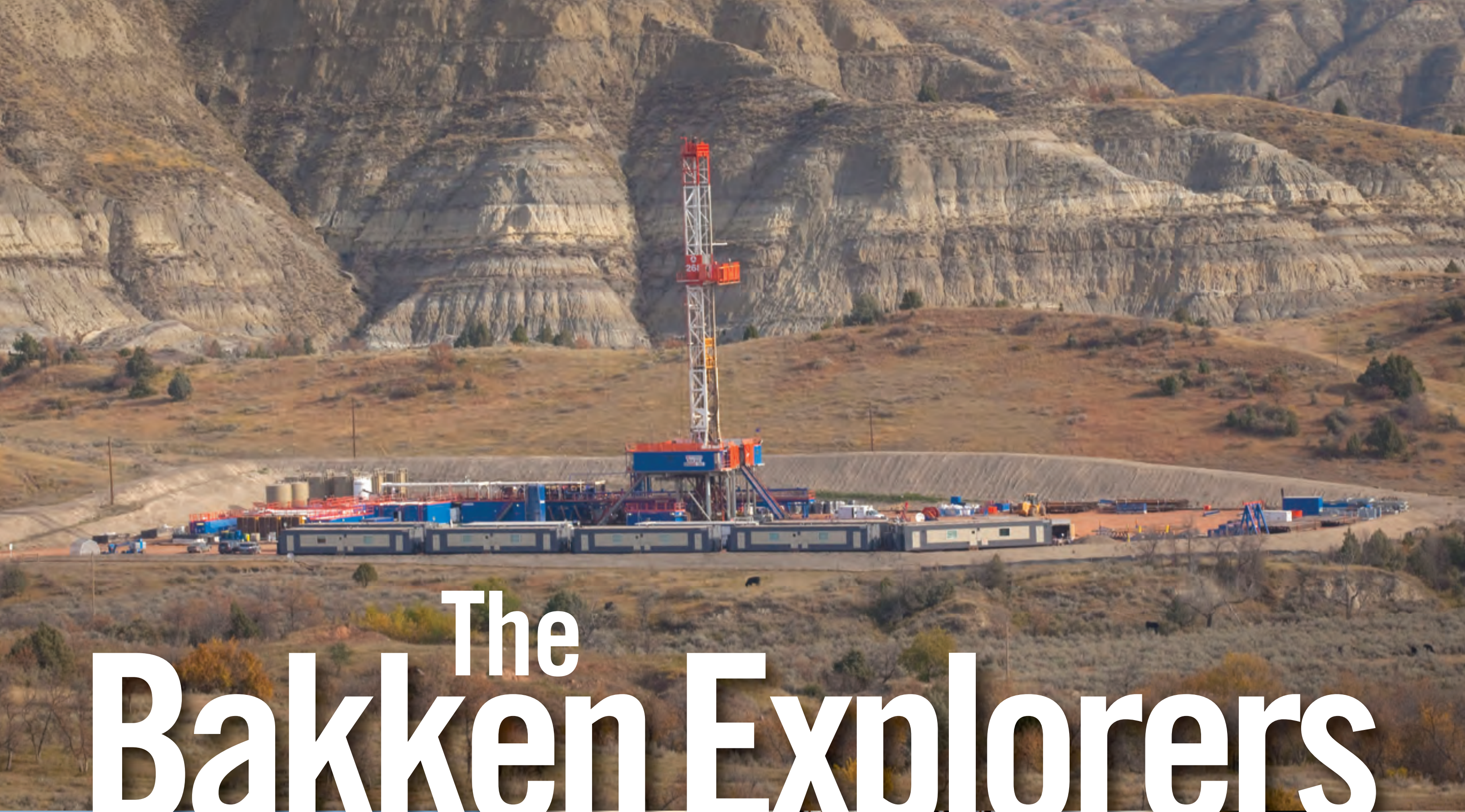

The Bakken Explorers

Extending the Bakken:
It just keeps getting better

Petroleum News Bakken

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The Bakken Explorers

Petroleum News Bakken

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Bakken Explorers again features those leading the exploration movement

For the second year, Petroleum News Bakken is pleased to issue The Bakken Explorers, our annual magazine that features exploration and production companies that explore the limits of North America's Bakken petroleum system. As the publication of record for the Bakken play, we follow the activities of operators across the Williston Basin on a weekly basis, and once a year we take the time to look more closely at the objectives and strategies of those operators that are continually striving to enhance the development and ultimate recovery of Bakken resource.

MIKE ELLERD

MARTI REEVE

We use three criteria when selecting companies to include in the annual Bakken Explorers magazine. First, we look for operators that explore the lateral limits of the Bakken petroleum system in the outlying or fringe regions of the system.

In addition, we look for operators that explore vertically within the Bakken system by looking at the more non-traditional formations and members, including but not limited to the upper Bakken shale, the lower benches of the Three Forks formation, and the Pronghorn as well as the False Bakken.

And we look for operators that are developing and utilizing innovative exploration and production technologies and techniques to enhance recoverable reserves within the system.

While our preference is to feature companies that meet all three criteria, we do consider operators who meet two and even sometimes just one of the three criteria.

Petroleum News Bakken sincerely appreciates the information that many companies share directly with us. That information enables us to more thoroughly and accurately report on the activities that have unlocked the enormous potential of one of the most prolific unconventional oil plays in the world.

Our thanks also go to the many advertisers whose support makes The Bakken Explorers magazine possible.

We hope you enjoy reading about the companies that are pioneers in the development of this world-class resource.

Mike Ellerd, editor-in-chief
Marti Reeve, special publications director

Continental: Three Forks lower benches commercial

Halfway to 2017 target of 300,000 boepd; exploration success makes 2012 forecast look conservative

By STEVE SUTHERLIN
For Petroleum News Bakken

Continental Resources has conducted extensive productivity testing of the lower benches of the Three Forks formation in North Dakota and the results are good, the company said, raising expectations that Continental will make yet another upward adjustment in its estimates of recoverable oil for its acreage in the Williston Basin.

"The Three Forks package is larger than anyone knew just two years ago," Harold Hamm, Continental founder and CEO told investors in a February conference call.

Continental is using its drilling data to design full-field developments where the Middle Bakken — as well as the Three Forks first bench, second bench and third bench — will be developed from mega pads.

HAROLD HAMM

Currently the company estimates it will recover 24 billion barrels of oil equivalent from the Bakken system based on an estimated 903 billion boe of in-place resource for the play.

Continental's 2012 plan to drive production to 300,000 boe per day by year-end 2017 was based entirely on anticipated output from the Middle Bakken and the first bench of the Three Forks formation.

Now Continental has established that the lower benches of the Three Forks are commercial, and its Oklahoma SCOOP shale play looks like a winning hand. Despite the exploration windfalls, the company plans to stay the course on its five year plan.

"We obviously have sufficient inventory to grow at a faster rate, but that would require outspending cash flow growth at a higher rate, and we don't want to do that," Warren Henry, Continental vice president of research and policy, told Petroleum News Bakken.

Henry said the company will seek to maintain a ratio of 1.6 to 1.7 times its net debt to cash flow, which is where it is today.

"We might accelerate a little or slow down a little depending on commodity prices, but we're in the sweet spot right now," he added.

The company expects to achieve its preliminary guidance of 26 percent to 32 percent production growth in 2014 over 2013, despite wicked winter weather in January.

Lower bench

Data from Continental's Hawkinson project in Dunn County, N.D., demonstrated that substantially more oil could be recovered than earlier believed. It showed that after four months of op-

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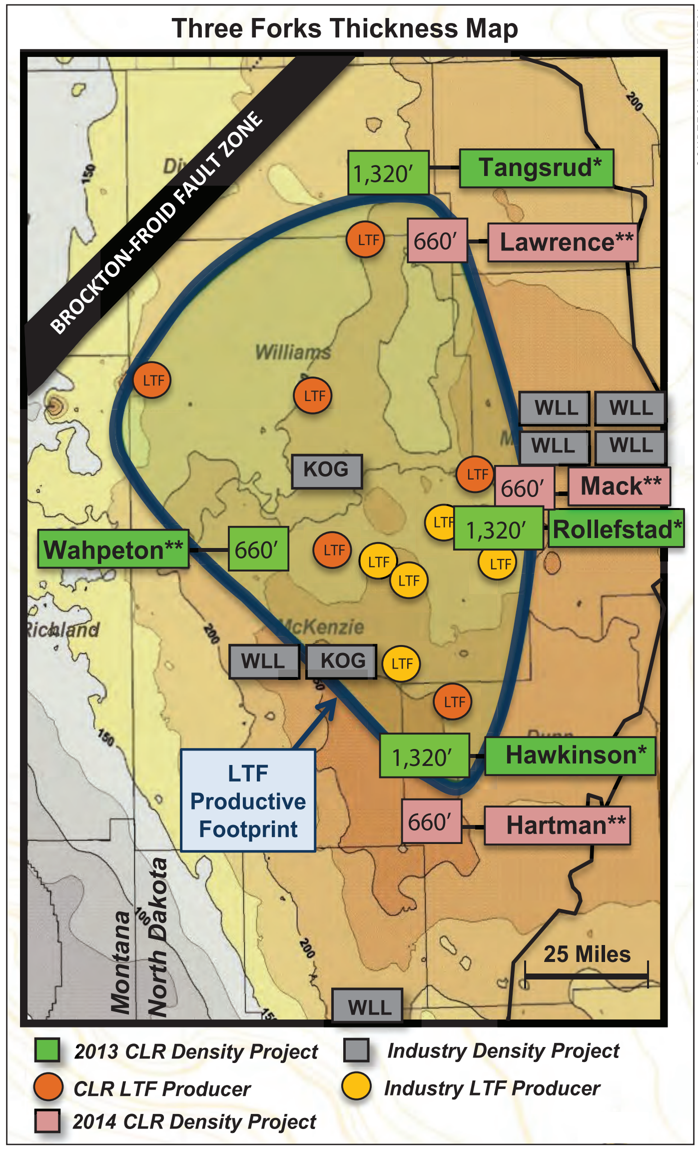

COURTESY CONTINENTAL

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CONTINENTAL *continued from page 8*

eration, average production of 12 of the 14 lower bench test wells together trended 50 percent above estimated ultimate recovery, EUR, model for a typical Bakken well.

After completing six more test projects in 2014, Continental will be poised to accelerate full-field development in multiple zones of the Three Forks, it said. The company produced 93,335 boepd from the Bakken system during fourth quarter 2013, flat to third quarter 2013 production, but a 38 percent increase versus the fourth quarter of 2012.

"This first test validates our vision for full-field development of the Bakken and the vast resource potential across our acreage position," Rick Bott, Continental president and COO said in a February conference call. "This is a landmark event for our company and the industry — unique production from four different intervals and spaced 1,320 feet apart."


FREDERICK BOTT

In November 2013, Continental said it had successfully completed the Hawkinson pilot with 14 individual wells, including three existing wells that tested at a daily rate of 14,850 barrels of oil equivalent.

Hawkinson included four middle Bakken and three first bench Three Forks wells, plus seven wells in the untested lower benches — four in the second bench and three in the third bench. The wells were spaced 1,320 feet apart in the same zone and offset 660 feet in the adjacent zones.

In February, Bott told analysts at the Credit Suisse Global Energy Summit in Vail, Colo., that Hawkinson had "proved some big things," including proof that the lower benches contained oil and could produce at commercial rates.

"We've proved that it's good quality rock. We've proved that there is oil in there. We've proved that we can produce at a commercial rate," Bott said.

Wells exemplary for Bakken

The Hawkinson wells are exemplary for the Bakken.

Continental said that based on 120 days of continuous production, 12 of the 14 Hawkinson wells are performing "very well," with average production trending 50 percent above its 603,000 boe estimated ultimate recovery, EUR, model for a typical North Dakota Bakken well.

The two "exception" wells, located in the third bench, were put on pumps and are producing on a trend below the 603,000-boe model and improving.

Continental has a 55 percent working interest in the Hawkinson project.

Continental is rolling out a plan for full-field development but it is a work in progress.

Bott said the goal of the Hawkinson tests is "to define the component parts of the petroleum system to determine how best to proceed with full field development."

The company wants more data before putting the final polish on a full-field plan.

Enough is known about the lower Three Forks benches to include them in the company's full-field development plan, Bott said, but he added that production histories from six additional density projects this year would be required before decisions on well spacing and other details are made.

"That's going to be kind of an area-by-area sort of basis," he said. "But we think the economics and rate of return in some of those deeper wells compete with anything we've got. We think it's significantly adding to the recoverable resource of the basin and the entire petroleum system."

Drilling results from three other 2013 density pilots — Tangsrud, Rollefstad and Wahpeton — are expected during the first half of 2014 and should shed even more light on the production capabilities of the deep zones, along with three additional density pilots — Hartman, Mack and Lawrence — scheduled for this year.

As part of its program, Continental will continue to explore the lower benches of the Three Forks, with plans to drill 26 exploration wells there in 2014.

Weather willies

Fourth quarter production was adversely affected by winter weather, especially in December, the company said. As a result, Continental has about 110 gross wells awaiting completion or infrastructure. To reduce the inventory and expedite initial production of recently drilled wells, the company has added additional third-party completion services.

Despite the weather, Continental was the U.S. Williston Basin's largest producer in December with 91,362 bpd — 74,332 bpd from North Dakota and 17,030 bpd from Montana.

Continental plans to complete about 287 net (870 gross) wells in the Bakken in 2014, including operated and non-operated wells. It operated 20 rigs in the play in the fourth quarter of 2013, and anticipates operating an average 22 rigs throughout 2014.

Continental also plans to test several different completion design techniques on about 20 percent of its Bakken completions in 2014, "to evaluate possible performance enhancements."

Bakken-bullish

Continental is bullish on the Bakken, having publicly announced increases in its estimated in-place oil several times and each time well above the federal government's official projections, to a current 903 billion barrels of oil equivalent.

Despite exploration results to the upside, since 2010 Continental has not revised its recoverable oil estimates for the Bakken — currently 24 billion boe.

"We're confident that the total now is larger," Henry told Petroleum News Bakken in a Feb. 21 email. "But we don't have a formal estimate of it yet."

If the company were to announce, it likely would wait until results are in hand from additional well-density pilots in 2014 that include the second, third and fourth benches of the Three Forks.

The prolific nature of the Middle Bakken and first bench of the underlying Three Forks formation has been known and exploited by industry for years, with Continental again taking the early lead in exploring both zones and establishing their commerciality.

"On an area by area basis, we don't necessarily see a tremendous difference between the Middle Bakken and first bench," Bott said. "In fact, in some areas, the first bench can be better than the Middle Bakken."

While the company is mum about specific numbers where estimates of oil in place are concerned, a few "what if?" scenarios extrapolate the significance of added pay zones in the Three Forks lower benches.

By Continental's estimates, a modest 3.5 percent recovery rate on 903 billion boe of in-place resource would increase its current

24 billion boe recovery rate to 32 billion boe, while 4 percent would yield 36 billion boe, and 5 percent could generate 45 billion boe.

Full-field at Antelope

In its first full-field development in the Bakken, including the deeper Three Forks benches, Continental has three rigs running, and has 18 wells in various stages of drilling or completion. The company will devote four or more rigs to the program, it said.

Dubbed the Antelope "Ears Back" program, the company plans to drill 350 to 400 gross wells over the next five years at Antelope. Fifty wells are budgeted for 2014.

Antelope, in McKenzie County and Mountrail County, was selected due to the company's "large operated footprint and historical results that are among the Company's highest rates of return," Continental said.

Antelope is an under-developed area, the company said. Pipeline infrastructure is currently being expanded there.

Antelope will make a large production impact in 2015, Continental said.

The company is also making progress in containing costs, it said.

Continental's average operated well costs in the Bakken continue to trend lower, it said. Fourth quarter 2013 operated Bakken well costs were approximately $8 million per well. Continental is targeting $7.5 million per operated Bakken well by year-end 2014 for its typical completion design, it said.

Continental plans to test several different completion design techniques on approximately 20 percent of its Bakken completions in 2014 to evaluate possible performance enhancements.

Projected capital expenditures for the Northern region, which includes the Bakken and the Red River units, are approximately $2.9 billion for 2014.

Data from Continental's Hawkinson project in Dunn County, N.D., demonstrated that substantially more oil could be recovered than earlier believed. It showed that after four months of operation, average production of 12 of the 14 lower bench test wells together trended 50 percent above estimated ultimate recovery, EUR, model for a typical Bakken well.

Boldly into the future

As the company executes its five-year plan, it is laying the foundation for a longer range plan extending many years onto the future.

Bott said an estimated 4,500 to 9,000 well locations in the Middle Bakken and Three Forks first bench alone gave the company the confidence for its five year-plan.

When adding the lower three benches of the Three Forks and SCOOP, he said, the number of well locations on Continental's 1.2 million acre leasehold increases to a range of 10,000 to 20,000.

