves could be found in the Upper Bakken Shale. Because of product prices and remoteness of the area, the next Bakken well was not drilled until 1976. This area then became known as the "Bakken Fairway" area. Wells drilled in the "fairway" targeted the upper Bakken Shale and other Paleozoic horizons (both shallower and deeper). The area occurs along the southwestern margin of the Bakken depositional basin in the general area of Billings Nose. Where the Bakken thins, fracture density increases. Sand-oil fracture stimulation treatment was used on these wells.

Horizontal drilling in the upper Bakken Shale commenced in 1987 in the fairway area. The first horizontal well, drilled by Meridian, was the #33-11 MOI well (Sec. 11, T143N, R102W, Elkhorn Ranch Field), which had a horizontal displacement of 2,603 ft in the Bakken. The well was completed for 258 b/d of oil and 299 Mcf/d, with production remarkably stable for the first two years. The success of this well set off the horizontal drilling phase of the upper Bakken Shale. The play continued into the 1990s with more than 20 operators. Product prices declined significantly in the 1990s and, along with the somewhat unpredictable production in the Upper Bakken Shale, brought this phase to a close. The "fairway" play met with mixed results. Good producing wells were often offset with poor producing wells. In addition, some pressure depletion and cross-well communication was reported.

Because of mixed results in the "fairway" trend and low product prices, the Bakken again returned to the status of being a secondary objective type of a reservoir rather than a primary exploration objective. This status changed with the discovery of significant reserves in the Middle Bakken in the Elm Coulee Field. The discovery and development of the Middle Bakken has resulted in the most significant of the exploration cycles to date.

The Elm Coulee Field of Richland County, Mont., was discovered with horizontal drilling in 2000. The key well for identifying the potential in the Bakken was the Kelly/Prospector Albin FLB 2-33 well (Sec. 33, T24N, R57E; Richland County). The well was drilled to test the Nisku and the deeper horizons did not work out, so the Bakken secondary objective was pursued. The 2-33 well was perforated in only the Middle Bakken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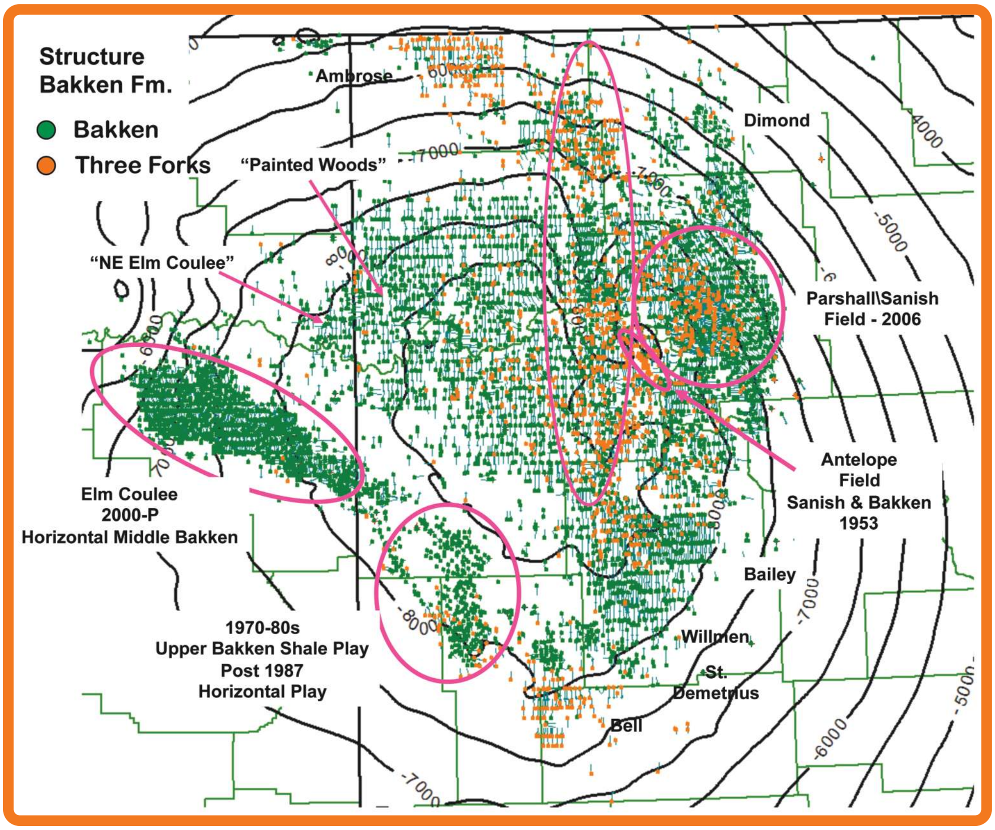
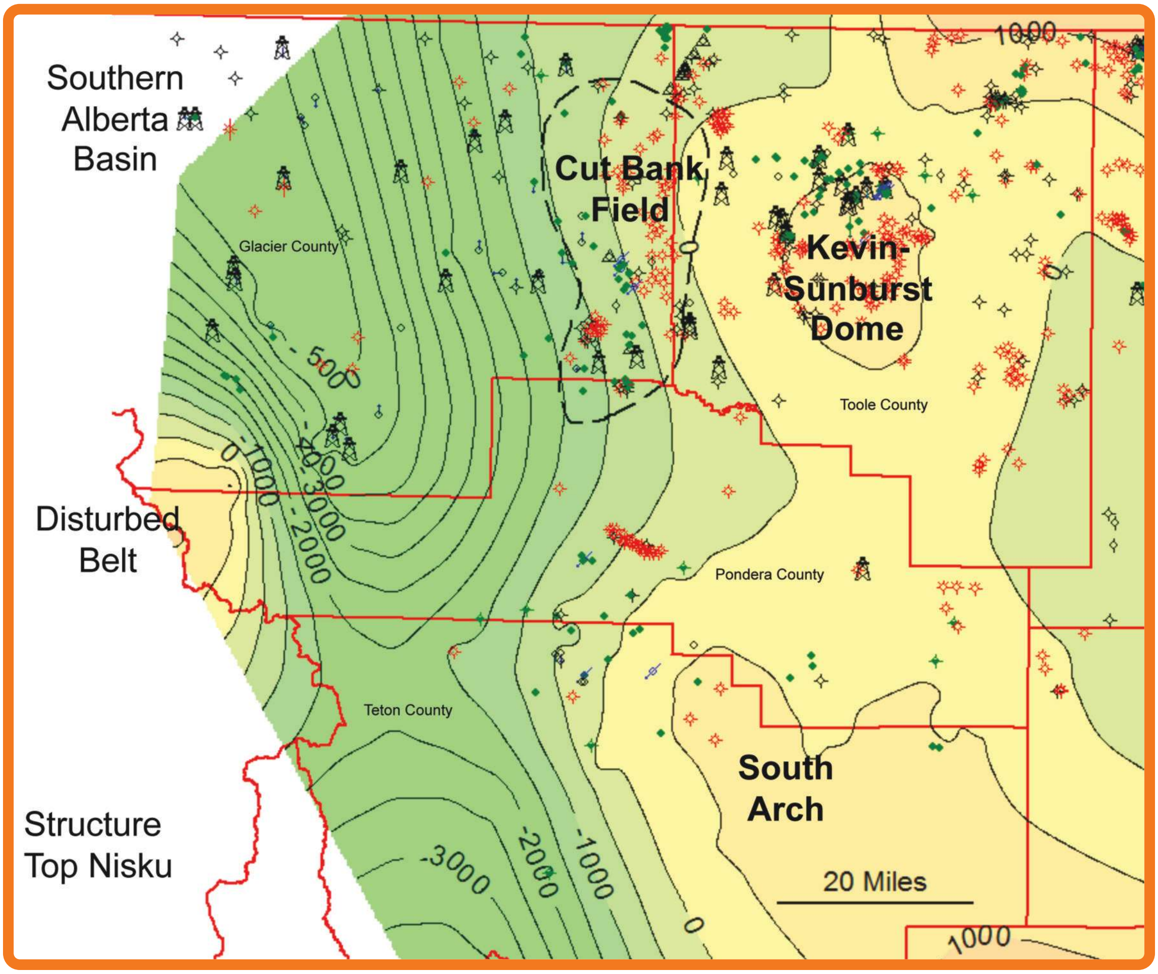


Structure map top Bakken, Williston Basin. Green dots are Bakken completions, orange dots are Three Forks completions. New development activity to note is the Dimond, Ambrose, NE Elm Coulee, and Bell field areas. *(Source: Stephen A. Sonnenberg)*

because of the shows seen on the mud log (whereas the upper shale typically would be perforated as well). The well was treated with a water-sand fracture stimulation (instead of the more normal oil fracture) consisting of 80,260 gallons of water and 151,800 pounds of sand. The Middle Bakken flowed 157 bbl of oil for the first 20 days beginning in March of 1996 and was still making 80 b/d after three months. The results of this well were very encouraging, and the concept was developed that a large field existed in the area that had previously been drilled through with more than 100 wells. An area 4 to 5 miles wide and 30 miles long was mapped out where the porosity development along with high resistivity was observed. Horizontal drilling in the middle member started in 2000, which led to the discovery and continuous development of the Elm Coulee Field since that time. Individual horizontal wells are sand-water fracture stimulated and have initial production of 200 to 1,200 b/d of oil and estimated ultimate recovery (EUR) of 300,000 bbl to 750,000 bbl per well. The field has an EUR of greater than 200 MMbbl of oil. Technology plays a significant role in this development with horizontal drilling and fracture stimulation.

The Elm Coulee discovery and development prompted operators also to target the middle Bakken in North Dakota. Prior to Elm Coulee most operators targeted only the upper shale in the Bakken. The expansion of the play into North Dakota resulted in new discoveries including the Parshall and Sanish fields. The new discoveries in North Dakota suggest the existence of an extremely large unconventional resource play. Product prices will probably influence this cycle too. Although regarded as a maturely drilled basin, the Williston continues to yield giant oil discoveries.

Horizontal wells in the Parshall-Sanish areas target specific facies (C, D, and E) of the Middle Bakken. Production is related to fracture development and matrix development in the Middle Bakken. The original oil in place in the greater Parshall area is estimated by various operators to be 8 MMbbl to 11 MMbbl per section for the Bakken and 4 MMbbl to 6 MMbbl per section for the Three Forks. Wells are drilled on either 1,280-acre spacing units or 640 spacing units. EURs for the Bakken are 600 bbl to 900,000 bbl of oil per section; EURs for the Three Forks are 350 bbl to 500,000 bbl of oil per section. The recovery factor for the tight reservoirs is approximately 8%. Current well costs are in the US $9 million to $12 million range. Because of high production rates, wells can pay out in four to six months. Some operators prefer the 1,280 spacing



Structure map top Nisku, northwest Montana. Several operators are targeting the Bakken/Exshaw Petroleum System in the area west of Cut Bank Field. Most of the drilling activity is by Rosetta Resources and Newfield. *(Source: Stephen A. Sonnenberg)*

units over the 640 spacing units because of cost savings associated with the drilling of one well instead of two. Operators are fracture stimulating wells with 10-plus fracture stimulation stages.

Several new areas are being developed by operators that are expanding the current limits of the play. The Dimond area is currently being developed by several operators showing that Bakken potential exists off to the northeast of Parshall in Burke County. This field is being developed by Occidental Petroleum, Cirque, and others. The Ambrose area located northwest of the Nesson Anticline is a large Three Forks developing area in Divide County. This area is being developed by SM Energy, Samson, Baytex Energy, and others. The northeastern Elm Coulee Field is being developed in the Bakken in Roosevelt County, Mont. The area is being developed by Oasis Petroleum, Petro-Hunt, and others. The Bell Field is largely a Three Forks/Pronghorn Field being developed in the southern Williston Basin. Along with these new fields, in-fill drilling continues in all the existing fields. Operators also are testing and modeling the Middle Bakken for secondary and tertiary recovery.

The latest cycle of exploration and development in the Williston Basin is the most significant to date. Production for the US part of the Williston Basin has gone from 2,500 b/d of oil to close to ~600,000 b/d.

Completion techniques continue to change. The initial fracture stimulations in Elm Coulee were single stage. The fracture stage count in 2007 aver-

aged three, and in 2011 averaged nearly 30. Some wells have been completed with 40 or more stages. In addition, the lateral length has increased from 4,000 ft to 9,500 ft in the last decade. The average proppant used per stage (lb/stage) is approximately 100,000. The average fluid volume per stage is between 1,500 bbl and 2,500 bbl.

Alberta Bakken/Exshaw play

The Exshaw, Bakken, and Sappington are all equivalent and very similar lithologically in western Montana.

The Lower Exshaw Shale is black, organic-rich siliceous shale, has healed fractures, micro-faults, and is finely laminated. The TOC of the shale ranges from 1 – 17 wt.%. The Middle Exshaw consists of two facies: A and B. The lowermost facies A consists of dolomitic siltstone, very burrowed, abundant brachiopods, and crinoids. Facies B consists of dolomitic very fine-grained sandstone, well-sorted, submature, heavily burrowed, lacking fossils, with patchy oil staining, few cm-scale ripple-laminated beds. The interval is interpreted as storm units deposited in a shelf environment. These two facies are almost identical to lower Middle Bakken facies found in the Williston Basin (Middle Bakken A and B). Both of these facies have low porosity (< 8%) and permeability (< 0.1 md).

The Three Forks is subdivided into Trident and Logan Gulch members. The Logan Gulch consists of three facies: TF1, TF2, and TF3. The TF1 is the lowest unit and consists of silty dolostone and nodular anhydrite. This unit is thought to have been deposited in a supratidal environment. The TF2 is a silty laminated dolomudstone with limited burrowing. The unit is thought to represent upper intertidal environments. The TF3 is a silty dolomudstone with large floating dolomite clasts. This unit is thought to be dominated by storm events and the floating dololmite clasts represent rip-up clasts. The three facies are very similar to the Three Forks of the Williston Basin.

The Trident member consists of two facies: TF4 and TF5. The TF4 is a lime grainstone, with mostly carbonate matrix, and some anhydrite. TF5 is fossiliferous lime wackestone, carbonate-rich, few fractures, and partially dolomitized. The Trident is very similar to the Pronghorn member of the Bakken in the Williston Basin.

Both the Trident and upper Logan Gulch are potential reservoirs. Additional potential reservoirs are the Lodgepole and Exshaw (or Bakken).

The Exshaw Petroleum System for this area includes the upper and lower Exshaw Shale source beds. Potential reservoirs are Three Forks, middle Exshaw facies A and B, and the lower Lodgepole. An additional sand reservoir known as the Banff occurs on top of the Upper Exshaw Shale and beneath the Lodgepole. This sand is a target in the Canadian portion of the Alberta Basin and may become a significant target in northwestern Montana. The Banff is limited in its distribution, however, and difficult with the present well control to effectively map. The shales have high resistivities indicating their thermal maturity. Source rock analysis also confirms the maturity of the shales in this area.

Companies active in the Alberta Bakken/Exshaw include Quicksilver, Rosetta Resources, Primary Petroleum, Newfield Exploration, and Frontpoint Energy.

Rosetta reports significant resource in place of 6 Bboe. The company has identified fracture azimuth and orientation and achieved good vertical growth in initial stimulations. It also has reported using cemented liners and plug and perf methods for more effective stimulations. Rosetta has a reported 1,500 potential locations, and its targeted assumptions for well commerciality are: IP 250 boe/d, EUR 185,000 boe, 160-acre spacing, and $4 million well cost.

Thus the resource potential in the US part of the southern Alberta Basin is large. The Exshaw Petroleum System in this area has "world-class" source rocks, making this an exciting area to explore.

Summary

Tight oil plays such as the Bakken and Exshaw are continually moving ahead with encouraging results. New fields and new pays (Middle Three Forks) have been delineated in the Williston Basin. The Southern Alberta Basin is an exciting new area that has enormous future potential. ■


FRIESEN

Bakken Consolidation Drives Efficiency

Experience and technology lead operators to squeeze the play for higher returns.

By Don Lyle
Contributing Editor

The Bakken Shale system, a great oil hope for dwindling US oil production, is fulfilling its potential as operators see limits only in transportation of the oil they produce.

Although the Eagle Ford has taken a greater share of the limelight since Montana and North Dakota became major oil producing states, the Bakken shows more signs of maturity as larger operators buy out smaller operators, technology results in more sophisticated horizontal length and fracture treatments, and pad drilling replaces individual wells at lower prices.

The Williston Basin still hogs the glory with the largest wells and fields on both the US and Canadian sides of the border, but a smaller play is growing slowly in the Southern Alberta Basin in Alberta and Montana.

In the Williston Basin, the Bakken system includes the Lower Lodgepole, Bakken, and the Three Forks/Bird Bear/Torquay. In the Southern Alberta Basin, the zones include the Banff, Exshaw, Big Valley, and Stettler/Wagamun formations. In many cases, operators refer to both systems as the Bakken system because that is the name the public recognizes.

In North Dakota alone, Bakken system activity grew from 433 wells in November 2007 to 4,910 in November 2012 as oil production rose from 29,376 b/d to 669,091 b/d, according to the North Dakota Industrial Commission.

The US Energy Information Administration predicted rig count on the US side would drop from an average 208 rigs in 2012 to about 196 in 2013 and 184 in 2014, but efficiency would allow each rig to drill one well a month.

As production filled pipelines, high-production operators turned to rail shipments to move their oil, and tank trucks bringing oil from the fields lined up for miles waiting for their turn to unload their payloads to rail tanker cars.

The Alberta Basin segment of the play developed more slowly with shallower wells and less-prolific initial production rates. Operators continue to search for the keys to flush production.

This section offers profiles of the larger and more active operators in the Bakken system on both sides of the border as the explorers and producers build a growing and changing oil empire.

US Key Players

Abraxas Petroleum Corp.

- *Land: 23,320 net acres*
- *Accelerating Bakken/Three Forks development*

Abraxas Petroleum Corp. focused its portfolio on its highest-return basins, the Williston, Powder River, and Permian basins, along with the Eagle Ford play leading the way.

It plans to pick up its Bakken/Three Forks activity as it dedicates one company-owned rig to the play for 2013 on its 109,658 gross (23,320 net) acres.

According to a February 2013 presentation, Abraxas will drill 12 gross (6.3 net) wells for US $47.4 million to the Bakken and Three Forks formations. That represents a major portion of the company's $70 million capital budget for 2013 and will give the company 10.8 net wells.

All the company's land is held by production and offers Abraxas 409 gross (64 net) risked drilling locations.

Among the company's properties, it holds 5,535 net acres and 17 locations each in the Bakken and Three Forks in McKenzie County; 3,255 net acres and 10 locations in each formation in Burke County; 1,879 net acres with six locations in each formation in Billings County; 1,442 net acres and five locations in each zone in Divide County; 1,239 net acres and four locations in each formation in Williams County; 563 net acres with two Three Forks locations in Stark County; and one location in each formation in Dunn County, all in North Dakota.

The company also holds 5,551 net acres with 17 unrisked locations in each formation in Richland County; 1,367 net acres with seven locations in each zone in Sheridan County; and 1,367 net acres and four wells sites each in Roosevelt County, all in Montana.

Like many other successful Bakken/Three Forks companies, Abraxas is using pad drilling on its operated projects.

Abraxas asked E-Specturm Advisors to market its nonoperated Bakken and Three Forks properties in Montana and North Dakota. That proposed sale involves 14,502 net acres of land and 435 boe/d of production.

American Eagle Energy Corp.

- *Land: More than 72,240 gross acres*
- *Works both sides of the US-Canada border*

One of the early supporters of the modern Bakken play, American Eagle Energy Corp. works the Alberta Basin Bakken in north-central Montana, the North Dakota Bakken/Three Forks, and the Hardy Bakken area in Saskatchewan.

In February 2013, the company had 15 operated horizontal Bakken wells producing in Saskatchewan and North Dakota, but that is just a peek at its operations.

It has two core properties, the Spyglass Project in Divide County, N.D., and the Hardy Project.

The company was instrumental in causing the first horizontal Bakken well to be drilled in Hoffer Field in 2009 by TriAxon, a company later acquired by Crescent Point Petroleum. That discovery led to a second discovery at Oungre and the development of the Spyglass Project in the US, where the Bakken and Three Forks show up at a relatively shallow 8,000 ft to 8,500 ft, according to a January 2013 report by American Eagle.

Samson Resources drilled the first Middle Bakken Spyglass-area well in June 2012 for an initial 30-day production rate of more than 300 b/d of oil. American Eagle followed up in August with its first Middle Bakken well in the area. That short-lateral well came online in November 2012 at a 30-day production rate of 153 b/d. It drilled its second well the following month and plans more wells in the area during 2013.

In 2006 Samson started drilling Three Forks wells offsetting the Spyglass area in one-mile-long laterals, and SM Energy drilled the first two-mile-long lateral in 2010, a standard that continues into 2013. SM Energy currently is working in the Spyglass area with similar Three Forks wells and Samson Resources is drilling both Three Forks and Bakken wells. American Eagle participated in 36 horizontal wells in the area during 2012 with both companies and other operators.

It also began operating wells in 2012 and drilled 14 horizontal wells, drilled and cased 12 of them, and had eight on production by year-end with average first-30-day production rates of 450 b/d. It currently operates two rigs at Spyglass.

Its West Spyglass Project, with approximately 4,000 net acres, also holds Bakken and Three Forks prospects.

In Saskatchewan, American Eagle made the Hardy Bakken discovery in 2008 and confirmed it in 2011 with a 150 b/d well. The property holds potential for another 31 horizontal wells producing a net 3.8 MMboe.

The Minton Bakken Project lies immediately south of the Hardy area in Saskatchewan, but most deep wells in the area went through the Bakken to the Winnepegosis and Red River formations. American Eagle holds a half interest in approximately 21,760 gross acres in the area and plans to participate in two horizontal Bakken earning wells.

The Benrude Project is in Roosevelt County, Mont., and also in the Williston Basin, where Nisku is the primary target and the Bakken and Three Forks are secondary objectives.

The company's Glacier Project lies to the west in northwestern Montana in the southern Alberta Basin. American Eagle said its experience in the Williston Basin helped it identify superior reservoir potential in the Bakken Formation in the area. The company holds a one-third interest in 10,000 acres with partners FX Energy Inc. and Big Sky Operating LLC. FX, the operator, has drilled a reentry of a shallow well.

American Eagle also holds 2,042 net acres in the same area, which it calls Glacier Central. It is evaluating the success of surrounding tests.

ConocoPhillips Co.

- *Land: 626,000 net acres*
- *Building positions in shale plays*

ConocoPhillips Co. proved its penchant for shale plays in 2011 as it added approximately 600,000 net acres in shale areas to existing prominent positions in the Bakken, Eagle Ford, Permian, and North Barnett shales in the US and the Montney and Muskwa shales in Canada.

That additional land included the Wolfcamp and Avalon shales in the Permian Basin, the Niobrara Shale in Colorado, and the Duvernay and Canol shales in Canada. ConocoPhillips also farmed into 11 million acres with a 75% interest in an exploratory shale play in Australia.

It already held 223,000 net acres in the Eagle Ford play.

The company raised its rig count in the Bakken/Three Forks trend from six at year-end 2011 to 10 during 2012.

During 2011, ConocoPhillips also made a decision to high-grade its exploration portfolio with acreage acquisitions in high-impact areas including shale prospects.

It produced 15,000 b/d of liquids and 12 MMcf/d of natural gas for total production of 17,000 boe/d from its Williston Basin properties in 2011, and it successfully reduced drilling time by developing and implementing new methods and best practices.

According to the company's 2012 Fact Book, "We utilize a multidisciplinary approach that combines expertise in geoscience, reservoir engineering, and completion technologies to identify the best play and 'sweet spots' within these plays. Our acreage position in the liquids-rich Eagle Ford, Bakken, and Permian plays is an example of successful deployment of our play identification technologies within unconventional reservoirs."

It uses microseismic interpretation to observe hydraulic fracturing operations to monitor microfracturing in the rock. Those studies help optimize future completions and increase production from its wells.

ConocoPhillips also uses core imaging techniques to characterize its unconventional reservoirs. Those techniques show geologists and engineers how oil and gas are stored in the reservoir and how they flow through low-permeability zones. They help predict production behavior and allow the company to optimize recoveries.

The company's properties are in Mountrail, McKenzie, Williams, Dunn, Stark, and Billings counties in North Dakota and in Richland County, Mont.

