Petroleum news

BAKKEN

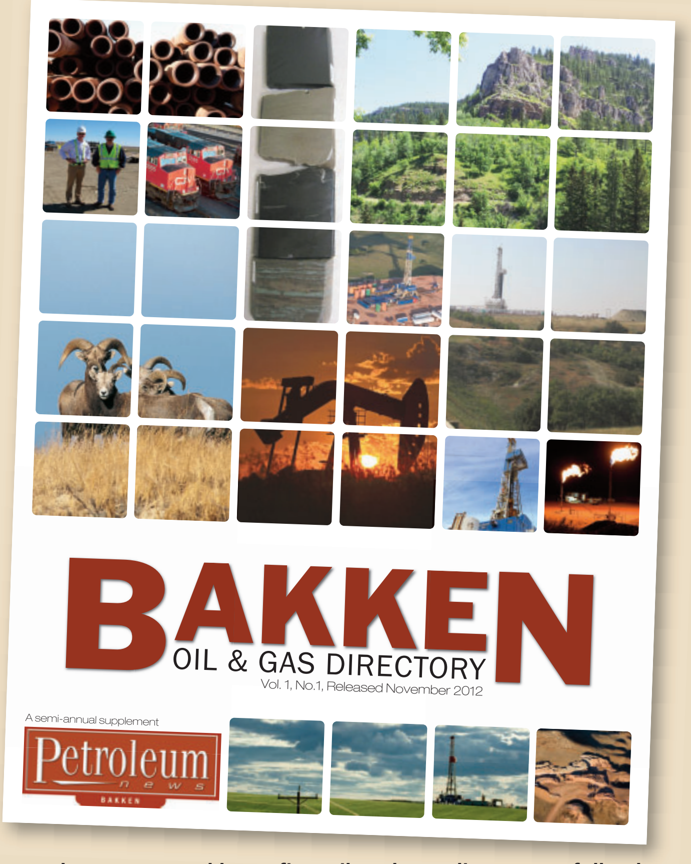
Vol. 1, No. 15 • www.PetroleumNewsBakken.com

A semi-monthly newspaper for industry and government

November 18, 2012

page 12 Kodiak production in Williston Basin up 281 percent from a year ago

Bakken Oil & Gas Directory inside



Petroleum News Bakken's first oil and gas directory, a full color magazine, accompanies this issue of the newspaper. The first of its kind, the directory will appear twice a year, with the next being released in May. It is a work in progress so the publisher welcomes additions, deletions and corrections, asking they be sent to publisher@petroleumnewsbakken.com.

Alberta opens door on huge resources; formations on parallel with Bakken, say agencies

Alberta's emerging shale and/or siltstone formations could ultimately yield 423.6 billion barrels of oil, 58.6 billion barrels of liquids and 3.3 trillion cubic feet of natural gas, says a long-awaited report by the Alberta Energy Resources Conservation Board and the Alberta Geological Survey.

The report is designed to provide baseline data, information and understanding of the geology, distribution, reservoir characteristics and hydrocarbon resource potential of Alberta shales.

The calculations for the formations, including the Duvernay, Montney and Muskwa, put the deposits in the same league as some of the major U.S. shale plays as part of

see **ALBERTA RESOURCES** *page 21*

Apache pleased with oil shows in logs from first Bakken well

G. STEVEN FARRIS

Apache Corp.'s top executive is pleased with what he's seen from the first well drilled in the company's newly acquired acreage in Daniels County, Mont., on the northwestern fringe of the Bakken petroleum system.

"As we continue to build and execute our global pipeline of exploration activity we're testing two wells (in two new plays for Apache) — one in the Williston Basin and one in the Mississippi Lime," G. Steven Farris, company chairman and chief executive officer, said in early November in Apache's third quarter earnings con-

see **APACHE WELL** *page 19*

MERGERS & ACQUISITIONS

Window closing

Hamm: most government land tied up; fewer takeover opportunities in Bakken

By RAY TYSON

Petroleum News Bakken

Williston Basin superstar Continental Resources Inc. said following disclosure of its latest Bakken acquisition that opportunities for such mega deals in the region may be coming to an end.

"We expect to see those opportunities diminish, and so this is especially one that fits us real well," Harold Hamm, Continental's chairman and chief executive officer, said of the company's recent $650 million deal in a Nov. 8 conference call with analysts and investors.

Others have tied up most of the available state and federal acreage, Hamm said, while takeover candidates in the way of smaller exploration and production companies are vanishing.

"In my estimation, we'll see a few of them going forward," he added. "There'll still be a few, but perhaps that window is closing."

Deal includes 120,000 acres

Continental, in its latest deal, entered into an agreement with an undisclosed seller or sellers to acquire Bakken producing and undeveloped

see **MEGA DEALS** *page 23*

Others have tied up most of the available state and federal acreage, while takeover candidates in the way of smaller exploration and production companies are vanishing, said Continental's Chairman and CEO Harold Hamm.

GEOLOGY

Redefining the Sanish

ND geological survey considers sands to be Pronghorn unit of Bakken formation

By MIKE ELLERD

For Petroleum News Bakken

JULIE LEFEVER

For years people had been seeing a limestone/lime mudstone unit between the lower Bakken Shale and the upper Three Forks formation in 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 formation within the same petroleum system, and have redefined it as the Pronghorn member.

A little history

In 1954, NDGS described an "unconformity sand" lying between the lower Bakken shale and the Three Forks formation, and referred to it as the Sanish sand, and included it as part of the Bakken for-

see **UNIT DEFINITION** *page 20*

LAND & LEASING

ND sale draws robust bids

Trust Lands auction price per acre averaged $1,997 on 9,421 acres; 4th highest

By MIKE ELLERD

For Petroleum News Bakken

DREW COMBS

The North Dakota Department of Trust Lands Minerals Management Division brought in just over $18.9 million in its November oil and gas lease auction, selling leases on 9,421 acres in 100 separate parcels in nine western North Dakota counties, for an average of approximately $1,998 per acre. The sale prices at the November auction ranged from a low of $25 per acre to a high of $15,300 per acre. Slightly over half of the acreage sold was in McKenzie County.

The average price of $1,998 per acre was the fourth highest auction average going back to 1970. The highest average price per acre was $3,526 set at the November 2011 auction, followed by $2,968 in May 2010, and $2,090 in February 2011.

In August, the Minerals Management Division sold a total of 16,665 acres at an average price per acre of $701 per acre. In May it sold 10,447 acres at an average price per acre of $1,000, and in February the total acreage sold was 69,942 with an average price per acre of $1,219.

"We were pleased with the sale," Minerals Management Division Director Dew Combs told

see **LEASE AUCTION** *page 23*

contents

Petroleum News Bakken

● COMPANY UPDATE

Fidelity testing Upper Bakken shale

MDU E&P arms sees huge Q3 output increase, mostly from Bakken, despite tardiness with oil wells; sees Utah play as game changer

By RAY TYSON
For Petroleum News Bakken

MDU Resources Group's exploration and production arm, Fidelity E&P, saw a double-digit surge in oil production during the third quarter, largely on the strength of North Dakota's Bakken-Three Forks play. But the numbers could have been much higher had Fidelity not been so late in bringing new wells on stream.

Production during the three-month period ending Sept. 30 averaged 12,200 barrels per day, a substantial 19 percent increase over last year's third quarter of 10,260 barrels per day.

"However, we did have some delays in our drilling and completion activity, and we did not bring online all the wells we had planned," Terry Hildestad, MDU's president and chief executive officer, disclosed in a Nov. 1 conference call.

But he said "a number of good wells" were brought on stream in late September and October, resulting in a weekly production record in October of 13,500 barrels per day, a hefty 32 percent increase over the 2011 third quarter and an 11 percent increase over the 2012 third quarter.

"This is primarily a timing issue," Hildestad explained. "We still expect to meet our full year oil production projection increase of 25 percent to 30 percent."

The company's planned Bakken capital budget for 2012 was $265 million, up from $165 million compared to last year (see adjacent chart).

Continues to curtail gas output

Fidelity said it continued to curtail natural gas output during the recent quarter because of prolonged price weakness. Production tumbled nearly 37 percent from the year-ago quarter.

"The curtailment focused on dry gas wells that were providing minimum margin in lower natural gas price environments," Hildestad said. "We plan to bring these wells back on production rather quickly when natural gas prices recover to an economic level."

Fidelity's realized natural gas prices were down 20 percent during the third quarter, while realized oil prices were down 5 percent. A higher Bakken oil price differential, which includes transportation charges, averaged about $12 to $13 per barrel throughout the third quarter and also affected Fidelity's oil price realization.

"Forecasts indicate a significant improvement in these pricing spreads for the fourth quarter," Hildestad told analysts.

Mountrail well had IP of 1,353 bpd of oil

Fidelity said it is operating five rigs in the Bakken, the company's primary growth area. Oil production there was up a substantial 46 percent over last year, setting a new production record of more than 7,000 net barrels per day, and is achieving that at a consistent level.

In Mountrail County, N.D., Fidelity has seen continued strong wells in this development phase acreage. The Amundson 23-14H well had a 24-hour initial production rate of 1,353 barrels of oil.

"We have identified approximately 40 remaining Middle Bakken wells in the area and we're evaluating our Three Forks potential following the lead of other operators, which would be incremental to these numbers," Hildestad said.

Identifies sweet spot in Stark

In Stark County, N.D., the company said it continues to see encouraging results, and gross production recently set a record of about 2,000 barrels a day. The company has 51,000 net acres here and, through its appraisal program and beginning stages of development, said it has identified a sweet spot area its believes will be highly productive.

The company said it recently completed a couple of strong wells in Stark. The Pavlish 19-20H came on line at 1,097 barrels of oil. The Kudrna 5-8H had a 24-hour IP rate of 1,151 barrels. And about 40 future drilling sites have been identified in the area.

Stay tuned for Upper Bakken results

In Richland County, Montana, Fidelity is initially targeting the Three Forks. However, data is pointing to significant upside potential in the Upper Bakken shale on this acreage, the company said.

"While initial rates are not as high as some of our other Middle Bakken and Three Forks wells, it appears that the decline rates are shallower and can provide good economic returns," Hildestad explained. "We still have a couple more wells planned for the Richland County this year, so stay tuned for further results as we continue to focus on cracking the code there."

Finishes Heath appraisal program

In Montana, Fidelity also has concluded its appraisal program this year for the Heath Shale play where the company has 90,000 net acres.

"We've drilled five wells, saw encouraging results in four of the five wells, but production issues are clouding the decision to move forward with additional drilling," Hildestad said. "These wells are being worked on by our production team."

Views Utah's Paradox as game changer

Paradox Basin in Utah is a potential game changer for Fidelity, the company said, noting that it kicked things off in this play with a strong well that was a Cane Creek unit number 26-2H well. It has been consistently producing roughly 1,500 barrels of oil a day over the past three weeks. It has a flowing pressure above 2,800 psi. And the company has identified 50 to 75 future locations with gross recovery rates estimated up to 1 million barrels per well and perhaps more.

In addition Utah's Paradox Basin and the Bakken-Three Forks play in North Dakota and Montana, MDU's Fidelity holds E&P interests in Colorado, Wyoming, Nebraska, Louisiana, Oklahoma, New Mexico, Texas, and offshore Gulf of Mexico.