"And when you turn that into potential unrisked resource that's between 4.5 billion and 7.2 billion (boe), which is on top of the proved reserves of (1.08) billion … there's a tremendous three to four decades worth of inventory."

"It's just the beginning of what we see as a multi-decade growth trajectory based on premium inventories, strong production growth, strong cash flow growth and operating excellence," Hamm said.

Contact Steve Sutherlin at stevepna@hotmail.com

COURTESY CRESCENT POINT

VIEWFIELD BAKKEN OIL RESOURCE PLAY

- >1,700 net locations in drilling inventory(1)
- 25-stage cemented liner completion technique is reducing water consumption by up to 45% per well and lowering declines
- 4.6 billion bbls OOIP with only 2.9% recovered to date(2)
- >2,100 gross wells on production, 124 million bbls produced to date(3)
- Upside reserves potential of >200 million bbls on primary recovery(4)

Viewfield Bakken Type Well Economics(5):

Type Well EUR	Production (bbl/d) 1st Month Avg	Production (bbl/d) 1st Year Avg.	NPV @ 10%	Rate of Return	Payout (Months)
75 mbbls	130	67	$1,538	75%	15.1
175 mbbls	206	118	$5,610	702%	5.1

Crescent Point Lands
Viewfield Bakken future drilling location
75 mbbls EUR type well contour curve
175 mbbls EUR type well contour curve

Crescent Point pioneer in Saskatchewan Bakken

Driving force in Canada's resource oil plays with waterflood, cemented liners driving dual-track growth

By GARY PARK
For Petroleum News Bakken

Calgary-based Crescent Point Energy was a pioneer in opening up Saskatchewan's Bakken and Lower Shaunavon formations, and is an established driving force in Canada's resource oil plays, counting on waterflood programs and cemented liner completions to achieve its dual-track growth strategy.

It has never shown the slightest hint of going on cruise control.

Having joined the top 10 on the Toronto Stock Exchange's Energy Index and added the New York Stock Exchange to its trading platforms in January, Crescent Point is constantly restless, but patient enough to allocate the time needed to evolve new technologies.

Independent recognition

The most notable symbolic milestone in 2013 occurred when its "improved recovery" reserves gained independent recognition in the early stages of the Viewfield Bakken waterflood program in Saskatchewan.

Neil Smith, chief operating officer, said the addition to reserves showed waterflooding is "commercial, it works, government recognizes it, independent (evaluators) recognize it and you're seeing great production numbers from us."

He declared that Crescent Point now has the "evidence that our waterflood works, without question."

The addition of 3 million barrels to the company's core Viewfield Bakken area are reserves that Crescent Point will not have to spend C$60 million of capital to find, Smith said.

What the independent engineers have established is just the first step on a journey that will generate a "little bit more every year," he said.

Smith noted that when Crescent Point started to develop its Viewfield Bakken core in 2007, the estimated ultimate recoveries, EUR, per well were 115,000 barrels. Now that the company is applying its new technological advances the EUR has climbed to 250,000-350,000 barrels per well, he said.

Shipments beyond North America

On another front, Crescent Point is on the verge of by-passing barriers within the U.S. administration by using rail to access Brent crude prices by shipping crude from U.S. ports to markets beyond North America.

Because those exports involve Canadian crude they are not affected by a four-decade-old ban on exporting U.S. crude and they sidestep the reviews by the Department of State and need for a Presidential Permit to cross the Canada-U.S. border. Instead the approvals come from the Department of Commerce and the Bureau of Industry and Security.

"We know there is already some Canadian crude that is being exported through the U.S., so it is very doable," said Trent Stangl, Crescent Point's vice president of marketing in a March call with analysts. "We have a lot of irons in the fire ... and we're working hard to get something in place by the end of the year."

Lowering water consumption

While it probes that option, Crescent Point is surging ahead with its water injection techniques and the latest generation of its cemented liner completions.

Chief Executive Officer Scott Saxberg said that "while U.S. companies use high volumes of water, sand and fluid (in their resource operations), we're going in the opposite direction," adding that the company is now "working on patents in and around waterfloods" that are lowering water consumption by up to 45 percent in the Viewfield Bakken.

Saxberg said independent evaluators completed initial studies of the play and determined there is a potential recovery factor of greater than 30 percent, which is more than a 50 percent increase above the primary recovery factor.

The company said the evaluators increased EURs by about 25 percent per well on average due to the application of cemented liner, which "provides more efficient fracture stimulation results, more controlled access to the reservoir and lower decline rates."

It said that in general the EUR increases have raised the value of its Bakken inner core area by about 35 percent.

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In addition, the evaluators raised the recovery factor in Crescent Point's waterflood patterns by 3 percent from previous primary recoverable reserve levels, which equates to a 16 percent rise in EURs, representing the first time that "improved recovery" reserves have been independently recognized.

Bullish on waterflood results

Crescent Point executives also offered a bullish assessment of ongoing results from their waterfloods, which are being implemented in the company's major unconventional oil fields in Western Canada.

In the Viewfield Bakken alone, volumes positively affected by waterfloods have grown by more than 15,000 barrels per day and are expected to double in the next two years.

In 2013, regulators approved the first waterflood unit in the Lower Shaunavon area and gave technical approval to the first Viewfield Bakken waterflood unit.

"This year we plan to pursue approvals for subsequent units in both plays to implement waterfloods across larger areas," Saxberg

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CRESCENT POINT *continued from page 13*

said.

"Based on solid results so far from our 25-stage cemented liner completion technique, we'll continue to refine this technology" which is being used on "every well we drill in those areas (and yields) improved production and first-year decline rates that are about 10 percent lower than the previous generation."

Crescent Point's plans for 2014 include the conversion of 30 producing wells to water injection wells, with the objective of lowering production declines and improving rates of return on adjacent producing wells.

The company is also pursuing waterflood unitization this year based on the success of its Manitoba Bakken play and is planning to build a battery to accommodate increased production.

Flat Lake drilling

On the emerging front, Crescent Point drilled 30 net wells last year at southern Saskatchewan's Flat Lake, which it said "gives exposure to the North Dakota basin," but being on the Canadian side of the border it is "able to capitalize on lower service costs."

Current production at Flat Lake is 5,500 barrels of oil equivalent per day, with the play targeted for 48 net wells in 2014.

The first full year of operations in the Uinta Basin posted a production increase of 30 percent to 10,000 boe per day, reserve additions and field operation cost reductions in a play that has an estimated 5.2 billion barrels of original-oil-in-place with only 0.4 percent recovered to date.

Crescent Point has listed the upside reserves potential at the Utah play of 75 million barrels on primary recovery, with a drilling inventory of 1,051 wells (in a corporate total of 7,139 wells) and risked finding and development costs of C$15.26 per boe, compared with a corporate average of C$21.08, including C$22.92 in the Bakken/Three Forks formation.

New completion techniques

Various new completion techniques are being tested in the Uinta with the goal of improving fracture stimulation efficiency, production rates and ultimate recoveries.

Based on results so far, Crescent Point said the resource play "has significant potential long-term upside."

The company is also seeking permits for a 3-D seismic program covering a large portion of the operated lands in Uinta's Randlett area and expects to start acquiring data in the third quarter.

As well, Utah state regulatory approval has been received for down-spaced drilling and a waterflood injection pilot in 2,560 acres of the Randlett area, where Smith said "multiple initiatives are under way," with water injection scheduled for early 2015.

Rail operations in Utah have allowed Crescent Point to broaden the market for Uinta crude beyond the Salt Lake City refining market. A permanent rail loading facility is fully operational, with capacity of 10,000 bpd and the ability to increase volumes.

Overall, Crescent Point boosted its production for 2013 by 22 percent to 127,641 boe per day (115,971 bpd of crude and liquids and 70 million cubic feet per day of gas), its proved plus probable reserves by 9 percent in 2013 to 663.8 million boe, weighted 91 percent to light and medium crude and liquids, while finding and development costs for the year averaged C$18.42 per proved plus probable boe.

Contact Gary Park through publisher@petroleumnews.com


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COURTESY ENERPLUS

Bursting with enthusiasm: Enerplus undergoes makeover

Canadian gas producer turned to oil with fall of gas prices; upbeat about Bakken/Three Forks prospects

By GARY PARK

For Petroleum News Bakken

Under a new helmsman for the first time in 12 years, Calgary-based Enerplus has experienced a fresh jolt of life with Ian Dundas as a chief executive officer who sees hope in the company's new frontiers.

IAN DUNDAS

Once embedded in the Western Canada Sedimentary Basin, with 75 percent of its business derived from the region's conventional natural gas, Enerplus now rates the Bakken and Three Forks plays in North Dakota as its largest project, with the U.S. Marcellus shale play as a prime growth driver.

As Canada's gas sector struggles to keep its head above water, Enerplus has tipped its investment balance decisively to oil.

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"The company has transformed itself," said Dundas. "We are not the company we once were."

Although the Canadian gas sector is far from down and out, a "pure gas play without any liquids in Alberta is going to be challenged," he told the Financial Post.

To underscore its change of direction, Enerplus unloaded 33,300 acres in Western Canada's Montney formation last year, pocketing C$130 million from a return of C$3,900 per acre in an area that offers "significant scope and scale" as an eventual dry gas play, Dundas said.

Goal to build on success

For Enerplus the immediate goal is to build on its success in 2013, when it added 8,000 barrels of oil equivalent per day to production, reaching 90,000 boe per day and targeting 98,000 boe per day for 2014.

Its proved plus probable, 2P, reserves were also raised by 60 million boe to 406 million boe.

For 2013 "we delivered on our objectives of improving on our cost structures," said Dundas, noting that finding and development costs were improved by 50 percent year-over-year to C$11.28 per boe.

"We delivered very attractive on-stream efficiencies, beating our internal targets and showing meaningful improvement from 2012 and 2011.

"We also advanced our strategic objective of continuing to consolidate our portfolio around four core areas. That involved buying strategically where we saw opportunities and rationalizing non-core properties, both undeveloped acreage and producing properties," he said.

The company said it has started drilling into the lower benches of the Three Forks, to test the productivity of those zones.

In particular, North Dakota achieved "significant improvement in our capital structures, associated with improvements in productivity," Dundas said.

"Our initial productivity from wells in the Bakken and Three Forks improved almost 50 percent from 2012," he said.

Given how investors viewed Enerplus and its financial prospects about a year ago, Dundas suggested the promised financial change "really showed up" in 2013, based on operational performance and "what it meant to our payouts, the sustainability of our growth and the affordability of that growth."

Gas sector retooling

What Dundas referred to as the transformation of Enerplus was nothing short of essential in a gas sector that has forced Canadian companies to retool and reinvent themselves in the face of a dramatic shrinkage of demand for their product as shale gas has swamped U.S. markets.

Those companies have been broadsided by the collapse of natural gas prices from double digits to below US$2 per million British thermal units in the space of two years, although benchmark AECO prices did climb back above US$4 during the peak winter-heating season.

RBC Capital Markets has given no reason for renewed optimism by forecasting AECO prices of US$3.58 this year and US$3.74 in 2015.

Rather than bemoaning its fate, Enerplus promoted 12-year veteran Dundas to the CEO's office last year when Gord Kerr stepped down after steering what had been an energy trust through a painful transformation into a dividend-paying intermediate-size producer.

He was already operating at peak speed when he occupied the top rung, intent on delivering sustainable, profitable growth and income to investors by focusing on top tier resource plays and mature assets with low decline.

Capital budget up

The capital budget for 2014 has been set at C$760 million, up almost C$80 million from last year, C$300 million-C$325 million earmarked for the North Dakota assets, including drilling, completion and tie-in of 20 net wells, seven of them testing downspacing in the area.

The company said it has started drilling into the lower benches of the Three Forks, to test the productivity of those zones.

The operated Bakken/Three Forks position includes 145 net future drilling locations, with light oil expected to account for 25 percent of Enerplus' 2014 production and Williston Basin output projected at 28,000 a boe per day — 20 percent from Sleeping Giant and 80 percent from Fort Berthold.

Enerplus estimates its 2P reserves in the Williston at 131 million boe, 105 million boe of which are in 73,000 net acres of Fort Berthold.

The company is counting on production growth of 33 percent this year in Fort Berthold to 22,000 boe per day, after achieving self-funded status last year and with hopes high that it will generate free cash flow this year.

In 2013, 400 percent of Fort Berthold production was replaced, adding 24.9 million boe at an F&D cost of US$19.74 per boe. A 2P reserves report has indentified 98 net future drilling sites.

The play has about seven years of inventory and a 2P recovery factor of 15 percent, while downspacing holds the promise of 150 net additional locations and another seven years of inventory.

Capital efficiencies in Fort Berthold made a sharp drop to US$12.30/boe in 2013 from US$19.80 in 2012, while production rose 50 percent to almost 38,000 boe per day, while well costs dipped to US$12.10 from US$13.10.

Little takeaway concern

Enerplus has little concern about takeaway capacity from North Dakota and Montana, estimating combined rail and pipeline capacity out of the Bakken is 1.4 million barrels per day, about 25 percent over current production.

In the Marcellus, Enerplus said production continues to surpass expectations, with output this year targeted at 120 million-140 million cubic feet per day, up 37 percent from 2012 from 2P reserves of 601 billion cubic feet, which surged by 168 percent in 2013.

In Alberta's core-growth Deep Basin, Enerplus has about 450 potential net future drilling locations in the liquids-rich Duvernay and Wilrich plays, with Wilrich offering 2P reserves of 61.6 billion cubic feet from 60,000 net acres and drilling costs dropping 40 percent since 2011 to almost C$4 million per well.

The Willesden Green in the Duvernay Shale includes 85,000 net acres (with a 100 percent working interest) accumulated over the past three years at C$750 per acre.

The company said "core analysis from vertical tests supports a range of free condensate yields across a significant portion of the acreage."

The last of the core operations are the company's waterfloods in Alberta and Saskatchewan, which have an estimated 160 future drilling locations, 2P reserves of 87 million boe, original oil in place of 1.3 billion boe and final quarter output last year of 17,000 boe per day.

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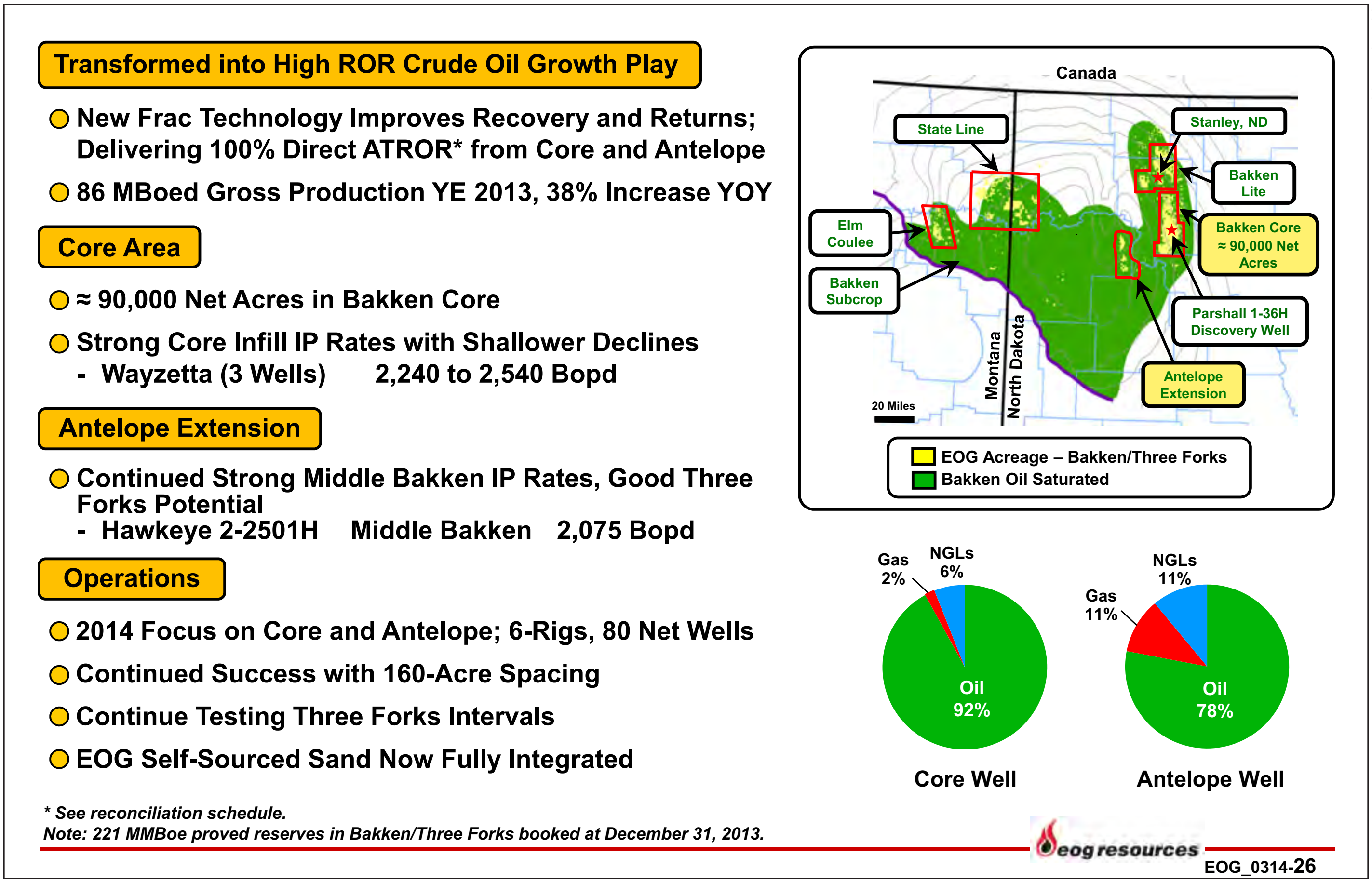

COURTESY EOG

EOG Resources reaps Bakken rewards on many levels

Expects 2-4 Three Forks benches to be commercial; touts use of own sand and packing more sand into wells

By STEVE SUTHERLIN
For Petroleum News Bakken

EOG Resources has never made a secret of the fact that it considers its Eagle Ford acreage to be the crown jewel of the company's land holdings, but its Bakken acreage has stolen a fair share of the spotlight in a very successful year for the company.