Continental Resources Inc.

- *Land: 1.14 million net acres*
- *A horizontal Bakken pioneer in North Dakota*

Continental Resources Inc. bills itself as "America's Oil Champion," and the company's record and current position in the Bakken/Three Forks offer a solid foundation for that statement.

It is the largest acreage holder in the Bakken with most of that acreage in North Dakota.

It completed the Robert Heuer 1-17R well in Divide County, N.D., in 2004, the first commercial Bakken well in the state to be both drilled horizontally and fractured.

The company was first to complete a 1,280-ft long-lateral multistage fracture treatment in 2007. It was first to complete a horizontal Three Forks well in 2008, and it was the first to complete a paired Bakken and Three Forks well in 2010.

In a February 2013 presentation, the company said it was the top oil producer, driller, and leasehold owner in the Williston Basin with 13% of total production in 2012 as it ran 11% of all rigs working in the basin, or 20 rigs in December 2012.

ECO-pads in the Bakken/Three Forks play minimize oil operation footprints and raise returns for operators. *(Photo courtesy of Continental Resources Inc.)*

Continental Resources gave shareholders 1.5 Bboe in net unrisked resource potential from 3,988 locations. It estimated the Williston Basin held 24 Bboe in technically recoverable resource in October 2010.

The company's track record is enviable. It turned in a 45% annual growth rate in proved reserves since 2009 and production grew 58% between 2011 and 2012.

All that action gave the company a solid handle on what it could expect from its wells. Its Bakken type curve starts out at 20,000 boe in the first month of production and drops to about 2,500 boe in the 100th month. By the 600th month, the decline rate falls to near zero and the well has produced a cumulative 603,000 boe.

That profile fits a horizontal well with a 10,000-ft lateral and a 30-stage completion.

A single well with a net revenue interest of 82.5% costs US $9.2 million to drill and offers a 52% rate of return. Like other operators, Continental is shifting its operations to ECO-Pads, groups of horizontal wells drilled from a single pad. In that case, the well cost falls to $8.5 million and the rate of return rises to 59%.

That is not good enough for Continental. Its target for a single well is $8.7 million for a 59% rate of return and $8 million for an ECO-Pad well for a 65% return.

Currently, six single wells cost $29.3 million from spud to rig release. For the future, ECO-Pads with six wells will cost $21.8 million to drill 129,321 ft to rig release in 128 days for a 35% reduction in rig time.

During 2012 Continental Resources drilled 259 gross wells in the Bakken, or an average of 12 wells per rig for the year, up from seven wells per rig in 2011.

The company allocated $3.15 billion to its 2013 capital budget, and 68% of that money will go into the Bakken petroleum system, which includes the Three Forks zones.

Continental Resources proved the separation of the Middle Bakken and Three Forks 1 zones, and through 2012 it drilled one-fourth of all Three Forks wells. Pioneering efforts continue as it hosted a 10-well coring program that proved up oil shows in the Three Forks 2, 3, and 4 benches.

It completed the industry's first Three Forks 2 producer and the first Three Forks 3 well, the Charlotte 3-22H, which tested for 953 boe/d. Continental Resources reported that well on Dec. 3, 2012.

The company will continue its concentration on the Three Forks during 2013 with a capital budget of $70 million set aside to further derisk that formation. It will spend $161 million on a 320-acre spacing pilot program and another $36 million on a 160-acre spacing pilot in the formation.

For the future, the company anticipates 4.5 Bboe in recoverable potential from its properties, with unrisked potential from 6,718 Bakken/Three Forks wells on 320-acre spacing and 13,285 wells on 160-acre spacing.

It has unbooked net resource potential of 2.84 Bboe on 320-acre spacing and 4.47 Bboe on 160-acre spacing, with most of that production coming from the Bakken and Three Forks 1 zones and the remaining from the Three Forks 2, 3, and 4 segments. It had 4.65 MMboe of proved reserves at year-end 2012.

Continental Resources produced an average 59,019 boe/d in 4Q 2012, up from 35,565 in 4Q 2011.

Enerplus Corp.

- *Land: 69,000 net acres*
- *Bakken gets lion's share of capital expenditures for 2013*

Enerplus Corp., with widespread holdings in the US and Canada, looks to its Bakken/Three Forks holdings as a primary conductor of company growth.

The Canadian company will reduce its capex in 2013 by 20% from 2012 levels, but the Bakken/Three Forks play in North Dakota will get about 50% of that budget. That is US $340 million for the Fort Berthold area. With the help of that investment, it expects its oil production in North Dakota to increase by more than 30% in 2013. It produced 16,245 boe/d in 2012 from its US Bakken/Three Forks operations in Montana and North Dakota.

"Our US crude oil activities are focused on two key assets – Fort Berthold, our growing Bakken/Three Forks play where we hold 69,000 net acres of land in the highly prolific region of Dunn, McKenzie, and Maclean counties in North Dakota and Sleeping Giant, our mature Bakken field in Richland County, Mont.," the company said on its website.

According to a March 2013 presentation, it has more than 130 future net operated drilling locations with 117 MMboe in proved and probable reserves and another 34 MMboe in crude oil contingent resources in the US Bakken/Three Forks.

It added an additional 20% working interest to its Sleeping Giant holdings during 2012, while it increased Fort Berthold production by approximately 120%.

It drilled 26 net operated wells – 19 Bakken and seven Three Forks – during the year and participated in five net nonoperated wells.

EOG Resources Inc.

- *Land: Approximately 580,000 net acres*
- *High returns rate high capital expenditures*

EOG Resources Inc. made a name for itself as one of the largest landholders in the Bakken play, one of the biggest oil producers in North Dakota,

A tank battery gathers Bakken system oil for tank truck pickup in the Williston Basin. *(Photo courtesy of Enerplus Corp.)*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and one of the most successful technology leaders in the play.

In an early 2013 presentation, the company said it held 90,000 net acres in its core area and additional land to the southwest. An earlier presentation said it held 580,000 net acres prospective for both Bakken and Three Forks zones at the end of 1Q 2010 and that 330,000 were "effective" net acres, or low-risk and economically prospective acres, in the Bakken Core, Bakken Lite, and Three Forks areas.

Statistics show its aggressive attitude toward the play and to its other prime liquids plays, the Eagle Ford Shale and Permian Basin formations. Those plays led the company's charge to a 28% growth in oil production from February 2012 to February 2013 following 35% growth from 2009 to 2010, 52% from 2010 to 2011, and 39% in 2012.

By the end of July 2012, the company produced 688,000 bbl of oil from the Bakken and 599,000 bbl of oil from the Eagle Ford, a combination that gave the company 82% of its oil production. Those two formations also helped make the company the largest horizontal drilling company in the nation with more than twice the horizontal wells as its nearest competitor.

It produced 62,100 boe/d gross from the Bakken and Three Forks at year-end 2012, and it plans to drill 53 net Bakken wells in 2013 from its seven-year inventory of drill sites.

During 2012 the company had success with downspacing to 320 acres and encouraging results from 160-acre spacing. The tighter spacing gave EOG two Wayzetta-area wells, one with an initial potential of 1,185 b/d of oil and the other with 1,265 b/d of oil plus rich gas.

It also found good results with 320-acre spacing on its Antelope extension southwest of the core area where Hawkeye wells gave it initial potentials of 2,945 b/d of oil and 2,445 b/d of oil plus rich gas. It also is testing 160-acre spacing in that area.

The core area gives the company 92% oil, 6% NGL, and 2% gas, while the Antelope area yields 78% oil, 11% NGL, and 11% gas.

New fracture treatments are making a difference for EOG Resources. It tested the new treatment in the Wayzetta 156-3329H in the core area for 197,000 bbl of oil in 300 days. The original offset well in the area produced 115,000 bbl of oil in the same amount of time, a 71% improvement.

With the compiled results from 3,814 wells, the company has a good idea how it stacks up against the rest of the industry. The industry average estimated ultimate recovery is 388,000 boe, while EOG measured an average recovery of 544,000 boe on its wells.

In its 4Q and full year report for 2012, the company said, "In the North Dakota Bakken/Three Forks, positive results from downspaced drilling tests, together with significant modifications in drilling and completion techniques, further boosted EOG's crude oil production growth.

"EOG made strides in increasing the amount of crude oil recoverable from both its Eagle Ford and Bakken resources by testing various drilling densities and further refining completion practices.

"Over the course of 2012, EOG's North Dakota wells showed marked productivity improvement following the implementation of new completion techniques. On its 90,000-net acre Bakken Core, EOG confirmed that 320-acre well spacing is economically sound, and it is very encouraged by 160-acre results. Recent downspaced tests reflect a gain of approximately 30% to 70% in cumulative production over earlier wells drilled in the field. The Fertile 51-0410H, in which EOG has a 94% working interest, had a maximum initial production rate of 1,800 b/d of oil, with 850 Mcf/d of rich natural gas."

Exxon Mobil Corp.

- *Land: Nearly 600,000 net acres*
- *XTO and Denbury deals raised position*

ExxonMobil Corp. landed a big position in the Bakken play in the Williston Basin and in other shales around the country when it purchased XTO Energy. It increased that position in North Dakota and Montana in 2012 with its purchase of Denbury Resources' Williston Basin assets for US $1.6 billion in cash and properties suited to Denbury's expertise.

That purchase gave ExxonMobil another 196,000 net acres in the popular shale play. According to ExxonMobil, the Denbury properties should have produced more than 15,000 boe/d in the second half of 2012.

"This agreement provides a strategic addition to ExxonMobil's North American unconventional resource base. ExxonMobil's financial and technical strength will support continued development of America's natural resources, which strengthens US energy security while creating jobs and new government revenues for vital services," said Andrew P. Swiger, senior vice president of ExxonMobil, in an official release.

In addition to the cash, Denbury received ExxonMobil's interests in Hartzog Draw Field in Wyoming and Webster Field in Texas, fields that produce a combined 3,600 boe/d in gas and liquids. Those fields are near CO_2 source fields. Denbury's expertise lies in developing fields using EOR with CO_2 injection.

In a report of operations in 2011 and plans for 2012, ExxonMobil said, "In the tight oil reservoirs of the Bakken Shale, we completed 51 wells in 2011 to delineate multiple core areas across our 395,000-net acre leasehold. We plan to move the play from delineation to development in 2012 using optimized drilling, spacing, and proprietary completions processes."

When ExxonMobil acquired XTO Energy in 2010, the world's largest oil company said that purchase increased its acreage in North Dakota and Montana by 450,000 net acres.

ExxonMobil will operate the Williston Basin assets through its XTO Energy subsidiary.

Fidelity Exploration & Production Inc.

- *Land: 124,000 net acres*
- *Cashing in on home territory*

Fidelity Exploration & Production Inc., the oil and gas operating subsidiary of Bismarck, N.D.-based MDU Resources Group Inc., has a strong foothold in the Bakken play and spends money to make the most of its opportunities in the play.

The company allocated US $215 million of its $475 million capital budget for 2012 to the Bakken/Three Forks play, an indication of its expectations from the shale that already produces more than 12,000 boe/d for the company.

In Mountrail County, N.D., one of the sweetest spots in the Bakken/Three Forks, Fidelity holds 16,000 net acres. It produces 5,100 boe/d and has 39 remaining gross Bakken locations. It has interests in 64 operated wells and more than 200 nonoperated wells in the county. Its estimated ultimate recoveries (EURs) in the area range from 250,000 bbl of oil to 600,000 bbl of oil per well. It also has more than 20 Three Forks drilling locations with EURs from 250,000 bbl of oil to 400,000 bbl of oil.

It holds another 51,000 net acres in Stark County, N.D., where the Three Forks is the primary target. The company holds 14 gross operated wells in that county. The company has more than 14 gross remaining wells in the Three Forks sweet spot and more than 25 gross potential locations in the development area. EURs range from 250,000 bbl of oil to 400,000 bbl of oil.

It controls another 60,000 net acres next to giant Elm Coulee Field in Richland County, Mont., targeting both the Bakken and Three Forks formations. It has 100 potential gross locations in that county and drilled its first well in February 2012. By year-end 2012, it had two producing wells, another flowing back, and a fourth still drilling. EURs in this county range from 250,000 bbl of oil to 500,000 bbl of oil.

Fidelity started 2012 working two rigs in the Bakken/Three Forks but boosted that count to five rigs in March.

Halcón Resources Corp.

- *Land: 130,000 net acres*
- *Bought GeoResources stake in Bakken*

Halcón Resources Corp. management, with highly successful forays into the Haynesville and Eagle Ford shales leading Petrohawk, entered the Bakken play with the US $1 billion acquisition of GeoResources Inc. in August 2012.

That purchase gave the company 12,710 boe/d of production (91% oil) in 4Q 2012 and 48.62 MMboe in reserves.

In October 2012, the company agreed to buy


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81,000 net acres in four North Dakota counties from Petro-Hunt for $700 million in cash and $750 million in Halcón shares.

Those properties produced more than 10,500 b/d of oil (net to Petro-Hunt).

In a February 2012 presentation, Halcón said it was beginning a high-growth phase for production, reserves, and cash flow as it focused on liquids-rich plays.

Company-wide, which included the Woodbine and Utica/Point Pleasant properties in addition to 130,000 net acres in the Bakken/Three Forks play, it produced 18,500 boe/d in 4Q 2012 and an estimated 2013 production of 42,500 boe/d, up 130% from 2012. Liquids will make up approximately 85% of that production.

Halcón operates 81% of its Bakken/Three Forks properties with an average 72% working interest and an average 43% net revenue interest.

Third-quarter 2012 production from the two formations totaled 11,720 boe/d, while 4Q production climbed to 12,710 boe/d.

It had 88 Bakken and 26 Three Forks wells on production, three Bakken wells being completed, nine Bakken and three Three Forks wells waiting on completion, and four Bakken and four Three Forks wells being drilled in February 2013.

The company focused on improving operations in areas with higher internal rates of return.

Looking to the future, Halcón expected to run six to eight rigs in 2013 to spud 65 to 75 gross operated wells in the Williston Basin. It also expected to participate in 90 to 100 gross nonoperated wells with a 10% to 12% working interest.

A $460 million drilling and completion budget for 2013 will help accomplish those goals.

Approximately 75% of the company's overall acreage is held by production, but 90% of its land on the Fort Berthold reservation is held by production.

It will direct $10 million of its drilling and completion budget to the Fort Berthold-Antelope area, where it expects spud-to-production times of 90 days. Bakken wells offer estimated ultimate recoveries (EURs) of 726,000 boe, made up of 630,000 bbl of oil and 578 MMcf of gas.

In the same area, Three Forks wells yield an EUR of 659,000 boe, comprising 572,000 bbl of oil and 523 MMcf of gas.

Those numbers give the company a 48% internal rate of return at $80/bbl of oil and a 73% return with $100/bbl oil from the Bakken. The Three Forks gives back 39% and 60% returns under the same oil prices.

It plans to spend another $10 million on drilling and completion on the Fort Berthold-McGregory Buttes properties with the same spud-to-production times.

In that area, the Bakken-well EUR is 623,000 boe (563,000 bbl of oil and 362 MMcf of gas), and a Three Forks well EUR comes in at 380,000 boe (343,000 bbl of oil and 219 MMcf of gas).

The Bakken internal rate of return is 35% at $80/bbl oil and 55% at $100/bbl oil, while the Three Forks gives up 9% at $80/bbl oil and 17% at $100/bbl of oil.

Hess Corp.

- *Land: Approximately 752,000 net acres*
- *Opened North Dakota to oil and gas production*

Hess Corp. may be divesting downstream, midstream, and some upstream assets to become a pure E&P company, but it opened the upstream oil industry in North Dakota and is sticking with those operations.

The company said its growth will be driven by the Bakken play, its Valhall Field offshore Norway, its Tubular Bells Project in the Gulf of Mexico, and the North Malay Basin. It already has taken some of the fracturing technology used in the Bakken to its Malaysia-Thailand joint development area operations.

It drilled the first commercial well in North Dakota on the Clarence Iverson Farm on April 4, 1951. It had to drill that 10,500-ft discovery through the Bakken and Three Forks zones to reach Silurian dolomite production.

By May the same year, oil industry operators had leased approximately 30 million of the 44.8 million acres of prospective land in North Dakota, with a concentration on Billings, Bottineau, Burke, McKenzie, Mountrail, and Williams counties.

A year after drilling the Clarence Iverson No. 1 well, it drilled another well on the Henry O. Bakken Farm, identified shale in the drill cuttings, and named the source formation after the owner of the farm.

The company still works the Tioga Field properties around that first Clarence Iverson well.

Hess held some 325,000 net acres of Bakken-

A Williston Basin christmas tree routes production from wells to pipelines and tank batteries. *(Photo courtesy of Kodiak Oil & Gas Corp.)*

prospective land at the end of 3Q 2007 and stretched that number to 400,000 by the first half of 2008. By August that year, it reached the half-million-acre mark.

Most of those properties were east of the Nesson Anticline, an area considered prime Bakken property. From north to south, Hess called its production areas Avalanche, Impact, East Nesson, Red Sky, Passport, and Stampede.

Subsequent acquisitions of American Oil & Gas (85,000 acres) and TRZ Energy in 2010 added 252,000 net acres to its Bakken position in North Dakota.

As the company added acreage, it also added production. It produced 5,000 boe/d from the formation in 1Q 2008. In a November 2009 presentation, Hess said it produced a net 10,000 boe/d from the Bakken and estimated its peak production at 80,000 boe/d at some point in the future.

It is getting closer to that point. The company averaged 64,000 boe/d of production from the Bakken in 4Q 2012, up 68% from the 38,000 boe/d it produced from the formation in 4Q 2011.

In a February 2013 presentation, the company said it planned to produce 64,000 boe/d to 70,000 boe/d from the Bakken/Three Forks combination in 2013, or

15% to 25% more than in 2012. It also said it plans to reach 120,000 boe/d from the zones by the middle of this decade.

The Bakken currently gives Hess 19% of its company-wide production and 23% of its 1.31 Bboe in reserves.

As the company increased its land position and production, it also increased efficiency and lowered costs.

A typical Hess well cost the company US $9 million to drill and complete in 4Q 2012, compared with $9.4 million for its pure-play peers. Its drilling and completion costs dropped from $12 million in 1Q 2012 with most of that decline in completion costs.

Increasing its drilling operations to pad drilling helped lower costs.

The company's spud-to-spud days dropped from 45 in 1Q 2011 to 28 in 4Q 2012.

Hess also said it completed three of the top five and 10 of the top 25 Bakken wells in 2012.

The company, however, is lowering its investment in the Bakken. It spent $3.1 billion on the Bakken in 2012, and it planned to lower that expenditure by 29% in 2013 to $2.2 billion.

Hunt Oil Co.

- *Land: Undisclosed*
- *An early North Dakota operator*

According to Hunt Oil Co.'s website, it holds a "significant land position and active programs" in the Bakken play. As stated in North Dakota records, Hunt entered the Bakken play in 2007 with wells in Parshall Field in Mountrail County, N.D., the most prolific field to date in the Bakken play. By year-end 2008, it was the 10th biggest producer from the Bakken with 634,417 bbl of oil produced from eight wells.

Hunt was a pioneer in the development of the Williston Basin and the oil industry in North Dakota.

By November 1952, when the basin produced its 1 millionth barrel of oil a year and a half after Hess drilled the discovery well, predecessor Amerada Corp. had 74 wells. Hunt Oil had nine wells on production by that time.

Led by Ray L. Hunt, the privately held company has been a strong operator in the Williston Basin ever since that time.

Kodiak Oil & Gas Corp.

- *Land: 153,000 net acres*
- *Seven years experience in the Bakken/Three Forks*

Denver-based Kodiak Oil & Gas Corp. started work in the Bakken play in 2006 and increased its activity with more land and more efficient operations.

In a February 2013 presentation, the company said it will work six to seven operated rigs and one to three nonoperated rigs during 2013 on its 232,000 gross (153,000 net) acres of land in the Williston Basin. It also works two dedicated hydraulic fracturing crews. It plans to support those operations with US $775 million to drill 75 net new wells, 61 operated and 14 nonoperated. Approximately $740 million of that will go to drilling and completions. That expenditure should allow the company to exit 2013 with 29,000 boe to 31,000 boe in daily production from 70.1 MMboe in proved reserves.

Kodiak will dedicate 37% of its expenditures to Polar Field, 27% to Smokey, 12% each to Koala and FBIR, and 13% to Grizzly/Wildrose.

That production would represent a 100% year-on-year increase in sales volume over the 15,000 boe/d produced in 2012.

By that time, the company should have 276 gross (122 net) producing wells.

By year-end 2013, nearly all of the company's leases will be held by production.

With a large, low-risk development drilling inventory to lock in growth, Kodiak is experimenting with production improvements under an ongoing program. It also plans a pilot program during 2013 to test 12 wellbores per 1,280 acres to see if the tight dolomite in the Middle Bakken will support that density.

An improving basin-wide midstream infrastructure and additional takeaway capacity for production also will help earnings.

In early 2013 the company had 70,000 net acres in three "bear" fields, Polar, Koala, and Smokey. It had an 80% net revenue interest in the fields where wells offered estimated ultimate recoveries (EURs) of 750,000 boe to 950,000 boe. It held another 49,000 net acres in Wildrose/Grizzly, also with an 80% net revenue interest with EURs in the 350,000 boe to 600,000 boe range. Its

Dunn County, N.D., 34,000 net acres gave the company an 82% net revenue interest in wells with EURs from 800,000 boe to 950,000 boe.

The company said a Bakken well with a lateral more than 5,000 ft long cost $10.5 million to drill and offered payout in 16 months with a 69% internal rate of return. That return was based on a $95/bbl price for West Texas Intermediate oil and a $10/bbl price penalty in the Williston Basin.

With the help of pad drilling, Kodiak's average drilling days have dropped from about 30 to about 25.

It holds an inventory of approximately 1,100 gross (800 net) Bakken and Three Forks locations.

LINN Energy LLC

- *Land: 23,000 net acres*
- *Growth includes Bakken/Three Forks position*

LINN Energy LLC traveled a high-growth path through a series of acquisitions in the past decade, entering 2013 as the nation's 11th largest E&P company. Although the Williston Basin represents a relatively minor holding, it is on the company growth list.

The company built its nonoperated position in the Bakken/Three Forks through three acquisitions that closed in 2011, which the company called "a base entry into a premier oil basin with vast resource potential."

Its largest acquisition was the early 2011 buyout of Concho Resources Inc.'s 11,200 net acres in Mountrail and McKenzie counties in North Dakota with a production at the time of 1,350 boe/d. That US $196 million acquisition gave it 400 drill sites and proved reserves of approximately 8 MMboe, with an 83% oil cut.

Partnering with quality operators allows the company to increase its knowledge in the play with reduced operating risk as it develops more than 800 horizontal drilling sites. It participated in 65 gross Bakken wells in 2011, with working interests averaging 6%. The company planned to participate in approximately 100 gross horizontal wells with an average 7% working interest in 2012.

Marathon Oil Corp.

- *Land: 410,000 net acres*
- *Bakken/Three Forks is an unconventional resource centerpiece*

Marathon Oil Corp. can draw on resources around the world to build its portfolio of strong-producing assets, and the Bakken/Three Forks play is a key onshore US ingredient to its growth plan.

In a February 2013 presentation, the company said it held 410,000 net acres in the play. That is down from a high of 416,000 net acres in 2011.

Its properties produced an average 33,000 boe/d in 2012, and Marathon plans to boost that production to more than 35,000 boe/d in 2013.

It produced a net 35,000 boe/d from the Bakken system during 4Q 2012, up from 30,000 boe/d in 3Q 2012. It expected production to drop to 33,000 boe/d in January 2013 because of weather and completion delays.

If the company's plans proceed according to its current schedule, it will produce 50,000 boe/d from the Bakken and Three Forks formations in 2020.

Currently it has 957 net well locations, 647 in the Middle Bakken and 310 in the Three Forks. Those numbers include the 286 wells the company drilled from 2006 to February 2013.

If Marathon adopts 320-acre spacing, it will have an inventory of 1,453 net wells, 901 in the Middle Bakken and 560 in the Three Forks. That count does not include recent development opportunities in additional Bakken and Three Forks zones.

Marathon drilled to total depth on 18 gross wells in 4Q 2012 and brought 18 gross wells onstream. Its average time from spud to spud was 27 days, which put it in the top 25% of companies working in the area.