Oil growth partly offset by lower prices

Fidelity's overall 19 percent increase in oil production partially offset lower commodity prices during the recent quar-

see **FIDELITY E&P** *page 4*

Petroleum news BAKKEN www.PetroleumNewsBakken.com

Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Ray Tyson	EDITOR
Gary Park	CONTRIBUTING WRITER (CANADA)
Eric Lidji	CONTRIBUTING COLUMNIST
Alan Bailey	STAFF WRITER
Rose Ragsdale	CONTRIBUTING COLUMNIST
Allen Baker	CONTRIBUTING WRITER
Mike Ellerd	CONTRIBUTING WRITER
Darryl Flowers	CONTRIBUTING WRITER
Mary Mack	CHIEF FINANCIAL OFFICER
Clint Lasley	GM & CIRCULATION DIRECTOR
Susan Crane	ADVERTISING DIRECTOR
Bonnie Yonker	AK / NATL ADVERTISING SPECIALIST
Steven Merritt	PRODUCTION DIRECTOR
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR
Tom Kearney	ADVERTISING DESIGN MANAGER
Heather Yates	BOOKKEEPER
John Lasley	DRILLING CONSULTANT
Amy Spittler	MARKETING CONSULTANT
Renee Garbutt	ADVERTISING ASSISTANT
Shane Lasley	IT CHIEF
Julie Bembry	CIRCULATION SALES EXECUTIVE
Dee Cashman	CIRCULATION REPRESENTATIVE
Joshua Borough	ASSISTANT TO THE PUBLISHER

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
RAY TYSON • 605.343.4031
rtyson@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX NUMBERS
SOUTH DAKOTA • 713.658.0125
ALASKA • 907.522.9583

Several of the individuals listed above are independent contractors

PETROLEUM NEWS BAKKEN is currently a semi-monthly supplement of Petroleum News, a weekly newspaper that covers Alaska and northern and western Canada. In March 2013 Petroleum News Bakken is scheduled to go weekly. To subscribe to Petroleum News Bakken email clasley@petroleumnews.com; or call Clint Lasley at 907.522.9469; or sign up online at www.petroleumnewsbakken.com.
A subscriber to Petroleum News also receives Petroleum News Bakken, and vice versa.
Print and/or online subscriptions are available.

● COMPANY UPDATE

Hess 3Q Bakken output up, costs below average

By MIKE ELLERD
For Petroleum News Bakken

In Hess Corp.'s third quarter 2012 earnings conference call on Nov. 2, Chairman and CEO John Hess said the company's net Bakken production averaged 62,000 barrels of oil equivalent per day in the third quarter, up from the 32,000 boe per day in the third quarter of 2011, an increase of 94 percent.

The company shipped approximately 37,000 barrels of oil per day from its Tioga rail facility to "higher value markets, improving our price realizations," Hess said, noting the company is currently evaluating the feasibility of building a rail unloading facility at its Port Reading, N.J., complex to market Bakken crude oil on the East Coast.

Hess currently has 16 drill rigs operating in the Bakken, 15 of which are in pad drilling mode, per Gregory Hill, Hess' executive vice president and president of worldwide exploration and production. "As we focus on capital efficiency, we may moderate the pace slightly. But it won't be a major downward reduction in pace in the Bakken," he said.

CFO John Rielly said the company has reduced its drilling costs in 2012 from an average of $13.4 million in the first quarter to $9.5 million in the third quarter. Hess has been getting more and more efficient quarter by quarter in the Bakken, and presently its Bakken costs are "slightly below our portfolio average." He said Hess plans to spend approximately $750 million this year on Bakken infrastructure.

In a statement, Hess said it "will substantially complete its 'held by production' drilling in the Bakken in the fourth quarter of 2012 and is transitioning to pad drilling (development drilling), which involves sequentially drilling a number of wells on a pad followed by sequential fracturing of the wells. This pad drilling process is expected to lead to a temporary flattening of the Bakken production profile until mid-2013, at which point steady-state operations will allow an upward growth trajectory."

Worldwide, John Hess said the company's crude and natural gas production was 402,000 boe per day in the third quarter of 2012, which is a 17 percent increase over the 344,000 boe the company produced in third quarter 2011. The growth was primarily the result of higher output from North Dakota's Bakken and Libya. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

continued from page 3

FIDELITY E&P

ter. But earnings from MDU's E&P operation fell to $13.1 million in the third quarter of 2012 from $22.5 million in the third quarter of 2011.

Fortunately, MDU had help from some of its other business segments, particularly from construction materials and services, which had combined earnings of $51.8 million, an increase of $13.6 million over last year. Contributing to the growth were improved volumes and margins in most material product lines, as well as higher equipment sales and rental margins and the company's lower cost structure. Revenues improved 6 percent and earnings 36 percent. This group also has a backlog that is $55 million higher compared to a year earlier.

Utility benefits from Bakken boom

MDU's electric utility earnings grew by 32 percent over the prior-year third quarter to $11 million, in large part because of a 5 percent increase in electric sales and lower operating expenses. The utility continues to benefit from continued economic growth in northwestern North Dakota's Bakken oil fields where the company saw an 8 percent increase in its electric customer count compared to a year ago.

Natural gas transport biz reports loss

MDU's natural gas transportation business reported a normal seasonal loss, which was an approximate 20 percent improvement compared to the third quarter of 2011, related to decreased operating expenses.

In September, the company filed an application with the Montana Public Service Commission for a natural gas rate increase of $3.5 million annually, or 5.9 percent, to cover costs associated with investments in facilities.

Overall, MDU had consolidated third-quarter earnings of $71.1 million, excluding a non-cash write-down primarily related to the lower natural gas prices. That compared to $63.8 million in earnings in last year's third quarter. Including the non-cash write-down, the company posted a consolidated loss of $29.8 million for this year's third quarter.

Diesel topping plant under consideration

Meanwhile, MDU, along with Calumet Refining, LLC, continues to explore the feasibility of building and operating a 20,000-barrel per day diesel topping plant in southwestern North Dakota.

The facility would process Bakken crude and market the diesel within the Bakken region. Options to purchase land for the plant site were recently exercised.

Total project costs are estimated to be about $280 million to $300 million with a projected in-service date in 2014.

In May, the company purchased a 50 percent undivided interest in Whiting Oil and Gas Corp.'s Pronghorn natural gas and oil midstream assets near Belfield, N.D., in the Bakken area.

The company expects to invest roughly $100 million in 2012 including the purchase price.

The Belfield natural gas processing plant has an inlet processing capacity of 35 million cubic feet per day. ●

Contact Ray Tyson at rtyson@petroleumnewsbakken.com

● COMPANY UPDATE

EOG sees good Bakken output

With focus on two Bakken/Three Forks core areas where recent tests show promising IPs, company continues to test downspacing

By MIKE ELLERD
For Petroleum News Bakken

EOG announced on Nov. 5 that it saw a 45 percent increase in North American crude oil production in the third quarter and 51 percent increase through the first nine months of 2012 compared to the same periods in 2011. Total North American liquids (crude oil, condensate and natural gas liquids) production increased 42 percent for the third quarter and 48 percent for the first three quarters of 2012 over the same periods a year ago.

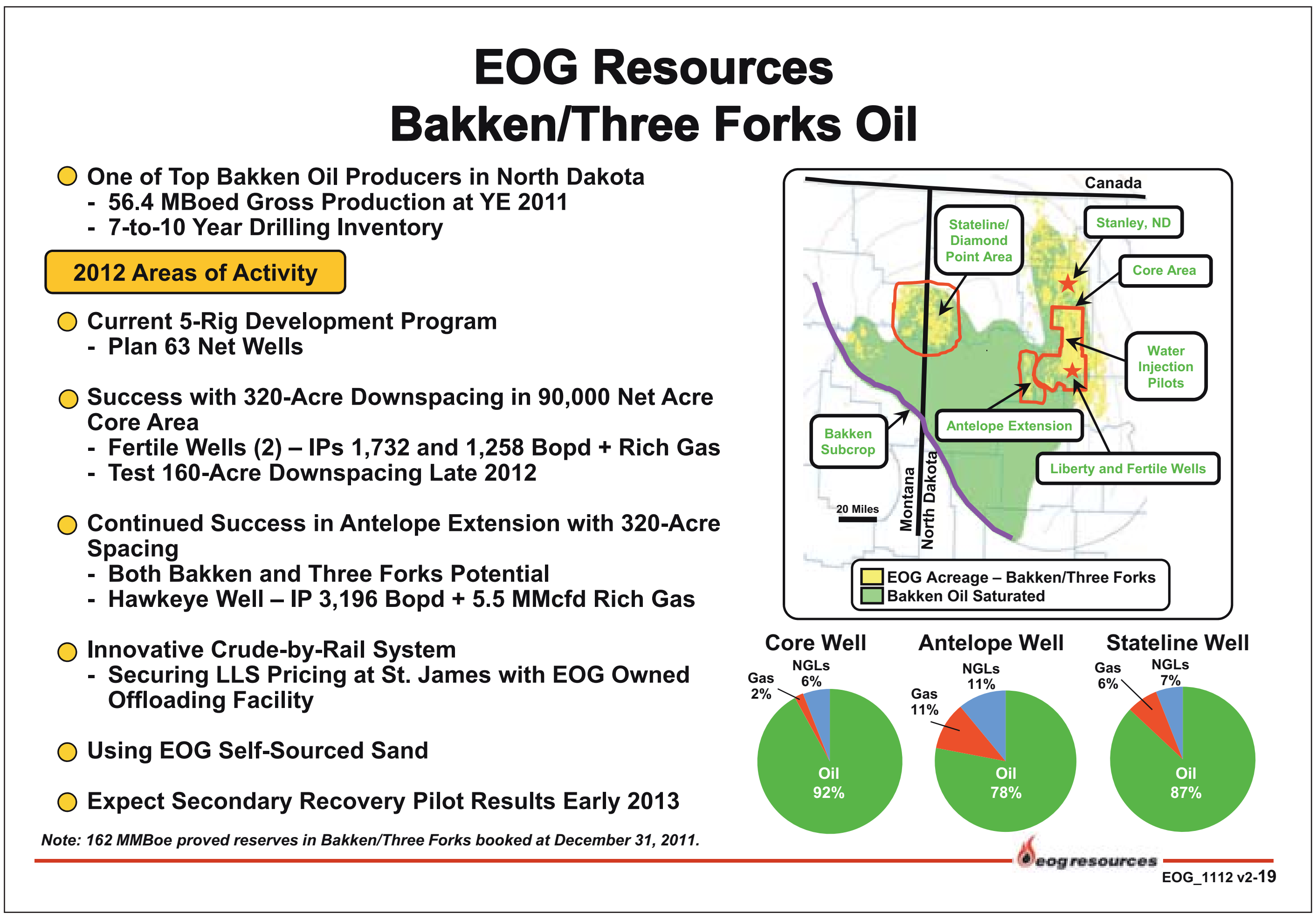
In a Nov. 6 conference call, EOG Chairman and Chief Executive Officer Mark Papa said the company's two largest production areas are its South Texas Eagle Ford play and the Bakken/Three Forks play in North Dakota. In that call, EOG President William Thomas, said EOG will "continue to be particularly upbeat about the Bakken and Three Forks potential on our acreage in the Williston Basin."

Most shipped by rail

Papa said most of EOG's Bakken crude oil is being shipped via rail to the company's terminal at St. James, La., where the crude is priced off of the Louisiana Light Crude index, which he said provides an advantage over West Texas Intermediate pricing.