MARK PAPA

In November, EOG Executive Chairman Mark Papa said EOG has substantially upgraded its opinion of its Bakken acreage, now seeing the Bakken as a major growth area akin to the Eagle Ford in the company's portfolio.

EOG is exploiting the synergy of working in both the Eagle Ford and the Bakken.

The company's Eagle Ford completion technology is adapting well to the Bakken; it's been a game changer, Papa said.

"The Bakken is a pretty big growth area for EOG, whereas a year ago we viewed it more as a kind of a stabilized production area," Papa told CNBC's Jim Cramer in a Nov. 8 broadcast. Productivity of new Bakken wells is up about 50 percent from year ago completions, he said.

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"It's a big upside for EOG," he said.

(Editor's note: Papa's term as executive chairman of the EOG board ended Dec. 31.)

Benches beckon

Technology transfer from the Eagle Ford has made for better Bakken wells, but the Bakken petroleum system has a unique upside it doesn't share with the Eagle Ford — the multiple benches of the Three Forks formation.

BILL THOMAS

Drilling has confirmed that EOG can expect some good wells in the first two benches of the Three Forks. The company has much more testing planned, believing the third bench and even the fourth bench of the Three Forks has potential.

"We are encouraged by the Three Forks' potential in the Antelope area," EOG President and CEO William R. "Bill" Thomas said in a Nov. 7 earnings call adding that, "We completed an excellent well in the second bench early this year and plan to test the third bench during 2014."

Thomas said EOG already has a number of good wells in the Three Forks first bench.

"It has been very successful," he said.

More Bakken wells

With so many avenues to sweeten its returns, EOG aims to aggressively increase its Williston Basin drilling in 2014.

This year, EOG plans to drill 80 new wells on its Bakken acreage, versus 54 wells drilled in 2013.

EOG has experimented with water injection in the Bakken — but so far it is the packing of more sand into Bakken wells that is working, Thomas said, adding that EOG has learned that there is a strong payoff that comes from connecting more rock and connecting that rock closer to the well bore.

Thomas said the company will test the third and fourth bench and it will design development patterns and spacing to develop the Three Forks and other areas in the Bakken which could have potential.

Operations will be primarily in the company's 90,000-acre Bakken Core area, followed by its Antelope Extension area, EOG said, adding that based on successful drilling results from the first and second intervals of the Three Forks formation in the Antelope Extension, it intends to test additional benches during 2014.

"In the Bakken, we created a technical renaissance not only for EOG, but also for the industry. We changed our completion techniques and improved the well productivity," Thomas told analysts in a Feb. 25 conference call.

"We continue to see plenty of opportunity on our Bakken Core acreage," he said.

Superlatives

2013 was a big year for EOG; the company certainly moved the needle on its production volumes. By year end 2013, EOG saw its daily Bakken production climb to a gross 86,000 barrels of oil equivalent, up 38 percent from year-end 2012.

continued on next page

EOG RESOURCES *continued from page 19*

At year-end 2013, EOG's total net proved reserves of 2.1 billion boe increased 17 percent over year-end 2012, while total net proved developed reserves increased 19 percent to 1.1 billion boe. U.S. net proved crude oil and condensate reserves increased 31 percent. And total proved liquids reserves increased 25 percent year-over-year, comprising 60 percent of total company proved reserves as of Dec. 31, 2013, EOG reported.

The production increase is not just a simple product of more wells; because of technology, the wells are better, Thomas said.

"EOG's 2013 completions have 58 percent more production in the first 100 days as compared to those completed in 2012," Thomas said, adding that EOG's average IP this year is 1.9 times better than the peer average when compared to 20 different Bakken operators.

Downspacing expands return

Downspacing has produced a curious but pleasant effect on well production for EOG. Downspacing has proven to both accelerate and expand recovery. Understanding the interplay between wells that are adjacent to each other can produce powerful results.

Downspacing has made individual wells better, EOG found in its tests at Parshall field in Mountrail County, N.D.; 320-acre spacing has shown higher initial production rates from the newer infill wells. Not only that, downspacing has actually improved recovery from existing wells where infill drilling is done. The synergies have accelerated the return on 320-acre spacing as compared to the company's previous spacing — a well every 640 acres.

The company plans to test 160-acre spacing on its core acreage and implement downspacing on its nearby Bakken Lite acreage sometime later in the year.

By year end 2013, EOG saw its daily Bakken production climb to a gross 86,000 barrels of oil equivalent, up 38 percent from year-end 2012.

Golden sands

Frack sand is another asset EOG is deploying strategically to tame the Bakken, and the company is finding ways to use frack sand to dress up both sides of the ledger.

EOG is cutting procurement costs by mining its own sand. By the same token, copious and economical sand supplies have allowed the company to experiment liberally to find optimum levels of sand injection into its stimulation fractures.

"We have had a big advantage with our EOG sand. As a company, it has not only provided very low cost and helped us reduce our completion cost, it's also really helped us technically to be able to experiment more — to use more sand — and that is a big part of the reason our wells are much better," Thomas said. In baseball terms, he said, EOG is probably in the fifth or sixth inning on the completion technology process.

EOG has experimented with water injection in the Bakken — but so far it is the packing of more sand into Bakken wells that is working, Thomas said, adding that EOG has learned that there is a strong payoff that comes from connecting more rock and connecting that rock closer to the well bore.

"As we increase the amount of sand that we put in the Bakken, we feel like we are also doing a much better job of distributing that sand and the fluid frack along the lateral more evenly, so that helps to connect more rock and get more of the oil in contact with the well," Thomas said.

The extra sand makes for a well that exhibits substantial initial production and a "little slower" decline rate, he said. Whether on a 30-day rate or a 100-day cumulative production rate, the wells are showing quite a bit of improvement.

Moving that oil forward in the production lot is good for cash flow, Thomas said.

True to the core

EOG's E&P capital spending in 2014 is largely earmarked for the company's two biggest liquids plays — the Bakken and the company's flagship Eagle Ford in South Texas, where EOG maintains 632,000 acres. EOG plans to deploy 26 rigs to drill 520 net wells in the Eagle Ford this year.

In the Williston, EOG will continue in 2014 to focus the lion's share of its drilling efforts on its Bakken Core area, said Billy Helms, EOG executive vice president of exploration and production.

"In 2014, we expect to again grow crude oil production," he said. "We have existing oil and pipeline infrastructure within the core and, with the integration of EOG sand into our Bakken operations, we will continue our focus on reducing well cost even further, while enhancing the productivity and recovery factor of the field."

In 2012 EOG predicted Bakken production would fall and it pulled rigs from the play. Today, however, EOG's Bakken production charts display an upward trajectory.

The Bakken continues to show new facets that add to its value, and it sparkles brightly enough to shine alongside the Eagle Ford in the EOG crown.

Contact Steve Sutherlin at stevepna@hotmail.com

Fidelity focus on technology, Three Forks potential

Completion technology and exploring Three Forks benches at the fore but firm de-emphasizes downspacing

By STEVE SUTHERLIN
For Petroleum News Bakken

Employing the proper completion technology — cemented liners and additional frack stages — is the "key" to Fidelity's Bakken inventory; that, and making the underlying Three Forks formation productive across as much acreage as possible, said J. Kent Wells, CEO of Fidelity Exploration and Production, at a March 18 MDU Resources conference in New York.

Fidelity is an indirect wholly owned subsidiary of MDU Resources Group Inc.

"I'm not sure exactly where that is going to land, but that could (take) a couple of years of drilling to do that," Wells said.

KENT WELLS

Despite the current excitement about Bakken downspacing, Fidelity is moving cautiously on infill drilling in the Middle Bakken.

Wells said employing downspacing before devising the proper completion technique is akin to putting the cart before the horse.

He acknowledged that other Williston Basin producers, looking to squeeze more oil out of their acreage, have become more aggressive than MDU at downspacing, a fairly recent — but generally successful — recovery method for the Bakken petroleum system.

"We're continuing to develop the Middle Bakken; but, in our acreage, we're getting toward the end of our Middle Bakken drilling, unless we go to additional downspacing," Wells said.

"Our approach is let's wait and see if that bears out," Wells said. "And if it does then that opportunity is still there. Yes, it would have taken us a little longer to exploit, but we think that's wiser than getting out and drilling more wells than we really needed."

David Goodin, MDU chief executive officer, said to "stay tuned" on the Bakken, a play "which gets a lot of headlines … whether it's downspacing (or) completion techniques."

"We just don't want to get out over our skis on that one," he said. "But we are pleased with our acreage, and we continue to appraise that."

Three Forks beckons

Wells said Fidelity is in the process of identifying well locations in the Three Forks, and that the company has had recent encouraging outcomes in that process.

Better-than-expected results from its Purcell well in southern Mountrail County could lead the company to 25-40 potential Three Forks drilling locations, he said.

The company also has been successful drilling in Stark County, a predominantly Three Forks play.

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"I think as we refine this completion technique and (determine) exactly what the frack length is will really help us determine what the well spacing should be," Wells said.

Fidelity will make $130 million in capital expenditures this year in the Bakken, Goodin said.

For Fidelity, early 2014 will be a time of experimenting with completion designs in the Bakken, Goodin said, adding that the company is crafting changes to its completion designs and it would make an announcement later in 2014 when the changes are expected to be finalized.

"We are testing alternative completion techniques in both counties utilizing more frack stages, cemented liners, higher strength propane and varying the pumping techniques," he said. "Results to date have been encouraging, but there is still more work to do."

Fidelity achieved a 36 percent annual increase in production in 2012 followed by a 30 percent increase in 2013. The Bakken accounted for nearly 60 percent of the company's 4.8 million net barrels last year, notably from the Middle Bakken formation.

On par with expectations

Fidelity's production came under pressure this winter from North Dakota's harsh weather, as well as from significant rig cutbacks mid-2013, as the company focused on new completion techniques for the Bakken and other areas.

Despite the wretched winter weather, Fidelity's production was on par with expectations while oil gained weight as a percentage of the company's production portfolio.

"Our E&P group had great results on the strength of a 30 percent increase in oil production compared to the prior year," Goodin said. "Further progress was made balancing its production portfolio with oil now representing 47 percent of total production in 2013, approximately double what it was in 2010."

The company is running one rig in Mountrail County, where

continued on next page

Bakken Oil Play

2012 Oil Production

2.1 Million Net Barrels

127,000 Net Acres

- 4Q 2012 oil production up 77% over 4Q 2011
- $200 million in capital spending planned for 2013
- Mountrail County – Current 2 rig program drilling Middle Bakken & Three Forks wells
- Stark County – Current 2 rig program drilling Three Forks wells
- Richland County – Detailed study underway to optimize drilling & completion techniques for this Upper Bakken Shale play. Activity likely in 2Q / 3Q

COURTESY FIDELITY

FIDELITY *continued from page 21*

the development area consists of 16,000 net acres, and one rig in Stark County, where the company holds 51,000 net acres.

Goodin said Fidelity is looking to increase its rig count in the Bakken.

"We do look to add more rigs over time to try to accelerate our growth there," Goodin said. "We have to be careful not to get ahead of the permits; we have to be careful not to get ahead of our learning and particularly as we are now starting to move to some different areas with the second rig as well as looking at the up-hole clastics.

"We could actually have a little bit of a slowdown in our production growth which will accelerate over time as we explore those new areas, so we are trying to be very disciplined here because this is an area where industry has not been able to make it work for five decades," he said. "We feel like we are on a really good track and we are trying not to get ahead of ourselves, so it will be a measured growth but as soon as we feel confident we will look to accelerate the number of rigs working there."

As the exploration and production arm of $6.49 billion market cap MDU Resources with the access to capital that represents, Fidelity seems quite comfortable taking its time to study its acreage rather than to horse the oil out of it in a rush for cash flow.

That's not to say that Fidelity isn't willing to venture outside of the box and try new things. In Richland County, Mont., Fidelity has drilled wells in the upper Bakken shale, making Fidelity the second Williston Basin operator to produce oil from actual shale with horizontal wells and hydraulic fracturing. The upper Bakken shale — the source of much of the oil in the tight sand reservoirs of the Bakken petroleum system — is a challenge. Its wells typically have lower initial production rates than Middle Bakken and Three Forks wells, but that is offset by a more gradual decline in production rates as the well ages, Fidelity said. The company said it will recomplete existing wells and it is working to find a more efficient completion design for Upper Bakken wells.

Also in Richland County, Fidelity is planning to begin an exploration program in the latter half of this year to test the Red River Horizon.

"We just don't want to get out over our skis on that one. But we are pleased with our acreage, and we continue to appraise that."
—David Goodin, MDU chief executive officer

Paradox

Utah's Paradox basin will see significant attention in 2014 as it assumes a more important role in supporting Fidelity's overall production.

"The Bakken continues to drive our E&P group but with each passing quarter over the past year, the Paradox has taken on increasing significance for us and we see that continuing as we move forward," Goodin said.

"For instance in 2012, we were encouraged by early results from the Paradox Basin, but it was largely based on the success of one or two wells and production from the play accounted for only 7 percent of our total oil production for the year," he said, "In 2013 we repeated those early successes and production from the play represented 17 percent of the total oil production, and in the fourth quarter the Paradox moved up to representing 21 percent of our oil production."

"This is, at least at this point in time, the gem of our portfolio," Wells said of the Paradox, where the company has accumulated 130,000 net acres and the option for 20,000 acres, nearly doubling its position from three years ago.

The company will spend $170 million in the Paradox this year, twice what was invested in the play in 2013. It has boosted production to 5,000 bpd from 100 bpd three years ago.

Fidelity also has plans for the Powder River in Wyoming, where it recently acquired 42,148 acres (24,475 net).

"We believe it adds the third leg to our oil growth story," Wells said.

Contact Steve Sutherlin at stevepna@hotmail.com

Slickwater fracks boost EURS for Halcon Resources

Moves to all pad drilling, will spend half of 2014 drilling, completions capex in Fort Berthold Bakken

By STEVE SUTHERLIN
For Petroleum News Bakken

Halcon Resources has raised its estimated ultimate recoveries 39 percent for wells in its Fort Berthold area acreage due in large part to the success of slickwater fracking, which the company began using in 2013. Halcon's average EUR now is 801,000 barrels of oil equivalent, of which 687,000 barrels or 86 percent is oil.

JON WRIGHT

"We plan to complete all future wells in Williston Basin with slickwater fracks," Floyd Wilson, Halcon chairman and CEO, said in a Feb. 27 conference call.

Halcon's revised EUR may be too conservative — the slickwater-completed wells in the Fort Berthold area are currently outperforming the 801,000 boe type curve. The company's engineers now estimate an average EUR for its Fort Berthold wells at 970,000 boe.

In its Williams County focus area, Halcon increased its estimated average gross EUR 43 percent to 477,000 boe, with oil making up 87 percent.

"We've increased the average type curves on our EUR estimates in all areas based on improved results related to drilling and completion modifications," Wilson said, adding that one of the big improvements has been slickwater fracks. "We started with those up in the Williams County area. They were very successful. We've started down in Fort Berthold with those, and they're meaningfully outperforming our new type curve."

As a result of that success, Halcon plans to spend 49 percent of its $950 million overall drilling and completions budget on its Fort Berthold acreage in 2014.

"In the Williston Basin, our Bakken/Three Forks program is going great," Wilson said. "We have production growth there in 2013 of 77 percent. This year, all of our rigs are drilling in the highest-return area at Fort Berthold. We expect to spend a little — just barely less than half — of our drilling and completion capex in 2014 in the Williston Basin."

Halcon will also move to all pad drilling in 2014.

"We expect to draw 100 percent of our 2014 wells off pad versus a little less than 75 percent last year," Wilson said.

Since transitioning to pad drilling, Halcon reports cutting its spud to total depth time by 25 days and reports a savings of $1.3 million in drilling four wells on one pad compared to drilling four separate wells.