The company plans to drill 190 to 220 gross (65 to 70 net) wells during 2013, and it will operate 60 to 70 of those wells.

According to the company's website, "The North Dakota Bakken Shale oil play is a centerpiece of our unconventional resource portfolio and a top investment priority for Marathon. In 2011, this growth asset accounted for 21% of Marathon's total US liquid hydrocarbon sales and 2% of our US natural gas sales."

To put its Williston Basin assets to their best use, the company uses automated drilling rigs for best drilling performance. That has allowed Marathon to reduce well costs and cycle times with


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It also implemented proactive environmental practices on federal land and tribal lands in its portfolio.

As a sign of the level of Marathon's activity in the US, it replaced 226% of its production in 2012, or 185% excluding acquisitions, all at an estimated cost of US $17/boe. "This outstanding performance was largely driven by what we consider to be the highest-value resource plays in the world: the Eagle Ford Shale in South Texas, the Bakken Shale in South Dakota, and the Oklahoma resource basins," the company said.

Marathon's worldwide sales averaged a net 388,000 boe/d, up 8% from the 2011 average of 358,000 boe/d. "The increases in the quarter and for the full year's were largely the result of ramped up production in the company's US resources plays, particularly the Eagle Ford and Bakken shale plays," Marathon added.

Mountainview Energy Ltd.

- *Land: 96,800 net acres*
- *Active in Williston and Southern Alberta basins*

Mountainview Energy Ltd., with low production and high hopes for its substantial land positions, is growing its operations in the Williston and Southern Alberta basins' Bakken/Three Forks plays.

It is backing those growth plans with a US $19 million capex program in 2012 and 2013 with five horizontal wells planned in the Williston Basin, including three operated wells in its 12 Gage Project in Divide County, N.D., and two nonoperated wells in the Medicine Lake Project area.

In the Williston Basin, it holds 12,600 net acres of land in the 12 Gage Prospect; another 12,000 net acres in the State Line Prospect, where it also is the operator; and 10,000 net acres in the Medicine Lake Prospect, where Samson Resources operates.

On the Montana side of the Alberta Basin, Mountainview controls 60,000 net acres as operator in the Williams Gas Field and Lake Frances Gas Field, where it produces 400 Mcf/d of gas. It holds another 2,500 net acres as operator in Red Creek Field with 110 boe/d of production, and it produces 5 boe/d from its 2,000 net acres in Lone Man Coulee Field.

Overall production is 190 boe/d from both basins.

It has 21 initial locations in 12 Gage, primarily with Three Forks potential but also with Bakken possibilities. It has finished the third well in a three-well program.

The company has 24 identified locations with Bakken and Three Forks potential in the Stateline Prospect.

Samson Resources drilled and completed two wells in the Medicine Lake Project and plans to continue drilling in 2013.

Mountainview is evaluating Bakken potential in Red Creek Field in the Alberta Basin. It currently has 35 wells producing from the Madison, Lower Cut Bank Sand, and Upper Cut Bank Sand zones.

Murex Petroleum Corp.

- *Land: Unknown acreage*
- *North Dakota veteran operator*

Murex Petroleum Corp. is a long-time operator in the Williston Basin since its incorporation in 1996. It has become the fifth largest operator in South Dakota and the 11th largest operator in North Dakota, according to the company website.

The company operates 170 wells in North Dakota, South Dakota, Montana, and Wyoming, and it currently directs its operations toward a horizontal Bakken drilling program on the Nesson Anticline in Williams County, N.D.

It was one of the first companies to spud a Bakken well with operations that started in 2005. It had 21 producing Bakken wells by April 2008 and 26 by mid-2009.

North Dakota called it the 10th largest Bakken producer in 2008, with 1.2 MMbbl of oil and 571 MMcf of natural gas from its interests in 110 wells. It farmed in to properties of other operators, including Northern Oil & Gas Inc., in addition to its own properties.

Newfield Exploration Co.

- *Land: 100,000 net acres*
- *Pad drilling in Montana and North Dakota*

Newfield Exploration Co. looks to its Williston Basin Bakken and Three Forks properties as one avenue to a higher concentration of liquids production.

The company holds some 40,000 net acres of land in the giant Elm Coulee Field in Richland


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County, Mont., and another 60,000 net acres along the Nesson Anticline in North Dakota. Approximately 41,000 net acres on and west of the Nesson Anticline are under development.

According to the company website, its current production from the area reached a recent high of 10,500 boe/d. It is running three operated drilling rigs as it works more than 300 potential Bakken and Three Forks locations on multiwell pads with superextended lateral legs.

In a February 2013 presentation, Newfield said it will spend about 16% of its US \$1.4 billion to \$1.5 billion in capex in the Williston and it will raise that figure to 18% of \$1.5 billion to \$1.6 billion in 2014.

That expenditure should help the company reach 20,000 boe/d in 2015.

Newfield estimated Middle Bakken and Three Forks proven reserves at 37 MMboe at year-end 2012 within an incremental net unrisked resources of approximately 2 Bboe. It has 585 potential gross drilling locations.

The company holds 24,000 net acres in the Aquarium/Watford area, 10,000 net acres at Westberg, and 7,000 net acres at Lost Bear Field, all in its development area in North Dakota.

It also is developing 25,000 net acres in the Elm Coulee/Cartwright area in Montana.

From 2013 to 2015, Newfield plans to keep an average four rigs working as it conducts research into optimal spacing with pilot projects and as it continues development of the Middle Bakken and Upper Three Forks. The company also plans to test upside potential in the deeper Three Forks benches.

It has a net operated unrisked resource potential of 45 MMboe in the Bakken, 35 MMboe in the Three Forks, and 58 MMboe in other acreage.

Based on 125 operated locations, Newfield expects returns of 25% to 45% for its Bakken wells. It drilled 24 operated wells in 2012 and plans 25 to 30 wells in 2013.

It expected 25% to 40% rates of return on its Three Forks wells. It planned four to six wells to be drilled in that formation in 2012 and 15 to 18 wells in 2013.

Northern Oil & Gas Inc.

- *Land: 184,000 net acres*
- *Bakken/Three Forks pure play*

Northern Oil and Gas Inc. put together a solid business assembling land in the Bakken and Three Forks territory of the Williston Basin and letting other operators drill the wells – a lot of wells.

According to the company's website, the company has participated in more than 1,200 Bakken and Three Forks wells in North Dakota since 2007.

Northern has not drilled any of those wells. The company has gotten so good at this phase of the business that other operators and landmen in the area sometimes use the company to divest their nonoperated positions in the play. The company's properties run from Divide and Burke counties along the Canadian border south through Williams, Mountrail, McKenzie, and Dunn counties and as far as Billings and Stark counties in the south.

Under its business model, if Northern holds 160 acres of leases in a 640-acre drilling unit – 25% of the unit – it participates for its 25% working interest in any well drilled on the unit. It does not have to deal with operating or overhead costs of the operating partner.

As operating partners get more efficient, Northern benefits. For example, with Continental Resources, stimulation costs fell from US $124,000 per stage in 4Q 2011 to $98,000 in 3Q 2012. It drilled eight wells per rig per year in 2010, seven wells per rig per year in 2011, and 11 wells per rig per year in 2012, and the company estimates it will drill 12 wells per rig in 2013. That goal is helped by spud-to-spud times that dropped from 50 days in 2011 to 37 days in 2012 for standalone wells. On ECO-pads, spud-to-spud times were drilled from 130 days to 100 days per well.

Slawson Exploration is the company's biggest operating partner. It had drilled 24.5% of wells on Northern land by mid-2012. It was followed, in order, by EOG Resources at 11.8% and Hess with 10%. Other partners include Statoil/Brigham, Sinclair, Samson, XTO Energy (ExxonMobil), Oasis Petroleum, Continental Resources, Marathon, Fidelity Exploration & Production, Kodiak Oil & Gas, Baytex, ConocoPhillips, Oxy, Hunt Oil, Zenergy, Whiting, Crescent Point, Ursa, Denbury, Newfield, SM Energy, Abraxas, Murex, Dakota-3 E&P, Cornerstone Natural Resources, and North Plains Energy.

Those partners had completed 1,104 gross wells from the start of Northern's operations through September 2012 with a 100% success rate.

At the end of 3Q 2012, the company had a cumulative 105 net wells producing more than 115,000 boe/d.

Northern held proved reserves of 57 MMboe at the end of June 2012.

Oasis Petroleum LLC

- *Land: 335,383 net acres*
- *Holds a 14-year potential drilling inventory*

Oasis Petroleum LLC operates properties in Montana and North Dakota with an aggressive drilling program designed to build sharp increases in production.

According to a March 2013 presentation, it has 280 operated spacing units, enough to drill 20 units a year for 14 years. Those spacing units give the company a primary inventory of 685 Bakken and 302 Three Forks wells and a potential inventory of another 234 Bakken and 799 Three Forks wells.

Of its 335,383 net acres, approximately 305,000 lie in the core Bakken area, and 87% of its Bakken properties are held by production. Its Three Forks Sanish properties cover some 110,000 net acres and 36% is under its core Bakken acreage.

During 2012, the company lowered its well costs by 16%, or US $1.7 million, and increased production by 110% to 22,469 boe/d. It completed 117 gross operated wells, increased reserves by 82% to 143 MMboe, and added 27,953 net acres to reach its current land position.

It operates in St. Croix, North Cottonwood, South Cottonwood, and Sanish fields along the Nesson Anticline from Burke County in the north and south to Mountrail County. It operates in Red Bank and Indian Hills fields in western North Dakota; Mondak and other fields straddling the North Dakota-Montana border; and Target, Hebron, and Missouri fields in Montana.

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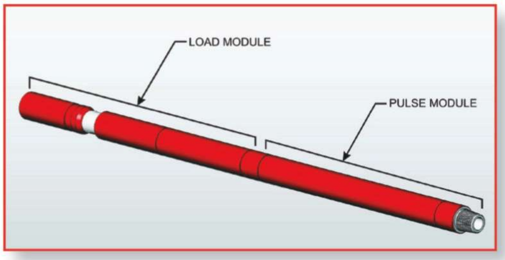

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The company's 2013 plan calls for a $996 million E&P budget to drill 128 gross (92.5 net) operated wells and complete 103.4 total net wells.

Oasis will make the transition to pad drilling in 2013, with plans to develop up to 70% of its wells on pads during the year.

The company also runs its subsidiary Oasis Well Services, a company that performed its first fracture job in March 2012. During the three months to March 2013, it averaged 100 fracture stages a month. That subsidiary saved the Oasis operating company $17.5 million in capital in 2012, and the company anticipates using the well services subsidiary to save $500,000 per gross well on 40% to 50% of operated wells in the future.

Occidental Petroleum Corp.

- *Land: 277,000 net acres*
- *Williston rates third-highest priority in US exploration*

Occidental Petroleum Corp. (Oxy) takes a big-project stance for its operations in the US and abroad, and the Bakken/Three Forks play is the newest of those operations in the US.

It is the largest acreage holder in California with 2.1 million acres and 2012 production of 148,000 boe/d, up from 138,000 boe/d in 2011.

The company is the largest producer in the Permian Basin at 207,000 boe/d in 2012, up from 198,000 boe/d in 2011.

Oxy's North Dakota assets consisted of producing and prospective unconventional properties in the Williston Basin, including Bakken and Three Forks properties. It bought a substantial amount of those properties in 2010 and 2011.

For example, Oxy bought a package of properties in California and the Permian and Williston basins for approximately US $2.6 billion in 2011.

Stephen I. Chazen, president and CEO, said in the company's 2011 annual report published in early 2012, that Oxy's exploration in the US would focus on California, the Permian Basin, and the Williston Basin.

Oxy did not break out specific production numbers for its Williston Basin properties but included them in the "Midcontinent and other" category, which produced 47,000 boe/d in 4Q 2012.

PetroShale Inc.

- *Land: 4,000 net acres*
- *Participating in Upper Bakken program*

PetroShale Inc. teamed up with Slawson Exploration in a program in Mondak Field to exploit the Upper Bakken Formation. Nearly all Bakken production to date has come from the Middle Bakken zone.

The companies have 40,000 gross (4,000 net) acres in Mondak Field south of giant Elm Cooley Field in Richland County, Mont., and McKenzie County, N.D., and PetroShale has an option to buy in to another 8,000 net acres in an 80,000-acre parcel in Slawson's False Bakken (Lodgepole) play. The companies planned to start drilling in that formation in late 2012 or early 2013.

According to PetroShale, the companies had drilled their first four test wells at Mondak by year-end 2012, all in the Upper Bakken in a pattern bracketing the play to the north, east, south, and west, a 30-sq-mile spread. Those were follow-up wells to five unstimulated wells drilled by Slawson in the area between 1994 and 2008 to define Mondak Field. They have more than 200 well locations in the Mondak Field.

The companies moved to a three-rig, three-wells-per-month program in 4Q 2012.

"Slawson has been the only Bakken operator with experience drilling the Upper Bakken Shale," said John Fair, CEO of PetroShale (US) Inc. As the companies test the boundaries of the play, they have cut well costs from US $6 million to less than $5 million.

Primary Petroleum Corp.

- *Land: 328,000 net acres*
- *Prominent player in Southern Alberta Basin in Montana*

Primary Petroleum Corp. has a substantial land position in north-central Montana, and it is building on that base as it works a joint venture program.

It completed a 95-sq-mile 3-D seismic program and drilled, logged, and cored six vertical Bakken system stratigraphic wells. It also completed a secondary vertical program with three wells to test the Nisku, Madison/Sawtooth, and Sunburst zones in the area. It also started a horizontal drilling program to test the Bakken system and the Nisku.


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Primary did not identify its joint venture partner in the play other than to say that it was a "US major industry partner."

In a February 2013 news release, Primary said its joint venture partner chose not to enter Phase II of the companies' planned development program, but it will retain its working interest in the Pondera-Teton leasehold and continue to work with Primary to determine the future value of the area.

Primary said it will evaluate the data from Phase I to decide on its next moves in the play.

QEP Resources Inc.

- *Land: 117,000 net acres*
- *Bakken builds liquids production*

QEP Resources Inc. credits its Bakken/Three Forks properties with a substantial contribution to its liquids production, and the company is investing heavily in that play.

"QEP Energy's dramatic growth in liquids production drove a 16% increase in total production compared to 2011. Crude oil and NGL volumes represented 22% of QEP Energy's production in 2012, a substantial increase from 14% in 2011. The positive impact of our North Dakota acquisition is clear; crude oil represented 17% of QEP Energy's production in the fourth quarter 2012 compared to just 10% in the prior year period and 11% in the third quarter 2012," said Chuck Stanley, chairman, president, and CEO, in a public release.

The company held 614.7 Bcfe of gas in reserves in the Williston Basin at the end of 4Q 2012, or 16% of total company reserves.

Fourth-quarter Bakken/Three Forks production averaged 18,300 boe/d as QEP turned 11 operated wells to sales, including two wells in the South Antelope area, where it holds an average 99% working interest, and nine wells in the Fort Berthold Reservation, where it has an average 74% working interest. The company completed the South Antelope wells in the Three Forks with an average 24-hour initial production rate of 2,550 boe/d.

QEP operated 84 producing wells in the basin – 38 Bakken, 43 Three Forks, and three dual-lateral horizontal wells producing from both formations – and it held working interests in 191 nonoperated producing wells.

The company had five rigs working the play at year-end 2012.

It directed 18% of its capital budget to the Bakken/Three Forks in 2011 and increased that to 32% of US $1.4 billion in 2012. For 2013, it will direct 53% of its $1.64 billion budget to the play.

Samson Oil & Gas Ltd.

- *Land: 37,477 net acres*
- *Montana and North Dakota operations*

Samson Oil & Gas Ltd. is solidifying its position in the Williston Basin and directing a drilling program based on 3-D seismic data.

In a 4Q 2012 operational report, the company said it completed an acreage swap that will allow it to continue work in North Stockyard Field in Williams County, N.D., in 1Q 2013. It has a 160-acre spacing order in hand to drill 14 wells, six in the Bakken and eight in the Three Forks formations. It plans six infill wells from two pads in the area, contingent on capital generation. It had seven producing wells in the field at year-end 2012.

Also in North Dakota, 76 sq miles of 3-D seismic have been shot and processed in the South Prairie area of Renville and Ward counties. Those data are being interpreted with an anticipated April 2013 drilling date for the first prospect.

The company has 1,221 net acres in North Stockyard, 6,256 net acres in the South Prairie Project, and 30,000 net acres in the Roosevelt Project in Montana.

Samson Oil & Gas has a 100% working interest in the completed Australia II and Gretel II wells in the Roosevelt Project in Roosevelt County, Mont., and a two-third interest in subsequent wells. Wells in this area could extend the Elm Coulee Field trend.

Samson Resources Co.

- *Land: 284,000 net acres*
- *Sold large acreage block*

Samson Resources Co. is a top-20 US-based E&P company with more than 404 MMboe of proved reserves and 112,000 boe/d of production, and it supports active operations in the Williston Basin.

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According to a December 2012 release, it sold 116,000 net acres of properties, primarily in Divide and Williams counties in North Dakota, to Continental Resources for US $650 million. The property was producing 5,600 boe/d.

That was part of a big divestiture program that included all of its international properties. It previously had sold substantially all of its oil and gas properties in the Permian Basin, and a KKR-led consortium bought Samson Investment in December 2011.

The company entered the Williston Basin through a joint venture in 2005 and expanded into one of the larger acreage positions in the Bakken/Three Forks play.

A recent Bakken wildcat in Sheridan County, Mont., the #15-22-35-58H Zuma, produced 4,375 bbl of oil from the profitable Bakken/Three Forks wells between June 2012 and August 2012. That well was 14 miles from the nearest Bakken production.

Slawson Exploration Co. Inc.

- *Land: At least 60,000 net acres*
- *Advanced drilling for itself and others*

Privately held Slawson Exploration Co. Inc. works its own properties in the Williston Basin, but it also uses its drilling and completion talent to bring in profitable Bakken/Three Forks for other companies. By year-end 2012, Slawson had approximately 200 wells in North Dakota.

According to a PetroShale release, Slawson has explored the Bakken since 1989. It was the third company to drill a horizontal well to the formation, and it completed a record 47-stage fracture treatment on an 8,000-ft lateral.

Among others, it has operated wells for Northern Oil & Gas, PetroShale, Voyager Oil & Gas, and Triangle Petroleum. GeoResources, subsequently acquired by Halcón Resources, participated in 72 nonoperated Bakken wells with Slawson as the operator.

According to PetroShale in September 2012, “PetroShale, in partnership with operator Slawson Exploration Co. Inc., has successfully completed the companies’ initial appraisal of the 40,000-acre Mondak Shale play with four stimulated horizontal test wells in the Upper Bakken Shale. Two more wells have been drilled and are awaiting flow back or completion.” The companies started a two-rig program immediately and moved to three rigs in 4Q 2012.

PetroShale has more than 200 Upper Bakken drilling locations.

One Slawson well, the #2-13H Canucks, in Richland County, Mont., tested for 3,137 bbl of oil and 260 Mcf of gas from the Upper Bakken in 26 days in September 2012. Nearly all Bakken production to date has come from the Middle Bakken.

“Slawson has been the only Bakken operator with experience drilling the Upper Bakken Shale,” according to PetroShale CEO John Fair.

SM Energy Co.

- *Land: 162,000 net*
- *Bakken and Eagle Ford drove record production*

SM Energy Co. completed 30 Bakken/Three Forks wells during 2012, eight in 4Q 2012 as it worked an 81,000-net-acre area focused on the Bear Den, Raven, and Gooseneck prospects in North Dakota.

That focus, along with the company’s Eagle Ford activity, allowed the company to count record quarterly production. It expects those two plays to continue to drive company growth in 2013.

According to its 2012 report to shareholders, SM Energy is working four rigs in North Dakota aimed at infill development. Later in the year, it plans to swap out two traditional rigs for more efficient walking rigs, and all of the rigs will then concentrate on pad drilling.

In a February 2012 presentation, SM Energy said it had 36,000 net acres in Gooseneck Field in Divide County and 45,000 net acres in Raven/Bear Den Field in Williams County, both in North Dakota.

Its net production from the area rose to 11,900 boe/d in 4Q 2012 from 8,500 boe/d in 4Q 2011.

It will dedicate US $290 million of its $1.5 billion 2013 capital budget to the Bakken/Three Forks play, second only to the $650 million that will go to the Eagle Ford.

Statoil ASA

- *Land: 375,000 net acres*
- *Building on Brigham acquisition*

Statoil ASA acquired Brigham Exploration, one of the largest operators in the Bakken/Three Forks

Dirt roads, wide open spaces, and neat and tidy drill sites are common in the North Dakota section of the Williston Basin. *(Photo by Ole Jørgen Bratland, courtesy of Statoil ASA)*

play in the Williston Basin, in late 2011, and the Norwegian oil major is building its production from Brigham's base.

The company bought Brigham for US $4.5 billion, including debt, and took over Brigham's 375,000 net acres in the play and another 40,000 net acres outside that play.

At the time of the acquisition, Brigham estimated its risked resource base between 300 MMboe and 500 MMboe. The property produced 21,000 boe/d, with the potential to ramp up to 60,000 boe/d to 100,000 boe/d in five years.

Statoil has progressed a long way toward achieving that potential. In 4Q 2011, it produced approximately 25,000 boe/d from the Bakken/Three Forks, and the company ramped up its activity to 16 drilling rigs. By 4Q 2012 it produced 43,400 b/d of oil and 3,300 boe in natural gas for a total 46,700 boe/d.

The Bakken/Three Forks became Statoil's second best North American producer after the Marcellus Shale in the Appalachian Basin and ahead of its Tahiti offshore field in the Gulf of Mexico.

According to the Statoil website, "Entering the Bakken and Three Forks tight oil plays and taking on operatorship represents a new significant step for Statoil. We are positioning ourselves as a leading player in the fast-growing US onshore oil and gas industry in line with the strategic direction we have set out."

Statoil's operations center on three areas, Easy Rider and Rough Rider fields in North Dakota and eastern Montana operations.

Brigham bought its first leases at Rough Rider in Williams and McKenzie counties in 2005 and finished that year with 46,000 net acres in the Williston. It drilled its first Bakken long-lateral well at Rough Rider, acquired its first leases, and finished 2006 with 120,000 net acres of land and three drilled wells.

In 2007, it bought its first leases in Easy Rider Field in Mountrail County and started short-lateral, multistage drilling. It finished that year with 143,000 net acres and 3.9 wells.

Its first short-lateral, 12-stage-frac well at Easy Rider tested for 1,100 boe/d in 2008. It drilled its first short-lateral Three Forks wells in the same field that year for 892 boe/d. By that time, it had accumulated 302,000 net acres in the basin and 8.7 net drilled wells.

By year-end 2009, it had delineated 282,600 net acres out of the 375,000 net acres it held. It was the first operator to drill long-lateral, high-fracture-stage wells. Nine of those wells averaged an initial potential of 2,066 boe/d.

It drilled a record Bakken well in 2010, a well that tested for an initial potential of 5,133 boe/d. It also tested its first Three Forks well in Rough Rider and its first Bakken well in eastern Montana. It spent $425 million that year in the Williston Basin, finishing the year with 364,300 net acres and 38 drilled wells.

By 2012, production from the Bakken and Three Forks from all operators in the Williston Basin had overloaded pipeline capacity, and Statoil, like other operators, turned to rail shipments to help move its production to refineries and markets.

"The value of our Bakken crude is lowered by present limited pipeline capacity in the region. The ability to create sufficiently marketable products and ensure that we have enough transport capacity is increasingly important. Transporting the crude by rail bypasses the pipeline bottlenecks and ensures our products get to market and that we get the highest possible price," said Tor Martin Anfinnsen, senior vice president of crude, liquids, and products for Statoil.

Triangle Petroleum Corp.

- *Land: 86,000 net acres*
- *Pure Williston Basin play*

Triangle Petroleum Corp. combines operated and nonoperated interests in properties with midstream services to grow in the North Dakota and Montana sectors of the Williston Basin.

It provides pressure pumping and ancillary field services through its Rockpile Energy Services arm and will offer Bakken operators gathering and processing capability through its Caliber Midstream subsidiary. Caliber also delivers dry gas to the Northern Border Pipeline. It brings produced water to its own disposal wells and delivers fresh water to the well site, according to a March 2013 presentation.