In the Nov. 6 conference call, Thomas said the company's 320-acre downspacing in its Bakken Core area has proven to be successful, and this was further confirmed, he said, by results from two recently completed wells. One of the wells, the Fertile 46-1608H, tested with an initial production of 1,732 barrels of oil per day, with 90 barrels per day of NGLs and 363,000 cubic feet per day of natural gas. The other well, the Fertile 47-0712H, tested with an IP of 1,258 barrels of oil per day, 83 barrels per day of NGLs and 332,000 cubic feet of gas. EOG has 92 percent and 78 percent working interest in these wells, respectively. Both wells are in Mountrail County.

In the Antelope Extension area, Thomas said the company is applying improved fracking technology to its current well completions. "We recently completed an outstanding Antelope Three Forks well, the Hawkeye 100-2501H, for 3,196 barrels of oil per day with 5.5 million cubic feet per day of rich natural gas." EOG has a 73 percent working interest of this well, which is located in McKenzie County.



In the Antelope Extension area, Thomas said the company is applying improved fracking technology to its current well completions: "We recently completed an outstanding Antelope Three Forks well, the Hawkeye 100-2501H, for 3,196 barrels of oil per day with 5.5 million cubic feet per day of rich natural gas."

Spending in focus areas

Thomas said EOG plans to spend most of its North Dakota capital in these same two focus areas from 2013 to 2015, primarily downspacing in the Bakken Core, and that the company will be testing 160-acre downspacing in its Core area late this year. In the Antelope Extension area, he said, EOG will be further developing both Bakken and Three Forks targets.

EOG also is also active in Leonard and Wolfcamp Shales in the Permian Basin, the Fort Worth Barnett Shale Combo, and it has natural gas assets in the Marcellus, Haynesville, Barnett and the Uinta Basin. Internationally, EOG is active in Canada, Trinidad, China, the United Kingdom and Argentina. Worldwide the company saw a 42 percent increase in crude oil and condensate production along with a 40 percent increase in total liquids production over the third quarter of 2011.

"With especially strong, consistent individual well results, EOG's best plays have become even better," Papa said in a Nov. 5 company statement. "Therefore, based on nine months of robust crude oil production, we are setting the bar higher for the third time this year. EOG has increased its 2012 crude oil production growth target to 40 percent from 37 percent. Because our outstanding oil results also impact total liquids production, we are also raising our total liquids production growth target to 38 percent from 35 percent and increasing our total company production target to 10.6 percent from 9 percent." ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

● COMPANY UPDATE

Legacy upbeat over Spearfish, Bakken

By GARY PARK

For Petroleum News Bakken

Calgary-based Legacy Oil + Gas is continuing to make gains in the Spearfish petroleum system of Manitoba and Bottineau County, N.D., claiming "excellent production results" in the third quarter.

It estimates that initial productive capability of a number of its wells at Pierson, Manitoba, will range from 120 to 280 barrels of oil equivalent per day, while the first four wells of the recent program in Bottineau County have come onstream at an average 150 boe per day, despite constrained production to maximize ultimate recovery.

In its third-quarter report, Legacy said it believes results at Pierson will lead to superior long-term performance, higher per-well reserve booking and the booking of additional locations.

Legacy said vertical wells drilled in Pierson over the first nine months of 2012 have drill, complete, equip and tie-in costs of less than C$1.5 million, while wells drilled in the latest quarter have all-in capital costs of C$1.2 million-C$1.3 million.

In North Dakota, no new operated wells were brought on production in the quarter, but the company anticipates having six additional gross wells onstream in the current quarter.

Total Spearfish play development drilling inventory is now estimated at 440 net potential locations (88 percent unbooked), based on eight wells per section.

Using other operators' results in the play, Legacy said its location count could increase by 50 percent through downspacing.

The company said it is also evaluating the waterflood potential of the play and anticipates recovery factors of up to 14 percent, based on analogous pools.

At its Bakken play in southeastern Saskatchewan, Legacy said it has applied leading fracture stimulation design developed in Heward.

Since the start of the third quarter, 11 gross Bakken wells have been brought on production at average 30-day initial rates of 200 boe per day.

The company believes its Bakken play boundaries have expanded, allowing it to increase its drilling location inventory to more than 50 net wells in Star Valley.

At Taylorton in Saskatchewan, Legacy has observed improved waterflood response in the original pilot area, with the production rate increase from one well reaching nearly 50 bpd, while drilling and completion costs have been 15 percent lower than historical levels.

At Heward, a pilot waterflood project initiated almost a year ago shows well production rates are up 50 percent to 500 percent from before the initiation of waterflood and plans are being developed to expand the pilot project later this year. ●

Contact Gary Park through publisher@petroleumnews.com

● COMPANY UPDATE

Magnolia buys in MT, partner drills in ND

Statoil drilling two new Jake wells in Williams County, four more planned; Magnolia acquires 6,700 acres in Montana

By MIKE ELLERD

For Petroleum News Bakken

Magnolia Petroleum said in early November that drilling is underway on two Statoil-operated horizontal Bakken wells, with four additional Statoil wells slated for drilling in early 2013, all from a single pad in southern Williams County.

The six Statoil wells are known as the "Jake" wells, and of the two currently being drilled, the Jake 2-11 1H is targeting the Bakken formation, and the other, the Jake 2-11 TFH, is targeting what has been known as the Three Forks Sanish formation (now technically redefined as the Pronghorn member of the Bakken petroleum system, see related story on page 1).

Total drilling costs for the two wells are estimated at $10.215 million each. Magnolia has a net revenue interest of just under 1.5 percent.

"Statoil has reported some of the best initial production rates in this region," Magnolia's chief operations officer, Rita Whittington, said in a company statement. "With this in mind, we are delighted that the two Jake wells have commenced drilling and that four additional wells in Williams County, also operated by Statoil, are due to be drilled in early 2013."

Norwegian-state owned integrated international giant Statoil moved into the Williston Basin in October 2011 through its acquisition of Brigham Exploration, which at the time held over 375,000 net acres in the basin.

New Montana acreage

Magnolia also said in early November that is has agreed to pay $4 million to acquire 6,700 net mineral acres on the Montana side of the Bakken, most of which is in Daniels county, on the Canadian border in far northeast Montana.

The new Montana acreage is surrounded by 320,000 leased acres that Apache Corp. acquired earlier this year and is already drilling, testing the fringes of the Bakken petroleum system, which includes other members, such as Three Forks.

In a Nov. 2 statement, Magnolia said the 6,700 acres "represent an opportunity for the company to build a position in an area where the directors believe there is strong prospectivity and increasing interest. The acreage lies amongst and is surrounded by Apache's leases. They are located in Daniels County and three surrounding counties in Montana."

"We believe that this acreage in Daniels County, Montana, has the potential to become a significant extension for production from the Bakken/Three Forks Sanish formations," COO Rita Wittingham said. "Today's acquisition matches our investment criteria, namely early, affordable access to liquids rich onshore U.S. formations, where the application of modern techniques such as horizontal drilling may dramatically improve recovery rates and, in the process, substantially increase net production and reserves. The directors believe that with lower drilling costs and multiple pay zones, the economics of drilling to the Bakken/Three Forks Sanish formations in Montana are very attractive."

Apache acquired its 300,000 acres in Daniels County, Mont. in June in a deal with Fort-Worth-based Shale Exploration LLC. As reported by Petroleum News Bakken in September, Apache is actively drilling in Daniels County and is targeting both the Middle Bakken and the Upper Three Forks formations (see Sept. 23 edition of Petroleum News Bakken).

Also in its Nov. 2 statement, Magnolia said "the level of investment being made by Apache in the area reflects their recognition of the scale of the opportunity to generate substantial value for shareholders. Apache believes their 320,000 net acres holds over 1,900 potential drilling locations and that on each of these up to 16 horizontal wells may be required to recover reserves, estimated by Apache at 1 billion barrels of oil."

According to both Apache and Magnolia, at 7,000 to 7,400 feet, the Bakken formation is shallower in Daniels County than in North Dakota, resulting in a lower estimated drilling cost of $7.5 million per well, as opposed to $10 million in North Dakota.

According to its website, "Magnolia Petroleum plc is an AIM listed oil and gas production company focused on the acquisition, exploitation and development of oil and gas properties primarily located onshore in the United States. Lead by a highly skilled management team with over 100 years combined experience in the on shore oil and gas industry, the company already has interests in over 60 producing properties and significant acreage in two major project areas, the potentially game-changing and highly productive Bakken shale in North Dakota and the proven Woodford and Hunton formations in Oklahoma. The company is also currently targeting the Mississippi Formation in Oklahoma, a known play with proven and substantial reservoirs."

Magnolia's "country of incorporation" is Great Britain, specifically England and Wales; again per its website http://www.magnoliapetroleum.com/

As of September 2012, the North Dakota Department of Minerals showed no production from any North Dakota wells operated by Magnolia. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

● DRILLING & COMPLETION

Montana weekly oil activity reports

COMPILED By DARRYL L. FLOWERS
For Petroleum News Bakken

With one exception, the Heath, Petroleum News Bakken's Montana weekly oil activity report focuses on the horizontal well activity in the eastern, northeastern and northwestern part of the state, where the geologic targets are repeatable plays that are either part of the Bakken petroleum system or somehow related to it.

The counties included in this coverage are Glacier, Toole, Pondera and Teton counties in northwest Montana, and Daniels, Dawson, Fallon, Garfield, McCone, Prairie, Richland, Roosevelt, Sheridan, Valley and Wibaux counties in the east and northeast part of the state. Although Petroleum News Bakken has begun to report on fledgling industry activities in the Heath shale of central Montana, that area is not included in this report.

Week of 10/26 to 11/1

New locations — horizontal wells

All the new horizontal activity for the period is centered in Richland County, with a total of eight wells permitted, all targeting the Bakken formation.

Five of the wells will fly the Continental Resources Inc. banner: The Joseph 1-22H, with a SHL at NW NE 22-23N-54E (225 FNL/1980 FEL) and a PBHL of 14,120 feet at SW SE 22-23N-54E (660 FSL/1980 FEL); the Reimann 3-23H, with an SHL at NW NE 23-23N-55E (305 FNL/2540 FEL) and a PBHL of 19,978 feet at SW SE 26-23N-55E (200 FSL/2640 FEL); the Thomas 3-27H, with an SHL at SE SW 27-23N-56E (225 FSL/2000 FWL) and a PBHL of 19,924 feet at NE NW 22-23N-56E (660 FNL/2000 FWL); the English Federal 1-5H, with an SHL at SW SE 5-26N-53E (299 FSL/1701 FEL) and a PBHL of 18,662 feet at NW NE 32-27N-53E (200 FNL/1980 FEL) and the Baird 1-34H, with an SHL at NW NE 34-27N-53E (305 FNL/2300 FEL) and a PBHL of 18,740 feet at SW SE 3-26N-53E (200 FSL/1980 FEL).

Slawson Exploration Co. Inc. was green lighted for two Bakken wells in Richland County: the Hobo 1-16H, with an SHL at NW NW 16-24N-52E (250 FNL/735 FWL) and a PBHL of 13,544 feet at SW SW 16-24N-52E (250 FSL/735 FWL) and the Knave 1-9-4H, with an SHL at NW NW 16-24N-52E (250 FNL/760 FWL) and a PBHL of 16,008 feet at W2 W2 4-24N-52E (250 FNL/760 FWL)

Wrapping up the Bakken wells in Richland County is the Pine 12-1 1H, operated by Kraken Operating LLC. The well has an SHL at SE SE 12-24N-51E (280 FSL/740 FEL) and a PBHL of 14,598 feet at W2 E2 1-24N-51E (660 FNL/1760 FEL).