Downspacing inventory boost

Downspacing continues to pay off for Halcon as it continues with infill drilling. Early results suggest that up to 16 wells per spacing unit may be feasible in the Fort Berthold area, a density which could potentially increase the company's Fort Berthold well inventory as much as three-fold, Wilson said. "Continued downspacing there has yielded real success and has the potential to more than triple our operated well inventory in the Fort Berthold, as events unfold," he said.

In pilot testing of downspacing in the northern end of its North Fort Berthold area in McKenzie County in the third quarter, Halcon had three Bakken wells on spacings of 660 feet that came in with an average initial potential, IP, of 2,665 boepd. Halcon decided to downspace the majority of future drilling in its Fort Berthold area

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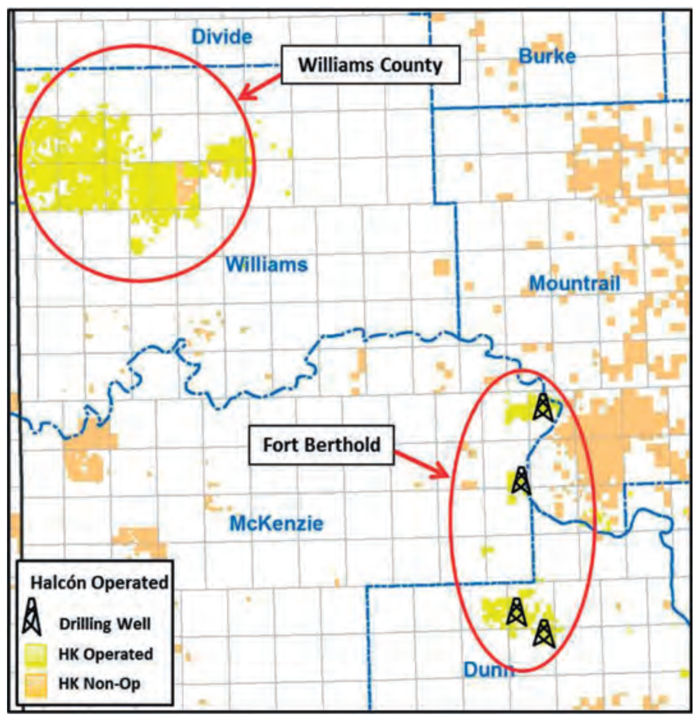

COURTESY HALCON

Kodiak Oil and Gas solving the Bakken puzzle

Downspacing pilots, zipper fracks drop well costs, efficiency rises; specialized gas-capable rigs planned

By STEVE SUTHERLIN
For Petroleum News Bakken

LYNN PETERSON

Puzzle solving involves decisions about where to put the pieces, and in the Bakken, tighter placement of wells has been the strategic mantra at Denver-based Kodiak Oil and Gas Corp. since the company undertook a downspacing push in 2013.

Kodiak is pleased with the results of its program to drill, complete, and evaluate higher density lateral spacing, Lynn Peterson, Kodiak CEO said in a February conference call.

"We delivered outstanding production and reserve growth, grew the size of our asset base both organically and through acquisitions, and continue to be one of the industry leaders and proving out downspacing in the basin, which ultimately lead to additional organic growth and drilling inventory," Peterson said.

Based on the initial results of its downspacing project, Kodiak expects to significantly improve the estimated ultimate recovery factor from each drilling spacing unit, or DSU, maximizing net present value and dramatically increasing overall well inventory across its acreage, said Ron Finch, Kodiak completions manager.

"The evaluation of the optimum lateral density for the Middle Bakken and Three Forks system is analogous to determine how many straws will be used to drain a punchbowl when each straw cost nearly $9 million," Finch said. "It is a balance between acceleration of recovery versus the cost."

The production response in the pilot well project has been very similar to the offset DSUs with conventional two to four well spacing, he said.

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The pilot projects appear to extrapolate across the core Kodiak acreage, particularly two 12 well pilot projects in the Polar and Smokey areas, and a six well high density project including three each Middle Bakken and Three Forks wells within a DSU in the Charging Eagle area of Dunn County, Finch said.

Downspacing upside

What are the limits for downspacing? Finch thinks those limits have yet to be reached.

"We believe that the ultimate development would probably result in even more higher density wells than are being considered in the pilot or experimental programs today," Finch said.

Finch compared the current stage of development in the Bakken petroleum system to the early times of the Jonah and Pinedale Anticline fields.

Wyoming State Historical Society records indicate that at the Jonah and Pinedale Anticline fields, downspacing and infill drilling tripled the number of wells that were actually drilled compared to initial estimates of wells needed to fully extract natural gas from the fields. Accordingly, the total projected lifetime of the fields dropped to 25 years, half of the original estimate.

It is a bit early to forecast the limits of downspacing in the Bakken, but so far the future looks promising.

With only a half-year of production on the books out of the 30-plus year life of the wells, initial work confirms that increased lateral density should increase the early time rate with more wells, improve the overall expected ultimate recovery from each DSU, optimize the overall recovery factor, maximize the net present value from each DSU, and significantly increase overall well inventory, Finch said.

For 2014, the company is embarking on its Polar Pilot Project 2.0, a downspacing program to analyze 16 wells per 1,280-acre DSU. It will feature 600 to 650 foot spacing between well bores, eight Middle Bakken wells, six Upper/Middle Three Forks wells, and two Lower Three Forks wells.

Additionally, Finch said, most of Kodiak's infill wells in its core areas are on 600 to 700 foot spacing, achieving higher density in each DSU going forward.

"In addition to production compressions, Kodiak has used several tools to evaluate the effect of the increased lateral density that include reservoir simulation, login core analysis from the pilot holes, tracer studies, diagnostic injection fracture tests and micro seismic evaluation," Finch said. "The result of all this has been incorporated in simulation production — in reservoir simulation, and so far we have a positive match between a reservoir simulation and the actual production history."

Performance management

As production rises, Kodiak is reducing its costs and increasing its operating efficiency.

Kodiak was able to reduce its 2014 capital expenditure budget to $940 million — approximately $60 million lower than its 2013 total capex of $1 billion — while still drilling the same number of wells.

The entire $940 million 2014 capex will go into the Bakken-focused independent's Williston Basin operations; $890 million is earmarked for the drilling and completion of an estimated 100 Bakken and Three Forks wells, while the remaining $50 million is going into the building of infrastructure as well as the acquisition of new, small acreages.

On the completion side, Kodiak has seen efficiencies through performance management. The company has successfully employed the zipper frack technique on its wells, decreasing the average frack time from 7.5 days to 5.4 days per well, said Russell

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HALCON *continued from page 23*

on 660-foot spacings, as well as to drill both Bakken and Three Forks wells on 660-foot spacings on four other pads in the Fort Berthold area. The company is also will test downspacing in its acreage in Williams County.

In addition to downspacing, Halcon is also testing deeper into the Three Forks formation, testing the second bench of the Three Forks in its Fort Berthold area. Halcon also has a 15.5 percent working interest in a Continental Resources operation that is testing the first three benches of the Three Forks.

"We're looking at 660-foot … middle Bakken wells," Wilson said. "We're looking at lease line wells wherever possible, so you don't leave that oil behind. We're looking at … full development of the first bench of the Three Forks and all the areas that we think it's good. And we're looking at significant second bench development in those areas that we think it's good. And those areas where we think it's good are being augmented daily by information from other operators, because everybody is solving for the same thing."

Good years

Halcon had a good year in 2013, and 2014 looks even better with production guidance up, reserves up, and costs and capital expenditure down.

Halcon's fourth quarter Bakken/Three Forks production rose 15 percent over the third quarter, despite brutal winter weather in December, which the company estimates cut production by 1,040 boepd.

In 2013, the company's Williston Basin production increased by more than 75 percent.

Williston Basin production averaged 24,125 boepd in the fourth quarter, compared to third quarter output of 21,039 boepd.

Halcon Resources is planning to increase company-wide production by more than 60 percent in 2014 while reducing its previously estimated capex. In mid-December, Halcon announced it had lowered its 2014 drilling and completions budget by 14 percent from $1.1 billion to $950 million. That revised 2014 drilling and completion capex is approximately 36 percent less than the approximately $1.5 billion the company spent on drilling and completions in 2013.

In the Williston Basin, Halcon plans to operate four drill rigs and spud between 40 and 50 gross operated wells, and plans to participate in another 200 to 225 gross non-operated wells with an average working interest of 3 percent.

The company currently has 141 Bakken and 39 Three Forks wells producing in the Williston Basin, another 12 Bakken and seven Three Forks wells either being completed or awaiting completion and two Bakken and two Three Forks well being drilled. Halcon holds approximately 142,000 net acres in the Williston Basin, and operates approximately 75 percent of that acreage with an average working interest of 94 percent.

Halcon ranked as the 12th largest Bakken oil producer in North Dakota in December based on output from operated, non-confidential wells.

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KODIAK *continued from page 25*

Branting, Kodiak vice president of operations.

"The record time so far is 2.7 days per well," he said. "The zipper frack technique also allows the optimization of water management."

"We continue to produce water more efficiently and we have increased our water gathering pipeline to 65 percent of the total daily volume," Branting said. "This has helped decrease our lease operating expenses as water handling disposal is one of the highest costs for a producing well."

Building our infrastructure

Kodiak will continue to build out its infrastructure in 2014, adding additional salt water disposal wells and gathering systems, he said.

In the second and third quarters of 2014, Kodiak will upgrade its rig fleet with two new BOSS rigs — a new design AC drive rig capable of the high loads necessary to move the rig, which will translate into quicker rig move times and less costs, Branting said. "The new rigs will have a dual fuel capacity, so they can run green on natural gas.

"We are also permitting eight-well pads in our Polar area, which with the addition of BOSS rigs and pump-up rigs, we should be able to drive additional efficiencies in our drilling operations," he said.

Augmenting its internal efficiencies, the company now enjoys an emerging low cost environment in the Williston Basin featuring a wealth of third party services now more readily available in the area, Branting said.

"A few years ago, when the service was really taking off, third party services were few and far between and they were difficult to secure in a timely manner," Branting said. "What a difference a few years has made; today we believe the supply of available services in North Dakota competes with any other play in North America.

"We were able to contract spot completions in a matter of days instead of months, making it no longer necessary to enter into long-term agreement for our pressure pumping services'" he said. "There are workover rigs and cold tubing units to service our wells whereas two or three years ago, they were almost impossible to come by."

In 2013 well costs declined by 15 percent to 20 percent from earlier years through the combination of service cost decreases and field level efficiencies, he said.

Current well costs, assuming a well in the deep part of the basin and completed with 100 percent intermediate strength proppant, range between \$8.7 million and \$9.1 million, Branting said. "With additional efficiency gains and cost reductions, we hope to realize an additional cost savings of 5 percent as we move throughout the year"

A new chapter

Peterson said he believes Kodiak is transitioning into a new era, moving to a focus on development and maximizing its return in the Bakken.

"As we continue to move toward full-scale development of our core Williston Basin properties, we believe we are transitioning to a new chapter for Kodiak," Peterson said. "Moving beyond the leasing, exploration, and delineation stages, we are excited to focus on development and maximizing recoveries and returns."

Kodiak said its total proved reserves on Dec. 31, 2013, were approximately 167.3 million barrels of oil equivalent, as compared to 94.7 million boe at the end of 2012.

The 2013 total represents a 77 percent increase from its 2012 estimated proved reserves on an equivalent basis, comprised of 138.2 million barrels of crude oil and 174 billion cubic feet of natural gas, the company said in a Feb. 11 preliminary unaudited operational and financial report. The 2013 reserve mix is 83 percent crude oil, along with 17 percent associated natural gas.

Approximately 46 percent of the 2013 total proved reserves are categorized as proved developed producing and approximately 54 percent are classified as proved undeveloped, which represents approximately 2.5 years of future drilling activity, the company said.

Reserve estimates for 2013 and 2012 were prepared by independent reservoir engineering consultant Netherland, Sewell & Associates Inc., Kodiak said.

Kodiak said its average daily sales volumes were 36,100 barrels of oil equivalent per day for the fourth quarter 2013, a 98 percent increase over sales volumes of 18,200 boepd for the fourth quarter 2012 and a 2 percent increase over third quarter 2013 sales volumes of 35,400 boepd. Crude oil accounted for 89 percent of fourth quarter 2013 sales volumes.

Average daily sales volumes were 29,200 boepd for 2013, representing a 103 percent increase over average daily sales volumes of 14,400 boepd in 2012, Kodiak said.

Kodiak expects its first quarter 2014 sales volumes to average between 36,000 and 38,000 boepd which is on pace to achieve the company's stated full year guidance of 42,000-44,000 boepd.

Kodiak holds approximately 192,000 net acres in the Williston Basin, and is moving into full development mode in its core areas in Williams, McKenzie and Dunn counties.

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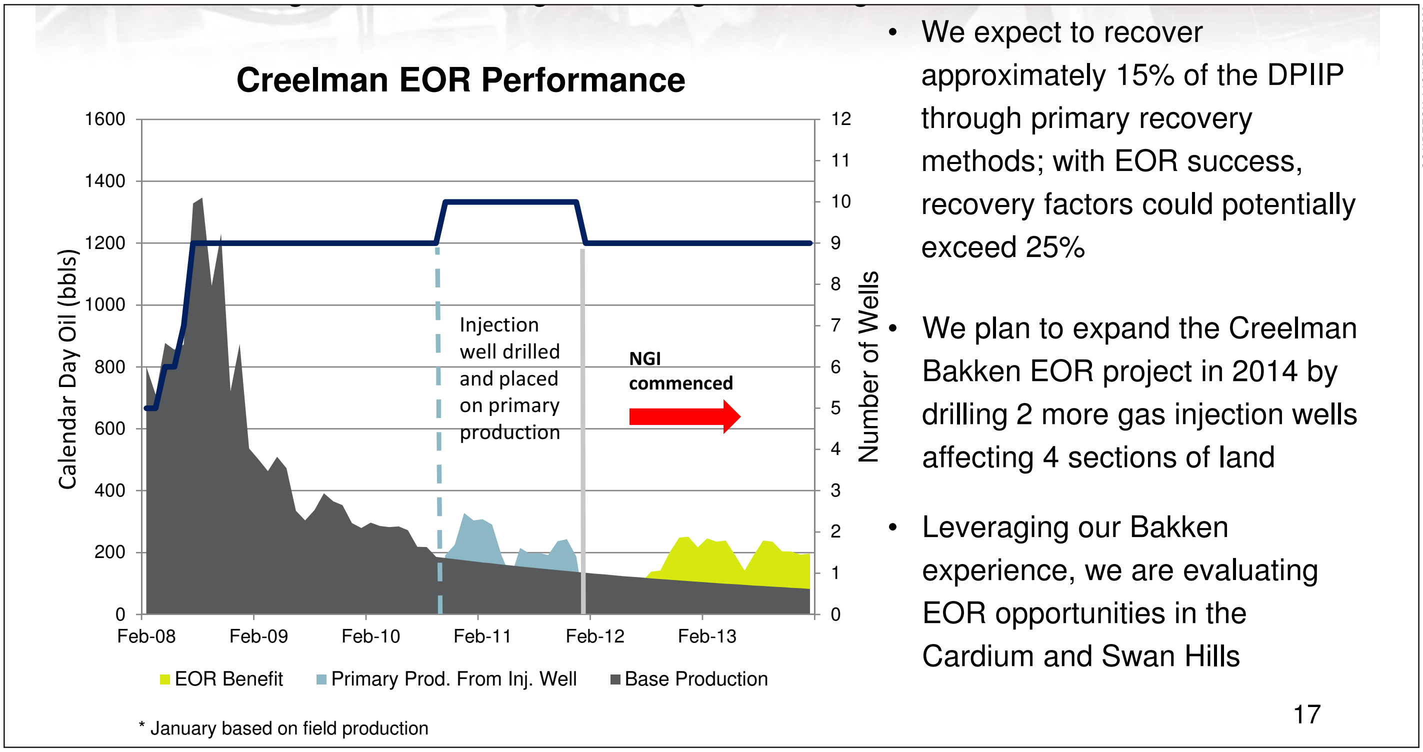

COURTESY LIGHTSTREAM

Lightstream Resources expanding its scope

Canadian junior focused on enhanced oil recovery for next 30 to 50 years in Saskatchewan Bakken

By MAXINE HERR
For Bakken News Bakken

As the first operator to successfully drill a horizontal well in the southeast Saskatchewan Bakken, Lightstream Resources has a simple business model: get into plays early, accumulate dominate land position and grow production.

The next level of growth for the technology leader is in its enhanced oil recovery, EOR, programs. The company has begun to see positive results with its natural gas flooding technique, and sees it as a solid part of the company's future.

"The Bakken has turned into a cash cow for us, becoming very sustainable," Wright said. "Primary recovery will leave a bunch of oil under the ground, but it's not a good rock for water flooding. We're using natural gas as injection and we've seen production gains — a very significant boost."