It produced 1,950 boe/d in its third fiscal quarter of 2013, which ended in October 2012, and anticipated production of 4,750 boe to 4,950 boe in the fourth fiscal quarter of 2014, which ends in January 2014.

Its fiscal year 2014 budget includes US $165 million for a three-rig operated program, $27 million for a nonoperated program, $15 million for infrastructure, and $20 million for Rockpile's operations.

It planned to start up a crude oil processing facility in 2Q 2014 fiscal year and make its gas processing operational in the following quarter.

US Energy Corp.

- *Land: 19,000 net acres*
- *Participates with active partners*

US Energy Corp. pulled substantial revenues from the Bakken/Three Forks play in the Williston Basin and it is setting up a 2013 program to extract more oil and cash from the area.

Directors approved a company-wide US $27.1 million capital budget for 2013 and $7.1 million of that will go into the Williston Basin in three drilling programs. It may adjust that contribution upward.

The company said, "Additionally, the company has budgeted $20 million for the acquisition of producing properties with associated proven reserves in 2013 with a primary focus on the Williston Basin."

In January 2013, the company listed 11 Bakken or Three Forks wells in progress by Zavanna LLC, Emerald Oil Inc., Brigham Oil & Gas LP (acquired by Statoil ASA), EOG Resources Inc., and Liberty Resources LLC. US Energy held working interests ranging from 0.29% to 9.36%.

It has a 4.69% interest in the Ash Federal 5300 11-18T, operated by Oasis. That well tested at an early flowback rate of 2,905 boe/d.

The company planned to participate in four Three Forks wells in 1Q 2013.

It had completed 19 gross (7.3 net) Bakken wells and one gross (0.18 net) Three Forks wells by year-end 2011.

Its most recently reported acquisition in the play, according to a September 2012 release, gave the company working interests in 23 drilling units on 400 net acres for $2.5 million with an estimated 307,000 boe in proved reserves. It obtained an average 1.45% working interest in the units, with 27 gross producing wells.

VAALCO

- *Land: 28,214 gross acres*
- *From Gabon to North Dakota*

VAALCO Energy Inc., better known for its international activities including exploration offshore West Africa, entered the Bakken play in 2011 when it acquired a 65% operated working interest in the Bakken and deeper formations in the East Poplar Unit and Northwest Poplar Field in Roosevelt County, Mont., from Magellan Petroleum.

In return, VAALCO agreed to pay an unspecified amount of cash and fund 100% of the cost of the first three wells to be drilled by year-end 2012.

It also acquired a 70% working interest in 5,214 acres in Sheridan County, Mont., about the same time.

In its 2012 report to shareholders published in March 2013, the company said it drilled two wells to the Middle Bakken on its Sheridan County properties, but neither was an economic success.

In Roosevelt County, it spud a vertical exploratory well in December 2011 and a second well in mid-2012. Both were unsuccessful. It started drilling the third Poplar Dome obligatory well in December 2012 on the western edge of the Williston Basin.

Whiting Petroleum Corp.

- *Land: 703,668 net acres in the Williston Basin*
- *Top producer in North Dakota*

Whiting Petroleum Corp. captured the top producer title for North Dakota as it raised both production and reserves during 2012.

It divides its North Dakota properties into three segments, the Western Williston Basin, which includes its Hidden Bench, Tarpon, Missouri Breaks, and Cassandra prospects on 183,508 gross (114,732 net) acres; the Southern Williston Basin, which adds its Pronghorn and Lewis & Clark prospects with 398,334 gross (262,974 net) acres of land; and its Sanish Field area with 175,529 gross (82,533 net) acres of land.

James J. Volker, Whiting's chairman and CEO, said, "2012 was a record year for Whiting Petroleum, and we are off to a great start in 2013. The development of the fields we discovered in 2011 such as Pronghorn, Hidden Bench, Tarpon, and Redtail generated excellent results in 2012. In the wake of this development, we posted records in production, proved reserves, and discretionary cash flow. According to the December 2012 Oil and Gas Production Report published by the North Dakota State Industrial Commission, Department of Minerals, Oil and Gas Division, Whiting was the number one oil producer in North Dakota at 66,155.7 barrels per day."

In the company's year-end 2012 report, Volker said the company planned to generate double-digit production growth as it spends close to its discretionary cash flow. It set a US $2.2 billion capital budget for 2013 and planned to raise production by 12% to 16% over 2012 levels. That includes $1.914 billion for exploration and development, $108 million for land, and $178 million for facilities. That expenditure should raise production from 30.2 MMboe in 2012 to a record 33.8 MMboe to 35 MMboe in 2013.

Tools for that growth include an optimization program to lower drilling and completion costs; higher-density pilot projects at Sanish, Pronghorn, and Hidden Bench; the emergence of its Redtail prospect as a major resource play; and strong Bakken prices with better differentials between Williston Basin oil and West Texas Intermediate.

It expects to spend $1.142 billion on its Northern Rockies properties to drill 219 gross (148 net) wells.

During 2012, Whiting booked an estimated 66.4 MMboe in new Bakken and Three Forks proved reserves to raise its northern Rockies total to 165.1 MMboe at year-end 2012. It said two-thirds of its total reserves were proved developed and a third were proved undeveloped.

It controls 1,104 gross (410.2 net) well locations in Lewis & Clark and Pronghorn, figuring three Pronghorn Sand wells on a 1,280-acre spacing unit.

It holds another 1,174 gross (380.5 net) well sites in the Western Williston territory with four Middle Bakken and three Upper Three Forks wells in each 1,280-acre spacing unit. It also has 260 gross (118.1 net) locations in its Sanish prospect in Sanish and Parshall fields, at 3.5 Middle Bakken and three Upper Three Forks wells on a spacing unit.

It also is testing a higher-density pilot program – six wells per 1,280 acres – at Pronghorn, or double the current density.

Among recent high-performance wells, Whiting drilled the Tarpon Federal 21-4-3H on its Tarpon Prospect in McKenzie County. That well tested for 4,971 b/d of oil and 11.45 MMcf/d of gas, or 6,879 boe/d from the Middle Bakken, on December 28, 2012. That was the third best well drilled in the Williston Basin. The best was Whiting's Tarpon Federal 21-4H with an initial production rate of 7,009 boe/d.

Whiting credited part of its success to its "Drill Well on Paper" program which provides an optimization process for step-by-step analysis of the programs. That system helped the company cut drilling times for Bakken and Three Forks wells in North Dakota from 38 days to 18.5 days per well.

It also reduced per-well cycle times from 90.8 days to 67.1 days, with a corresponding reduction in drilling and completion costs.

At year-end 2012, the company was working 20 rigs in its northern Rockies area.

Only Continental Resources with 430, EOG with 252, and Statoil with 230 drilled more wells in 2012 than Whiting.

Canada Key Players

Crescent Point Energy Corp.

- *Land: 512,000 net acres in Viewfield alone; 1 million net acres in Alberta*
- *Biggest Bakken producer in Canada*

Crescent Point Energy Corp., through purchases of land and competing companies, established itself as a premier Bakken producer with properties in southeast Saskatchewan, Manitoba, southern Alberta, North Dakota, and Montana.

It does not list current acreage holdings, but in 2010 it had 512,000 net acres in Viewfield, Canada's largest Bakken pool. It has been working that field for more than five years and still has a large drilling inventory remaining, along with an expanding waterflood program.

It has another large Bakken pool in southwestern Manitoba that offers high net backs. Crescent Point plans to increase recoveries in that field over time.

It participated in 78 gross (66.1 net) wells in southeastern Saskatchewan and Manitoba in 4Q 2012, and 62 gross (56.8 net) wells bottomed in the Bakken.

Its Flat Lake Bakken properties lie along the border with North Dakota. That location gives it access to lower service costs and higher rates of return.

It started working its Bakken/Three Forks properties in 2010 and added more land. There it is focusing on long-term development and high recovery factors at reduced costs. It drilled 168.7 net Bakken horizontal wells during 2012 with a 99% success rate and plans 163 net wells in the Viewfield Bakken play alone in 2013.

It added five water injection wells to raise the number of injection wells to 46 in the Viewfield Bakken waterflood. It also reentered existing wells with eight- and 16-stage fracture treatments and recompleted them with 25- and 30-stage treatments with cemented liners.

It also drilled its fourth two-mile horizontal

well in the Flat Lake area and plans six more during 2013. It based those wells on wells being drilled across the border in North Dakota.

Crescent Point increased oil deliveries through its Stoughton rail facility to more than 19,000 b/d of oil in 4Q 2001. It has expanded that facility to increase capacity to more than 45,000 b/d of oil and expected to deliver 30,000 b/d in 1Q 2013. The rail systems supplement its pipeline deliveries.

The company also has approximately 1 million net acres of Bakken system land in southern Alberta, much of it from its acquisition of Darian Resouces in July 2010, and has been exploring in that area. It drilled eight wells in 4Q 2012 and is evaluating those wells.

Its US Bakken properties lie in Divide and Williams counties in North Dakota and Richland and Sheridan counties in Montana. It drilled 27 gross (5.4 net) wells in North Dakota in 4Q 2012 with a 100% success rate. It plans only two net wells in the area in 2013.

The Bakken, with help from the company's Shaunavon and Beaverhill Lake properties, helped Crescent Point set a production recovery and deliver its 11th consecutive year of higher reserves.

Overall, the company has approximately 7,700 well locations, including properties in the Uinta Basin in Utah and the Shaunavon, Viking, and Beaverhill Lake properties in Alberta and Saskatchewan.

Its properties are 85% operated and it holds an average 80% working interest in its holding.

It estimated 4.6 Bbbl of original oil in place in the Bakken Formation at Clearview, with another 1 Bbbl at Flat Lake and 100 MMbbl in Manitoba.

Only 1.9% of the original oil in place had been recovered at Clearview, where the company had a 3,800-net well inventory. It estimated a possible upside of more than 200 MMbbl of oil.

The company produced an average 60,500 boe/d from the Saskatchewan and Manitoba Bakken and planned to increase that to 77,000 boe/d in five years. It planned to raise its North Dakota production from a current 4,000 boe/d to 5,000 boe/d in the same time period with the help of 50-stage fracture treatments. It also planned to produce 1,700 boe/d from its southern Alberta Bakken properties.

DeeThree Exploration Ltd.

- *Land: Approximately 33,640 net acres*
- *Developing prospects in the Alberta Basin*

DeeThree Exploration Ltd., building on success in 2012, put together an aggressive drilling program to develop prospects in the Bakken and other zones in the Southern Alberta Basin in Canada.

In a December 2012 presentation, the company said it spent US $137.64 million (CAN $140 million) on its Bakken properties in 2012.

It drilled 17 Bakken horizontal wells during the year with a 100% success rate. That included one well that tested for 957 b/d of oil in its first six days online, 520 b/d of oil during the first 30 days, 429 b/d of oil for the first 60 days, and 390 b/d of oil over the first 90 days of production.

For 2013, the company plans to spend approximately $147.49 million (CAN $150 million) with a focus on increasing oil production from its Bakken properties in the Lethbridge area of southern Alberta and its Belly River properties in the Brazeau area of central Alberta. It plans 20 Bakken wells.

In addition to its producing properties, it holds ownership interests in gas transportation and processing.

DeeThree's Bakken properties in the Lethbridge area of southern Alberta break down into three operating areas, the eastern, western, and northern lands.

The company holds 15 sections in its eastern lands where it drilled its final well of 2012, a well with a two-mile-long lateral to the east of its producing Ferguson Bakken Field. That well extended the known limits of the Bakken pool to a 40-sq-mile fairway. The well tested for 448 b/d of oil over its first 30 days online. It planned more wells to delineate the production limits early in 2013.

It controls another 19 sections of Crown property on its western lands, where it is trying to define the western edge of the Ferguson Bakken pool. The company plans to drill one or two wells in the area in 2013.

On its recently acquired 17 sections of northern lands, north of its core area, it completed geological and geophysical studies and potentially identified two distinct oil prospects, each 12 to 15 miles in size and five to 10 miles from its existing core area. The company will drill two to four wells on that property during 2013.

At year-end 2012, DeeThree's oil processing facil-

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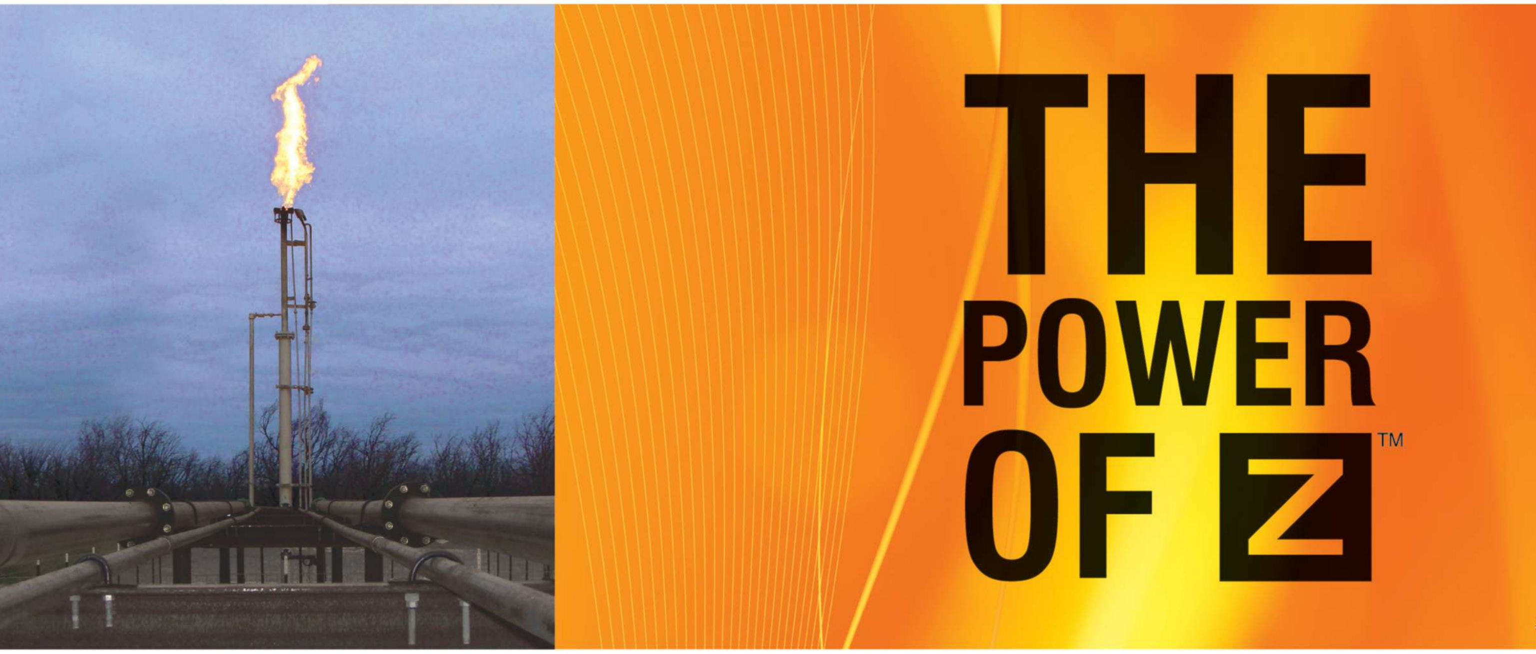

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ities were working close to capacity, but it planned to commission a second battery in 2Q 2013 to increase its processing capacity to 8,000 b/d of oil.

LGX Oil + Gas Inc.

- *Land: 167,000 net acres*
- *Drilled first two Bakken wells*

LGX Oil + Gas Inc. built a foundation for its Bakken exploration program in southern Alberta with its first two wells and plans to continue building the play into a commercial development project.

In the company's year-end 2012 operations release, the company said it completed the purchase of 58,481 net acres of southern Alberta land from Legacy Oil + Gas Inc. It also acquired Bowood Energy Inc.

The company completed a 95-sq-mile 3-D seismic program over its Bakken properties on the Blood Tribe First Nation Reservation and identified a number of anomalies. It plans to spud a minimum of two wells by the fall of 2013.

LGX plans to spend US $7.47 million (CAN $7.6 million) on capital projects in 2013 with 78% of that directed to drilling, completions, and tie-ins in the Alberta Bakken. It plans two gross (1.6 net) wells in 2013.

Those wells should help it achieve a 2013 production exit rate of 900 boe/d made up of 69% light oil and NGL.

Murphy Oil Corp.

- *Land: 151,000 net acres*
- *Few wells but promising results*

Murphy Oil Corp. jumped into the Canadian side of the Bakken system play in the Southern Alberta Basin early in the game, and it is still seeking the combination that will bring the most profitable results.

The company started its work in the play in 2010 with the acquisition of 129,280 acres of land from Kainaiwa Resources Inc., an associate organization of the Blood Tribe First Nation in Canada on the tribe's Alberta reserves. All the land was prospective for the Bakken, which included the Banff, Exshaw, Big Valley, Stettler, and Wabamun zones.

That contract was good for five years and Murphy committed to a minimum of 16 wells during the period.

By year-end 2010, the company had accumulated approximately 150,000 acres in the area, including Reagan-area property near the US border with Alberta. At the time, Murphy planned to drill six test-of-concept wells during 2011.

In its 2012 annual report, Murphy talked about activity in the Eagle Ford Shale play in South Texas, but the company had little to say about the Bakken system in Canada. It said it began drilling in the Bakken in early 2011 and expensed several dry holes that year and in 2012. It had one well on production test in 2012 and early 2013 and planned additional wells in 2013 "to test various formations within this acreage."

It drilled apparent successes in the Wabamun and Big Valley sweet spots. By year-end 2012, Murphy had 26 licenses and five producing wells in southern Alberta.

Painted Pony Petroleum Ltd.

- *Land: 77,600 net acres*
- *Bakken provides base for new resource plays*

Painted Pony Petroleum Ltd. put together a solid base of production in the stacked pays in the Bakken area of Saskatchewan as it added reserves and potential in the Alberta Viking and British Columbia Montney plays.

According to a March 2013 presentation, it will spend US $137.75 million to $142.67 million (CAN $140 million to $145 million) on capital projects and less than 20% of that money will go into Alberta and Saskatchewan. The money that goes to those areas will maintain the Bakken assets and prove up resource potential in the Alberta light oil plays.

Painted Pony gets substantial rewards from the Bakken. It produced 1,680 boe/d for the company in 4Q 2012 with a netback in the first nine months of that year of $48.22/boe (CAN $49/boe). Bakken advantages include high-quality light oil, premium netbacks, year-round access to properties, multizone potential, and favorable royalties.

It plans to drill seven gross (5.4 net) wells in 2013. Its Bakken-area properties are in Midale, Huntoon, and Kisbey fields near the heart of the Saskatchewan Bakken play around the town of Stoughton, and Flat Lake, a newer play along the border with North Dakota, where it holds 13,700 net acres.

It completed its first two-mile horizontal well in the area for production of less than 150 b/d of oil, dropping to about 60 b/d of oil at six months, and 40 b/d of oil after a year with a flat decline curve thereafter to about 30 b/d of oil at two years.

Painted Pony participated in 29 gross (20.7 net) wells in the area in 2011, including 19.2 net horizontal wells. That year, production averaged 1,640 boe/d.

Passport Energy Ltd.

- *Land: 29,900 gross acres*
- *Focus on Hardy-area Bakken development*

In the fiscal year ended Sept. 30, 2012, Passport Energy Ltd. participated in two gross (0.65 net) horizontal development wells in the Hardy area of southeastern Saskatchewan. It earned a 15% interest in production from the nonoperated 91/03-17-004-21w2 well, and it operated the 91/15-33-003-21w2/0 horizontal Bakken well. It has a half working interest in that well. It also acquired an additional six sections of land with Bakken potential in the area in late 2011.

In all, it has interests in three horizontal Bakken wells (0.9 net) in the area with a combined gross production rate of 95 b/d of oil.

In the US, Passport Energy Ltd. holds a 60% share of 43,554 gross acres of oil and gas leases in Toole and Pondera counties in north central Montana with potential for Bakken production.

At this time, however, the company has no work commitments and does not anticipate exploration or development of the properties during 2013, according to its website.

Exploration previously has concentrated on shallower intervals that produce natural gas from the Bow Island, Dakota, and Burwash zones, but the land lies east of the property under exploration by Quicksilver Resources, Rosetta, Newfield Exploration, and Anschutz Corp., among others.

PetroBakken Energy Ltd.

- *Land: More than 256,000 net acres*
- *Second largest landholder in Saskatchewan Bakken*

Although PetroBakken Energy Ltd. is a major landholder in the Canadian Bakken play with the second largest acreage position and more than 900 drilling locations, it plans to concentrate more of its funds on its Cardium assets.

According to a March 2013 presentation, it plans to spend US $83.62 million (CAN $85 million) to drill 32 net wells in the Bakken during 2013, but it will spend $285.28 million (CAN $290 million) on the Cardium.

The company's website said, "We combine Bakken reserves, Cardium production growth, and additional development opportunities."

Even with that shift in investment, the Bakken pays PetroBakken well for its investment. One bilateral well offers an estimated ultimate recovery of 141,000 boe and costs $2.85 million (CAN $2.9 million) to drill and complete. With a finding and development cost of $20.16/boe (CAN $20.49/boe) and a netback of $61.27/boe (CAN $62.27/boe), payout shows up in approximately one year.

PetroBakken produced an average 17,770 boe/d from the formation in 2012, but the netback had dropped to $53.88/boe (CAN $54.76/boe).

So far the company has booked only 5% of its 1.69 Bboe in original hydrocarbons in place on the property.

It develops its Bakken wells using bilateral wellbores, two horizontal wellbores radiating in different directions from the same vertical hole. That dual-leg tactic allows four bilateral wells to fully develop a section of Bakken land, the same area that would require eight single-lateral wells.

It also uses delayed fracture treatment and Cleantech fracturing solutions.

PetroBakken also has started an EOR pilot project, which showed gas injection was an effective drive mechanism, better than CO_2 injection and less complex. Natural gas also is more readily available. That injection reduced decline rates and increases ultimate recoveries.

The company will continue to evaluate its Creelman Bakken EOR pilot as it prepares for commercial gas injection in the area in 2014. It also started a Bakken waterflood in the Handsworth area in 1Q 2013.

It supplements its drilling and production operations with company-run gathering systems, pipeline access, and oil and gas processing facilities to control costs and increase income.

Royal Dutch Shell plc

- *Land: 60,000 net acres*
- *Scouting Bakken system territory*

Royal Dutch Shell plc, through its Shell Canada Ltd. subsidiary, entered the Canadian Bakken petroleum system play in Alberta with a small – for an operator like Shell – land acquisition and a timid drilling program.

It purchased 21,300 net acres of deep rights below the top of the Mississippian, which include the Bakken system, from Raimount Energy Inc. Those properties are in the Woolford area of southwestern Alberta.

A March 2011 report by Scotia Capital said the company purchased more land in Crown sales using multiple brokers. A June 2012 report on Investors Hub said the company held approximately 60,000 net acres of land in the Del Bonita area and had drilled five wells and licensed six more.

By year-end 2012 it had four producing wells on 14 licenses. ■

The Bakken: New Ways of Conducting Business

Innovative technologies are optimizing wellhead production, while logistics and infrastructure struggle to keep pace.

By Glenn R. Meyers
Contributing Editor

The Falcon multistage stimulation system uses swellable or hydraulically set packers to isolate numerous stages that are then treated continuously. The system is installed in a single trip, reducing rig time, costs, and operational risks. *(Image courtesy of Schlumberger)*

On this huge stretch of North Dakota prairie, Theodore Roosevelt, the 26th president of the US, once hunted massive herds of buffalo that sometimes spread farther than the eye could see. When those herds vanished, the vast desolate land became part of America's landscape to the north. Not much later came the new migrant American farmer and a cadre of settlers who would transform much of this soil into tillable land. But it remained a geographic locale to which most Americans paid little or no heed, unless it was time to relish some of the food on the dining room table.

Less than two miles beneath this farmland lies the Bakken Shale, an enormous formation stretching from North Dakota into Montana, before culminating in Alberta and Saskatchewan, Canada. Today many believe this formation is on the verge of serving as a key hub for US and Canadian oil drilling. But for this region to be a national oil and gas epicenter, smartly designed pipeline and highway logistics supported by a solid infrastructure are needed, none of which is yet in place. To underscore this need, in the last two years oil output has more than doubled, a growth trend that is expected to continue upward.