Re-issued locations

All three Re-Issued Locations for the reporting period are in Richland County. Slawson Exploration Co. Inc. was approved for two wells: the Dirk Federal 1-22-21H, with an SHL at NW NW 23-21N-59E (587 FNL/286 FWL) and a PBHL of 20,667 at NW NW 21-21N-59E (750 FNL/250 FWL) and the Boomerang 1-4H, with an SHL at SE SE 36-21N-59E (200 FSL/760 FEL) and a PBHL of 15,436 at SW SW 4-20N-60E (700 FSL/773 FWL).

Oasis Petroleum North America LLC won approval for the Stilt Federal 2658 42-22H, with an SHL at SE SW 22-26N-58E (200 FSL/1670 FWL) and a PBHL of 20,916 feet at SW SW 34-26N-58E (200 FSL/550 FWL).

All the Re-Issued Locations will aim for the Bakken Formation.

Completions

In Richland County, Continental Resources Inc. reported the completion of the Abercrombie 1-10H. The Bakken formation well has an SHL at SE SW 10-27N-53E (305 FSL/2450 FWL) and a BHL of 18,682 feet at NE NW 3-27N-53E (257 FNL/1977 FWL). The well turned in an IP of 451 BOPD; 483 MCFPD and 515 BWPD.

Abbreviations & parameters

With a few exceptions, the Montana weekly oil activity report includes Bakken petroleum system horizontal well activity in the eastern, northeastern and northwestern part of the state.

Following are the abbreviations used in the report and what they mean.

BHL: bottomhole location
BOPD: barrels of oil per day
BWPD: barrels of water per day
IP: initial production
MCFPD: thousand cubic feet per day
PBHL: probable bottomhole location
SHL: surface hole location

Week of 11/2 to 11/8

New locations

There were three new horizontal locations approved during the reporting period, all in Richland County and targeting the Bakken formation. Whiting Oil and Gas Corp. was green lighted for the Sundheim 44-8-3H, with an SHL at NW NE 17-25N-58E (345 FNL/1925 FEL) and a PBHL of 21,045 feet at NW NE 5-25N-58E (240 FNL/1980 FEL).

In Musselshell County, North Range Exploration LLC has been approved for the Barile 2-7, a Heath formation well with a SHL at NE SW 7-10N-28E (3014 FNL/2056 FWL). The well has a proposed depth of 4,100 feet.

New locations — horizontal wells

There were three new horizontal locations approved during the reporting period, all in Richland County and targeting the Bakken formation.

Whiting Oil and Gas Corp. was green lighted for the Sundheim 44-8-3H, with an SHL at NW NE 17-25N-58E (345 FNL/1925 FEL) and a PBHL of 21,045 feet at NW NE 5-25N-58E (240 FNL/1980 FEL).

Slawson Exploration Co. Inc. won approval of two wells: the Curmudgeon 2-20H, with an SHL at SE SE 20-24N-52E (600 FSL/280 FEL) and a PBHL of 13,908 feet at SW SW 20-24N-52E (250 FSL/735 FWL) and the Scavenger 2-28H, with an SHL at NE NE 28-24N-52E (350 FNL/280 FEL) and a PBHL of 13,992 feet at NW NW 28-24N-52E (750 FNL/250 FWL).

Re-issued locations

In Rosebud County, Fidelity Exploration & Production Co. won approval for the Sun Coulee 24-14H. The well is heading for the Heath formation with an SHL at SE SW 14-9N-34E (330 FSL/2310 FWL) and a PBHL of 9,580 feet at NW NW 14-9N-34E (380 FNL/380 FWL).

Permit modifications/corrections

In Richland County, Oasis Petroleum North America LLC was granted Permit Modifications / Corrections for two Bakken formation wells: the Stilt Federal 2658 42-22H, with an SHL at SE SW 22-26N-58E (200 FSL/1670 FWL) and a PBHL of 20,795 feet at SW SW 34-26N-58E (248 FSL/1506 FWL) and the Dianne Federal 2658 42-22H, with an SHL at SE SW 22-26N-58E (200 FSL/1770 FWL) and a PBHL of 20,332 feet at NE NW 15-26N-58E (200 FNL/1770 FWL).

Completions

Slawson Exploration Co. Inc. reported the completion of the Dart (Federal) 1-30H, a Richland County well with an SHL at NW NW 30-21N-59E (290 FNL/1250 FWL) and a BHL of 14,643 feet at SW SW 30-21N-59E (252 FSL/882 FWL). The well taps into the Bakken formation. ●

Darryl L. Flowers, a contributor to Petroleum News Bakken, is the publisher of the Sun Times in Fairfield, Mont., www.fairfieldsun-times.com, and can be reached at publisher@fairfieldsuntimes.com.

● COMPANY UPDATE

PetroBakken set to take off

Fledgling Bakken, Cardium company earmarks C$975M of capital spending for 2013, pulling some spending forward to achieve '12 rate

By GARY PARK
For Petroleum News Bakken

PetroBakken, which is gearing up to fly solo when released by its parent company Petrobank Energy and Resources on Dec. 31, is setting ambitious goals for 2013, including a C$975 million capital budget to drill new wells and hike tight oil production from its Bakken and Cardium acreages.

"We are cautiously excited," Chief Executive Officer John Wright told analysts, while injecting a note of reality by suggesting the rewards from some of the assets in Saskatchewan and Alberta "are going to come over the next number of years, not the next number of quarters."

But he announced that some of the capital program planned for the first quarter of 2013 is being accelerated into the current quarter.

The Bakken unit averaged 15,676 boe per day in the third quarter, up 6 percent over the second quarter, as the majority of production shut-in during the spring breakup was restored.

"This increase is due to an active land acquisition strategy in a potential new resource play in Western Canada where we have acquired 218 net sections (almost 140,000 acres) and to reduce mobilization expenses during the winter."

Wright did not locate the new play, although PetroBakken said it made C$25 million in unplanned spending at government land sales and through other deals to acquire the property, adding about 50 percent to its emerging play portfolio of lands prospective for the Nordegg, Montney, Beaverhill Lake and Duvernay formations.

Drive for production

It's all part of the company's drive to achieve an exit production rate for 2012 of 52,000-56,000 barrels of oil equivalent per day, compared with an average 38,503 boe per day in the third quarter and early November output of 45,000 boe per day.

Wright said next year's budget will also be spent on drilling and well completions, facility construction and optimization efforts "which we expect will positively impact production levels in early 2013."

He said there is a special emphasis on accelerating facility construction in southeast Saskatchewan to reduce downtime during the spring melt in 2013.

PetroBakken holds 450 net sections (288,000 acres) in the Bakken play in Saskatchewan and 350 net sections (224,000 acres) in Alberta's Cardium.

The company has earmarked C$30 million in additional capital to build infrastructure and C$30 million to drill 15 Cardium wells in the place of 10 Bakken wells.

"We currently have 17 drilling rigs, six frack spreads and 13 completion service rigs working in the field," said Rene LaPrade, senior vice president of operations. "From now until the end of the year we plan to drill 42 more wells and bring 74 wells into production."

He said a new production facility in the Cardium business unit at Brazzeau in Saskatchewan is also expected to be completed by the end of November, setting the stage for incremental output of 2,500 boe per day.

Disagreement among analysts

Analysts have been dubious about PetroBakken's chances of achieving its exit rate production, although Jeremy Kaliel of CIBC World Markets said the goal is within reach.

"Contrary to popular belief, we believe PetroBakken will comfortably meet its 2012 exit guidance," he wrote, adding the "grey lining to the quarter's silver cloud" is the extra capital spending.

The Bakken unit averaged 15,676 boe per day in the third quarter, up 6 percent over the second quarter, as the majority of production shut-in during the spring breakup was restored. Drilling in the play increased through the latest quarter to 40 net wells, with 31 net wells brought on production. Currently, the company has seven drilling rigs operating in the unit and has drilled 17 wells since quarter-end, with 15 net wells waiting to be completed and brought online.

In the Alberta Cardium output averaged 14,721 boe per day, down 7 percent from the second quarter, due to a delayed start in the second quarter capital program and restricted production and downtime from routine maintenance of individual wells and facilities.

System near completion

A battery and gathering system expansion in the Brazzeau area of West Pembina is expected to be completed by November 30 and will significantly reduce current well restrictions, reducing trucking expenses and add more than 2,500 boe per day of production.

During the third quarter, PetroBakken drilled 32 net wells and brought 15 net wells on production in the Cardium, most of which were in the latter half of the quarter and had only minimal impact on production.

The company currently has eight drilling rigs operating in the Cardium and has drilled 16 net wells since the end of September, with 29 net wells in inventory waiting to be completed or brought on production.

In the Alberta-British Columbia unit, PetroBakken has 2,578 boe per day of production and has compiled an inventory of more than 294 net sections (188,160 acres) of land prospective for new oil resource plays in one or more of the Nordegg, Montney, Duvernay and Swan Hills zones. It plans to drill six wells in the current quarter targeting Swan Hills or Montney zones. ●

Contact Gary Park through publisher@petroleumnews.com

● MOVING HYDROCARBONS

Inergy new ND transport player

Kansas City midstream company acquires Rangeland's COLT facility at Epping, ND, for $425 million; a perfect fit for Inergy

By MIKE ELLERD
For Petroleum News Bakken

Rangeland Energy LLC, the Sugar Land, Texas-based company that recently built the large, open access crude oil loading terminal at Epping in Williams County, N.D., known as COLT, announced earlier in November that it is selling the facility to Kansas City-based Inergy Midstream for $425 million. The deal, which is expected to close in December, marks Inergy's first venture into the Williston Basin and its first venture into crude oil transport.


BILL GAUTREAUX

The COLT facility, which went into service in May, includes 120,000 barrels per day rail loading capacity on Burlington Northern Santa Fe unit trains, eight truck unloading bays with a total capacity of 64,000 barrels per day, and 600,000 barrels of dedicated customer storage capacity. The COLT facility is currently connected to the Banner Highland Partners gathering system, and an agreement is in place to connect the facility to the Bear Tracker gathering system.

With two 8,700-foot rail loops, the facility can load a 120-car unit train in less than 10 hours, according to Inergy. The rail-loading facility is covered, which avoids slowdowns in harsh to winter weather. The first loaded BNSF unit train left the COLT facility on June 5.

In addition to the COLT facility, the Rangeland deal includes the COLT Connector, a 21-mile, bi-directional 10-inch pipeline that extends to the east and connects the COLT facility with the Dry Fork Terminal located at the Beaver Lodge/Ramberg pipeline hub junction south of Tioga. There, the COLT Connector pipeline connects with Enbridge and Tesoro pipelines, and according to Inergy, has potential for future connection to such existing and proposed pipelines operated by Oneok, Hess and TransCanada at Dry Fork. The Dry Fork terminal has a working storage capacity of 120,000 barrels.