The company plans to drill 35 wells and invest in its EOR programs in 2014, spending approximately $45 million on optimizations and workovers to continue to mitigate its decline rates.

"We have 100 places we can do this, but it won't all happen (in 2014)," said CEO John Wright. "We do plan to do a lot more natural gas flooding. … We could do it for 30 to 50 years."

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"The Bakken has turned into a cash cow for us, becoming very sustainable. …We're using natural gas as injection and we've seen production gains — a very significant boost."
—CEO John Wright, Lightstream Resources

Expanding the EOR side of the business

Based on the initial success of its gas injection EOR project, Lightstream Resources intends to expand the scope of the project in 2014 by placing one additional well on injection and drilling two

continued on next page

LIGHTSTREAM *continued from page 27*

further injection wells.

EOR is not a new concept in oil and gas development, but applying it to tight oil reservoirs is a challenge. Lightstream Resources found through laboratory analysis that natural gas is a more effective flooding agent, and it has been able to utilize its own produced gas for the process.

"Our simulation work suggests reserve recovery factors could improve from approximately 15 percent under primary methods to over 25 percent with natural gas as a flooding agent. Initially, natural gas used in our planned EOR projects will come from our production facilities and is expected to be recovered and sold at a later date, further enhancing the full cycle economics of EOR," the company said.

Lightstream Resources has historically focused on increasing the efficiency of its oil production, whether that means growing production or lowering expenses, and in some instances, both. The company's technological advancements are what allow it to increase recovery at a lower cost.

The company targets light oil opportunities and has drilled and operated more than 1,000 wells using horizontal multistage fracture technology. It has developed a drilling and extraction strategy that provides greater exposure to the low permeability of the Bakken reservoir.

"We've taken our knowledge and gone to bilateral with two horizontal wells from each vertical well," said CEO John Wright. "So we double the wells underground from a single pump jack. Four bilateral wells will fully develop a section in the Bakken, while eight single laterals are required to achieve the same well density."

Evolving with new technology

Lightstream Resources was the first company to apply a fracturing technology called Cleantech, a completion fluid used in the Bakken to better control the fracturing process within the desired zone and reduce water cuts. It led to higher initial production rates and greater economic returns. The company has also modified its fluids and proppants, injection rates, and pressure environment to create multistage fracturing to unlock more oil and gas with greater efficiency.

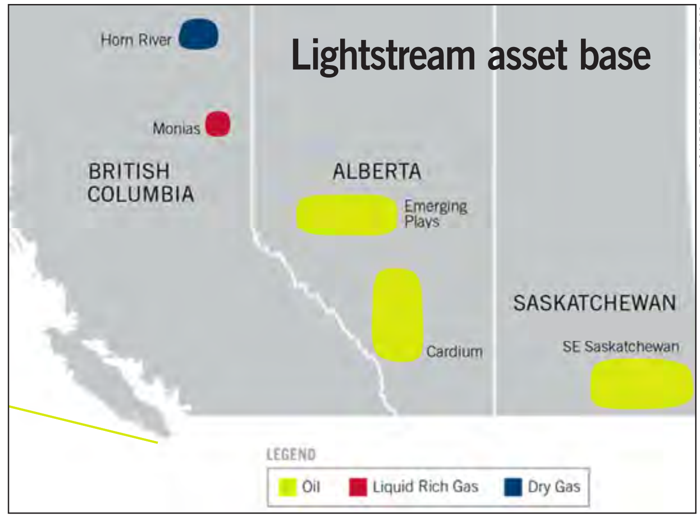
The company has moved through a few stages as it looks to optimize production. The first stage, called Bakken 1.0, applied eight fracture stimulations to shorter horizontal wells, effectively doubling the fracture density in the reservoir.

Bakken 2.0 completed long horizontal wells with 15 to 20 stage fractures, eliminating the need for two vertical well bores and two surface locations. Finally, Bakken 3.0 brought bilateral horizontal wells with 15 fractures per leg. This continues to be Lightstream Resources' standard drilling and completions method for the majority of its Bakken wells.

"Our approach has yielded positive results over the years and our latest efforts continue to motivate us to invest in our technology portfolio," the company said. "Innovation has become an essential part of the oil and gas industry and Lightstream Resources plans to continue to be at the forefront of the practical application of the innovation curve."

Other targets for the light oil-focused explorer

Lightstream plans to leverage its Bakken experience to evaluate other opportunities in its Cardium and Swan Hills formations. The two plays, in central and north-central Alberta respectively, present the prospect of benefitting from the use of horizontal wells with multistage fracture completions. In the Cardium play, the company uses slickwater fracturing, an innovation it has termed Cardium 1.0, as it believes there is room for improvement.



COURTESY LIGHTSTREAM

"Our simulation work suggests reserve recovery factors could improve from approximately 15 percent under primary methods to over 25 percent with natural gas as a flooding agent."
—Lightstream Resources

The Swan Hills area is positioned to become a critical piece for Lightstream Resources. In the past, the development of the Swan Hills was limited to conventional reservoirs. Now, multistage fracturing has untapped its potential and Lightstream has secured a key land position in the heart of the play through land sales, farm-ins and acquisitions. It has access to 92 net sections in the play with approximately 220 potential drilling locations and the possibility of future enhanced oil recovery projects.

"While we are still in the early development stage in the Swan Hills play, initial results have been encouraging with attractive economic returns," the company said.

Overall, Lightstream Resources has accumulated 120,000 net acres of land in Alberta and maintained a significant land position in northeast British Columbia within the Monias and Horn River plays.

"Our portfolio has grown to include significant holdings in four major light oil plays, a strong reserve base and a large undeveloped land inventory, positioning us for long-term growth," the company stated in its March corporate presentation.

Along with a moderate drill program scheduled for 2014, Lightstream Resources plans to focus on commercializing its EOR projects in the Bakken using what the company describes as "an extensive network of facilities that allow us to be a low cost operator."

The company's 1,200 Bakken wells averaged 22,414 of barrels of oil equivalent per day in 2013. In addition to the 35 wells slated for 2014 in the Bakken, Lightstream Resources plans to drill 42 wells in the Cardium and 14 wells in other emerging plays. Production results from Swan Hills wells already produced 17,000 barrels of oil above the company's original forecast.

Formerly known as PetroBakken Energy, Lightstream Resources changed its name in May 2013. It is headquartered in Calgary, Canada.

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Oasis: Full DSU logistics

Focus on pad development, downspacing tests, and resource potential of lower Three Forks benches as Oasis sets up for full DSU development

By STEVE SUTHERLIN
For Petroleum News Bakken

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Oasis Petroleum Inc. is evaluating not just the optimum number of wells for its Bakken drilling spacing units, but also the logistics of developing full DSUs and improving well economics, Thomas B. Nusz, Oasis chairman and CEO, said in a Feb. 4 conference call.

"Our work is not done but the team executed well on all fronts, setting us up for our first full DSU development projects in 2014," Nusz said.

With the bulk of its acreage effectively held by production at the end of 2012, Oasis entered 2013 focused on the transition to pad development, incorporating tests of effective downspacing, and measuring resource potential in the lower benches of the Three Forks, Nusz said.

TAYLOR REID

In 2013, the company saw significant growth on multiple metrics including volumes, reserves, acreage and inventory, Nusz said, while continuing to optimize well cost.

Oasis drove its well cost down from $8.5 million in the fourth quarter of 2012 to $7.5 million exiting 2013, Nusz said. In 2013, Oasis completed 136 gross operated wells, eight more than it had budgeted, while spending an estimated $40 million less in drilling and completion capital.

The company lifted its annual production by 51 percent in 2013 to 33,900 barrels of oil equivalent per day with fourth quarter production of 42,100 boepd, as its estimated net total proved reserves grew by 59 percent to 227.9 million barrels, Nusz said.

The company also grew through acquisition.

"We were able to increase our net acreage by 54 percent to 515,000 net acres" Nusz said. "This was largely as a result of the significant acquisitions where the team has done a tremendous job on integrating the assets into our operations, but also where our team was able to high-grade acreage, adding additional interest in our existing operative blocks, as well as new blocks."

Oasis also expanded its inventory with tighter downspacing and additional lower bench Three Forks wells.

"We now have 3,590 gross operated drilling locations, up 78 percent year-over-year, which provides us approximately 17 years of drilling inventory with our current rig plan," Nusz said. "The inventory will continue to evolve over time as we find ways to maximize the economics of our 403 operated DSUs."

Full DSU focus

Oasis focused on the transition to full DSU infield development through evaluation of the Three Forks, infill spacing and optimization of surface operations, said Taylor L. Reid, Oasis president and COO.

"The first component we focused on was the lower bench of the Three Forks," Reid said. "We cored seven wells through the Three Forks and conducted extensive core and log analysis, and based on those results, developed our Three Forks drilling program."

Currently Oasis has five lower bench Three Forks wells on production, Reid said.

"In Indian Hills, two second bench wells, the Paul S and the Patsy, as well as a third bench well, the Omlid, are performing in line with Three Forks wells in the area," Reid said. "On the east side, we have also been encouraged by the results of our first two lower bench completions."

"In South Cottonwood, the Mangum, our first third bench well in the area, has been on for 25 days and averaged 944 barrels of oil per day in its first seven days and 580 barrels of oil per day since it went on production, in spite of flowing at restricted rates since that first week," Reid said. "In North Cottonwood, the Bonita, our first second bench well in the area, has been on pump for 25 days; during that time, it averaged about 150 barrels of oil per day at a 73 percent water cut, and in the last five days averaged 180 barrels of oil per day at a 70 percent water cut."

A profile of increasing oil and decreasing water production is typical of both Bakken and Three Forks wells in the North Cottonwood area, Reid said, and as a result, Oasis is optimistic about the second bench in the area.

North Cottonwood well costs are generally the company's lowest at about $6.8 million per well, Reid said.

"Given these successful lower bench results on the east and the west sides, we plan to complete approximately 30 lower bench Three Forks wells in 2014," he said.

Infill density testing

Infill density testing is the second key aspect to understanding the subsurface, Reid said.

"We have 16 of our 22 density tests currently producing," Reid said. "Results from these tests have been positive, and when combined with our work on oil in place, reservoir modeling and pressure testing, lead us to believe that on average across our position, we will drill approximately 10 wells per DSU."

Well spacing will vary, depending on the reservoir in the area, Reid said.

"Across our 403 spacing units, we have grouped the inventory into three buckets: the first are spacing units where we expect to drill 15 or more wells per unit; the second are DSUs where we expect to drill 10 wells; and the third, where we expect to drill seven wells," he said, adding that the DSUs in the three buckets account for 26 percent; 40 percent; and 34 percent of the company's total 403 DSUs, respectively.

"Keep in mind that these counts include second bench wells only in Indian Hills and South Cottonwood, and no third bench wells in any area," Reid said.

2014

IN 2014, Oasis will focus on four key themes: inventory acceleration, subsurface well density, surface pad operations and cost control, and well performance, Reid said.

Oasis has significantly grown its inventory, and the company has made the decision to accelerate its development, Reid said.

"We are currently running 14 rigs and plan to add two rigs in the middle of the year," Reid said. "With the additional rigs, we are expecting to average between 46,000 and 50,000 barrels of oil equivalent per day."

Winter impacts to production combined with a focus on pad drilling through the winter and breakup has set Oasis up for a production profile that is back loaded as in previous years, with about 60 percent of completions occurring in the second half of the year, Reid said.

Oasis has set a total capital expenditure budget of $1.425 billion in 2014.

"With about 90 percent of it going to the drill bit, we expect to complete 205 gross operated wells and 155 total net wells, including non-operated wells, for a 35 percent increase over 2013," Reid said.

Subsurface well density drives the third theme in the company's focus list: surface pad operations and cost control.

"The second and third themes go hand-in-hand as the subsurface well configuration dictates the number of wells captured on our pads," Reid said. "With respect to the subsurface, you will see us drill more and more full DSUs as the year goes on and especially as we move into 2015; this translates into higher density pad drilling."

More multiwell pads

In its 2014 program, Oasis will spud about 90 percent of its wells from multiwell pads compared to 60 to 70 percent of its wells in 2013.

"With larger pad sizes, we can generate further efficiencies and cost reductions that should drive our well cost to $7.3 million, including the impact of OWS by the end of 2014," Reid said.

Oasis Well Services, OWS, is a Bakken-based subsidiary of Oasis, offering service lines including fracture stimulation, water treatment, drill pipe rental, tubing rental, water transfer, gas coolers, and other equipment. OWS has been a factor in its parent company's cost reduction program.

Finally, Oasis will be focused on improving well economics through both cost reductions and completion techniques.

In the search for better wells, the least expensive option is not always the best option, and Oasis is finding that to be true in the case of slickwater fracks.

On the west side of the company's acreage, early production results from slickwater fracks have performed in the top quartile of wells in certain areas, but there is an offset — slickwater completions cost $1.5 million to $2 million more than typical wells, Reid said, adding that Oasis will perform 15 to 20 slickwater fracks in 2014.

MAXINE HERR

"There is still a lot of work to understand the EUR impacts associated with the fracks, but we are cautiously optimistic that it will result in an increase to well economics," Reid said. "In addition to slickwater, we continue to test a number of other variants with respect to our stimulation techniques.

"In summary, we have come a long way this year in setting us up for full field development."

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Oxy on its way out but checking out the Pronghorn

Texas, California get star billing; but continues to reduce Bakken drilling costs, improve well performance

By STEVE SUTHERLIN
For Petroleum News Bakken

Oxy USA Inc. held the number 18 spot on the top Bakken producers list derived from the preliminary January 2014 Oil & Gas Production Report published by Petroleum News Bakken and based on data for operated, non-confidential wells.compiled by the North Dakota Department of Mineral Resources Oil and Gas Division.

But Oxy isn't aggressively seeking to move up on the list because its acreage effectively has a for sale sign planted in it.

Oxy is "pursuing strategic alternatives for select Midcontinent assets, including the trade and/or sale of its oil and gas interests in the Williston Basin, Hugoton Field, Piceance Basin and other Rocky Mountain assets," the company said in a recent Form 8-K filing with the Securities and Exchange Commission.


STEPHEN I. CHAZEN

Oxy hasn't abandoned all curiosity about the subsurface of its Williston Basin acreage — it recently made an exploration foray into the Bakken's Pronghorn* member— but the company has otherwise dialed down its pace in the Bakken petroleum system in favor of accelerating production in Texas.

Occidental Petroleum Corp. President and Chief Executive Officer Stephen Chazen said the company, which operates as Oxy USA domestically, has made progress on its streamlining plan which Oxy announced in October 2013, involving domestic oil and gas interests including those in the Williston Basin.

"We do expect the company to look significantly different by the end of the year," Chazen said in a Jan. 30 conference call. "We have made good progress in our pursuit of strategic alternatives to the select Midcon assets. We expect to provide further information on any transactions as they conclude, some around the end of the second quarter, and we'll announce material developments as they occur."

While 16,618 barrels of Bakken oil production per day is nothing to sneeze at, it is but a tiny morsel on the plate of $76 billion Occidental.

When Oxy's California assets — representing 154,000 boepd — are rolled into a separate publicly traded company under a plan announced in February, the remaining Oxy will generate about 600,000 boepd, mostly from the Permian Basin of Texas.

Oxy is bullish on Texas.

Along with its Middle Eastern and North African assets and its oil trading division, Oxy is looking to shed its Bakken assets in order to focus on Texas.

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On the Bakken

Oxy has approximately 341,000 net acres of oil producing and prospective unconventional properties in the Williston Basin where its teams based in Dickinson and Kenmare, N.D., are developing the Bakken petroleum system, including the Bakken, Three Forks and Pronghorn members.

The company has two core areas in the Williston Basin, the largest being in south-central and west-central Dunn County and the other in southeast Burke County.

According to early April 2014 Oil and Gas Division records, Oxy has 191 active wells, 22 on confidential status, 29 being drilled and another 43 with permitted locations.

In Dunn County, Oxy' assets are spread over 13 contiguous fields, most in the Murphy Creek, Fayette Willmen, Manning and Cabernet fields. In southeast Burke County, Oxy has 28 active wells with another six permitted in the Dimond field. Oxy has two active wells in the neighboring Vanville field and one well permitted in the Thompson Lake field. The three Burke County fields are contiguous.

Oxy's position in the Williston Basin offers "exposure to over 500,000 gross acres in the prolific Bakken resource play, Pronghorn and Three Forks upside potential," and "potential for oil-driven rate and reserve growth," the company said in its Form 8-K filing.

Occidental has pegged its overall 2014 capital expenditure, capex, at $10.2 billion, with 50 percent or $5.1 billion going into domestic operations, $510 million of which is earmarked for the Williston, down from 2013 Williston Basin expenditures of $528 million.

Seeds of revolution

In 2012, Occidental Petroleum Corp. said it was reducing its exposure in the Bakken because of stubborn operating costs, but the company insisted it still had long-term plans for the Williston Basin.