"The only challenge for the Bakken is that it's in a state that has no infrastructure," an Openheimer energy analyst recently said. Most of the distribution supply chain is still in the planning stage. Produced oil is moved the expensive way: by truck to far-away rail depots. And when it comes to bringing experienced employees, there is little in the way of homes, schools, shopping options, or even hotels to lure them.

According to data from North Dakota's Department of Mineral Resources and the Energy Information Agency, Bakken crude production surged from 274,000 b/d in January 2011 to 673,000 b/d in January 2013. Private estimates put that figure even higher, stating the Bakken generates more than 800,000 b/d and has the potential to top 1 MMb/d within the next few years. Analysts expect some 33,000 wells will be drilled in the play over the next 20 years, with more than 5,000 coming online by 2015. Schlumberger engineers say this 2015 wells projection has already occurred.

While the Bakken/Three Forks play in the Williston Basin represents one of the largest sources of crude production in the US, its logistics infrastructure is far behind the production curve. The state of North Dakota lacks the refining capacity and has almost no advanced infrastructure like Texas or Louisiana.

Even so, while the arduous and painstaking process of planning for the development of the needed infrastructure and supporting logistics takes place in meeting rooms, a number of service companies are developing new methods for drilling and completions for operators, undertakings that have dramatically changed how drilling and completions are engineered, managed, and executed.

Rob Fulks, director, Shale Resource Projects at Weatherford, measures the changes he sees taking place in the Bakken compared to a few years earlier where barefoot, openhole completions were abundant. "There's a great deal of sophistication there," Fulks said. "Everybody is becoming more efficient. And now the wells are becoming more and more productive at the same time."

Efficiency is one of the prevailing themes in today's Bakken Shale play, especially when it comes to pad drilling using both sliding and walking rigs and completions, which count an increased number of lateral stages, each of them shorter in length, and using newly designed fluids and proppants. A range of new or advanced products and technologies are being used in the Bakken provided by companies like Weatherford, Schlumberger, Halliburton, Baker Hughes, and Packers Plus, to name a few.

In the Bakken Shale, service companies like Schlumberger are leveraging recent mergers and acquisitions with existing expertise to deploy new technologies; Schlumberger merged with Smith International in 2010. Mike Brunstein, vice president, Rockies region, pointed out the company has had a wireline and pumping service presence in the Williston area for more than 50 years. "We've been in the Williston area for a long time. However, we've seen lots of change over the last few years as a result of the merger with Smith International. By combining the technology and expertise of the two organizations, we now have a wider range of services and technologies to address the challenges in this area," Brunstein said.

From the Schlumberger Commerce City, Colo., facility, real-time monitoring is performed for nearly all the rigs the company works in the Bakken. "This provides us a tremendous amount of support where we can have an engineering staff watching and monitoring drilling parameters and making adjustments in real time," Brunstein said.

Pad drilling: the new standard

It appears most Bakken engineering activities are oriented with similar technological toolkits. This is especially true with the significant increase in sophisticated pad drilling operations, which appears to be a game-changer. When companies convert to pad drilling, there's an increased need for survey management because of drilling in proximity to other wells, noted Jeff Sack, Halliburton well construction sales manager for the Drilling & Evaluation Division. "One of the advantages associated with pad drilling is the ability to drill wells in batches. Operators will drill the surface of well #1, #2, #3, #4; then they'll go to the vertical and build, then they'll do the lateral – saves time on managing drillpipe, and if they're switching drilling fluids, they can make multiple changes for each interval," he said. Such aggressive multiwell approaches are becoming common, starting with the pad.

Ask anybody in the Bakken Shale about pad drilling and it will be said that the practice is more prevalent than ever before. Allen Starkey, senior account representative for Schlumberger, anticipates pad drilling becoming the preferred drilling technique in the Bakken/Three Forks Williston Basin, adding that most operators the company is working with have pad drilling designs in their "go-forward" designs or already have it in place today.

The StarTrak electrical imaging service from Baker Hughes produces high-resolution LWD images that provide input to reservoir navigation; early indication of wellbore stability problems; and detailed formation evaluation, including fracture characterization. *(Image courtesy of Baker Hughes)*

One of the main reasons for this is that pad drilling enables operators to drill multiple wells in a section. "With pad drilling, the operating company may be considering drilling four to six wells in a section, and they're alternating between a Bakken and Three Forks well, or a lateral in each one of those formations," Starkey said. "If you can imagine a square section, on the far west side, they may drill a Three Forks well then the next well over would be a Bakken well going north to south; then the next well would be a Three Forks well, so they can get better coverage of the entire section that way."

Integrated drilling capabilities in the company's Petrel software platform support optimized pad placement and pad well trajectory design. Designs incorporate ground level constraints; elevations; and location of rivers, roads, and other surface features common in the Williston Basin, as well as targeted reservoir sweet spots to optimize well and pad placement and evaluate potential drilling risks. Costing capabilities support calculating the estimated cost to drill based on defined inputs for ROP, percent time on bottom, and rig day rate.

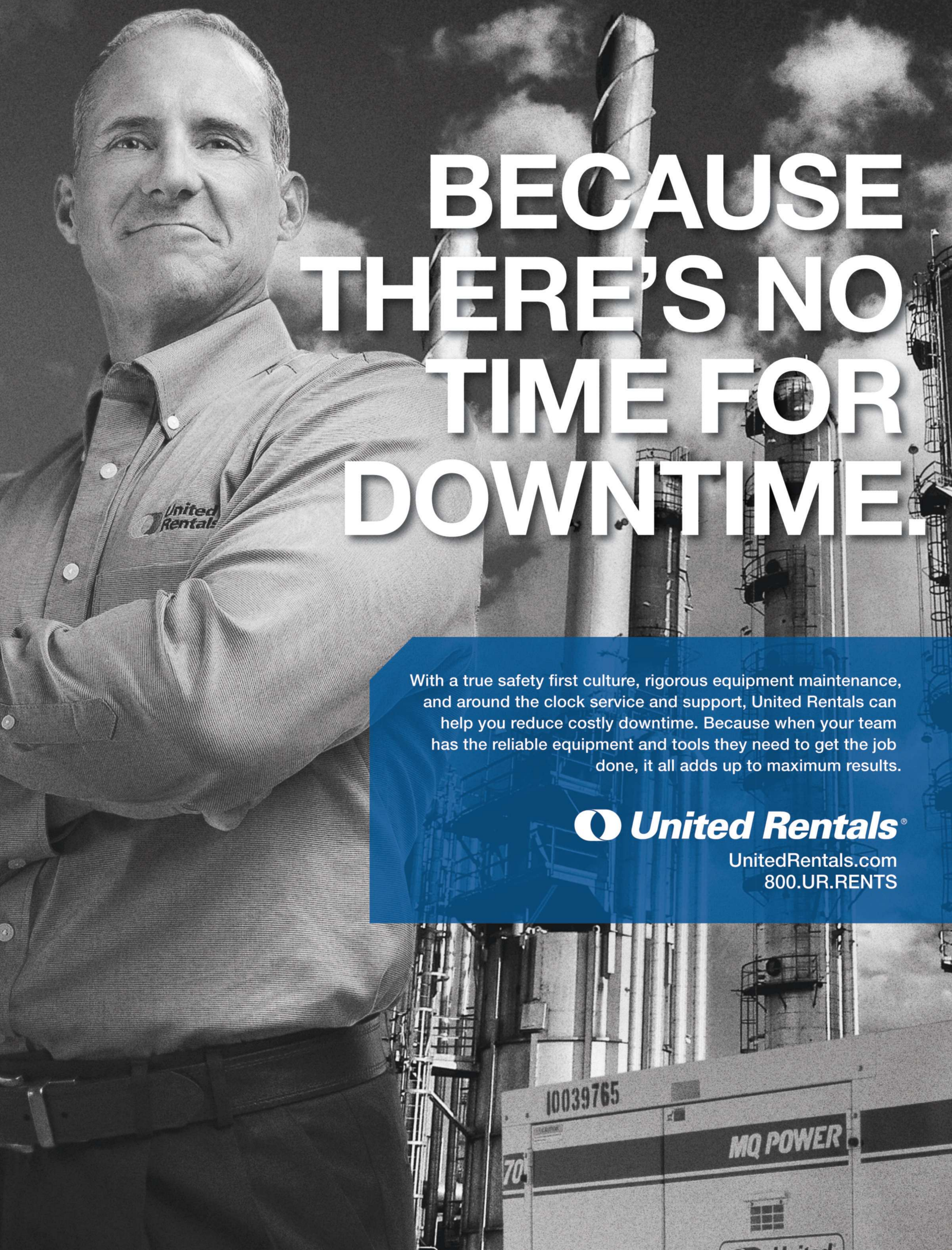
Drilling efficiencies

Ask if any big drilling efficiency gains have been made and the answer is invariably affirmative, said Neil Buffington, Baker Hughes area completion sales manager, Rocky Mountain area. "We have made, since 2004, substantial gains in steering technology. For example, now operators know precisely where they are after drilling a 15,000-ft lateral."

But more improvement should be expected. "I think there are more gains to be made in the efficiencies and the durability of the tools," he continued. "That's one of the key components.

"It's hard on the equipment; you're constantly pushing – you want to get as much footage per day as possible because that's a direct cost savings. The faster the better doesn't always lead to the greatest wellbore. Enhancing the durability of the tools would be one key to improving the efficiencies," Buffington explained.

Baker Hughes drilling efficiency tools includes the StarTrak logging-while-drilling (LWD) service, which provides high-resolution LWD images. This electrical imaging platform can be used in various drilling environments and assist with smartly engineered decisions concerning wellbore stability. This service is designed for subsurface exploration and development teams needing highly detailed sedimentary and structural information for drilling optimization, wellbore placement, completion design, and geological modeling. The service delivers high-quality image logs at ROP of up to 150 ft/hr while experiencing moderate levels of stick/slip. Drillers can see how the rock is reacting to the drilling process and can directly identify drilling-induced fractures, break-



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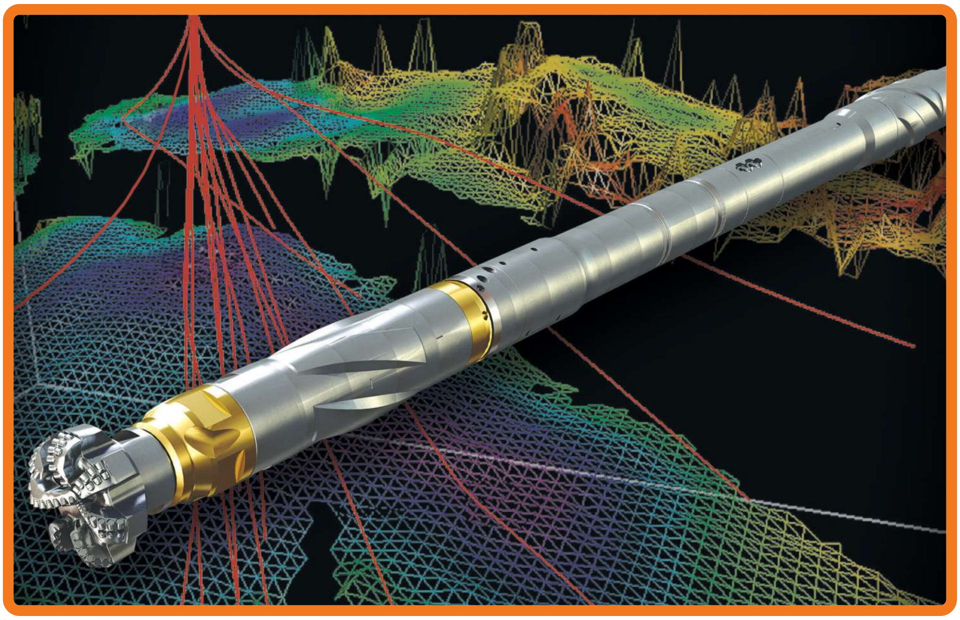

The slimhole PowerDrive Archer high build rate RSS can drill well profiles previously only possible with motors. *(Image courtesy of Schlumberger)*

outs, sheer plane failures, and other drilling hazards such as ledges.

The high-definition electrical images provide important input into the reservoir navigation process in unconventional plays. These images show fracture type and density in detail and allow operators to optimize their completion and hydraulic stimulation program. According to Baker Hughes, by selecting completion stages using information in the image log, operators have realized approximately 20% more production compared to using regularly spaced intervals. Considerable savings have been realized by optimizing hydraulic stimulation programs to focus treatment on zones that have the most potential, while reducing treatment on intervals that will not benefit from it. Images can be viewed in real time, with azimuthal resolution of 16, 32, or 64 sectors, depending upon the mud pulse telemetry equipment used. With wired pipe, the full 120-sector image can be sent uphole in real time. After drilling, the full 120-sector memory data are recovered from the tool, and high-resolution image logs are used for in-depth analysis of the entire length of the lateral section.

Avoiding collisions

According to Schlumberger's Starkey, some of the challenges and concerns are inherent with pad drilling of multiple wells. "When you are drilling four wells at 10,000 ft and they all spud at the surface 30-ft apart, you don't want to have collisions below the surface. You must have good procedures for collision avoidance," he said. A Schlumberger technology solution that addresses such concerns is the use of rotary steerable systems (RSS) that can keep holes straight to avoid collision.

The Schlumberger PowerDrive RSS provides drilling engineers with continuous rotation for smoother boreholes and dependable directional steering. Full rotation reduces drag, improves ROP, decreases the risk of sticking, and achieves superior hole cleaning, according to the company. This steerable drilling system enables improved penetration rates due to the elimination of stationary components that can create friction and reduce efficiency. Flow of drilled cuttings past the BHA is enhanced because annular bottlenecks are not created in the wellbore.

Schlumberger PowerDrive RSS include the following system tools: PowerDrive Archer high build rate RSS, PowerDrive X6 RSS, PowerDrive X5, PowerDrive Xceed RSS for harsh, rugged environments, PowerV vertical drilling system, and PowerDrive vorteX powered RSS.

Bakken Shale drilling, from its engineering to its tools, has changed dramatically over the last five years, beginning with much improved drilling performance. Walt Kordziel, Schlumberger West business development manager for pressure pumping services, said, "Five years ago, it was taking 30 days to drill these wells. The goal now is to do them in 15 to 20. Within the last four to five years we have cut in half the time it takes to drill a 10,000-ft lateral in the Bakken. This has been a dramatic improvement in efficiencies." He added that Schlumberger still sees steps it can take to possibly shave two more days off of the drilling process.

Adding cutting efficiencies

To increase efficiencies, Dustin Langford, Rockies district manager, Smith Bits, elaborated, "With the increase in competition and understanding of the Bakken play, we are no longer looking at increasing efficiency in terms of weeks or days, but now we are looking at breaking down savings and efficiencies into hours." On the bit side, that means keeping tools in the hole longer while drilling faster. The Stinger conical diamond technology is a new product from Smith Bits. Preliminary testing took place in the Bakken before the bit was brought out last quarter.

The Stinger conical diamond element (foreground) centrally placed in a PDC drillbit cutting structure has increased ROP by more than 46%. (Image courtesy of Schlumberger)

This cone-shaped cutter can help increase steerability, moving cuttings at a faster rate. At the same time, the cutters are cutting through new formation and not recutting old cuttings. "Among the highlights of this new technology, we're getting higher percentages of single-bit runs in the lateral," Langford said. "When you're at 18,000 ft of measured depth and you've got 2,000 ft left to go, if you have to trip for a bit or for a motor, the time it takes to pull all of the pipe out of hole and trip back in is tremendously expensive."

Metamorphosis in completion technology

The use of pads has not just affected drilling protocols; it has substantially influenced how completions are executed. Halliburton's Pat Kundert, senior technical advisor for Production Enhancement, discussed how the length of the stages in laterals has in general decreased from five years ago. First, 1,000-ft stage lengths went down to 500 ft, and now most stages are focused on 250-ft to 300-ft intervals of the lateral length. "That's changed with our ability to perform those smaller-stage intervals using sliding sleeves only," he said. "Now there are 30- to 37-stage systems where you can do sleeve treatments if you want to, without the need for bridge plugs and perforating guns that you have to pump down."

Kundert added that pad drilling provides other efficiencies. "If you are working on a pad, you can work on multiple wells, alternating between wells, if you're doing plug-and-perf treatments." He pointed out engineers can fracture one well while pumping down plugs and perforating guns on another well. "That's improved efficiencies tremendously," he said. "A typical lateral might have taken a week to get accomplished, whereas if you have two or four wells on a pad, you can do them in maybe three or four days."

Ongoing evolution of fracturing

According to the director of the North Dakota Department of Mineral Resources (NDDMR), hydraulic fracturing is a critical component of developing not just the Bakken Formation, but all shale plays throughout the US and Canada. Without hydraulic fracturing, under regulation of the states, this resource could not be produced, the NDDMR has written.

It is also worth pointing out that horizontal drilling of the middle member of the Bakken using multistage fracturing has outperformed all previously completed Bakken wells in North Dakota.

Both operators and service companies are presently striving to find designs that use water and proppant in the most judicious way possible. Josh Jany, a Denver-based technical sales representative for Packers Plus, takes a philosophical perspective. "I think it's a bell curve; when we started, we were fairly conservative with the pump designs, and then as our production started to increase with some of the new technologies that were being implemented at that time, everybody was on the bandwagon of more water, more sand. I think that peaked out at some point and now we're on the backside of that and coming back down. Really getting into the nuts and bolts of production optimization as far as how much water and sand is actually needed to yield the same results with the new technologies that exist. I think ultimately going forward you're going to see water utilization probably drop, and sand as well. The jury's still out as far as what the best means of completion is in terms of fluid design. Is it crosslink, is it hybrid, is it slickwater? White sand, ceramic?"

Increasing conductivity, using less water and proppant

The HiWAY flow-channel hydraulic fracturing technique from Schlumberger has delivered production increases of more than 20% while reducing water and proppant consumption, according to the company. Schlumberger engineers report that the HiWAY service has helped operators on average use 40% less proppant per job and up to 60% less water when compared to slickwater treatments. This fracturing technique uses viscosified fracturing fluid in conjunction with engineered fibers and high-frequency pulses to enhance fracture conductivity in both vertical and horizontal wells. A comprehensive workflow using the results from advanced reservoir characterization and modeling is applied to optimize the well performance.

"We've taken completions and the fracture design to a whole new level," said Brunstein, discussing this successful conductivity technique that was launched in 2010. Should a single-trip multistage stimulation system be needed for uncemented wells, the Schlumberger Falcon stimulation system may be appropriate. This system stimulates many stages in sequence, minimizing downhole trips, reducing downtime between stages, and again lowering the amount of fluids and proppant needed.

Residue-free fluid system for stimulation

Halliburton developed PermStim, a residue-free fracturing fluid system, as an alternative to guar-based fracturing fluids. Company officials believe PermStim will help meet the demands created by the rapid increase in North American fracturing.

Traditionally, guar-based fracturing fluid systems have been used for fractures. But guar gum, with a high molecular weight, has 8% to 10% insoluble materials that can cause significant problems in terms of residue. Guar residue has damaged the permeability of the proppant pack when produced back through the proppant pack following a fracturing treatment. By contrast, PermStim fracturing service delivers a residue-free fluid system that is clean and cost-effective.

Recalculating water, fluids, and fuel

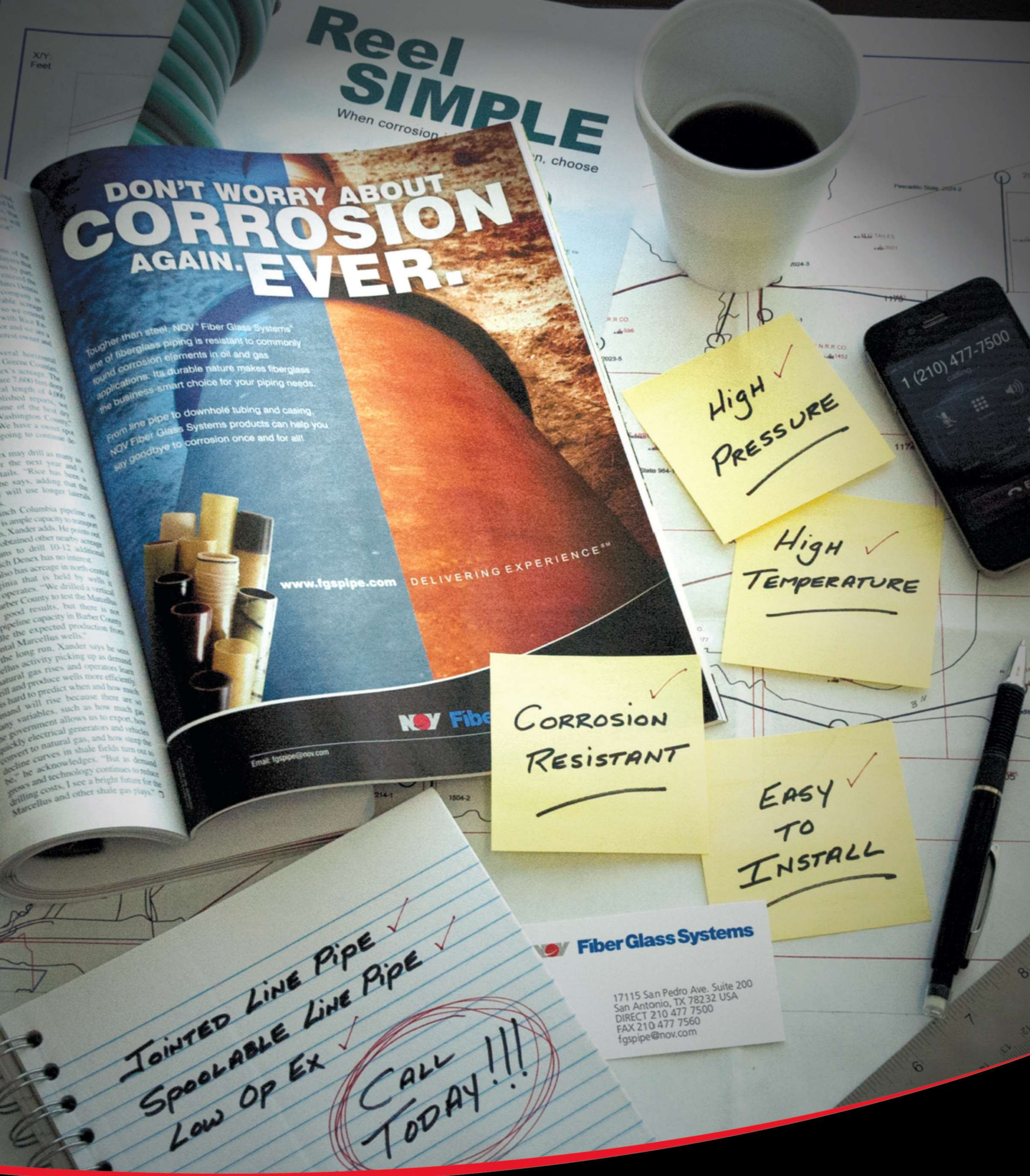
Joe Kelly, from Baker Hughes Pressure Pumping Services, was straightforward when asked about changes

Case history: Williston Basin fluid system

Two Bakken wells were treated with the Halliburton PermStim fluid system while another 16 offset wells were treated with a borate fluid technique. All wells were for the same operator.

All wells were long laterals and were recent completions with at least six months of recorded production. The wells were completed using a comparable number of sliding sleeves or perf-and-plug stages. Treatment rates, proppant type, and volumes also were similar.

The wells treated with the PermStim fluid system resulted in better production when compared to the offset wells treated with borate fluid, with the enhanced performance attributable to using a residue-free fluid system. The increased production from the PermStim-fluid-treated well had an estimated value of US $1.174 million over a six-month period (assuming a 9,000-ft lateral length and $80/bbl oil price). *(Source: Halliburton)*



NOV Fiber Glass Systems

Email: fgspipe@nov.com

Baker Hughes SmartCare fluids represent a significant advance in reducing the environmental footprint. *(Image courtesy of Baker Hughes)*

that have occurred and what fluids are being used now in Bakken operations. "We've stopped using diesel as a carrier fluid," he said. "We're using [Baker Hughes] SmartCare fluids now." He explained that these fluids are green-based, a significant advance on the environmental front. This includes recycling produced water when possible and using different type brines for fracturing fluids.