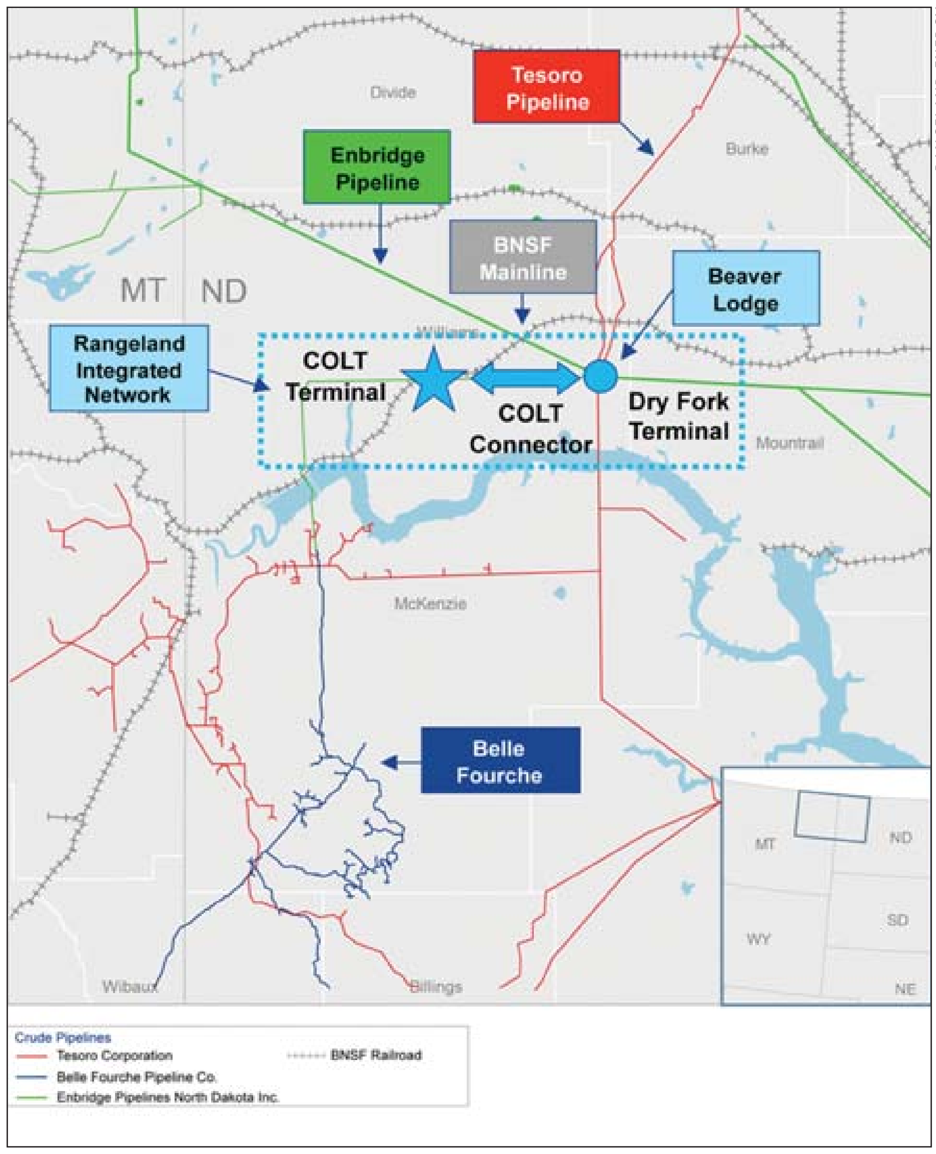
Expansion potential

According to Bill Gautreaux, president of Inergy's NGL supply logistics business Inergy Services, the COLT facility covers approximately 318 acres, which Gautreaux says provides Inergy with significant expansion capacity, including opportunity for a second rail loop. A second rail loop could provide an additional 40,000 to 80,000 barrels of unit train loading capacity, although Gautreaux said an additional 40,000 barrels capacity "is a much easier grab than perhaps the 60,000 or 80,000."

There is also room for additional storage according to Gautreaux. There are currently five 120,000 barrel storage tanks and he believes the facility is capable of holding up to 15 to 20 such tanks.

About Inergy

Inergy is a publicly traded master limited partnership historically focused on natural gas and natural gas liquids with operations in California, Texas, New York and Pennsylvania. Inergy Midstream is engaged in the development and operation of natural gas and NGL transportation, storage and serving refiners in the northeast and California.



RANGELAND ENERGY

In August, Inergy sold its retail propane operations to New Jersey-based Suburban Propane Partners for $1.8 billion. At the time, Inergy was the third largest propane retailer in the country with retail outlets in 33 states. With the divestiture of the propane operations, Inergy had repositioned the partnership "as a pure-play midstream business with a strong financial position," according to Inergy Chairman and CEO John Sherman.

The company started as a propane retailer, but diversified into midstream natural gas and NGLs. Gautreaux told Petroleum News Bakken that over the years the retail propane business changed with increasing prices and conservation efforts, and his company saw slight although consistent declines in demand year over year. As the midstream component grew, the company became about half midstream and half retail propane and a decision was made to divest the propane retail component and focus on midstream opportunities. At that point the company became 100 percent midstream, Gautreaux said, and it began looking into midstream acquisitions, which led it to Rangeland and the Bakken COLT facility.

"When you look at our criteria, what assets do we have, what is our focus and what are we best at, the Bakken deal hit on a couple of areas, one being that it gets us into the crude business, which we decided already makes a lot of sense to be in. It was just a question of where. And it is very compatible with our NGL business because we're already serving those refiners on the east coast and the west coast in PADD I and PADD V," Gautreaux told Petroleum News Bakken.

He said the operations at the COLT facility are similar to what Inergy does in its midstream operations. For example, when you look at trucking crude in, putting it in into storage, putting it back out through a terminal or a pipeline or into rail cars, and serving producers with takeaway on the one hand but also creating deliverability for refiners, the COLT project, Gautreaux said, "fits us like a glove."

With the Rangeland acquisition, Inergy now moves into the crude transportation business in the Williston Basin, and plans to provide Bakken crude to refiners in the northeast (Petroleum Administration for Defense District or PADD I) and California (PADD V).

A portion of the funding for the acquisition will come from an agreement Inergy has to sell institutional investors $225 million in discounted Inergy Midstream common stock. In addition, Inergy expects to access long-term debt capital markets prior to closing the deal, but the company has obtained $225 million in committed unsecured bridge financing to ensure sufficient available capital when the deal closes. Through these funding mechanisms, Inergy will have fully equity financed the transaction.

Executive perspectives

"This is an exciting day for both companies. It's also a great day for the crude oil industry in the Bakken, which will be well served by Inergy's dynamic new

see INERGY page 10

COURTESY RANGELAND ENERGY

Exterior view of the rail loading canopy at COLT taken in April before completion.

continued from page 9

INERGY

presence in the play," said Rangeland CEO Chris Keene in a Nov. 5 press release. "Inergy's CEO, John Sherman, and the rest of his very seasoned leadership team have the experience and desire to serve our current customers with distinction and aggressively grow the business we've developed at COLT. We started with a piece of paper and a vision and now, just three years later, COLT is well positioned to be the premier crude oil terminal in the Bakken. I'm very proud of what the Rangeland team has accomplished in North Dakota in a very short period of time. The scope, quality and efficiency of the storage, rail and pipeline facilities we've put in place are unparalleled in the market," Keene said.

In a Nov. 5 conference call discussing the transaction, Inergy Chief Operating Officer John Sherman said that "the location, the scale, and capabilities of this complex are outstanding. We inherited a solid customer base that we expect to grow, and this asset was designed for cost-effective expansion that we believe will result in high-return bolt-on projects for our investors."

"The COLT Hub is an attractive asset that provides refiners with crucial access to Bakken-sourced crude oil and offers producers reliable takeaway capacity to premium demand markets," Inergy's Gautreaux said in a Nov. 5 press release. "We are excited to acquire and grow this business."

In a Nov. 5 conference call, Inergy President Brooks Sherman said, "crude and NGL logistics are highly compatible, and it's a good platform for us for growth. This is a newly constructed crude terminalling system, an integrated network of railcar loading, pipeline and storage assets, creating a source of liquidity and access to crude oil import-dependent PADD I and PADD V markets. So today, this asset is supplying PADDs I and V that are otherwise import-dependent." Sherman also said the COLT hub is the largest rail terminal in the Bakken with the largest rail terminal storage capacity, and provides access to multiple downstream markets. "It's really a first-mover advantage in building a regional crude hub," Sherman said.

Inergy Vice President for Corporate Development Will Moore said BNSF is running two to three unit trains out of the Bakken each day, and the railroad has said publically that it can run up to 14 if necessary. And Moore is very impressed with the round trip times to California. "We've actually been seeing trip times of five days round trip between this facility and PADD V, and we think that's phenomenal," Moore said.

90% contracted

According to Sherman, 90 percent of the capacity of the facility is either currently contracted or committed under long-term take-or-pay contracts, and over the course of the next 11 months, new contracts coming online will lead to the full utilization of 120,000 barrels per day of rail capacity.

Inergy's Gautreaux said the company's Bakersfield, Calif., NGL plant management will oversee operations at the COLT facility, but Inergy is retaining all of the existing operating employee relationships at COLT. "All of the employees at COLT who actually operate the facility will be staying with us," Gautreaux told PNB.

Inergy's John Sherman said the company is looking forward to "welcoming Rangeland's customers and the highly talented employees at COLT into the Inergy family. The COLT assets provide Inergy with a solid position in this prolific region and are a great complement to our existing midstream operations."

Prior to acquiring the COLT facility, Gautreaux told Petroleum News Bakken that Inergy was approached by customers on the West Coast who hold Bakken acreage about building a crude receipt facility at Bakersfield because of Bakersfield's proximity to California refineries and crude pipelines. That, Gautreaux said, is an option that Inergy will evaluate.

What's next for Rangeland?

In the transaction, Inergy will acquire Rangeland Energy LLC assets, which consist of the COLT facility and Connector pipeline, but the Rangeland management team is retaining the company name, and according to a press release, Rangeland "will continue to pursue midstream development opportunities across North America." Rangeland's Keene recently told the Houston Chronicle that Rangeland has looked at the Utica, Eagle Ford and the Permian Basin plays, but as yet has made no decisions about future ventures.

Rangeland was founded in 2009 with financial backing in private equity commitments from San Antonio-based EnCap Flatrock Midstream. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

● MOVING HYDROCARBONS

Fate of Keystone XL still uncertain

Obama's win revives controversial pipeline as hot energy issue; no clear message from re-elected president where he stands

By GARY PARK

For Petroleum News Bakken

The Canadian and Alberta governments have made it clear they will not live on hope, nor will they get bogged down by doubt when it comes to the future of TransCanada's Keystone XL pipeline under a re-elected President Barack Obama.

Prime Minister Stephen Harper, on the heels of two trips to China this year, was in India during the US election making his case for foreign investment in the Alberta oil sands in return for access to Canadian energy supplies.

Alberta International and Intergovernmental Relations Minister Cal Dallas followed the election by heading to the Middle East for two weeks in an effort to drum up C$120 billion of energy investment and to sell some of the world's oil giants on Alberta oil and gas technology.

Both trips were scheduled long before the outcome of the election was known and would have occurred regardless of whether Obama or Mitt Romney claimed the White House.

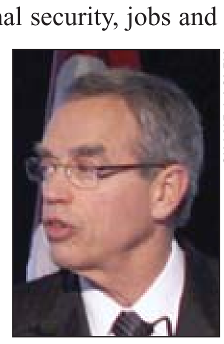
They are all closely linked to the drive by both governments to diversify and expand Canada's energy sales outside North America.

And they mirror the unease within government and industry circles over the chances of Obama approving the C$7.6 billion Keystone XL to deliver oil sands crude to Gulf Coast refineries in Texas.