Because the cost of drilling for oil in North Dakota has "still not come down to the level that's appropriate" the Los Angeles, Calif.-based company has "a lot better places to put money right now than the Bakken," Chazen told analysts in April 2012.

Chazen said although Occidental was reducing its rig count in the Bakken, "we don't plan to exit it," adding that the company would "add to the position and build it out as a long-term resource."

But Chazen's further remarks forebode the design of the company's future streamlining plan: Chazen said Occidental would turn its focus domestically to California and the Permian Basin of West Texas and New Mexico.

The pace of drilling activity in the Bakken had overwhelmed the place and made it hard to find workers, he said.

Given that Occidental's service costs had been "essentially flat" in both Texas and California, Chazen said it didn't make sense for the company to rush to develop the Bakken until costs come down.

"It might be effective for somebody else to compete for capital, but it's not effective for us to compete for capital," he said.

Optimism in early '13

One year later, in April 2013, Occidental sounded more optimistic about its Bakken assets, saying that the company was continually increasing production, while focusing on improving capital efficiency and driving down operational costs.

In an April 2013 conference call, Oxy Oil and Gas USA President William Albrecht said the company reduced rig downtimes by an average of 20 percent, which drove down mobilization costs. "For example," Albrecht said, "in the Williston, our optimized drilling schedule designed to minimize rig mobilizations has reduced move cost by 33 percent."

Albrecht said Occidental was making "numerous incremental changes" to its daily activities, resulting in significant improvements in the company's Williston Basin and Permian operations.

"In both areas," Albrecht said, "we're optimizing our use of water in completion operations by using flow back-end or produced water in stimulations, which is generating substantial savings this year. In the Williston, more of the wells we're drilling have been trouble free, particularly due to improved directional tool reliability."

Occidental also made a strategic decision to rely less on contractors and outside consultants, and more on its own personnel, Albrecht said, resulting in efficiencies and also providing more growth opportunities for Occidental's people.

Occidental's contracting strategies also led to cost reductions.

"In this regard, principally in the Permian, Williston and at Elk Hills," Albrecht said, "we've reduced our stimulation contract pricing. We've also reduced our fluid hauling costs by implementing a trucking cluster concept, whereby certain trucking fleets are dedicated to specific core areas."

Dramatic changes

Changes were dramatic. Albrecht said Occidental slashed its completed well costs in the Williston from an average $10 million per well to $8.2 million per well in a span of just four months.

But Albrecht said Occidental was not satisfied with an average cost of $8.5 million per well. "We believe that we're now top quartile in well costs in the play and our current goal is to bring average Williston well cost down to $7.5 million."

Occidental also took steps to reduce its operating costs, especially in the areas of downhole maintenance and workovers, which together, according to Albrecht, made up the bulk of Occidental operating costs.

Occidental's efforts in driving capital efficiency and lowering operations costs paid off, he said, and the company saw a significant drop in overall costs in 2013 compared to 2012.

As compared to 2012 levels, Albrecht said, downhole maintenance and workover costs dropped 36 percent and overall surface operations costs dropped by 16 percent, contributing to a 19 percent reduction in operating costs on a boe basis across all of the company's domestic assets.

Despite the progress the company had made, six months later in October 2013, Oxy's Bakken assets were on the block.

Occidental was once bullish on the Bakken.

As one of the five largest U.S. oil companies, Occidental made headlines in late 2010 when it sold its Argentinean oil interests to a subsidiary of China Petrochemical Corp. and spent $3.2 billion on unconventional acreage in North Dakota and South Texas.

In 2011, Occidental increased its holdings in the Williston Basin to 277,000 acres.

At the time, the company said it expected to grow Williston Basin production to at least 30,000 barrels of oil equivalent per day (from 6,000 boe per day) within five years.

Perhaps that goal could still be met, if a nimbler, Bakken-focused acquirer stepped in.

Note: For years people had been seeing a limestone/lime mudstone unit between the lower Bakken and the upper Three Forks geological members underlying parts of Stark, Dunn, McKenzie, Billings and Golden Valley counties in western North Dakota, but that limestone/mudstone unit had never been well defined or well described. That was until three years ago when Anschutz Petroleum cut a long core in a well it drilled in far southern Dunn County that fully transcended what for years had been commonly known as the Sanish sand, a unit that has been considered part of the Three Forks formation in the larger Bakken petroleum system. With the information gained from the Anschutz core, the North Dakota Geological Survey now formally considers this limestone/mudstone unit to be part of the Bakken unit within the petroleum system of the same name, and have redefined it as the Pronghorn member.

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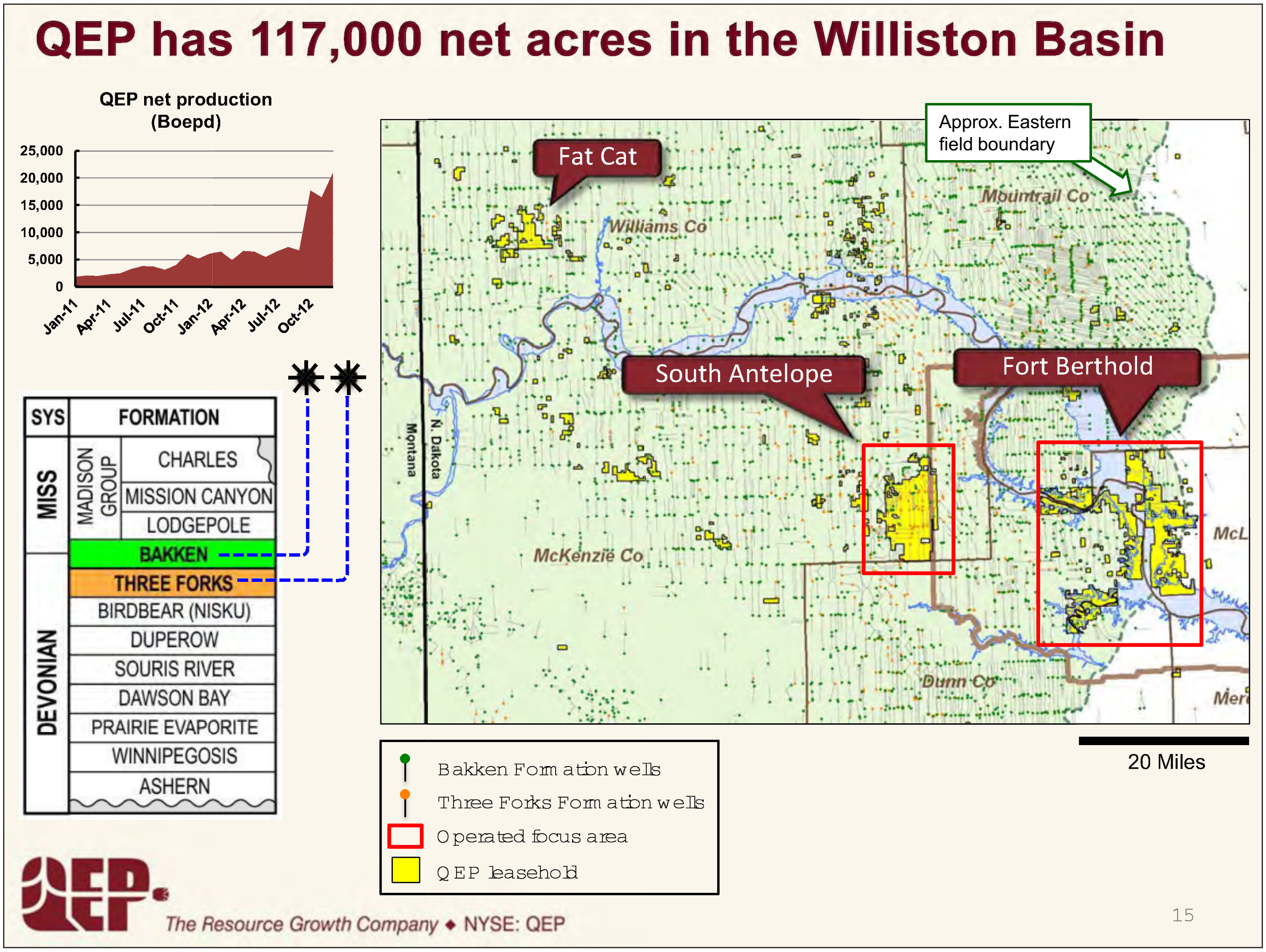

QEP: Downspacing pilot in works

Company plans downspacing pilot in 'near future'; gushes over South Antelope progress; experiments with proppant loads

By **STEVE SUTHERLIN**
For Petroleum News Bakken

QEP Resources is evaluating increased well densities on its Williston Basin acreage.

The company plans to start drilling an in-field pilot program in the near future to better understand the geology in its own leases.

CHUCK STANLEY

"We're monitoring the results from several pilot programs that are being conducted by nearby operators, and we have our own pilot program under way to evaluate applicability of increased density development on our own acreage," said Chuck Stanley, QEP Resources chairman, president and CEO in a Feb. 26 conference call.

"The geology, even though at 40,000 feet it looks layer cake, there's quite a bit of variability in both the middle Bakken and in the Three Forks; and while pilot programs run by other operators will give us a hint as to the applicability on our acreage, the only way we'll know for sure will be through piloting on our own acreage," Stanley said earlier in a Nov. 6 conference call.

Good buy

For good news, QEP need only turn to its South Antelope acreage in far eastern McKenzie County, which the Denver-based independent acquired in 2012.

QEP set a new annual production record producing 10.2 million barrels of oil, a 62 percent increase over 2013, due primarily to "successful development" of the 3,900 net South Antelope acres.

QEP reported total production for 2013 at 47.2 billion cubic feet of gas equivalent in the Williston Basin, which represents an increase of 133 percent over 2012 production. In January, QEP ranked 11th among North Dakota's oil producers averaging 32,861 barrels of oil per day for operated, non-confidential wells.

"In spite of initial delays due to downstream and weather related issues, our current South Antelope oil production has grown to levels that are commensurate with the company's expectations at the time of the acquisition," Stanley said.

QEP logged a 30 percent increase in its fourth quarter Williston Basin production despite severe winter weather conditions that dropped North Dakota's average daily oil production by more than 5 percent in December.

"Overall we remain very pleased with the technical results from the Williston Basin, and with the future potential of the play," Stanley said.

"We have our own pilot program under way to evaluate applicability of increased density development on our own acreage." —Chuck Stanley, QEP Resources chairman, president and CEO

Value almost doubles

QEP scooped up the South Antelope acreage in 2012 for $1.4 billion and saw the value of that asset almost double, Stanley said. "Including probable reserves and associated development costs, the year-end 2013 pre-tax PV-10 value of South Antelope was over $2.8 billion, nearly double the net capital investment today," he said.

QEP is striving to lower well costs, with the latest group of QEP-operated wells coming in at approximately $10 million for gross drilled, completed and equipped costs.

"As we drive efficiencies in our drilling and completion operations through pad drilling, we've also made significant progress on completed well costs during the year, with a reduction amount in actual gross completed well costs of more than a million dollars from our initial assumptions at the time of the acquisition," Stanley said, adding that "our wells costs today are approximately one-and-a-half million less than nearby, third party operated wells in which we have an interest."

Frackingstein

QEP is experimenting with hydraulic fracturing methods and testing various proppants and proppant loads in its South Antelope wells, although thus far the company hasn't seen any noticeable results.

Overall, QEP has increased the amount of proppant it uses in its wells, Stanley said.

"Generally, we've seen a pretty strong correlation between increased proppant density per stage and initial well performance," Stanley said. "And if initial well performance indicates ultimate recovery, then we should see better recoveries over the life of the well."

Stanley said QEP has "a good family of wells in the Three Forks" because the previous operator designed completions with cemented liner and plug-and-perf fracks in its Three Forks wells that can be used to compare proppant performance.

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In contrast, QEP is using a sliding sleeve frack technique, averaging approximately 30 frack stages per well on its Three Forks wells. Those wells are near the Three Forks wells the former operator drilled and the fracks were of similar size. However, Stanley said thus far QEP has not seen any "material difference" in results from Three Forks wells fracked by the previous operator and QEP fracked wells.

The former operator used 100 percent ceramic proppant, while QEP has shifted to hybrid proppant consisting of primarily sand but with a "tail-in" of either ceramic proppant or resin-coated sand. In addition, QEP has increased proppant loads from between 2 million and 2.5 million pounds to as high as 5 million pounds to reveal the "point of diminishing returns." But here too, QEP has not seen any notable performance difference.

"It's been a great natural laboratory to compare early well performance and longer-term well performance, and frankly, we struggle to see any significant difference," Stanley said. "Now, that doesn't mean that in certain parts of the basin, where rock quality may not be as good, where geology is different, that there may be a material difference between sliding sleeve and plug-and-perf cemented liner completions. We just don't see it in the area where we're operating."

Eight bits

In Q4 2013, QEP had eight drill rigs operating in the basin: six in the South Antelope area and two in Fort Berthold. In the third quarter QEP had five rigs in South Antelope and three in Fort Berthold.

QEP plans to keep its rigs busy with new spacing units, having filed applications seeking creation of two overlapping 2,560-acre spacing units with the North Dakota Industrial Commission for its hearings March 26 and 27.

In the Spotted Horn field of far eastern McKenzie County, QEP sought one overlapping 2,560-acre unit to drill up to 16 horizontal wells. In the neighboring Grail and/or Bear Den fields, QEP requested three separate overlapping 2,560s to drill one or more horizontal Bakken pool wells on each.

QEP completed 26 operated wells in the fourth quarter, up from 21 completions in the third quarter and nearly equal to the 27 seven wells completed in the first two quarters.

Of 26 wells completed in the fourth quarter, 17 in the South Antelope area had an average 24-hour initial production of 3,025 barrels of oil equivalent, while nine completed wells in the Fort Berthold clocked an average IP of 1,850 boe.

At the Fort Berthold Indian Reservation core area, QEP completed nine wells in the fourth quarter.

QEP's overall fourth quarter Bakken production averaged approximately 27,700 barrels of oil equivalent per day, which was 96 percent liquids, a 30 percent jump over third quarter and 51 percent above production in fourth quarter 2012.

For 2014, Stanley said QEP has allocated 55 percent of its $1.65 billion to $1.75 billion capital budget to the Williston Basin.

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Pushing Bakken limits

Slawson Exploration moves into its fifth decade as a leader in exploring the Bakken petroleum system

By **MIKE ELLERD**

Petroleum News Bakken

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As a privately held company, Slawson Exploration maintains a low profile in its development of its Williston Basin resources, or at least it tries to. After some 40 years of using successful innovative technologies to develop some of the most challenging formations in the basin, Slawson is well-known and well-respected in the industry and has earned a reputation as a leading Bakken explorer.

From its earliest days of drilling conventional Red River wells in Roosevelt County, Mont., in the early 1970s, to drilling its first horizontal Bakken well in 1989, its more recent exploration of the upper Bakken shale and the False Bakken, and its current middle Bakken and Three Forks development in the Stockyard Creek field in Williams County, N.D., Slawson has always been a leader when it comes pushing the limits of exploration.

The family-owned, Wichita-based independent was founded in 1957 by geologist Donald Slawson. In the late 1980s, Slawson drilled its first horizontal well in the Williston Basin into the Bakken formation in the Ash Coulee area in northern Billings County, N.D. According to Slawson, when that well was tested in February 1990, it came in with a then record-setting initial production rate of 1,362 barrels per day. Since then, Slawson Exploration has evolved into "an aggressive exploration firm" active in 10 western states and now led by Donald Slawson's son Todd.

In the Williston Basin, Slawson is an innovator in exploring the vertical and horizontal extents of the Bakken petroleum system using both state-of-the-art technologies and state-of-the-art ideas, and also is one of the top oil producers in the basin.

While most of Slawson's Bakken activity is in the mature region of the Bakken petroleum system in southwest Mountrail County, N.D., the company is known for exploring farther out into the fringes of the Bakken system in both North Dakota and Montana, targeting the middle Bakken dolomite, as well as pioneering exploration in the upper Bakken shale and what has come to be known as the False Bakken.

Upper Bakken shale

When Slawson first began drilling into the upper Bakken shale in the late 1980s and early 1990s it drilled some un-stimulated test wells in the Billings Nose region of southwest North Dakota, albeit with limited success. Slawson continued exploring the upper shale into the mid-2000s drilling un-stimulated wells in the Mondak area that lies south of the Elm Coulee field in eastern Richland County, Mont., and extends east into western McKenzie County, N.D. Those wells had low initial production rates but flat curves with high estimated ultimate recoveries.

In 2007 and 2008, Slawson drilled two upper Bakken shale wells in the Squaw Gap field near the Montana border in southwest McKenzie County, N.D. Still producing through December 2013, one of those wells produced a total of 185,223 barrels averaging 81 bpd, and the other produced 100,121 barrels through January 2014 averaging 48 bpd.

In the Elm Coulee field in western Richland County, Mont., Slawson drilled a series of test wells in the upper Bakken shale in 2012 and 2013. Four of those wells went on production between July 2012 and February 2013, and through January 2014 had been on production between 323 and 514 days with daily production averaging between 59 and 197 barrels per day.