Under SmartCare, Baker Hughes' chemists and researchers evaluate and rate the components of a chemical product for potential environmental and health impacts. A product also is rated for performance, cost effectiveness, and compatibility with other chemical treatments.

Buffington commented on the goal to minimize water use while performing fracturing work in North Dakota – something the company has focused on minimizing for 2013 and beyond. Alternative methods for water use are being explored. Presently, that means using Baker Hughes brine waters for fractures rather than all freshwater. Buffington estimated that fracturing jobs today sometimes use a 50/50 split between recycled and freshwater.

Baker Hughes is continuing to make a substantial commitment to environmental stewardship, Buffington added. He said the company has near-term plans to use LNG from wells for fuel and already uses compressed natural gas to fuel some of its light-duty field truck fleet. "It's a very, very important part of our business in terms of environmental impact," he said.

Ceramic proppants gain favor

Because Bakken Formation rock has high closing forces, sand proppants traditionally used with fracturing often do not keep the fracture open to create greater conductivity of fluids to the wellbore. As a result, ceramic proppants are used as a solution. Numerous ceramic proppants (e.g., sintered bauxite, alumina, kaolin) have been used in the Bakken Formation to withstand closure stresses of 6,000 psi to 14,000 psi, but these come with significantly higher price tags than sand.

An Energy & Environmental Research Center (EERC) research report said that while it has been documented propped fractures can be created to breach the lower Bakken Shale, field evidence also suggests that operators typically are unable to sustain a hydraulic connection through this barrier.

Weatherford's Fulks provided this perspective on Bakken fracturing: "To generalize, you really have to separate the Three Forks and the Sanish formations from the middle Bakken itself. We started with slickwater, propelling sand-based proppant of different weights. This evolved later into crosslink fluids or hybrid fluids that could basically carry more proppant."

When fluids are thickened, they slow down the pumping rate. According to Fulks, some oper-

ators are going back to using slickwater, but doing it differently, pumping at high rates with higher strength proppants, including manmade materials like ceramics. "The closure force in the Bakken has a pressure gradient of .61 to .73," he said. "This means when you frac it and open the rock, the rock wants to close itself very quickly. And with such a pressure you will crush most sand grades. The sand isn't capable of keeping the fracture open." As a result, there is a movement toward higher-strength proppants.

It also has been reported that operators sometimes need to drill redundant wells completed in each of the middle Bakken and Three Forks reservoirs. EERC has reported Bakken operators have fractured into offset wells that are spaced more than 2,000 ft away, demonstrating that very long propped fractures can be created. Even so, such fractures tend to lose hydraulic continuity over time.

Tools to help pad well efficiency

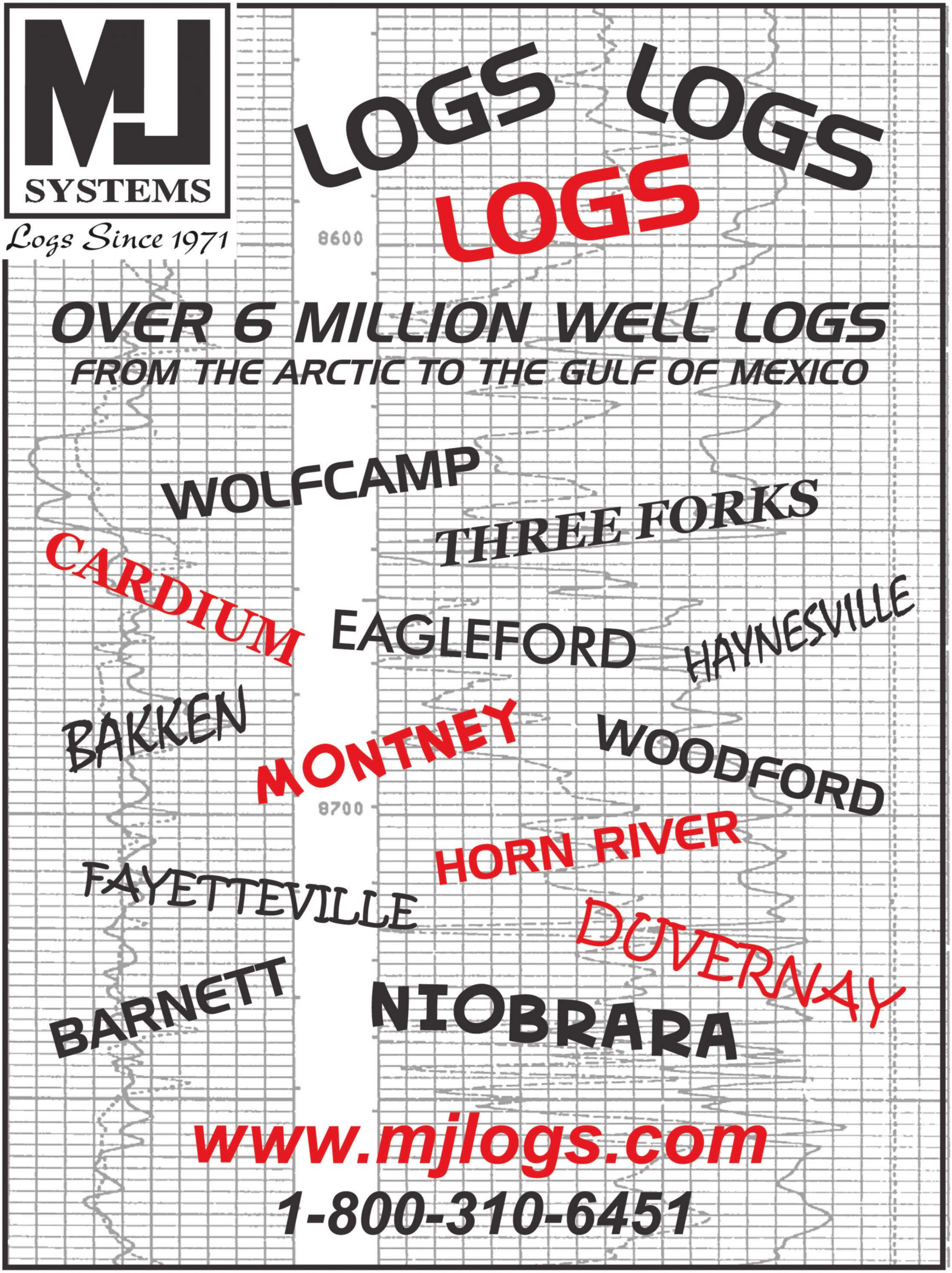
According to Eric Blanton, director, Lower Completions at Weatherford, once operations are set up for identical completions on a pad, the best success is determined by efficiency. "So we want to efficiently get those completions to depth and set the packers, get them in place and do that for all four wells on a pad, and then hook up and start fracturing these wells," he explained. "And to be able to do that efficiently, with no hiccups and minimal or no down time, is the biggest driver behind making these completions more profitable."

To reduce costs and shorten procedural duration, future success will be based on eliminating as much intervention as possible. To assist on this end, a new product being introduced by Weatherford – part of its ZoneSelect system – is called the i-ball. This frac sleeve technology uses a single ball to activate an unlimited number of zones and requires no milling and no intervention post-fracture.

According to Blanton, the method provides an improvement over the traditional sequence of tapered ball seats, which uses a limited number of balls at the top of the well, followed with increasingly smaller balls toward the bottom. Bottom line, the technology is capable of maximizing production, reducing operating costs, and increasing fracturing efficiency, he said.

"That's a big deal," Blanton said, citing the use of traditional frac sleeves in a 40-zone system as an

The i-ball technology eliminates downhole pressure buildup and associated logistics and storage concerns by using one ball and one seat size for all sleeves in the lateral casing string. *(Image courtesy of Weatherford)*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example. "You basically start with zone #1, with a slightly less than 1-in. ball. You drop that down 10,000 ft vertically, then you pump it another 10,000 ft horizontally. It's trying to make its way through all of these ball seeds to find the very toe there, then it lands on the ball seed, shifts the sleeve open, then you pump your frac for that zone…each subsequent zone uses a slightly larger ball," he explained.

With the i-ball technology, there is no milling. It retracts to a near fullbore ID. "You can either flow all the balls back, or we've also had some customers who put different equipment down in the toe of the well so they can trap the balls down in the toe, and these just stay there," Blanton said.

Following up

Once, the Bakken Shale seemed to go like this: "Hurry as fast as you can, then hurry some more." That gold-rush mode has changed now, according to Jany at Packers Plus. "Companies are starting to slow down and apply a little more post-job follow-up and production analysis. For a while everybody was trying to drill their leases to a point to where it was one well after another and there wasn't a lot of time to sit back and reflect. Now the operators are getting more [involved] in the development mode," Jany said. A number of companies have teams in place that take a "look-back" to determine where a company can improve on the work it has undertaken.

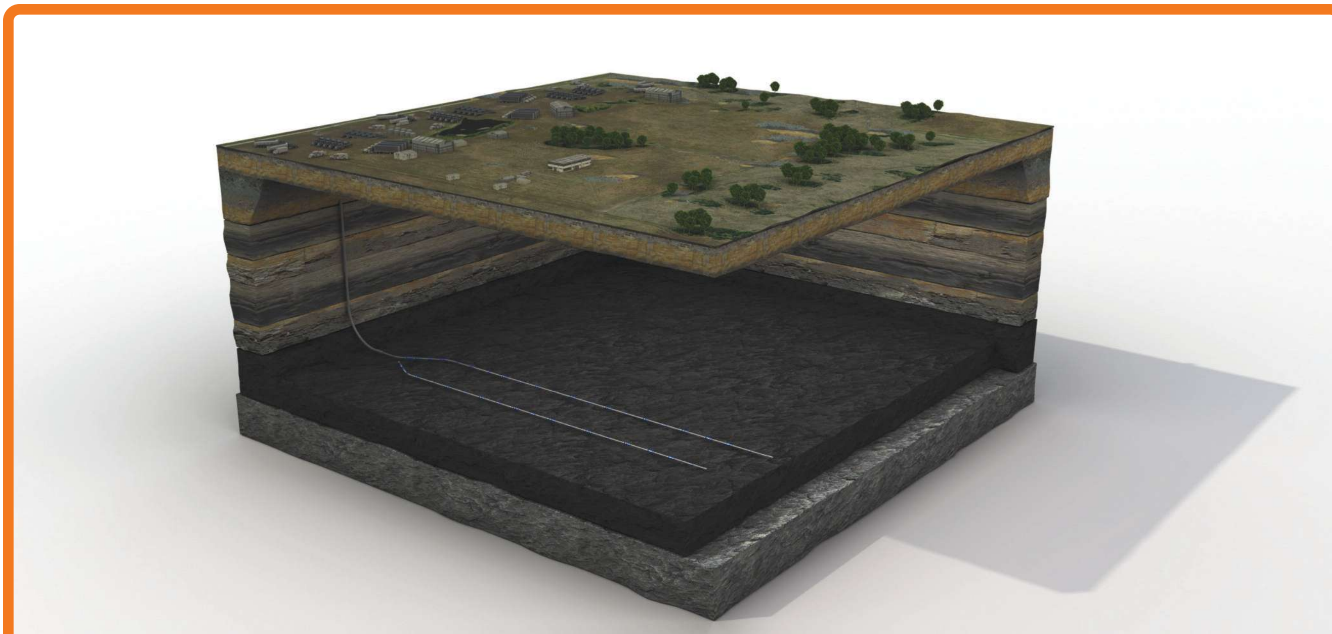
There is no shortage of opinions associated with what is the best treatment for the well, all of which provide good fuel for the evolution of wellhead efficiencies. "I think the science associated with trying to seek the most effective and efficient means of completion from a pumping perspective has really grown as well," Jany added.

Case study: promoting efficient operations in the Bakken

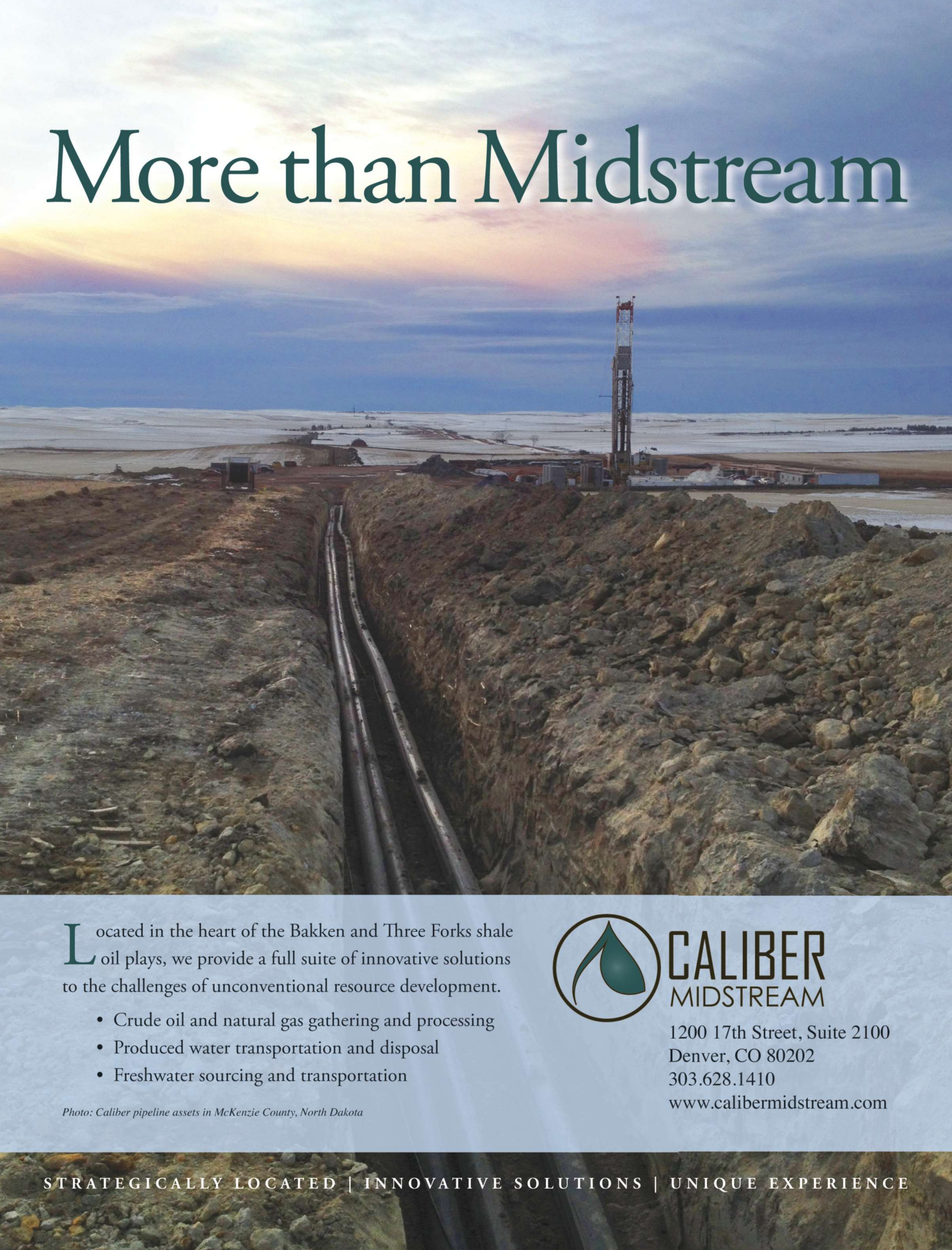
The Bakken Formation has a low average permeability (0.04 mD) and porosity (5%). With such low producible rock characteristics, the formation is ideal for horizontal drilling with multistage fracturing. Due to high oil and gas in place estimates, many operators have been dedicated to developing in new technologies that increase production and reduce operational costs.

Packers Plus has focused on increasing lateral length and stage count to maximize recovery, segmenting longer lateral lengths with more stages to maintain the same stage spacing.

An operator working the Bakken Formation



Packers Plus horizontal multilateral wells reduce upfront capital costs compared to drilling individual horizontals and effectively double or triple the reservoir contact from a single vertical well. *(Image courtesy of Packers Plus)*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wanted to increase lateral length while maintaining stage density on a well in McKenzie County, N.D. Various multistage fracturing technologies were available, but this operator focused on openhole, multistage fracturing systems using mechanical packers from the Packers Plus StackFRAC HD system. A Packers Plus spokesperson said this decision was based on the increased production realized with openhole completions and the reliability of the StackFRAC HD system deploying technological enhancements that could address the trend of increasing stage density in the Bakken.

Packers Plus completed openhole wells with higher stage numbers using FracPORT sleeves with 1/16-in. ball seat increments. Newly designed, lightweight SF7 balls were used to activate the FracPORT sleeves. A specific gravity of 1.8 enabled the high-strength SF7 ball to meet pressure demands, which needed to be light enough to flow back or easily milled, if desired.

The StackFRAC HD system with 1/16-in. ball seat increments was used to fracture the 34-stage well. The system was run into a wellbore with a lateral length of approximately 8,960 ft and a measured depth of 21,800 ft. FracPORT sleeves with the 1/16-in. ball seat increments were used at an average stage length of 262 ft, the same stage spacing used in the wells with shorter laterals. The operator was successful using the 1/16-in. FracPORT ball seat increments in conjunction with the SF7 ball. All 34 stages were completed in 2.5 days.

The other side of the border

Venture on the other side of the border to Canada and one will find everything to be remarkably different. This includes everything from the configuration of the Bakken Formation, from the Alberta Bakken to the Saskatchewan Bakken, total true vertical depth (TVD), the length of laterals, and how completions are executed.

"There are some distinct differences between the formations north of the border and south of the border," said James King, Baker Hughes applications engineering director for US land. "The Canadian Bakken is shallower. It makes a very good place to apply some coil tubing intervention technologies such as the Baker Hughes OptiPort coiled-tubing frac sleeves. And in Canada there are hundreds, if not thousands, of wells completed using a coil tubing intervention method."

According to Canada's National Energy Board (NEB), the Bakken tight oil play stretches into Saskatchewan and Manitoba, and production in March 2011 came in at more than 12,400 m^3/d (78,000 b/d), with the vast majority of growth occurring since mid-2007. The NEB estimated Canadian tight oil production in March 2011 to be over 25,400 m^3/d (160,000 b/d), much of that from lateral wells.

Completions take place at 4,000 ft to 6,500 ft average TVD compared to North Dakota's 9,000-ft to 11,000-ft average TVD. Lateral lengths in the Canadian Bakken have increased since 2009. While stage count is smaller than in the US, the average number of stages here has more than doubled over the last four years. Fraser McNeil, Halliburton country manager, technology, Canada, added his perspective. "In 2009 we were looking at an average of nine stages and the average in 2012 has gone up to 20," he said. Smaller appears to be a key word for 2013 completions: less fluid and proppant per stage and smaller fractures – but more of them. McNeil added that he sees the change in fracturing accompanied with an average production increase of 35% from 2009 to 2012. Halliburton also is reducing the amount of freshwater required by reusing flowback and produced water in fracturing fluid treatments.

"Whether we're operating in the Canadian Bakken or Exshaw, the pay zone is always relatively thin. Therefore, upfront frac modeling and engineering design is essential to ensure you stay in zone while optimizing the fracture treatment," McNeil said.

In Canada coil tubing (CT) fracturing is common as this method provides an efficient and effective way to deliver multiple small- to medium-sized fractures, one at a time. Many methods are available, where Halliburton has had significant success with CT straddle systems and more recently with its advanced Anchor tool. "In Canada, single-stage fracturing is key to focus the fluid energy in one spot to optimize the frac treatment, while minimizing rate and pressure to contain the fracture in the pay zone," McNeil said.

While the Alberta Exshaw Bakken has received mixed reviews because it is so different than North Dakota, the same tepid response does not apply to the Saskatchewan Bakken, said Mike Kenyon, Packers Plus director of Canadian operations. According to Kenyon, the advances taking place with drilling in southeast Saskatchewan involve extended-reach dual laterals, a technology that has been economically successful for PetroBakken Energy, the second largest landowner in Saskatchewan's Bakken play.

The PetroBakken website has reported developing a drilling and extraction strategy for drilling bilateral wells (two horizontal legs drilled from one vertical wellbore). This bilateral method has "...increased exposure to this generally low permeability reservoir," the company said, adding that four bilateral wells can completely develop a section, while eight single laterals are required to achieve the same well density.

"We're actually doing dual-lateral wells and that gives us a lot better efficiency," said Kenyon about the Saskatchewan Bakken play. "So we can drill the first lateral, then do the second lateral. And basically at the end of the day it looks like a pitchfork." In Saskatchewan, wells are drilled 656 ft apart.

Kenyon added that the rate of return on this kind of procedure is significant. "And you get the benefit and drainage of two laterals, and their economics are really good when they do it that way," he added.

Similar to the Canadian plays, the Saskatchewan pay zone is thin. It also exists over water in the lodgepole formation. "So it's very, very key to keep in that zone," he said. "If you go too high up, you can't frac that section, and it will break up into the water, and you'll have a water well."

Kenyon's progress report for Saskatchewan is positive. Drilling and maintaining in this thin zone has been one of the biggest gains over the last two years, he said, coupled with the efficiencies of the dual-lateral wells.

Conclusion

As Halliburton's Pat Kundert sees it, today's most successful completions demand using more of an engineered approach, rather than the "frac-factory" approach. To achieve this, Halliburton is becoming more specialized and more focused on treatment designs. "We're trying to engineer so we can optimize treatments and design, staging, and all materials used. Those are the challenges we face to improve well production performance," he said.

On the Canadian side, Halliburton's McNeil agreed, but concluded that this evolution has not yet come to its end. "We are continually striving to make wells more productive and cost-effective," he said. "Whether that gain comes from efficiency improvements on surface or frac treatment changes downhole, we must continue to aim for that silver bullet."

He continued, "And from my perspective, the reservoir tells you everything you need to know. As our understanding of the reservoir develops we are able to apply fit-for-purpose technology to maximize well performance. There are so many different ways that you can do that during the life of a well." According to Kundert, one way is using an engineered approach from start to finish. "It's all about reservoir understanding and using that knowledge to drive solutions forward," he said.

As for future development and infrastructure, a number of issues need to be addressed in North Dakota. Buffington knows these issues well because he served as Baker Hughes' North Dakota operations area manager prior to transferring to Denver. He listed the following priorities, among them:

- Convince experienced people to move to North Dakota;
- Find alternatives to routinely flying personnel in and out on rotation; and
- Start providing the basic infrastructure people will expect, from roads and grocery stores to police and fire services, plus schools for children.

"In order for us to expand in the oil industry as a whole, we've had to do it in conjunction with expansion of the basic infrastructure," Buffington said. "I would say the state and the industry together have worked hard to build the services needed to sustain the influx of people required to continue the growth in North Dakota. It has been a significant challenge and continues to be one today." ■

Abundant Production Challenges Operators

With the Bakken emerging as a world-class play in the last five years, midstream operators have scrambled to move that production to market – including the use of some creative techniques.

By Paul Hart
Editor, *Midstream Business*

The Williston Basin's Bakken and Three Forks formations have emerged as one of the most exciting oil discoveries in many years. The play continues to climb toward the million-barrel-per-day production mark – putting it in a league with just a handful of oil fields. North Dakota's oil production alone notched above 760,000 b/d in early 2013, with additional production from wells in neighboring Montana, Saskatchewan, and Manitoba.

North of the border, Tim McMillan, Saskatchewan's minister of energy and resources, said his province "is very fortunate that the largest portion of the Bakken in Canada is in our province, with a small portion in Manitoba. It has been a great resource." Saskatchewan's Ministry of Energy and Resources said the province's year-end 2012 Bakken output was nearly 70,000 b/d.

That is the good news from upstream, but now there is the midstream problem: How to get all that oil to market? McMillan added that the midstream "is the largest challenge we face today."

The Williston has been a modest conventional oil producer since 1951. The corresponding midstream infrastructure has been modest as well. Now, there is a lot of oil produced in a region with a small population and light industrial base. There is not a lot of local demand for crude, natural gas, or NGL.

North Dakota has just one refinery at Mandan, operated by Tesoro Corp. The refiner and marketer expanded the plant by 10,000 b/d in 2012 to 68,000 b/d – claiming about 9% of North Dakota's share of Bakken crude production. Much of that production goes into products pipelines to Minneapolis/St. Paul. The expansion included extension of the firm's Tesoro High Plains Pipeline gathering and mainline system to 750 miles, linking the plant to Williston producers.