Continued advocating

Canada's Natural Resources Minister Joe Oliver said his government will continue advocating for the pipeline and expressed confidence that it will get approved.

"It is clearly in the U.S. national interest in terms of national security, jobs and economic growth," he said.



SHANE LASLEY

JOE OLIVER

Alberta Energy Minister Ken Hughes said his government will "continue to advance Alberta's interests in any way that we possibly can. Watch us. We will be executing a game plan over time."

A spokesman for TransCanada argued Keystone XL "fits very well" with Obama's energy strategy of moving the U.S. away from its dependence on foreign oil, including 500,000 barrels per day of heavy crude from Venezuela and Mexico.

He said the company is also preparing to rebuff "misinformation" about the pipeline by explaining "the facts of the project as we see them and its benefits."

Al Monaco, chief executive officer of rival crude exporter Enbridge, said it is "in everybody's interest to get new infrastructure built and I think that has been the Obama's administration's view to this point. I think we will see (that position) going forward."

One issue Romney was never accused of wavering on during the U.S. campaign was a pledge to authorize the pipeline on Day One of his administration — a commitment he made again only two days before the vote.

BARACK OBAMA

STEPHEN HARPER

Obama noncommittal

Obama has been noncommittal since rejecting TransCanada's application in January, arguing there had not been enough time to complete an environmental analysis — a move seen as appeasing his supporters in the powerful environmental movement.

The U.S. State Department and departments in the Nebraska government are reviewing a new application, which is designed to reroute a portion of the line away from sensitive areas in Nebraska, including the Ogallala Aquifer.

Obama's victory has inspired environmental leaders who have turned Keystone XL into their own benchmark fight against the oil sands.

"The new Obama administration should be an opportunity for Canadians and Americans to work together to fight climate change," said Danielle Droitsch, Canada program director for the Natural Resources Defense Council.

"Now is the time to be at odds over dirty energy sources such as tar sands. It is the time for North American leadership in tackling one of the world's most pressing threats."

Uncertainty

The uncertainty has spread deep into political and industry ranks, with David Wilkins, the former U.S. ambassador to Canada and now a partner in a South Caroline-based law firm that advises Canadian energy companies, said he is unsure about Keystone XL.

His best advice to Canada was to keeping pushing for approval and be vocal about its position.

The current ambassador, David Jacobson — selected by Obama — agreed that speedy approval of the pipeline under Obama is uncertain.

"This thing has got to move in an orderly fashion," he said, emphasizing that Keystone XL would not be a huge part of the world's largest two-way energy relationship.

Andrew Finn, program associate at the Canada Institute of the Woodrow Wilson International Center for Scholars in Washington, D.C., urged Canada to make the case that the oil sands will be pro-

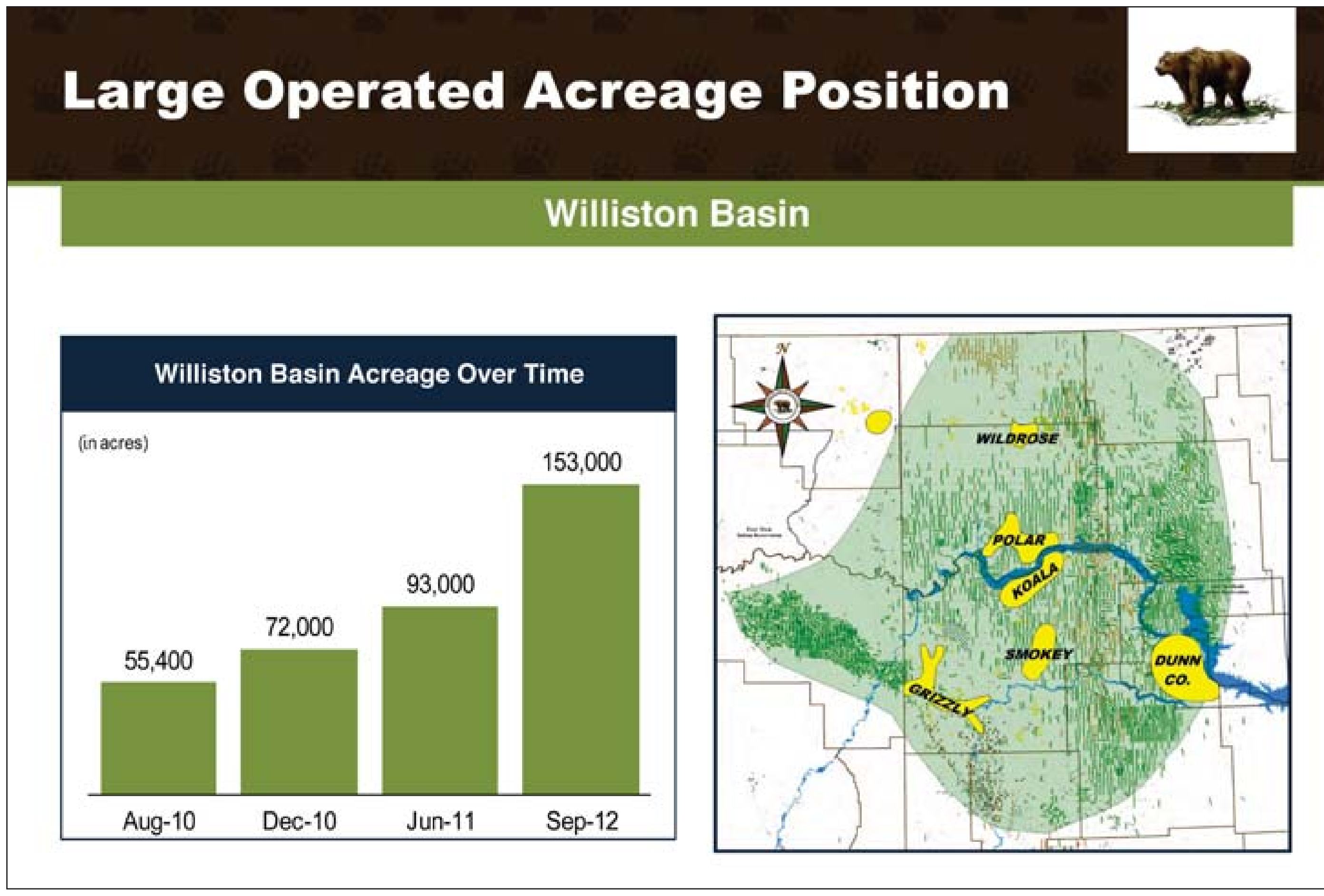
see KEYSTONE XL FATE page 12

● COMPANY UPDATE

Extraordinary production growth

Kodiak Oil & Gas boosts 2012 capital spending 28%; increases staff 73% and production 281% since same period last year

By RAY TYSON
For Petroleum News Bakken



Saying that Kodiak Oil & Gas Corp. is on a mission from above may be understating the company's resolve to increase Bakken-Three Forks production in the U.S. Williston Basin, its sole producing region (see map adjacent to this article).

The Denver-based E&P independent, on a steep climb for a relatively short period of time, is now looking to exit 2012 producing a net 27,000 barrels or more of oil equivalent per day.


LYNN A. PETERSON

This compares to average production of 17,190 boe per day for this year's third quarter, 13,998 boe per day for the prior quarter, and just 4,509 boe per day in the year-ago third quarter.

Put another way, Kodiak's production increased 24 percent just from the second to third quarter of 2012, and rocketed 281 percent when compared to the year-ago third quarter.

Output could be extraordinary

Obviously, Kodiak's output would again have to increase at a good clip throughout this year's fourth quarter to reach a year-end exit of 27,000 boe per day. But, if this projected rate remains steady or continues to grow over the course of next year's first quarter, as it should, the results would be extraordinary.

"With a large number of wells scheduled to be completed in the fourth quarter, we should see that same upward trajectory continue over the coming quarters," Lynn A. Peterson, Kodiak's chairman and chief executive officer, said in a Nov. 2 conference call with analysts and investors.

However, this kind of spirited production growth does not come cheap, as Kodiak's own capital expenditure projections show.

Capex reaches $750 million

Since the beginning of the year, Kodiak's capex budget has been increased 28 percent from $585 million to $750 million, with much of the additional investment allocated to its non-operated properties, where the company has experienced a much larger number of wells drilled this year than anticipated.

Kodiak budgeted $45 million for these non-operated interests, but invested more than $100 million through Sept. 30, and anticipates an additional $40 million in non-operated capital investment by year-end.

"These non-operated interests are adjacent to our core acreage blocks, and we believe it is important to elect to participate in the drilling of the wells in order to retain our economic interests in the lands and develop our Williston Basin asset base," Peterson said. "The increased investment in both operated and non-operated properties should result in an acceleration of our production as we exit the year and continue into 2013."

Kodiak increases barrowing

Kodiak said it intends to pay for the spending increase through a combination of barrowing and cash flow from operations. Kodiak's lenders recently agreed to increase the company's borrowing base to $450 million from the previous $375 million.

Over the past year Kodiak also has increased the number of its employees 73 percent from 60 to 104, giving the company added strength in the field but causing the company's general and administrative expenses to more than double to $9.1 million from $4.5 million.

But the company also has taken major steps to decrease operational costs through efficiency moves, which includes the reduction of drilling days from spud to rig release. On average drilling time has been curtailed from 25 to 20 days, with certain rigs released in less than 20 days. Last year drilling times averaged nearly 35 days.

"As a result we feel that we will drill more wells with our current seven rig count in 2013 than we did with eight in 2012," Peterson said, noting that the company has employed a second well completion crew since min-October. "The two crews are working efficiently at this time and the number of days to complete wells continues to improve. As we move to the fourth quarter, our goal is to complete approximately 23 net operated wells."

Wells increase to 55

For the entire year, the estimated number of net wells scheduled for completion has been increased from 46 to about 55. As a result of the additional wells, the company has increased capital spending on its operated properties by nearly $90 million.

see **KODIAK GROWTH** *page 19*

continued from page 11

KEYSTONE XL FATE

duced, "it's just a matter of where it's going. We can't get off fossil fuels tomorrow."

But Adams Brooks, an advisor to PPHD Limited Partnership, a small energy investment firm, told a Calgary audience there is no chance that Keystone XL will be built under an Obama administration, which he said will have an "anti-fossil fuel orientation.

"They believe that government knows best about how we should live and consume energy," he said.

"So be prepared for (rejection of Keystone XL). That's going to put some pressure on Canada to figure out how to get your oil and gas out of the country," Brooks said. ●

Contact Gary Park through publisher@petroleumnews.com

● COMPANY UPDATE

Enerplus backs off Fort Berthold

PETROLEUM NEWS BAKKEN

Calgary-based Enerplus posted a 10 percent gain to 12,800 barrels of oil equivalent per day from its third-quarter production at the Bakken tight oil play in the Fort Berthold Indian Reservation in North Dakota, but expects to trim spending in that play in 2013.

"Economics in Fort Berthold are still attractive. However, the combination of lower oil prices and 'sticky' costs has eroded significant margins with rate of returns under strip pricing for our Bakken wells in the 30 percent to 40 percent range," Ian Dundas, the company's executive vice president and chief operating officer, told a third-quarter earnings call.

"We're not prepared to adjust our spending plans beyond our current two-rig program until we see sustained improvements in cost performance," he said.