Closer to the North Dakota border in southeastern Richland County, Slawson drilled another upper Bakken shale well that went on production in January 2013. Through January 2014, that well was on production for 363 days averaging 76 bpd.

First in the False Bakken

In August 2012, Slawson began producing from a well believed to be the first successfully completed well in the False Bakken. Although an organic-rich limestone, the False Bakken often appeared very similar to, and was sometimes confused with, the upper Bakken shale during drilling, and drillers eventually coined the term "false" Bakken. While it was known to be organic-rich, nobody appeared to be interested in exploring it — except Slawson.

Slawson's first False Bakken well, in far western Richland County, Mont., went on production in August 2012, and in the first 46 days of production averaged 127 bpd. Through January 2014, that well had produced 18,190 barrels over 487 days of production for an average of 37 bpd. While not chart-topping, Slawson did show that a well in that formation could be economic.

Overcoming drilling challenges

Drilling horizontally through shale poses certain risks, most notably the tendency for the shale to collapse. Slawson, however, found it could successfully drill horizontally through the upper Bakken shale by using shorter laterals.

Fracture stimulating multilateral wells in the shale proved problematic, and many operators simply drill single-lateral wells in the shale. Slawson, however, showed multilateral wells in the upper shale could be successfully fracture-stimulated; one of the four upper shale wells it drilled in western Richland County was a dual-lateral well with one sidetrack, and it is the well that averaged 197 bpd over 323 days of production through January 2014.

Stockyard Creek

In 2013 Slawson and its joint venture non-operating partner PetroShale Inc. acquired half of Australia-based Samson Oil and Gas's equity position in Samson's then undeveloped acreage in the Stockyard Creek field in south-central Williams County. As the operator, Slawson completed one well that was being drilled in the prospect and as of late March 2014, Slawson has completed and tested four middle Bakken wells, with six more Bakken wells that have either been completed, are awaiting completion or are being drilled. In addition, eight Three Forks wells are in the works with applications for permits to drill either being submitted or being prepared. The four middle-Bakken wells on production in the Stockyard Creek had 24-hour initial production rates of 501, 556, 1,078 and 1,323 bpd.

Bakken footprint and output

Currently Slawson's focus in the Williston Basin is in the peninsula region in southwest Mountrail County, primarily in the Big Bend and Van Hook fields. The company's activities, however, are spread over scores of oil fields in western North Dakota and eastern Montana. Most recently Slawson has been infilling in its acreage in central McKenzie County.

As of early April, North Dakota Department of Mineral Resources Oil and Gas Division records indicated Slawson had 192 wells on active status, 86 on confidential status, 10 being drilled and another six permitted. Most of those wells are in the Big Bend and Van Hook fields. As of January 2014, Slawson ranked 14th among the top 50 Bakken oil producers in North Dakota for operated, non-confidential wells with an average daily production of 21,720 bpd.

In Montana, Slawson had 64 producing wells as of early April. Most are horizontal Bakken-system wells and most of those are in the Elm Coulee field in Richland County, but a few extend into Roosevelt County. Slawson had another three wells permitted in Montana, two in Richland County and one in Wibaux County. In January, Slawson ranked as the seventh largest Bakken producer with an average of 1,904 bpd.

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OLE JORGEN BRATLAND, ASA STATOIL

Statoil adheres to flat decline curve philosophy

Known for long-term approach to reservoir development, firm methodically moves forward in Williston Basin

By MIKE ELLERD

Petroleum News Bakken

In 2012, Statoil Oil and Gas more than doubled its Bakken production over 2011, but in 2013 the company's Bakken output remained essentially flat with fourth quarter 2013 production of 49,900 barrels of oil equivalent per day, an increase of only 6 percent over the 47,000 boepd output in the fourth quarter 2012.

STEPHEN BULL

While those numbers might cause many Bakken operators to do some serious soul searching, especially during the current period of rapid development in the Williston Basin, for Statoil it is all part of the game plan as the Norwegian-based exploration and production giant takes a slower, longer-term approach to developing its onshore assets.

In an April 2013 conversation Petroleum News Bakken had with Stephen Bull, Statoil's vice president for integration of Brigham into Statoil, Bull said doubling production in one year, especially in the middle of integrating Brigham into a much larger company, "was a pretty amazing feat." When Statoil acquired Brigham in 2011, Bull said, Brigham was "on the ramp up," operating as many as 19 drill rigs at one point.

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However, for 2014, Bull said Statoil was looking to increase production some, but certainly not double it again. Statoil, he said, wants to avoid "super high" production peaks followed by "super high" decline rates he said are often seen in onshore oil production. Instead, Statoil wants to flatten its production curves over time.

With that mindset, Statoil cut back on the number of rigs operating in the basin in 2013 and began taking a more methodical approach to acquiring and evaluating drilling and completion data.

Learn before you leap


TROND ISAKSEN, STATOIL ASA

TORGRIM REITAN

A key component of Statoil's slower strategy in the Bakken is to take what it learns from drilling operations and apply that information to future drilling. To that end, Statoil cut down its rig count in the Williston Basin from 15 rigs in the first quarter of 2013 to five in the third quarter.

In an October 2013 conference call reporting third quarter financial and operational results, Torgrim Reitan, Statoil's chief financial officer, said that with a smaller number of operating drill rigs, lessons learned from one Bakken drilling operation can more effectively be applied to other drilling operations in the play. "For us it's very important to take a long-term perspective on that asset," Retain said in regard to using a smaller rig fleet in the Bakken.

But that doesn't mean Statoil won't add rigs at some point farther down the road. "We'll increase rigs, we'll decrease them over time, and it will vary," Bull told Petroleum News Bakken in April 2013. "It's that kind of optionality that Statoil likes about the onshore business."

Stay behind technology

Another facet of Statoil's slower development approach is not to get too far ahead of technology. In the April 2013 interview, Bull spoke of the importance of slow but continuous application of technologies as those technologies develop. For example, Bull said that in the early years of development in the Norwegian continental shelf, recovery rates were in the 20 percent range, but as new additional uplift technologies developed, Bull said those North Sea recoveries are among the highest in the world reaching 70 percent and averaging 55 percent. "In the good old days of petroleum engineering, people wouldn't dream that would ever be possible," Bull said.

Not getting ahead of technology, Bull said, is another part of the company's longer-term and more efficient approach to development. "That's important for us," Bull said, "because we think we can come back here and probably apply better technology and get more out of the rock than with current methods."

Side-by-side frack testing

Throughout 2013, Statoil experimented extensively with slickwater completions comparing results to wells completed using gelled fluids, the method traditionally used by Brigham in the basin. After testing side-by-side slickwater and gel wells, Statoil found that in certain areas of its Bakken operations the slickwater-completed wells outperformed gel-completed wells. However, true to its convictions, Statoil reserved judgment.


LANCE LANGFORD

In January 2014, Lance Langford, Statoil's vice president for Bakken operations visited with Petroleum News Bakken about its frack testing and said the really hard part about conducting such tests is knowing how much data are enough. "It's about a confidence level," Langford said. "The longer you have production, the more confidence you have

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Whiting on fast forward in Williston Basin

Stepping it up in Billings, Stark; accelerating Redtail development; adjusting viscosity of all fracks

By STEVE SUTHERLIN
For Petroleum News Bakken

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Whiting Oil and Gas Corp., part of Whiting Petroleum, led the way as nine Bakken operators filed applications to the North Dakota Industrial Commission for hearings March 26 and 27, seeking creation of 67 overlapping 2,560-acre spacing units, all Bakken pool units.

Whiting filed for 27 separate overlapping 2,560s.

Whiting plans one or more horizontal wells on or near the common spacing unit boundaries in each of the new overlapping units. The 27 spacing units are in the Bell, Zenith, Fryberg and Park fields, all adjacent fields in east-central Billings and northwest Stark counties.

In 2014, Whiting will continue to exploit its Williston Basin acreage in a big way.

Whiting will invest $2.4 billion of its $2.7 billion 2014 capital budget in exploration and development, a level of capital spending it forecasts will push production growth of 17 percent to 19 percent, James J. Volker, Whiting chairman and CEO, said in a Feb. 27 conference call.

"At the current drilling pace, we estimate we have 22 years of drilling inventory in the Williston Basin," he said.

In 2013, Whiting increased its production 21 percent and its proved reserves increased 31 percent.

"We grew our gross and net potential drilling locations by 47 percent and 66 percent, respectively," Volker said.

Whiting sold $917 million of non-core assets and picked up new potential resource plays in 2013.

"As a result of these actions, we have an exceptionally strong balance sheet, which we've used to increase our position in the Williston Basin, accelerate development at our Redtail field and acquire over 500,000 net acres in three new potential oil resource plays," Volker said, adding that Whiting now controls approximately 715,000 net acres in six primary fields in the basin.

Completion design instituted

Whiting has instituted an improved completion design in the Williston Basin using cemented liners to enhance well results, along with a plug and perf method of completion.

"This achieves a better breakup of the near wellbore reservoir," Volker said, adding that Whiting has achieved improved results at its Missouri Breaks, Pronghorn and Hidden Bench areas using its new completion design — seeing productivity increases greater than 50 percent across the three areas.

Whiting's production topped 100,000 barrels of oil equivalent per day in the fourth quarter of 2013.

"Our reserves increased to 438.5 million boe," Volker said. "Our reserve mix is 79 percent black crude and 89 percent liquids, and our (reserves-to-production) ratio is a healthy 13 years."

Whiting is seeing positive results from its higher-density pilots, having recently completed the Uran higher-density wells at its Sanish Field, Volker said.

"These two infill wells posted an average production rate of 1,352 boe per day versus the original two wells that had an average IP of 789 boe per day," Volker said. "Both infill wells were completed with our new completion design."

Whiting has also been experimenting with proppant in its Williston Basin fracks. During its Oct. 24 conference call, Whiting President and Chief Operating Officer James Brown said the company has used proppant masses as high as 8 million pounds but has found a "sweet spot" in the 4 million to 5 million pound range.

A good bit faster

Whiting has made a switch to more robust drill bits, which have essentially slashed the company's drilling time in half.

Volker told CNBC's Jim Cramer on Oct. 25 that through improved technology, Whiting has been able to cut the time required to drill a Bakken well to total depth, i.e., 10,000 feet vertically then 10,000 feet horizontally, from approximately 30 days to between 11 and 15 days.

Volker said Whiting's use of strong drill bits to drill its laterals often allows the company to drill the entire 10,000-foot horizontal wellbore with just one bit. "So we don't stop to have to come out of the hole to replace the drill bit. That has really been the major improvement in cutting down our drilling time."

A little dry powder

Mark R. Williams, Whiting senior vice president of exploration and development, said Whiting's reserve estimates had a

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STATOIL *continued from page 39*

in your decision." Langford said he likes to see at least 12 months of production data from wells before making any decisions about expanding a particular method to full-field development.

Langford said wells completed with slickwater tend to have longer but skinnier propped frack wings than gel-frack wells, and depending on formation thickness and rock properties in a certain area, slickwater fracks tend to extend more laterally than vertically. Gelled fracks, on the other hand, result in shorter frack wings but those frack wings tend to extend more vertically than laterally, and in certain areas, again depending on formation thickness and rock properties, fracking into the upper Bakken can enhance a well's performance.

And because of the spatial variation in geology, Statoil separates its well performance data into subgroups within certain counties in both North Dakota and Montana. That allows Statoil to directly compare its own well data in a particular area to data acquired by other operators in the same area.

Going forward, Statoil will carefully evaluate results of its completion testing, and at some point in late 2014 or early 2015, Langford believes Statoil will have sufficient data to make decisions as to when and where slickwater completions may be applied to full-field development.

That approach, said Langford, is nothing new for Statoil in the Williston Basin. "It's the same approach we've had since day one. We don't want to change too many variables, and we don't want to jump out and change what we're doing that we know works too quickly because you make mistakes."

Winning a race it didn't enter

As a part of Statoil's longer-term strategy for onshore development, the company focuses on flatter decline curves and does not intentionally go after high initial production, IP, rates. In the October 2013 conference call, Reitan said Statoil puts more importance on a reservoir's long-term production rather than trying to maximize short-term production. Boosting initial production to high rates is easy in the Bakken, Retain said, but added that the high initial production can be followed by rapid decline.

That said, Statoil dominated 24-hour IPs in North Dakota in 2013. Statoil wells were among the top 10 wells with the highest IP in 35 of the 47 weeks that Petroleum News Bakken tabulated the top 10 IPs in 2013 (Petroleum News Bakken published biweekly in January and February before going weekly in March).

Even more impressive is the fact that Statoil wells topped the top 10 IP list in 19 of the 47 weeks it was complied, and three of those top 10 IPs were record highs. All three of those top 2013 IP wells are on the same pad in the Banks field, most of which lies in north-central McKenzie County but with a small portion extending north under Lake Sakakawea into south-central Williams County. The IPs of those wells ranged from 5,070 to 5,417 barrels. The latter, Statoil's Beaux 18-19 7H, currently holds the highest IP on record in North Dakota.

At the end of 2013, Statoil held 312,000 acres in the Bakken. Most of the company's North Dakota activity is centered in around the Banks field in McKenzie County and the Alger field in western Mountrail County. In Montana, Statoil's activity is focused in the Elm Coulee Northeast field in Richland and Roosevelt counties.

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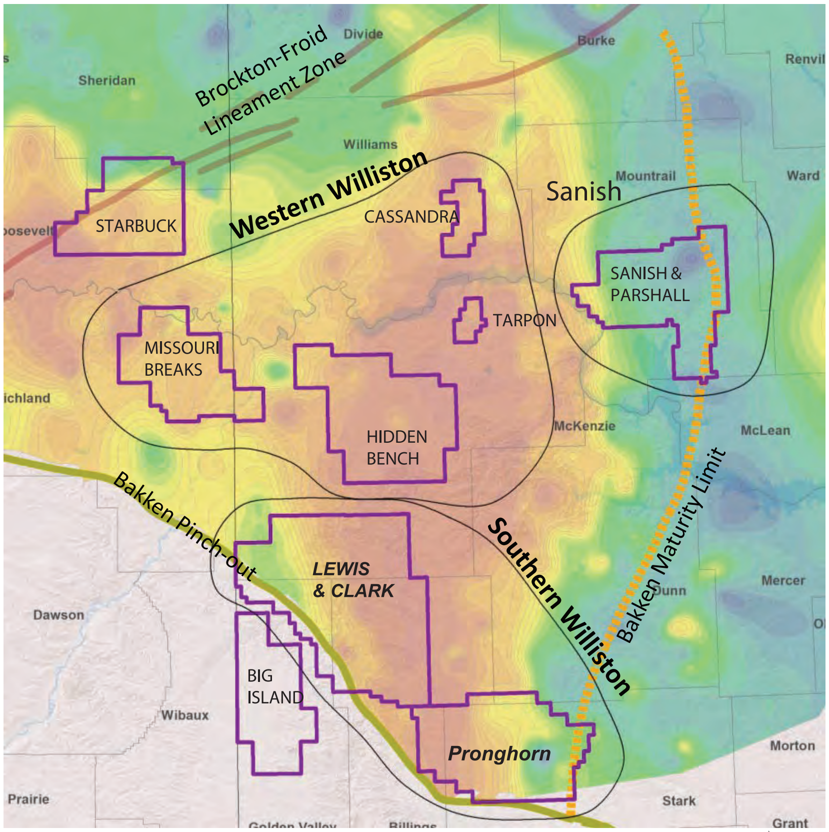
Whiting Lease Areas in Williston Basin

December 31, 2013



Field	Target	Gross Acres	Net Acres
Sanish / Parshall	Middle Bakken Three Forks	174,666	82,410
Pronghorn	Pronghorn Sand	194,217	126,866
Lewis & Clark	Three Forks	198,266	136,510
Hidden Bench	Middle Bakken Three Forks	66,805	37,418
Tarpon	Middle Bakken Three Forks	8,805	6,265
Starbuck	Middle Bakken Three Forks Red River	66,858	49,662
Missouri Breaks	Middle Bakken Three Forks	98,601	64,277
Cassandra	Middle Bakken Three Forks	29,987	13,949
Big Island	Red River	185,527	142,816
Other ND & Montana		123,793	54,862
Total		1,147,525	715,035

Energy + Technology = WHITING Growth

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WHITING *continued from page 41*

bit of potential upside from the reported numbers, as the company waits for data on its new wells to calculate their contribution to the company's reserves.


MARK WILLIAMS

"When we prepared our year end engineering database, we really didn't have enough performance data to move the majority of the results from either the cemented liners or the high-density infills into our reserve base," he said.

At issue, he said, was that in the case of its cemented liner completions and high density wells. Whiting needs to see 120 days worth of production data before it can add those into the reserves.

"So in the well count, yes, some of those are added in, but in the reserve database, they're not; it's a matter of timing," he said. "We're just waiting for performance data to get comfortable with the reserves. ... Selectively, we've started to include those as we've gotten comfortable with the results of our cemented liner completions and our high-density pilots."