Construction started in 1Q 2013 on a second North Dakota refinery, actually a topping plant, intended to help meet heavy distillate demand created in great part by Bakken/Three Forks field work. The Dakota Prairie refinery is going up on a 318-acre site outside Dickinson, N.D. Developers are MDU Resources Group Inc. and Calumet Specialty Products Partners LP. Capacity will be 20,000 b/d. Dakota Oil Processing has proposed another small-scale, distillate-focused plant at Trenton, N.D., but the company has not announced final plans.

Too much

The abundant Bakken may indeed represent too much of a good thing for midstream operators, according to Bernard Colson, director of energy infrastructure equity research for Global Hunter Securities. Colson rates pipeline capacity in the Williston at a premium, and when there is space available the existing pipelines can only take the

Crude Oil Pipeline Systems

Company	System	Explanation	Capacity (Mb/d)	Timeline
DeeThree Exploration Ltd.	Pipeline system	Oil battery, 124-mile pipeline infrastructure, and CO2 removal facilities	–	Existing
		A second main battery will be commissioned to increase total capacity in the area to 8,000 b/d.	–	2Q 2013
Enbridge Inc./Enbridge Energy Partners	Enbridge Mainline	Enbridge Mainline (US and Canadian mainlines) including the existing Phase I additions via the Alberta Clipper (+450,000 b/d) and Southern Access (+400,000 b/d) projects	2,500	Existing
	Sandpiper	Light Oil Market Access (LOMA) Sandpiper Pipeline initial capacity	+ 225	1Q 2016
	Sandpiper Expansion	Light Oil Market Access (LOMA) Sandpiper Ultimate Expandability	+ 250	1Q 2016
InterPipeline Fund	Central Alberta Pipeline	345-mile feeder and gathering system, storage capacity of 113,700 bbl	22	Existing
	Bow River Pipeline	1,667-mile crude oil feeder pipeline and gathering system, storage capacity of 464,500 bbl	110	Existing
Pembina Pipeline Corp.	Alberta Pipeline system	Eight crude oil, condensate, and NGL pipelines	430	Existing
		Peace Pipeline LVP system	155	Existing
		Phase I - Peace Pipeline LVP expansion - Upgrade two existing pump stations to increase crude and condensate capacity.	40	3Q 2013
		Phase II - Peace Pipeline LVP expansion - Install five new pump stations, upgrade six existing pump stations, and add additional operational storage. Reconfigure existing pipelines and build a total of 6 miles of new pipeline from Gordondale to Spirit River.	55	Late 2014
Plains All American Pipeline	Rangeland Pipeline system	Mid Alberta Pipeline (MAPL) and Rangeland Pipeline - 891.3 km (554 miles) of 8-in. to 16-in. mainline pipeline and 660 miles of 3-in. to 8-in. gathering pipelines. MAPL transports crude from Sundre, Alberta, to Edmonton, Alberta. Rangeland pipeline transports crude from Sundre, Alberta, to the US/Canadian border near Cut Bank, Mont., where it connects to its Western Corridor system and Cenex Pipeline.	52	Existing
	Cenex pipeline	Delivers oil to the Cenex refinery at Laurel, Mont.	–	Existing
	Phillips 66 (79%) and Western Corridor System (21%) - Glacier Pipeline	614-mile crude oil pipeline consisting of two parallel lines: A 277-mile, 12-in. trunk pipeline, a 288-mile, 8-in. and 10-in. trunk pipeline, and a 49-mile, 12-in. loop line, all extending from the Canadian border and Cut Bank, Mont., to the refineries at Billings and Laurel, Mont.	100	Existing
	Western Corridor System - Big Horn Pipeline	Transports crude oil south to Wyoming refineries	–	Existing
	Western Corridor System - Beartooth Pipeline	Connects Glacier Pipeline to Big Horn Pipeline	–	Existing
Spectra Energy Corp.	Express Platte Pipeline	1,717-mile, 24-in. mainline transporting crude oil from Hardisty, Alberta, to US Rocky Mountain and Midwest markets in Montana, Wyoming, Nebraska, Missouri, and Illinois.	280 Express to Wyoming 145 Platte into Illinois	Existing
TransCanada Corp.	Keystone Pipeline System	2,154-mile pipeline. Phase I - Converted gas into crude oil pipeline connecting from Canada to US Midwest markets. Phase II - Extension from Steele City, Neb., to Cushing, Okla.	590	Existing
	Keystone XL pipeline	Submitted presidential permit	830	2015
	Canadian Gas Mainline	Decision to be made early 2013 whether or not to Reconfigure Canadian Gas Mainline to transport crude oil to the East Coast refineries.	800	2017

Natural Gas Infrastructure

Company	System	Capacity (MMcf/d)	Timeline
Croft Petroleum Co.	Cascade system gas processing plant	-	Existing
Chevron Canada, Apache Corp.	Pacific Trail Pipeline: New 288-mile, 36-in. natural gas pipeline from the Spectra Energy natural gas transmission system at Summit Lake, British Columbia, to the Kitimat LNG export facility with 1 Bcf/d gas capacity	1,000	2014
Enbridge and Veresen Inc.	Alliance Pipeline: Rich gas pipeline extending 2,311 miles from northeastern British Columbia and northwestern Alberta to the US Midwest	5,350	Existing
InterPipeline Fund	Cochrane plant - NGL extraction plant on TransCanada Alberta system	4,000	Existing
	Empress II and V plants - NGL extraction plants on TransCanada Alberta system	2,200	Existing
Kinder Morgan Energy Partners LP	Cochin NGL Pipeline - 1,900-mile, 12-in. mult-product pipeline operating between Fort Saskatchewan, Alberta, and Windsor, Ontario, including five terminals. Plans to reverse the line by 2014. Border crossing requires US Presidential Permit which is pending at the US Department of State.	70	Existing
Omimex Resources	Natural gas processing plant in Cut Bank field, Mont.	–	Existing
Pembina Pipeline Corp.	Expand its Cutbank Complex gas processing (by 50 MMcf/d) at Musreau gas plant and new 205 MMcf/d ethane extraction facility.	50	Existing (Sept. 2012)
	Cutbank complex - Cutbank, Musreau, and Kakwa gas plants	360	Existing
William Fulton	The Miner Cooley gas processing plant	–	Existing
TransCanada Corp.	Foothills Pipeline gas system - 771-mile natural gas pipeline for export from central Alberta to two US border points - British Columbia and Saskatchewan	3,900	Existing
	Canadian Mainline - 8,762-mile natural gas pipeline from Alberta to Quebec	4,500	Existing
	TransCanada NGTL System stretches across Alberta and British Columbia through more than 15,000 miles of pipeline to connect the Western Canada Sedimentary Basin with 1,000 receipt points and 200 delivery points and interconnects with 320 Bcf of storage at 7 locations. Connects to the Nova Inventory Transfer System trading hub with over 60 Bcf/d of transactions.	10,000	Existing

crude where producers do not want to go. The existing pipeline network routes most of that crude to trading hubs already filled with crude from other unconventional plays, namely Cushing, Okla., and Clearbrook, Minn.

"We've had a big shortage of pipeline transportation capacity there," Colson said. "Think of the US as a funnel with Cushing as kind of the neck of the funnel." The growing Bakken crude output competes at those hubs with growing production from other North American shale plays and Canada's oil sands.

Tad True, vice president of Bridger Pipeline LLC, put the Bakken's pipeline problem into perspective in a presentation at Hart Energy's Rockies Midstream Conference in Denver at year-end 2012. True pointed out that "there's a 900,000 b/d difference between total takeaway capacity and total peak production" in the Bakken, adding "some OPECs don't produce that much."

Given that production greatly exceeds pipeline capacity, Bakken producers early on turned to a midstream medium that had seen only a minor, niche-player role since World War II – railroads. That created a spike in rail-related traffic and infrastructure additions in the region. Lengthy unit trains of 100-plus tanks cars have become a regular sight on the prairie.

Justin Kringstad, director of the North Dakota Pipeline Authority, estimated that 52% of the state's Bakken crude production went to market via train at the first of 2013. For comparison, industry estimates peg rail shipments a year earlier at less than 20% of Bakken output.

Rail trends

Global Hunter's Colson credits two things for the trend. First, Bakken production grew so fast producers had to resort to rail just to move the production. "Obviously, rail has a shorter lead time, it is less capital intensive, and it gives you more flexibility," he says. "So while it is more expensive on a per-barrel basis, you have a lot more flexibility."

But there is a second and possibly even greater reason for rail's now-dominant role in the Bakken midstream: Credit the current price differential refiners must pay between Cushing and other inland hubs versus coastal ports that price according to North Sea Brent and other crudes. A basic rule of economics has emerged at inland hubs: Abundant supply and limited customers result in lower prices.

"There are just enormous opportunities for producing companies right now. It doesn't matter if you pay the US $10 or $15 (per barrel) it takes to rail the crude to market, it's worth it," Colson says. The differential between West Texas Intermediate at Cushing and Brent on the East Coast, for example, hovered around $20/bbl in recent months in 2012 and into 2013, so producers come out ahead despite the higher rail tariff – and refiners come out ahead with lower feedstock prices.

To keep this unusual situation in perspective, True reminded the Rockies Midstream attendees that "it wasn't that long ago when the absolute price of crude oil was between $22 and $26, and now we're looking at differentials of about the same amount."

The biggest beneficiary of that swelling rail traffic has been BNSF Railway Co. It shipped its first Bakken unit train in 2009, according to John Miller, vice president of industrial product sales. By year-end 2012, BNSF had increased its crude-handling capacity to 1 MMbbl/d of crude oil and NGL out of North Dakota and Montana. Unit trains of as many as 118 cars are now the rule on BNSF rails headed in every direction, Miller said.

A typical railroad tank car holds around 650 bbl of crude so the average unit train can handle somewhere around 65,000 bbl to 75,000 bbl of oil, depending on the type of equipment used and the quality of the oil.

The Bakken will receive a "significant" share of BNSF's capital budget in 2013. "We're looking to invest and reinvest because this is a growing area for us, and our customers are spending significantly to upgrade loading capacity in the Bakken," Miller said.

The Williston Basin's tight midstream situation "leads to the great advantages of rail," Miller said, adding that railroads offer flexibility to multiple destinations, the ability to respond quickly, and rail's capacity to develop loading terminals much faster than pipelines can. Producers' rail contracts can be comparatively short term, one to five years, versus the 10- to 15-year commitments required for pipeline capacity.

Niche player

However, North American railroads remain small midstream players everywhere except in the Bakken. Association of American Railroads statistics found the major Class I railroads handled 233,811 carloads of crude oil in 2012, a 256% increase from 2011. A sizeable increase, but crude shipments still represented only 0.8% of Class I freight in 2012 – but the biggest share of that traffic was Bakken crude going to market.

The Bakken's rail surge has brought new players, or new roles for existing players, into the Williston's midstream. Salt Lake City-based Savage Cos. opened its Trenton, N.D., rail terminal in 2012, located in the heart of the Bakken's most productive area near the North Dakota/Montana border. The terminal has 300,000 bbl of storage capacity, five truck bays, and a double-loop track that can handle trains of 118 cars.

Savage has been heavily involved in oilfield trucking and materials-handling for years but the rail terminal was a natural addition to existing operations there, said Nathan Savage, senior vice president and group leader for the oil and gas solutions group. The terminal represents a major investment for the firm; the Bakken is a big play so players there must be big.

"It seems kind of like the nature of this business: Go big or go home," Savage said. "And so we started with a relatively large facility. But if the market dictates that we expand that facility, we certainly will. We stick very close with our (producer) customers because this is largely a customer-driven business by what they see as their requirements and what we need to do to meet those requirements."

BNSF's Miller points out rail customers also can take advantage of changing market dynamics by shifting destinations on the fly, capturing the best rate of return and ultimately maximizing profits. He cited the railroad's handling of East Coast shipments when Hurricane Sandy came ashore in late 2012. BNSF and other railroads rerouted eastbound unit trains that were in transit to other customers temporarily. The oil kept moving, which is the important thing for Bakken producers.

Rail's higher cost

Rail can be pricey in comparison to conventional pipeline moves. Rail shipments to Gulf Coast refiners run several dollars higher than pipeline, for example.

Tesoro provided numbers in early 2013 investor presentations that set out the economics behind what makes rail work as a midstream alternative in the Bakken.

For its Anacortes plant, the firm estimated a $22.60/bbl savings compared to Alaska North Slope (ANS), which has been the refinery's chief feedstock in recent years. Take out an average of $9.75/bbl in rail costs from that number.

The difference in those numbers creates compelling numbers for the refiner. Tesoro estimated Anacortes' runs during 2013 will be 40% to 50% Bakken and 10% to 20% ANS, with the balance in feedstock coming from Canadian and foreign producers.

In 2011, Anacortes ran 57% ANS, plus Canadian and foreign and zero Bakken. The company projects its $60 million capital investment to handle Bakken unit trains and their crude will create annual earnings before interest, tax, depreciation, and amortization of $160 million to $180 million with a 220% internal rate of return. And in this example, pipelines cannot provide a competing service – and probably never will, given the distance and lengthy permitting procedures and environmental requirements. In comparison, rail is there and already in service.

Global Hunter published a report in early 2013 that projects takeaway capacity in 2012 at 1.17 MMbbl/d, including around 700,000 b/d of rail capacity. The report projects a 69% increase in total Williston midstream capacity by 2017 to nearly 2 MMbbl/d.

"There seems to be a shortage of pipeline capacity through 2013. However, with all the projects currently in development, 2014 and beyond are looking more than adequately covered with pipeline alone. Given that in 2012 rail has been absolutely vital and has grown tremendously over the past several years, we estimate a large overcapacity of rail transport in the out years of our forecast."

Rail's domination of the play has been credited by some for shelving a major pipeline proposal in late 2012.

Lack of interest

ONEOK Partners LP failed to receive sufficient interest in its proposed 200,000 b/d Bakken Crude Express project during an open season. Bakken Crude Express had a price tag of more than $4 billion and would have linked Williston producers with the Cushing hub. Perhaps the concept of yet another link to Cushing and its sluggish crude prices gave Bakken producers pause.

ONEOK announced the project's cancellation at year-end 2012, although some industry observers speculate it may be reborn later, perhaps with capacity or destination changes. Some industry observers speculated that the opening of the Seaway Pipeline in late 2012 and the completion of the southern leg of the Keystone Gulf Coast Project by late 2013 – both intended to move crude out of Cushing to Gulf Coast refiners – could change things for the Bakken Crude Express and other Bakken-focused pipeline projects as the Cushing glut ends. The long-delayed Keystone XL Pipeline, which primarily will handle Alberta oil sands output, could become a factor in moving Bakken crude south if it receives presidential approval. Capacity will be 830,000 b/d and it could go in service during 2015.

But crude production that grows at a compound annual growth rate of 80% creates the same challenges everywhere.

Canada's midstream industry is scrambling to respond. The Canadian Association of Petroleum Producers produced a report in 2012, "Crude Oil Forecast, Markets & Pipelines," that outlines the challenges faced by Canadian producers in general and Bakken operators in particular. As in North Dakota and Montana, a growing share of Saskatchewan's Bakken crude now moves by rail. Canadian Pacific Railway is a player on both sides of the border.

Enbridge Inc. is among the pipelines serving the region with expansion plans that will serve both sides of the border. And with a proposal reminiscent of the recent Seaway pipeline reversal in Texas and Oklahoma, Enbridge filed an application with Canada's National Energy Board for permission to reverse the flow of its 30-in., 240,000 b/d Line 9 between Sarnia and Westover, Ontario. The line has been moving imported crude to the Sarnia petrochemical complex. There also are discussions about reversing the entire line from Sarnia to its Montreal terminal by 2014.

Enbridge has been a major player in the basin for years and has construction under way on a Bakken-area expansion. It has a 240-mile crude oil pipeline gathering system in North Dakota, connected to its interstate transmission pipeline system, which delivers most of the oil to the Clearbrook hub and customers in the Midwest. Its Sandpiper and Sandpiper Expansion are expected to add 475,000 b/d of capacity by 1Q 2016.

It also plans the Beaver Lodge Project, looping a portion of Enbridge's existing North Dakota system – plus a new line, pumping, and line replacements in the Bakken Pipeline project. It is scheduled to go onstream in early 2013, adding 120,000 b/d of new takeaway capacity. Future work could raise capacity to 325,000 b/d.

But the current pipeline hub gluts have caused producers and pipelines to move cautiously on conventional, hub-directed projects.

To the east, Enbridge has refused a connection at the Clearbrook hub with the proposed 450-mile, 16-in. High Prairie Pipeline project. High Prairie Pipeline LLC has proposed a 120,000 b/d link between Alexander, N.D., and the Minnesota hub. But Enterprise replied that there is no available capacity at Clearbook to handle the additional crude. That triggered regulatory proceedings with the Federal Energy Regulatory Commission in 2012.

Pipelines and rails are not mutually exclusive as means to the midstream end. For example, Enbridge has a major interest in the Berthold Station rail terminal expansion, located just west of Berthold, N.D. Phase one, with a capacity of 10,000 b/d, entered service in late 2012. Phase two, adding another 80,000 b/d, is scheduled to enter service in early 2013.

Gas and flaring

While most midstream operators focus on moving the Bakken's abundant crude production, the play also has a sizeable output of associated gas and NGL – although those products represent only around 3% of a typical well's revenues by some estimates. A North Dakota Pipeline Authority study found year-end 2012 gas production at around 720 MMcf/d. But the study, done for the authority by Bentek, projects a steep gas production rise to 2 Bcf/d to 2.4 Bcf/d sometime after 2020.

The play is similar to other unconventional shale plays in that it produces wet gas with an abundant NGL cut, including a higher-than-usual ethane component. A Wells Fargo Securities report released at year-end 2012 estimated late-2012 Bakken NGL production at 250,000 b/d, increasing to 310,000 b/d in 2017.

Bakken gas and NGL volumes – as with crude – must shoehorn into markets already filled with production from elsewhere, in this case primarily Canadian output from Alberta and British Columbia that moves to the Midwest through Northern Border Pipeline Co. and the Alliance Pipeline LP system.

The 2,300-mile Alliance system is unusual because it can move 1.6 Bcf/d of dense-phase gas that includes NGL, headed for the Aux Sable gas processing plant outside Chicago. The partnership's proposing new services and tolls that would take effect in late 2015 when existing contracts expire, which could rearrange gas and NGL service in the region. It plans an open season in early 2013 to solicit capacity bids from producers.

Gas and NGL production requires separate midstream investments in new infrastructure dedicated to processing, fractionation, and transportation.

"While the overall magnitude of gas production in the Bakken Shale is likely to be relatively small compared to projected growth in oil production, the resulting growth in NGL supply is fairly substantial," Wells Fargo said in a note to clients.

One variable in gas and NGL production estimates is that producers can legally flare light-hydrocarbon production in North Dakota in certain situations – and many do. Wells Fargo estimated that as much as 34% of the gas produced in the state in the latter half of 2012 went up flare stacks.

But that may have to change. Political and environmental pressures should increase as overall production grows. That will cause producers to seek end markets for their gas and NGL production.

"Processing capacity does not appear to be the limiting factor for natural gas sales in the region; rather, the constraint appears to be on the gathering side. Unlike crude oil, which can be gathered from the wellhead via trucks, natural gas must be produced into gathering lines," the report said. "Similarly, for midstream companies, gathering economics are currently not that compelling on a stand-alone basis as the absolute volume of gas produced in the play is still relatively small."

North Dakota is stepping up local gas demand. Lignite fuels the bulk of the state's electrical power grid – thanks to abundant coal reserves – but that is changing, according to Great Plains Energy Corridor, a research group at Bismarck State College.

Several gas-fired power plants are planned or under construction. Basin Electric Power Cooperative expects to place two combustion turbine generator trains online by year-end 2013. It also has applications with the state Public Service Commission for gas-fired additions to its Pioneer station at Williston and the Lonesome Creek station near Watford City. Montana-Dakota Utilities has construction under way on a simple-cycle combustion turbine at its Heskett station outside Mandan, expected to enter service in 2014.

Ethane issues

Despite gathering and processing disadvantages, the midstream seems well prepared to handle an increase in ethane volumes during the next five years based on both announced and in-development projects, but propane might be more of a challenge, according to Wells Fargo.

Currently, Bakken-produced propane goes by rail to the Bumstead, Ariz., NGL hub and rail capacity will continue to play a major role in keeping that market balanced.

Midstream NGL capacity will be adequate for the next three years, though it will be very tight until ONEOK places an expansion of its Bakken NGL Pipeline in service in mid-2014, Wells Fargo estimated. In that case, if 100% of the gas produced in the play were processed and not flared, then as much as 30,000 b/d of takeaway capacity would be needed to keep the propane market balanced.

By 2016, Wells Fargo anticipates propane could again become bottlenecked out of the play. This would require an additional 10,000 b/d of capacity to be added, which implies construction of an additional 80,000 b/d of Y-grade (mixed NGL) takeaway capacity or 200 MMcf/d of wet gas takeaway.

But industry observers say there is minimal incentive to process Bakken ethane until prices improve. A combination of rising gas prices, comparatively high pipeline tariffs, and depressed prices at the Conway, Kan., NGL hub probably means ethane rejection and continued flaring.

According to Wells Fargo, processors may be better off flaring ethane instead of processing it while prices remain at current low levels. On a long-term basis, the investment firm anticipates ethane demand will increase to 112,000 b/d by 2017 from 9,000 b/d in 2010.

ONEOK remains a major midstream operator in the region and has announced multiple Bakken-related projects. It has announced construction of the Garden Creek II gas processing plant and related infrastructure, which could cost as much as $345 million by the time it enters service in the second half of 2014. The facility is going in adjacent to ONEOK's existing Garden Creek plant that entered service at year-end 2011.

Related to that work, ONEOK announced it will add additional pumping horsepower to its under-construction Bakken NGL Pipeline, raising capacity to 135,000 b/d from 60,000 b/d. The line is scheduled to enter service in the first half of 2013, with the expansion work expected to be completed in second-half 2014. The 600-mile line will move unfractionated NGL to the Overland Pass Pipeline, which links Colorado gas liquids producers with the Conway hub.

Combined, ONEOK's Bakken NGL system will have a capacity of 490 MMcf/d in the Bakken with more than 5,000 miles of gathering lines at completion in late 2014.