Underscoring its measured strategy, Enerplus said it expects to set a 2013 company-wide capital budget of C$680 million, 20 percent below this year's projected spending, after booking a C$63 million net loss for the latest quarter due mainly to non-cash charges involving asset write-downs. The cuts will be made across all the company's properties, including its Marcellus and Canadian assets, Dundas said in a Q&A session that followed the call.

"Our tight oil project at Fort Berthold, North Dakota continues to attract the lion's share of our capital with $80 million invested there during the quarter. Year-to-date, we spent approximately $370 million in North Dakota," he said.

The company's efforts in 2012 are "focused on growing production, improving our cost structures, managing lease expiries and advancing our understanding" of the Three Forks formation in the Bakken petroleum system.

Enerplus drilled 24 wells year-to-date on its Fort Berthold acreage, 80 percent of which were long horizontals with 24 net wells brought on-stream.

Enerplus tested seven Three Forks wells in 2012, and although it has seen some "variability," Dundas said "we've been quite encouraged by the results," noting the company is modeling its Three Forks wells to be "approximately 70 percent as productive" as a Bakken formation well.

Going back to 28-29 frack stages

"We've tested a number of different completion designs this year to understand if we can enhance well economics with smaller fracks. While we've seen cost reductions, these wells have not met our performance expectations and we believe we are sacrificing return," Dundas said.

As a result, the company is "moving back closer" to its original design; its recent completions for a 9,800 foot lateral have 28 to 29 stages, with approximately 9,000 pounds of ceramic proppant per stage and higher gel weighting, he said.

Although the increased stages put "cost pressure" on Enerplus' frack jobs, Dundas said the company was "starting to see cost release in other line items, such proppants, which are down about 20 percent per pound from the beginning of the year.

Drilling performance has also improved "significantly" since January, "in part related to eliminating our two least efficient rigs. Drilling days from rig up to TD are averaging about 30 days for a single well drilled on a pad," Dundas said, giving Enerplus a per well drilling cost of $5 million and a total drilling and completion cost, before facilities and tie-in, of less than $12 million.

"This is net," he said, noting "we've drilled more single wells than multiple wells on pads. We have one four-well pad that we drilled earlier this year and we saw the average drilling days drop to under 25 days."

Once the company starts development drilling in 2013, moving to more high-density pads, it should see a further reduction in cost, which Dundas estimated would be a half million dollars per well.

Three Forks model 70% as productive as Bakken

Enerplus tested seven Three Forks wells in 2012, and although it has seen some "variability," Dundas said "we've been quite encouraged by the results," noting the company is modeling its Three Forks wells to be "approximately 70 percent as productive" as a Bakken formation well.

"Our best Three Forks well with any significant runtime is a 4,500 foot short lateral with about 10 months of production history. This well will produce more than 100,000 barrels in its first year," he said.

Next year Enerplus plans to drill "another half dozen wells in Three Forks."

Price differentials volatile

Enerplus is shipping 70 percent of its Bakken crude by pipeline on the Enbridge and Duke systems with the remaining 30 percent going by rail to the Gulf Coast. Differentials continue to be very volatile, Dundas said.

"We've seen Fort Berthold field differentials tighten from a $15 barrel discount to WTI in the first half of the year to less than $10 in September. And in October, we saw differentials in the $2 per barrel range," he said.

"While differentials remain tight in November, we continue to expect volatility in the region and are continuing to forecast wider differentials in 2013. Our rail capacity has been providing some pricing production with approximately 15 percent of our total Bakken production being priced off of Gulf Coast markets which have been more closely linked to Brent pricing," Dundas said. ●

PRODUCTION & RECOVERY

Forecasting a Bakken bubble

Plains All American Pipeline expects the economics of Eagle Ford and Permian production could prick the growing Bakken bubble, Plains Chief Executive Officer Greg Armstrong told a third-quarter conference call.

He said higher costs and the distance to market make the Bakken less attractive than the Texas plays, indicating that the North Dakota/Montana formation is "probably the one that is on the economic bubble."

Armstrong said higher costs and the distance to market make the Bakken less attractive than the Texas plays, indicating that the North Dakota/Montana formation is "probably the one that is on the economic bubble."

Armstrong forecast that price differentials could make Bakken crude less attractive in the near term and will likely widen as the market is saturated with light sweet crudes.

As a result there could be "some slowdown" in the Bakken, he said, without setting a timeline, suggesting that producers with limited access to capital will likely allocate their resources to the Permian and Eagle Ford.

Armstrong predicted that Eagle Ford volumes would grow to 1.6 million barrels per day in 2018, up 600,000 bpd from Plains' earlier estimate.

Faced with changing price differentials, he suggested producers will be reluctant to make long-term pipeline shipping commitments, making rail out of the shale the preferred transportation mode to handle excess Bakken volumes.

He estimated that although pipeline transportation from the Bakken to the Gulf Coast costs about $10 per barrel, while rail runs to $13-$15, producers are hesitant when it comes to signing 10-year contracts to support pipeline projects.

Armstrong said Plains now has about 6,000 rail cars, which are evenly divided between natural gas liquids and crude, but, outside the Bakken, he said the company is sticking with pipelines, viewing them as the "most efficient way to move crudes."

—GARY PARK

● PRODUCTION & RECOVERY

North Dakota posts record annual oil output — again

By JAMES MACPHERSON

The Associated Press

North Dakota already has set an oil production record for the fifth consecutive year and the state is on pace to best the previous mark by more than 50 million barrels.

The state Department of Mineral Resources said Nov. 13 that crude production through September totaled more than 173.9 million barrels, up from the record 152.9 million barrels set last year. (See related charts on pages 14 and 15 of this issue, including the adjacent Top 50 North Dakota producers.)

North Dakota produced 21.8 million barrels in September, up from 21.7 million barrels in August, agency spokesman Alison Ritter said.

Oil production numbers typically lag at least two months. Ritter said its "pretty feasible" that the state will end the year at more than 200 million barrels, once October, November and December production results are factored.

Steve Grape, the domestic reserves project manager for the U.S. Department of Energy's information administration, said North Dakota accounts for nearly 12 percent of total U.S. crude production, up from 1 percent less than five years ago.

Trails only Texas

Steve Grape, the domestic reserves project manager for the U.S. Department of Energy's information administration, said North Dakota accounts for nearly 12 percent of total U.S. crude production, up from 1 percent less than five years ago.

North Dakota trails only Texas in oil output. North Dakota has risen from the ninth biggest oil state just six years ago with improved horizontal drilling techniques in the rich Bakken petroleum system, which includes the Bakken and Three Forks formations, in the western part of the state.

"No way has North Dakota's oil production been a straight line," Grape said. "The growth has been amazing."

Ron Ness, president of the North Dakota Petroleum Council, said oil companies have benefited this year from more efficient drill rigs and favorable weather.

"It's remarkable," said Ness, whose group represents several hundred companies working in the state's oil patch. "Bakken oil is going to refiners all across the country now."

The ability to move crude to market is keeping pace with North Dakota's oil production, Kringstad said. Nearly half of North Dakota's crude is being shipped by rail due to the lack of pipeline capacity, he said.

Three billion barrel mark — soon

Justin Kringstad, director of the North Dakota Pipeline Authority, said the state has forecast oil production over the next decade.

The ability to move crude to market is keeping pace with North Dakota's oil production, Kringstad said. Nearly half of North Dakota's crude is being shipped by rail due to the lack of pipeline capacity, he said.

Increased pipeline infrastructure that could increase so-called takeaway capacity by 195,000 barrels daily is expected to come on line early next year, Kringstad said.

North Dakota began producing oil in 1951. Ritter, of the state Department of Mineral Resources, said the state has tallied more than 2 billion barrels of oil since then, mostly in the last few years.

"We've done some number crunching, and if we average 20 million barrels a month, we could hit our 3 billionth barrel in less than three years," she said. ●

Petroleum news BAKKEN

September 2012

Top 50 North Dakota Bakken Oil Producers

Company	BDP*
1 Continental Resources, Inc.	62,264.4
2 Whiting Oil and Gas Corporation	59,092
3 Hess Corporation	54,953.9
4 EOG Resources, Inc.	44,365.4
5 Brigham Oil & Gas, LP (Statoil)	40,035.6
6 Marathon Oil Company	28,450.3
7 Burlington (ConocoPhillips)	21,530.3
8 Slawson Exploration Company, Inc.	21,296
9 Petro-Hunt, LLC	18,669.8
10 XTO Energy Inc.	17,877
11 Kodiak Oil & Gas (USA), Inc.	17,746.7
12 Oasis Petroleum North America LLC	17,698
13 SM Energy Company	12,860
14 Denbury (XTO & ExxonMobil)	12,617.1
15 WPX Energy Williston, LLC	12,390
16 Oxy USA, Inc.	11,629
17 Zavanna, LLC	10,296
18 Enerplus Resources USA Corporation	9,689.4
19 Hunt Oil Company	9,105.5
20 Newfield Production Company	8,923.5
21 QEP Energy Company	8,028.6
22 Helis Oil & Gas Company, LLC	7,395.2
23 Zenergy, Inc.	7,386.9
24 Fidelity Exploration & Production	6,514.1
25 Murex Petroleum Corporation	6,255.1
26 Samson Resources Company	5,754
27 Baytex Energy USA Ltd	3,058.0
28 Crescent Point Energy US Corp.	2,522.9
29 G3 Operating, LLC	2,492.2
30 Sinclair Oil and Gas Company	1,977
31 Liberty Resources, LLC	1,189.7
32 Cornerstone Natural Resources, LLC	1,124.7
33 Arsenal Energy USA, Inc.	1,124.5
34 Triangle USA Petroleum Corporation	739.0
35 American Eagle Energy Corporation	668.0
36 GMX Resources, Inc.	412.0
37 Windsor Energy Group, LLC	244
38 Prima Exploration, Inc.	235.9
39 Resource Drilling, LLC	217.1
40 Abraxas Petroleum Corp	204.4
41 Sequel Energy, LLC	203
42 Gadeco, LLC	186.4
43 True Oil, LLC	149.2
44 Legacy Reserves Operating LP	127.7
45 Resolute Natural Resources Company, LLC	57.5
46 BTA Oil Producers, LLC	54.6
47 Texakota, Inc.	55
48 Petro Havester Operating Company, LLC	38
49 Tri-C Resources, LLC	27.4
50 Sundance Energy, Inc.	19

*Barrels of oil per day

Numbers derived from the September 2012 Oil & Gas Production Report published by the North Dakota State Industrial Commission, Department of Minerals, Oil & Gas Division. Note this is the oil produced by wells operated by these companies; it does not identify the percentage of Bakken petroleum system oil (including Three Forks) that is owned by the company or its partners, so it may differ from what the company reports.

September 2012
North Dakota Bakken oil production by company

Derived from the September 2012 Oil & Gas Production Report published by the North Dakota State Industrial Commission, Department of Minerals, Oil & Gas Division. Note this is the oil produced by wells operated by these companies; it does not identify the percentage of Bakken petroleum system oil (including Three Forks) that is owned by the company or its partners, so it may differ from what the company reports. Also, the daily average was derived from dividing the total production by the number of days in September, versus the number of days the well was actually producing. There are a few wells that did not produce for the entire month.