Viscosity variations

Whiting is adjusting the viscosity, "if you will, of all our fracks," Williams said.

"What we're trying to find is that right mix; so going purely to slickwater, I think we've really only done a couple that are pure slickwater right now, a lot more of them are linear gels or somewhere between a cross-link and a slickwater," he said, adding that Whiting is also modifying viscosity of fracks between the early part of the stage and the last part of the stage.

"It's way too early to say that we'll go entirely slickwater, but we're trying to find a happy medium in there," Williams said.

Whiting is cued up to do another pure slickwater job, which it will compare to its cemented liner plug and perf method "to see if are we are getting the uptick from the slick liner or from the slickwater," said Brown. "Can we get to the same point with a cemented liner plug and perf and generate the same end result?"

Three Forks vs. Bakken

Which is better, a Three Forks well, or a Bakken well? It depends on where the well is located.

For years now there's been a controversy around the value of a Three Forks well, as compared to a Bakken well, said Michael J. Stevens, Whiting vice president and CFO.

"In some areas, the Three Forks will be as good and in some areas better than the Bakken," Stevens said. "You probably have to look at it regionally; broadly, maybe across the whole basin."

Williams said Whiting will place an increasing focus on the

> *"At the current drilling pace, we estimate we have 22 years of drilling inventory in the Williston Basin."*
> *—James J. Volker, Whiting chairman and CEO*

Three Forks, especially the lower Three Forks, which is less well known.

"The upper bench of the Three Forks has been firmly established over the vast majority of the basin," he said. "We've got upper Three Forks just about all of our acreage."

The second and third bench of the Three Forks may have more concentrated sweet spots.

Industry consensus is converging on the central part of the basin as the most prospective area for the second bench of the Three Forks, Williams said, adding, "That would include our Hidden Bench, our Tarpon fields, a portion of our Cassandra field, and then going east over into at least part of Sanish."

"So the central part of the basin is going to have good second bench potential; that's a lot of what we've added in this year," Williams said. "As far as the extremities of the basin, it will be less prospective as you get towards the margins."

Whiting sees upside potential in the Three Forks second bench at its Sanish/Parshall area on the east side of the basin in Mountrail County, where it holds 174,666 (82,410 net) acres and is targeting the Middle Bakken and the Three Forks.

In the Pronghorn area of the southern Williston, Whiting is targeting the Pronghorn sand; it holds 194,217 (126,866 net) acres there. The Three Forks is the target at the Lewis and Clark area, where the company has 198,266 (136,510 net) acres.

The Middle Bakken and the Three Forks are the targets across Whiting's holdings in the western Williston, where the company holds 66,805 (37,418 net) acres in the Hidden Bench area, 98,601 (64,277 net) acres in the Missouri Breaks area, 29,987 (13,949 net) in the Cassandra area, and 8,805 (6,265 net) acres in the Tarpon area.

In the 66,858 (49,662 net) acre Starbuck area, northwest of the Missouri Breaks area of the western Williston, the company is targeting the Middle Bakken, Three Forks and Red River formations.

The Big Island area lies just to the southwest of the Lewis and Clark area of the southern Williston. Whiting is targeting the Red River formation at Big Island, and it holds 185,527 (142,816 net) acres there.

Whiting has an additional 123,793 (54,862 net) acres scattered about North Dakota and Montana, bringing its total Bakken holdings to 1,147,525 (715,035 net) acres.

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JIM BLECHA/COURTESY WPX

WPX claims top cumulative Bakken oil production

Highest 1, 2-year total outputs; credits liners, plug, perf completions, ceramic proppant, zipper fracks

By STEVE SUTHERLIN
For Petroleum News Bakken

JAMES BENDER

WPX Energy Inc. has rocketed to top gun status amongst middle Bakken long lateral producers where top cumulative production is concerned.

"We had excellent results in the Williston Basin in 2013 with oil production up 39 percent year over year," James J. Bender, WPX president and CEO said in a Feb. 27 conference call. "In fact, over recent one and two year periods, WPX has been the number one cumulative middle Bakken long lateral producer in the basin."

The company reported an average 365-day cumulative production of 136,800 barrels of oil per well based on North Dakota Industrial Commission production data, which WPX says is 52 percent higher than the average of its peers in the basin. And on 730-day basis, the company reports average production of 240,800 barrels per well, 66 percent above peers.

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"We do look really good in this analysis versus the peer group," said Bryan Guderian, WPX senior vice president of operations. "I think it's indicative of the quality of the reservoir that we have, the quality of our well construction and in particular the effectiveness of our completion design."

Early on, WPX took criticism for costs when it made an early move to cement liners and more traditional plug-and-perf completion designs, Guderian said, "but this has proved to be a best practice in the basin, and our well results reflect the quality of how we're drilling and completing these wells."

WPX is reluctant to change its completion design due to the success of its wells, however it is experimenting with promising new completion designs prompted by well reservoir characterization studies in its pilot program and it expects to have production results later in the year.

WPX conducted either dual or triple fracks on 17 pads in 2013, cutting its cycle times, Guderian said.

Ceramic proppant, in high concentrations, is a key contributor to the high performance of WPX wells.

"We're currently using about a two-thirds to one-third ratio of ceramic to sand," the company's operations department said. "Although that adds about $1 million to our costs, ceramic completions are more predictable than sand, leading to better results."

WPX had a strong reserve booking at the end of the year, Guderian said, calling both middle Bakken and Three Forks well performance outstanding.

"We increased our average middle Bakken reserves by about 6 percent and also increased our average well reserves for Three Forks by some 17 percent," he said. "So what we see in our reservoir is continued strong performance and, at least during 2013, performance that exceeded our expectations."

3-D seismic guides geosteering

Advanced processing of Bakken 3-D seismic data has yielded improved geosteering performance on WPX wells — another driver of lower wells costs in the Williston Basin.

"Geosteering errors in the basin were reduced by 90 percent from mid 2012 to early 2013," Angie Southcott, WPX geology team lead told AAPG Explorer for its January 2014 issue.

Southcott said advanced high frequency extender processing of 3-D seismic data proved a breakthrough for resolving the Bakken interval, and accurately converting seismic surfaces to depth.

"It's almost like we gained a whole other octave level in frequency content of the data," Southcott said.

"With that, we were able to image and map the Upper and Lower Bakken shales."

The Bakken presents unusual issues for geosteering, she said.

"Everyone says it's just flat and not changing often or suddenly, but we can see dramatic thinning across the course of a lateral," she said. "Ten to 15 feet of Bakken mid-section can suddenly be gone.

"The fault may not be huge, but it could fault enough feet so you're confused," Southcott said. "If you see the fault on the seismic — and you do — your correlation is exact."

Scientific eye

For WPX, drilling density is an ongoing science project.

"We've been discussing over the past year or so what we called a science project; a lot of deep analysis under way to help us confirm well density across our acreage position," said Guderian. "Through evaluating cores, logs and various pressure information, along with actual well performance, we've come to some initial conclusions, and we've begun the process … of setting up our pads for tighter well spacing and infill development."

WPX is adding one additional middle Bakken well to a three well pad north of the Van Hook area on the Fort Berthold Indian reservation, Guderian said, adding that results look favorable, but the company will not be ready to make a conclusion on increased density in the Three Forks formation until the second quarter.

"We've been discussing over the past year or so what we called a science project; a lot of deep analysis under way to help us confirm well density across our acreage position."
—Bryan Guderian, WPX Energy senior vice president of operations

South of Lake Sakakawea in the Mandaree area, WPX has had a longer production history from the Three Forks and its Middle Bakken wells are performing well, Guderian said. WPX is increasing middle Bakken laterals from four wells to six wells per pad and Three Forks laterals from three wells to five wells per pad. The new pattern will boost the total lateral count to 11, versus the company's prior plan of seven wells.

"We'll be completing some of these wells late first quarter and should have some results in the second quarter," he said.

In 2013, the company spud 49 total wells with four rigs and made great strides in cycle times and costs, Guderian said.

"Fifteen wells were turned to first sales in the fourth quarter," he said, adding that the company shrugged off challenges of the wicked winter weather.

"Certainly, I think we probably could have done even better if the weather had been mild," he said. "However, due to winterization efforts that we've undertaken over the last couple of years and great focus by our field operations personnel, we kept our wells on stream and made our year, our quarter and our exit targets."

In the next few WPX will add a fifth drilling rig in the Bakken, Guderian said. "We expect to drill 62 total wells in 2014, and that activity should generate 30 percent to 35 percent production growth for the year."

In recent filings with the North Dakota Industrial Commission WPX sought authorization to drill up to 28 Bakken pool wells on an existing 2,560-acre unit in Squaw Creek field in far eastern McKenzie County. WPX also asked the commission to establish a new overlapping 3,840-acre unit in the neighboring Spotted Horn field on which it wants to drill up to 42 Bakken pool wells.

Guderian said WPX expects to see some production lag in early 2014, but said it is all part of the plan.

"As you move to pad developments, we'll be drilling three wells in succession and then completing three wells sequentially;

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Exxon sub XTO quietly blasts to No. 6 Bakken producer

Credits pad drilling, optimized well completions and acquisitions; more drilling rigs coming this year

By STEVE SUTHERLIN
For Petroleum News Bakken

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ExxonMobil subsidiary XTO Energy quietly employs 58 people at its Williston, Alexander and Killdeer, N.D., offices to manage operations across the 531,000 gross acres it controls in the state.

With ExxonMobil behind it, XTO doesn't need to make a lot of noise to raise debt or equity financing. Unlike a number of other operators in the Williston Basin, XTO doesn't release much information about its operations there.

XTO reported North Dakota oil production of 44,516 barrels per day for February 2014, with an associated 46,000 cubic feet per day of natural gas.

Those numbers lifted XTO to sixth place among the top 50 oil producers in North Dakota, up from 12th position in 2012, with 18,989 bpd for operated non-confidential wells.

In 2013, XTO set a company production record with its third quarter Bakken production coming in at 65,000 barrels of oil equivalent per day. That output, according to David Rosenthal, ExxonMobil's vice president for investor relations, was an 81 percent increase over third quarter 2012 production.

In an Oct. 31 conference call, Rosenthal attributed the increase in Bakken production to several factors, including a record 85 wells going on production since the first of the year, as well as production from the Danbury Resources Bakken assets that ExxonMobil acquired in 2012.

The record number of wells that came on line in 2013 were better wells.

Well pad drilling

"This volume increase reflects the benefits of well pad development drilling and optimized well completions across our core Bakken acreage," Rosenthal said.

In early 2014, Rosenthal said ExxonMobil was pleased with the progress XTO has made, and that the companies were working well together.

"Certainly we have continued to make good progress in terms of productivity, well rates, down spacing, optimizing our completions and drilling," Rosenthal told analysts on Jan. 30. "So we have been able to make the progress we always thought we would when we acquired XTO and combined their folks with our folks and looking at some of these things. So that continues to improve."

Rosenthal also credited XTO for its expertise in analyzing prospective areas within its various oil plays, so ExxonMobil doesn't "waste a lot of money drilling wells." He said most of ExxonMobil's rigs are focused on liquids-rich areas, with production up 33,000 barrels per day from the fourth quarter of 2012.

"The biggest places for us — the Bakken, the Permian and the Woodford Ardmore — most all of our rigs are running in those areas," Rosenthal said. "Thus you have seen that significant increase in production. We are bringing a lot of wells onto sales every quarter and continue to ramp that up."

In 2013, XTO had about 40 drill rigs running in the U.S., most them drilling in its three core areas.

"If you think about our three core areas," Rosenthal said, "the Bakken, and the Ardmore and the Permian, those are where the wells we are drilling are; that's what we are seeing, not only the increase in production, but very pleased with the progress we are making on operating expense reduction, productivity of the wells, capex, efficiency and all of that as you know helps on unit profitability in the portfolio as well as cash flow generation."

Unit filings

XTO filed applications to the North Dakota Industrial Commission for its hearings on March 26 and 27 seeking creation of 17 new spacing units: 12 overlapping 2,560-acre and five 1,280-acre units in Dunn and Williams counties. Eleven of the 2,560s are in the Heart Butte field in far northeast Dunn County. The other 2,560 is in the Lindahl field in far northeast Williams County. Three of the 1,280s are in the Heart Butte field in far northeast Dunn County. On all 12 of the 2,560s and the three 1,280s, XTO wants to drill one horizontal Bakken pool well on or near the section lines of the smaller component spacing units. The other two 1,280s are in the Bear Creek field in northwest Dunn County, and on those XTO wants to drill multiple wells.

During hearings Jan. 15 and 16 in Bismarck, the commission considered an XTO application to drill a total of seven wells on an existing 640-acre unit in the Heart Butte field in far northeast Dunn County, and a total of four wells on existing 640-acre unit

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in the Charlson field in northeastern McKenzie County. XTO also asked permission to drill four wells on each of two existing 320-acre units in the Squaw Creek field in far eastern McKenzie County.

XTO submitted applications with the commission in October seeking 33 separate overlapping 2,560-acre spacing units in two fields in McKenzie and Williams counties. That is the highest number of new spacing unit requests by any single operator that the commission heard that month.

In the Siverston field in north-central McKenzie County, XTO asked the commission to create 23 separate 2,560-acre units, and another 2,560-acre unit which will span the Siverston and the neighboring North Fork field. In the Grinnell field, which runs from northeast McKenzie County north under Lake Sakakawea into Williams County, XTO is asking the commission to create nine 2,560-acre spacing units.

XTO sought authority to drill one horizontal well on or near the section lines of 640-acre and/or 1,280-acre spacing units that comprise the new overlapping 2,560s.

In August hearings, at the Siverston field in north-central McKenzie County, XTO Energy asked to drill up to 10 Bakken pool wells on an existing 640-acre spacing unit. XTO had one well on that spacing unit, the Lundin 11-4SH, which went on production in July 2012 with a 24-hour IP of 878 bpd. Through June the well produced 39,777 barrels over 333 days for an average of 119.45 bpd,

Although XTO focuses primarily on the prolific middle Bakken member and the first bench of the Three Forks, it has acreage it considers prospective for second bench wells and is working to incorporate the zone into its long-term plan for optimization of its Bakken petroleum system assets in the Williston Basin.

"This volume increase reflects the benefits of well pad development drilling and optimized well completions across our core Bakken acreage." —David Rosenthal, ExxonMobil's vice president for investor relations

Top U.S. gas producer

ExxonMobil established its presence in the Williston Basin when it acquired Fort Worth-based XTO Energy in 2010.

XTO operates in eight North Dakota counties, primarily in McKenzie, Williams and Dunn counties. It also has wells in Golden Valley, Billings, Mountrail, and along the border of Divide and Burke counties.

XTO operates in 16 states across the U.S. and recently established a division in Calgary.

XTO has operations across the Gulf Coast, Appalachia, Mid-Continent and the Great Plains. Its western operations, reaching from the San Juan and Raton, to the Piceance and Uinta, to offshore Cook Inlet in Alaska, and to the Bakken, are managed by its office in Denver.

"Together, we are the nation's largest holder of natural gas reserves and are the nation's top gas producer, about 20 percent larger than our nearest competitor. We are also among the leaders as a liquids producer, Randy J. Cleveland, XTO president said at the Rocky Mountain Energy Summit in Denver, Colo., on Aug. 6, 2013. "All told, we own interests in about 50,000 wells producing oil and natural gas across the country.

"At ExxonMobil, we saw in XTO a tremendous opportunity." Cleveland said. "Success in unconventional development requires a unique approach; it demands a business model with characteristics of being nimble, flexible, and fast learners."

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that activity can take 90 to 100 days or so," he said. "There will be some production lag in the beginning, and we would expect that in Q1, but it is planned and to be expected."

The company anticipates it will see strong results by the end of the first quarter of the year.

"Current well costs are about $5.5 million, and we're confident — we've only drilled 16 wells; I think we're confident we can drive them lower," Guderian said. "Our completion activity at our first three well pads is under way this week, and we expect those wells to deliver in early March."

Acquired 2010

WPX, a wholly owned subsidiary of Williams until late 2011, entered the Williston Basin at the end of 2010 with the $949 million acquisition of Dakota-3 E&P Co.

The company has offices in Minot and New Town, N.D. It has an interest in more than 100 local wells on a gross basis, and holds 84,000 net acres in the Williston Basin on the Fort Berthold Indian Reservation.

"Current well costs are about $5.5 million, and we're confident — we've only drilled 16 wells; I think we're confident we can drive them lower," Guderian said. "Our completion activity at our first three well pads is under way this week, and we expect those wells to deliver in early March."

WPX is planning to invest $580 million to $600 million for drilling in North Dakota in 2014.

The company also operates in Colorado's Piceance Basin, Pennsylvania's Marcellus Shale, New Mexico's San Juan Basin, and Wyoming's Powder River Basin.

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VERN WHITTEN PHOTOGRAPHY

Thank you Bakken explorers for securing future production