Rail Terminals

Company	Facilities	Capacity (b/d)	Start date
EOG Resources Inc.	Crude-by-rail terminal at Stanley, N.D., to load Bakken crude for a trip to a second EOG facility at Stroud, then through EOG's pipeline to a storage center at Cushing, Okla.	65,000	Existing
	Full utilization of constructed capacity could enable two 100-car unit trains to be loaded per day, per website of construction firm.	65,000	Utilization Improvements TBD
Dakota Plains Holdings, World Fuel Services Corp.	New Town, N.D., rail terminal. Other small rail terminals at Stampede, Donnybrook, Minot. launched trucking service to transport oil from producing wells to loading terminals in September 2012.	50,000	Existing
Inergy LP and Inergy Midstream LP/ Rangeland Energy LLC	Inergy Midstream LP announces $425 million purchase offer for COLT Terminal and interconnected pipeline COLT connectors - six 120,000 barrel storage tanks, (5 in COLT hub and 1 in Dry Fork terminal) and two 8,700-ft rail loops.	120,000	Existing
	Inergy Midstream management expressed possibility of expanding the COLT terminal to handle and additional 40,000 to 80,000 b/d of crude by rail loading by using the 2nd loop of rail at the facility.	80,000	TBD
Hess Corp.	New Phase I crude oil rail load-out facility at Tioga, N.D.	25,000	Existing
	Capacity expansion at sendout terminal presumed completed in 2012.	54,000	Existing
	Phase II crude-by-rail loading facility expansion at Tioga, N.D.	20,000	2014
Watco Companies LLC and Kinder Morgan Energy Partners LP	Crude-by-rail facilities at Dore, N.D.	70,000	Existing
Musket Corp.	Crude-by-rail loading terminal at Dore, N.D.	60,000	Existing
Savage Co.'s, Kansas City Southern Inc.	Savage announced completion of its Trenton, N.D., railport that provides logistics and material services in partnership with Kansas City Southern Railroad. Existing facilities can handle two unit trains with 118 tanker cars each. That implies over 160,000 b/d of capacity.	160,000	Existing
Enbridge Energy Partners LP	Bridger Logistics LLC, the operator of the Berthold Rail project, begain shipping 10,000 b/d of crude by rail in 2012 from the Phase I construction project at Berthold, N.D.	10,000	Existing
	Phase II expansion will be needed to take Berthold project to 80,000 b/d of loading capacity to meet delivery needs at the Eddystone Rail Co. terminal in Philadelphia, Pa., by 3Q 2013.	70,000	3Q 2013
Great Northern Midstream	Fryburg Bakkenlink crude-by-rail terminal in southwestern N.D. Startup was to occur in 4Q 2012, which we presume to have happened per prior disclosures.	60,000	Existing (Presumed)
Plains All American Partners, LP	Ross complex, Manitou, N.D.	20,000	Existing
	Management on Dec. 13 disclosed a year-end 2012 startup of the expansion at the Ross complex - Crude and NGL rail transloading facility with unit train capability, presumed completed.	45,000	Existing (Presumed)
	Van Hook Phase I crude terminal in Van Hook Township, N.D.	35,000	Existing
	Van Hook Phase II expansion to 65,000 b/d under way toward 2H 2013 completion, per management on Dec. 13, 2012.	30,000	2H 2013
Hiland Partners	Proposed Hiland rail facility west of Trenton, N.D.	-	Expansion TBD.
Bakken Oil Express (Lario Logistics LLC)	Newly constructed rail hub. Unit train departed the rail hub near Dickinson, N.D.	100,000	Existing
	Bakken Oil Express - Phase II	250,000	Expansion TBD
Sable NGL	NGL truck offloading facility at Palermo Conditioning plant	7,500	Existing
Global Partners LP Zap	Global Partners LP announced the close of an $85 million purchase of 60% interest in Basin Transload LLC whose operations include the Zap oil truck tanking terminal and two crude-by-rail facilities: one in Coumbus, N.D., serving the Albany, N.Y., area on the Canadian Pacific Railway lines, and another at Beulah, N.D., serving the Gulf and West coasts along the BNSF rairoad.	160,000	2013
Targa Resources Partners LP	Johnson Corner NGL gathering facility can now transload onto rail tanker from gathering truck, per 4Q 2012 slide disclosures. We estimate capacity for this manifest facility at under 2,000 b/d.	2,000	Existing
BP Plc	Railroad loading system at Williston Basin to its 225,000 b/d Cherry Point refinery in Blaine, Wash. Media quotes BP officials tagging capacity at 20,000 b/d starting up in 2014.	20,000	2014

The other Bakken

Farther west, the Alberta Bakken/Exshaw play straddles the Montana-Alberta border. The play is geologically similar to the Bakken in Saskatchewan but earlier in its development, according to Hart Energy's North American Shale Quarterly.

Alberta's heavy oil sands to the north could offer a ready diluents market for the play's light, sweet crude. There are existing crude and gas pipelines in the area with expansion proposals as the play develops.

The play faces some of the gas gathering and processing challenges that the Bakken-Three Forks region faces. A potential dry gas market in Vancouver, British Columbia, and proposed gas liquefaction export plants on the British Columbia coast may provide markets for production.

Looking ahead

So has midstream's infrastructure investment in the Bakken/Three Forks overcome the midstream limits to moving the play's production? Things may be getting better, some observers think.

"I do think it's easing," said Savage. "There are a number of facilities that have come online. In fact, some projections would indicate that there is going to be an overcapacity of rail as we move forward. When you combine that with the pipe that is already in place, and some of the pipe that has been announced, clearly I think if you look at, say, the Lower 48, there is certainly a lot of pipeline capacity going south to the Gulf Coast.

"But if you look at the East Coast and West Coast destinations, and you look at rail facilities that are being built to handle that, our sense is there is going to be some balance. It is not all rail. It is not all pipe. Certainly rail is new when you consider what a small percentage of crude in this country was even moved by rail a handful of years ago," he said. ■

Bakken: Both Sides of the Border

Stateside returns benefit from geological superiority.

By Maggie Salamon
Upstream Research Analyst, Hart Energy

The 49th parallel north forms a large part of the border between Canada and the US with the Bakken extending over both sides of the boundary and the Exshaw (also called the Alberta Bakken) nestled right on the Canadian side of the border. The two formations may be lithologically equivalent, yet obvious differences in the size of the resource have led to a vast variation in the development of the plays.

For the US, the Bakken is the most prolific light tight oil formation in North America. At year-end 2012, the North American Shale Quarterly (NASQ) forecasted North Dakota and Montana Bakken production at 704,441 b/d. As of

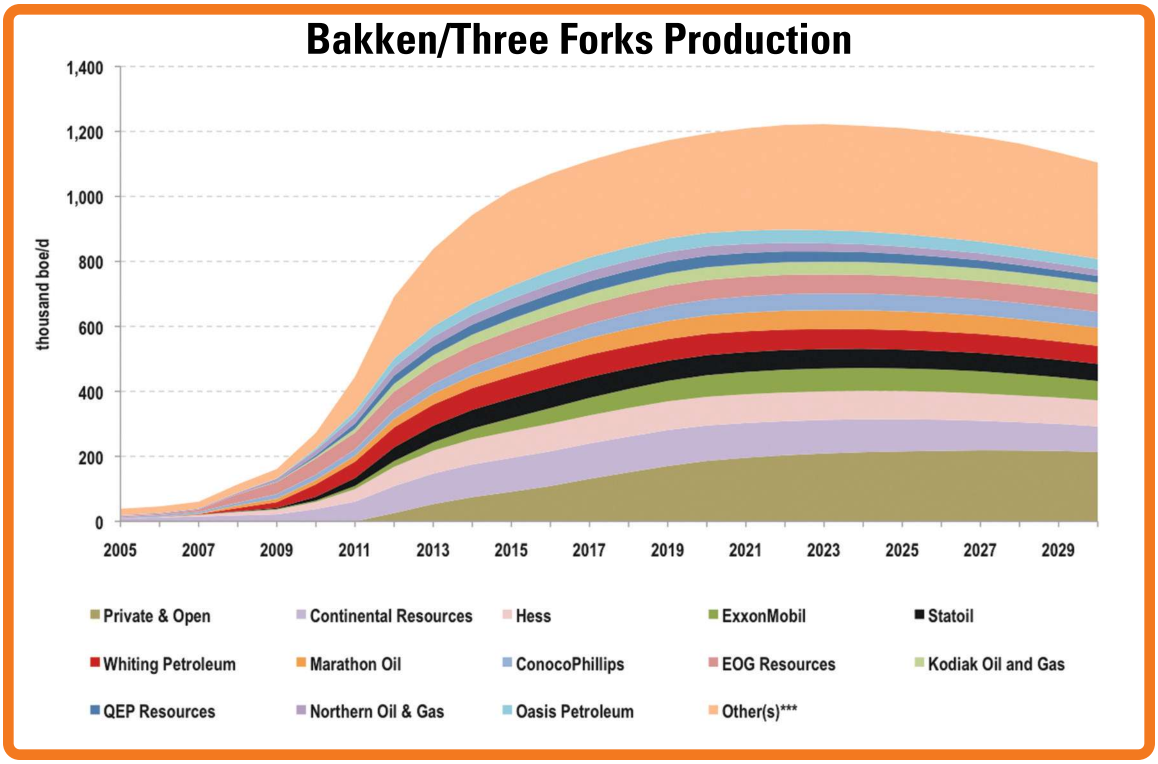
January 2013, Bakken production set a new record of 768,853 b/d, per state authorities; that is a near seven-fold increase since the play's inception back in 2006. For the Exshaw, production volumes are only 5,300 boe/d.

Low natural gas prices over several years have forced operators to look for liquids in order to stay in business and bolster margins. Several large- and mid-cap operators have been presented with an unparalleled exploration opportunity from the Bakken in the Williston Basin and they are willing to pay a premium for undeveloped acreage. In the Exshaw, Crescent Point Energy has by far the largest footprint, and the company appears to be willing to let other operators with lower capex budgets do more derisking of the play. Consequently, merger and acquisition (M&A) activity in the Alberta/Bakken has been minimal.

Valuable acreage south of the border

In the Williston Basin, there is sizeable M&A activity as operators secure liquids-rich acreage. Among the fastest growing oil and gas companies and those with the greatest potential for success are operators such as Continental Resources, the recognized leader in the region. Continental recently concluded its purchase from Samson Resources Co. of 119,218 net acres in the Bakken Field, mostly in Williams and Divide counties in North Dakota, at a cash price of US $649.3 million. The purchase includes production equivalent to about 6,500 b/d of oil, of which 82% is crude oil. This transaction put Continental Resources at the head of the table, as the leaseholder now holds more than 1.1 million acres in the play.

The announcement of another sizeable yet tricky M&A transaction in the Williston Basin came from Exxon Mobil Corp. as it bought shale assets owned by a subsidiary of Denbury Resources Inc., which entailed 196,000 net acres in North Dakota and Montana. In exchange for its Bakken Shale assets, Denbury will receive $1.6 billion in cash and acquire ExxonMobil's interests in the Hartzog Draw Field in Wyoming and Webster Field in Texas, which currently produce approximately 3,600 net boe/d of natural gas and



Bakken/Three Forks production forecast includes a selection of publicly traded companies and private companies. *(Source: North American Shale Quarterly [NASQ], 1Q 2013)*

liquids. The North Dakota and Montana assets were expected to produce more than 15,000 boe/d in the second half of 2012.

Analysts applauded the transaction, saying it was a win-win for both operators. Jason Wangler, an analyst with Wunderlich Securities Inc., said the Williston Basin was never a strategic area for Denbury. "The company seemingly never wanted to be in the Williston, and the assets, while valuable, were not a core focus for Denbury," he said after the exchange was announced. "The lack of excitement by Denbury seemed to be reflected in the stock price as it received minimal value for the assets, and in some cases they could have been considered a distraction. By selling these assets, Denbury is able to remove the distraction and unlock value as it continues to focus on its core competency of tertiary oil recovery." Wunderlich calculated that "ExxonMobil paid about $20/boe for proven reserves or $130,000 per flowing boe for the assets."

Another transaction of significant importance was the Halcón Resources acquisition of about 81,000 net producing acres in the Williston Basin from the privately held Petro-Hunt LLC for $700 million in cash and $750 million in equity. The $9,500 per acre Halcón paid for Hunt's land is about average for recent deals in the Williston Basin, according to Eli Kantor, senior E&P analyst with Iberia Capital Partners LLC in New Orleans, La.

QEP Resources also added on to its previous leasehold of 90,000 net acres with the purchase of 27,600 net acres in the Williston Basin for $1.38 billion. The properties are located in Williams and McKenzie counties in North Dakota, fairly close to the company's core acreage. The leasehold has both developed and undeveloped acreage and has current production of 10,500 boe/d. QEP Resources estimated that the acreage contains net proved and probable reserves of approximately 125 MMboe, with approximately 90% of the reserves composed of oil and other liquids. The company's acquisition is in line with its strategic plan to shift to liquids-rich plays only.

Other majors in the play such as Whiting Petroleum hold 714,567 net acres in one of the most prospective areas of the Bakken. Whiting Petroleum's acreage, considering other transactions from equivalent areas, is worth $6,000 per acre for a value of $4.3 billion. Bakken acreage has sold for a premium throughout 2012 and will continue to do so

Play	Company name	30-day IP (boe/d)	30-year EUR (boe)	Dry gas (%)	Net Acreage	Well Spacing (acres/well)	Capex ($MM)	Type Well NPV ($MM)	Breakeven oil price ($/boe)
Bakken	Continental Resources	945	610,000	4.5%	1,139,799	160-320	9	5	37
Bakken	EOG Resources	532	565,000	2.5%	90,000	160-320	8	6	43
Bakken	Whiting Petroleum (Sanish Field)	630	583,000	5.4%	137,808	640	7	6	49
Bakken	Whiting Petroleum (South Williston Basin)	517	575,000	6.2%	262,974	213	6	6	49
Alberta Bakken (CA)	Crescent Point Energy (South of Lethbridge)	220	203,000	20.0%	50,000	160	4	2	54
Alberta Bakken (CA)	Murphy Oil (Kainai)	263	244,000	20.0%	120,000	160	4	3	46
Alberta Bakken (CA)	DeeThree Exploration	573	484,000	20.0%	25,600	160	4	8	26
Alberta Bakken (CA)	Argosy Energy (Claresholm/Pearce)	182	219,000	20.0%	31,183	160	6	1	77

A set of compiled data shows the differences between wells in the Williston Basin and Alberta Bakken. *(Source: Hart Energy)*

in 2013. The area is approximately 92% oil, 6% NGL, and 2% natural gas, and as long as those splits are maintained and pilot testing does not prove otherwise, acreage will remain rather pricey.

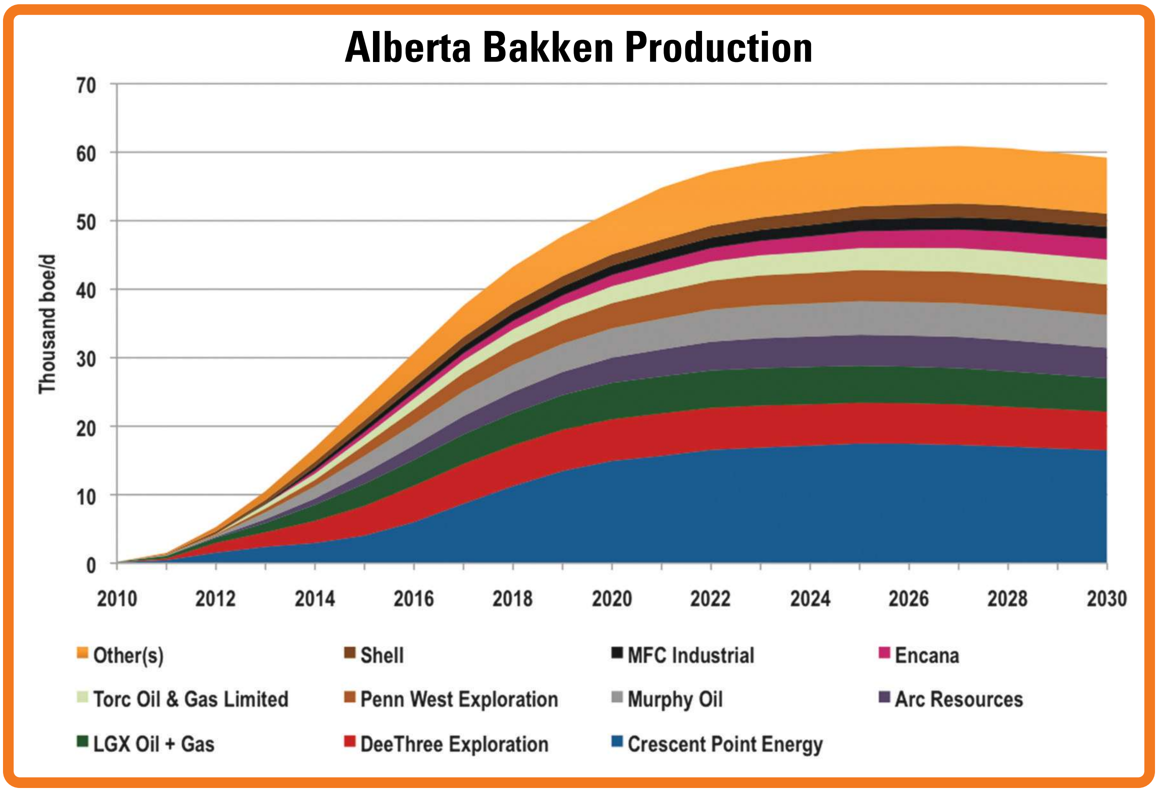
While the Alberta Bakken is still in the assessment and exploration phase, the Bakken is in full blown development. Operators are now focusing on lower costs to increase margins instead of finding oil. With that said, Bakken operators have reported drastically different well costs throughout the play. The location of their acreage, various drilling depths, bottomhole well pressure, and completion techniques all affect well costs per operator. Well costs had been exceptionally high in the Williston Basin and peaked at roughly $10 million per well over the past years. Now, operators are scrambling to find ways of reducing costs and better managing a multitude of inefficiencies associated with drilling.

Continental Resources is one of many Bakken operators that have touted declining well costs. The company has managed to cut cost from $9.2 million to $8.2 million through ECO-Pad drilling. Its pad drilling technique is a method in which four wells are drilled from a single drilling pad instead of one. In the most recent company presentation, management said it recently completed its six-well Florida-Alpha Project for $46.8 million, or less than $8 million per well. The company is well on its way toward having a reduction of $1 million per well, at minimum, by year-end 2013.

Smaller E&P companies such as Kodiak Oil & Gas noted it saw a 15% to 20% reduction in well cost due to its spud-to-rig release days now averaging in the low 20s. Kodiak has acreage in one of the deepest parts of the Williston Basin and is regarded as having lower-pressure windows, therefore costs for the company have been noted as high as $9.7 million to $10.2 million. The company expects to reduce its well costs by an additional 5% this year and initiate two multiwell pilots that include Three Forks 2 (TF2) testing. Tests to the Three Forks formations are bound to become needle-moving projects as production from these areas will likely contribute greatly to estimated ultimate recovery (EUR) totals per acreage position.

Oasis Petroleum also is focused on low expense strategies as it drives down well cost by 16% from $10.5 million in the first half of 2012 to $8.8 million as of year-end 2012, while maintaining similar EURs. The company hopes for savings of approximately $110 million in drilling and completion within the 2013 capex budget.

Lease operating expenses (LOE), which are associated to the costs of operating and maintaining property and equipment on leasehold acreage, is another area in which operators have found ways to cut cost. To reduce LOE and slash cost, companies



Alberta Bakken production forecast includes a selection of publicly traded companies and private companies from Hart Energy *(Source: North American Shale Quarterly [NASQ], 1Q 2013)*

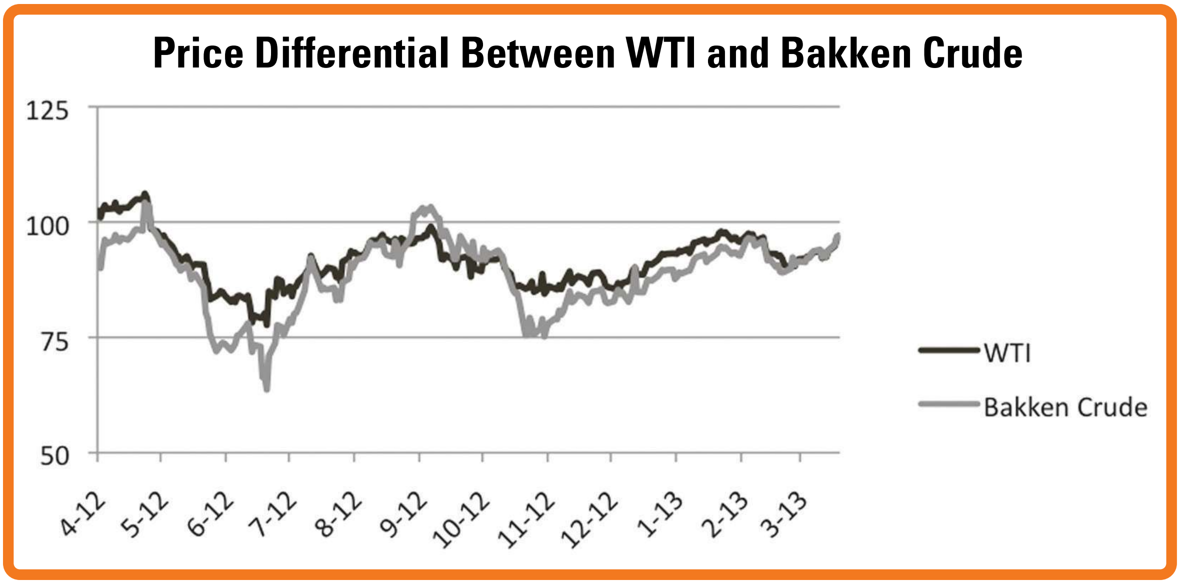
have made improvements in water disposal, one of the largest components of LOE. Kodiak Oil and Gas has made some major progress in reducing its LOE in 2012, when its sum expenditures came out to $31.7 million, or $6.04/boe, representing a 30% decrease per boe compared to 2011. The main drivers behind this reduction were improvements in water disposal costs as the company improved trucking availability and wastewater disposal facilities. It also drilled four saltwater disposal injection wells, which helped relieve it of dependence upon third parties for water handling and disposal.

As mentioned previously, some acreage positions have access to multiple formations, such as the deeper Three Forks formations, that significantly improve volumes, EUR, and margins. Continental Resources also is ramping up an aggressive Deeper Three Forks (TF) exploration program, on top of the company's successful production from Bakken wells, now with 15 additional TF2, TF3, and TF4 tests planned for the year.

The Alberta Bakken is in the assessment phase and operators are just now beginning to explore the play after picking up acreage in 2010. Since then, producers have attempted various drilling techniques and are attempting pilot programs to understand the play better. "There are two key attributes that have not been found in the Exshaw just yet," noted Brad Hayes, president of Petrel Robertson Consulting Ltd. "First, the Bakken has a low permeability sandstone or siltstone bed in the middle that is a great tight oil reservoir and is the target for horizontal drilling. Secondly, the Bakken is overpressured in the Williston Basin, giving the reservoir more energy to produce oil. We see a tight oil siltstone in the Exshaw in places, and the small amount of well control suggests over-pressuring to the west, but we haven't yet demonstrated these factors to be as well developed or extensive as in the Bakken." In Hayes' opinion, the industry "can't tell yet whether the Exshaw will be as good as the Bakken." His guess is that the early signs indicate a more difficult reservoir that won't be as productive.

Railing crude

One of the most important developments over the past year has been the transport of crude by rail.



Price Differential between WTI and Bakken crude *(Source: Bloomberg, LP; data through March 2013)*

With limited pipeline infrastructure available and an oversupplied "Cushing Coast," operators contracted with railroads to bring their product to markets on the East and West coasts. The result has higher realized oil prices for Bakken crude as refiners in the East Coast were paying over $100/bbl for imported crude oil. After contracting with Bakken producers for direct rail shipment, North American light tight oil displaced nearly 400,000 b/d from Nigeria. Prior to the use of rail to move oil in 2012, Bakken prices were $28/bbl lower than WTI. By the beginning of 2013, this price differential has narrowed to near parity.

Per state authorities, crude oil production in the Bakken set a new record of 768,853 b/d. NASQ estimates that about 70% of North Dakota Bakken crude oil is likely to move through rail. Companies such as Continental Resources see rail as having a significant impact on the bottom line. The company's production increase, higher realized oil prices, and lower operated well costs are sure to bring in strong cash flows for the Bakken operator in 2013.

Breakeven economics

Looking at Hart Energy's half-cycle breakeven economics does not fully capture the impact of higher realized prices. The key point is that Bakken operators, in general, have lower breakeven costs because the play is in full commercial development mode. For the Alberta Bakken, the breakevens have a greater variance because access to well data is less abundant and it is hard to ascertain breakeven costs

Well economics between the Williston Basin and the Alberta Bakken areas suggest that well productivity varies quite heavily, and until operators figure out the best way to crack the Alberta Bakken/Exshaw nut, activity will remain hot in the Williston Basin and cold on the Canadian side.

While there are several differences between the well economics found in the Alberta Bakken compared to the Bakken, it is important to note the dramatic variation found in 30-day initial production (IP) rates between the plays. The average 30-day IP rate for the selected operators in the Bakken is approximately 581 boe/d, whereas the average 30-day IP rate for the selected operators in the Alberta Bakken is only around 309 boe/d (around 47% less productive). It also should be noted that while production rates are lower in the Alberta Bakken, gas percentage is also higher on average.

While the Alberta Bakken is still being explored, Hart Energy anticipates that the hydrocarbon content operators derive from prospective wells will vary significantly. The combination of higher production rates and higher liquid content establish the Bakken as one of the most prolific pure-oil plays in North America, a title that the Alberta Bakken is unlikely to challenge for some time.

Additional Information on the Bakken/Exshaw Plays

For more details on the Bakken/Exshaw plays, consult the selected sources below.

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Senior Editor, *E&P*

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