Legend:
Company
Field — Pool — County — Barrels of oil
Daily average barrels

Abraxas Petroleum Corp
Demores — Bakken – Billings 374
North Fork — Bakken – McKenzie 5,431
Roosevelt — Bakken – Billings 530

Daily Average — 204.4

American Eagle Energy Corporation
Colgan — Bakken – Divide — 20,708

Daily Average — 668.0

Arsenal Energy USA, Inc.
Stanley — Bakken – Mountrail — 34,860

Daily Average — 1,124.5

Baytex Energy USA Ltd
Ambrose — Bakken – Divide — 39,792
Burg — Bakken — DIV/WIL — 2,588
Garnet — Bakken – Divide — 2,818
Lone Tree — Bakken – Williams — 4,962
Lone Tree Lake — Bakken – Williams — 3,014
Musta — Bakken – Divide — 4,871
Plumer — Bakken – Divide — 599
Skabo — Bakken – Divide — 1,507
Smoky Butte — Bakken – Divide — 4,794
West Ambrose — Bakken – Divide — 21,751
Whiteaker — Bakken — Divide — 5,036
Wildcat — Bakken – Williams — 3,066

Daily Average — 3,058.0

Brigham Oil & Gas, LP (Statoil)
Alexander — Bakken – McKenzie — 11,760
Alger — Bakken – Mountrail — 383,715
Avoca — Bakken – Williams — 10,339
Banks — Bakken – McKenzie — 109,018
Briar Creek — Bakken – McKenzie — 24,929
Buford — Bakken – Williams — 4,541
Bull Butte — Bakken – Williams — 35,953
Camp — Bakken – McKenzie — 74,555
Catwalk — Bakken — Williams — 11,738
Cow Creek — Bakken – Williams — 28,617
East Fork — Bakken – Williams — 42,898
Elk — Bakken – McKenzie — 12,058
Foreman Butte — Bakken – McKenzie — 6,352
Glass Bluff — Bakken – McKenzie — 2,106
Kittleson Slough — Bakken – Mountrail — 11,607
Lake Trenton — Bakken – Williams — 4,785
Last Chance — Bakken – Williams — 43,771
Nameless — Bakken – McKenzie — 9,973
Painted Woods — Bakken — Williams — 71,177
Parshall — Bakken – Mountrail — 393
Poe — Bakken – McKenzie — 28,922
Ragged Butte — Bakken – McKenzie — 24,012
Rosebud — Bakken – Williams — 9,459
Ross — Bakken – Mountrail — 259
Sakakawea — Bakken – McKenzie — 4,176
Sandrocks — Bakken – McKenzie — 16,958
Spring Creek — Bakken – McKenzie — 7,801
Squires — Bakken – Williams — 41,412
Stony Creek — Bakken – Williams — 28,794
Sugar Beet — Bakken – Williams — 12,788
Todd — Bakken – Williams — 120,435
Wildcat — Bakken — MCK/WIL — 15,068
Williston — Bakken – Williams — 30,736

Daily Average — 40,035.6

BTA Oil Producers, LLC
Bicentennial — Bakken — Golden Valley — 273
Elkhorn Ranch — Bakken – Billings — 54
North Tioga — Bakken – Burke — 138
Pierre Creek — Bakken – McKenzie — 196
Stoneview — Bakken — Divide — 1,032

Daily Average — 54.6

Burlington Resources Oil & Gas Company, LP (ConocoPhillips)
Bailey — Bakken – Dunn — 24,486
Bennett Creek — Bakken — McKenzie — 3,676
Blue Buttes — Bakken – McKenzie — 53,392
Bully — Bakken – McKenzie — 6,207
Cabernet — Bakken – Dunn — 17,996
Camel Butte — Bakken – McKenzie — 5,641
Charlson — Bakken – McKenzie — 51,757
Clear Creek — Bakken – McKenzie — 33,819
Corral Creek — Bakken – Dunn — 16,405
Croff — Bakken – McKenzie — 10,320
Crooked Creek — Bakken – Dunn — 4,750
Dimmick Lake — Bakken — McKenzie — 5,131
Elidah — Bakken – McKenzie — 56,541
Fayette — Bakken – Dunn — 6,832
Hawkeye — Bakken – McKenzie — 16,190
Haystack Butte — Bakken – McKenzie — 52,618
Jim Creek — Bakken – Dunn — 3,656
Johnson Corner — Bakken – McKenzie — 7,519
Keene — Bakken/Three Forks – McKenzie — 86,313
Killdeer — Bakken – Dunn — 8,212
Little Knife — Bakken – Dunn — 11,894
Lone Butte — Bakken – Dunn — 5,173
Mondak — Bakken – McKenzie — 135
Morgan Draw — Bakken — Golden Valley — 1,197
Murphy Creek — Bakken – Dunn — 42,321
North Fork — Bakken – McKenzie — 12,021
Pershing — Bakken – McKenzie — 7,020
Pierre Creek — Bakken – McKenzie — 703
Sand Creek — Bakken – McKenzie — 24,883
Twin Buttes — Bakken – Dunn — 4,837
Union Center — Bakken – McKenzie — 48,033
Westberg — Bakken – McKenzie — 33,217
Wildcat — Bakken – McKenzie — 493
Willmen — Bakken — Dunn — 4,052

Daily Average — 21,530.3

Carl H. Nordstrand
Pierre Creek — Bakken – McKenzie — 159

Daily Average — 5.1

Charger Resources, LLC
Buckhorn — Bakken – McKenzie — 39
Johnson Corner — Bakken – McKenzie — 182
Morgan Draw — Bakken — Golden Valley — 179
Pierre Creek — Bakken – McKenzie — 0

Daily Average — 12.9

Chesapeake Operating, Inc.
Wildcat — Bakken/Three Forks – Stark — 77
Wildcat — Bakken/Three Forks – Golden Valley

Daily Average — 2.5

Citation Oil & Gas Corporation
Sadler — Bakken – Divide — 114

Daily Average — 3.7

Condor Petroleum, Inc.
Big Bend — Bakken – Mountrail — 0
Hayland — Bakken – Divide — 104
Stoneview — Bakken — Divide — 113

Daily Average — 7.0

Continental Resources, Inc.
Alkali Creek — Bakken – Mountrail — 13,981
Banks — Bakken – McKenzie — 132,226
Barta — Bakken – Billings — 3,464
Battleview — Bakken – Williams — 4,157
Bear Creek — Bakken – Dunn — 9,438
Beaver Creek — Bakken — Golden Valley — 4,524
Beaver Creek Bay — Bakken – Mercer — 0
Beaver Lodge — Bakken – Williams — 293
Bell — Bakken – Stark — 4,570
Bicentennial — Bakken – McKenzie — 619
Big Gulch — Bakken – Dunn — 10,480
Border — Bakken — BRK/DIV — 4,505
Brooklyn — Bakken – Williams — 86,714
Bully — Bakken – McKenzie — 8,360
Cabernet — Bakken – Dunn — 9,495
Camel Butte — Bakken – McKenzie — 1,522
Camp — Bakken – McKenzie — 50,234
Cedar Coulee — Bakken – Dunn — 6,696
Charlie Bob — Bakken – McKenzie — 226
Charlson — Bakken – McKenzie — 18
Chimney Butte — Bakken – Dunn — 72,175
Corinth — Bakken – Williams — 9,220
Corral Creek — Bakken – Dunn — 6,338
Crazy Man Creek — Bakken – Williams — 16,377
Demores — Bakken – Billings — 1,079
Dimmick Lake — Bakken — McKenzie — 10,927
Dollar Joe — Bakken – Williams — 24,986
Dolphin — Bakken – Divide — 26,712
Dutch Henry Butte — Bakken — Stark — 132
East Fork — Bakken – Williams — 66,106
Edge — Bakken – McKenzie — 4,176
Elidah — Bakken – McKenzie — 21,931
Elk — Bakken – McKenzie — 3,710
Elkhorn Ranch — Bakken – Billings — 11,406
Elm Tree — Bakken – McKenzie — 113,369
Epping — Bakken – Williams — 32,572
Glade — Bakken – Billings — 253
Hamlet — Bakken – Divide — 37,829
Hanson — Bakken – Williams — 15,162
Haystack Butte — Bakken — MCK/DUN — 24,013
Hebron — Bakken – Williams — 17,977
Indian Hill — Bakken – McKenzie — 25,338
Jim Creek — Bakken – Dunn — 94,914
Last Chance — Bakken – Williams — 23,156
Lindahl — Bakken – Williams — 18,253
Little Knife — Bakken – Williams — 28,973
Lone Tree Lake — Bakken – Williams — 12,307
Long Creek — Bakken – Williams — 10,595
Mary — Bakken – McKenzie — 1,268
Mondak — Bakken – McKenzie — 2,561
Murphy Creek — Bakken – Dunn — 71,691
North Fork — Bakken – McKenzie — 1,292
North Tioga — Bakken — WIL/BRK — 65,416
North Tobacco Garden — Bakken – McKenzie — 22,240
Northwest McGregor — Bakken – Williams — 24,160
Oakdale — Bakken – Dunn — 118,539
Oliver — Bakken – Williams — 64,737
Patent Gate — Bakken – McKenzie — 23,522
Pembroke — Bakken – McKenzie — 9,524
Pershing — Bakken – McKenzie — 16,282
Pleasant Valley — Bakken — Williams — 10,951
Poe — Bakken – McKenzie — 8,607
Rainbow — Bakken – Williams — 12,524
Ranch Coulee — Bakken – McKenzie — 3,430
Ranch Creek — Bakken – McKenzie — 1,297
Rattlesnake Point — Bakken – Dunn — 30,042
Ross — Bakken – Mountrail — 89
Sadler — Bakken – Divide — 17,885
Sauk — Bakken — DIV/WiL — 9,595
Siverston — Bakken – McKenzie — 3,580
South Boxcar — Bakken – McKenzie — 401
Squires — Bakken – Williams — 6,464
St. Demetrius — Bakken – Billings — 44,621
Stoneview — Bakken — DIV/WIL/BRK — 109,099
Temple — Bakken – Williams — 6,538
Todd — Bakken – Williams — 5,873
Upland — Bakken – Divide — 39,823
Viking — Bakken – Burke — 24,139
West Capa — Bakken – Williams — 5,550
Westberg — Bakken – McKenzie — 15,525
Wildcat — Bakken — WIL/BIL/MCK — 25,946
Wildrose — Bakken – Divide — 31,261
Willow Creek — Bakken – Williams — 14,215

Daily Average — 62,264.4

Cornerstone Natural Resources, LLC
Bailey — Bakken – Dunn — 1,397
Carter — Bakken – Burke — 9,397
Clear Water — Bakken – Burke — 2,008
Coteau — Bakken – Dunn — 783
Customs — Bakken – Burke — 2,063
Flaxton — Bakken – Burke — 6,895
Lostwood — Bakken – Burke — 369
Northeast Foothills — Bakken – Burke — 1,324
South Coteau — Bakken – Burke — 2,229
Wildcat — Bakken – Burke — 508
Woburn — Bakken – Burke — 7,892

Daily Average — 1,124.7

Crescent Point Energy US Corp.
Colgan — Bakken – Divide — 4,273
Dublin — Bakken – Williams — 6,908
Ellisville — Bakken – Williams — 18,311
Gooseneck — Bakken – Divide — 10,065
Little Muddy — Bakken – Williams — 4,446
New Home — Bakken – Williams — 478
West Ambrose — Bakken – Divide — 4,806
Wheelock — Bakken – Williams — 747
Wildcat — Bakken — DIV/WIL — 28,176

Daily Average — 2,522.9

Denbury Onshore, LLC (XTO & ExxonMobil)
Arnegard — Bakken – McKenzie — 6,012
Bear Creek — Bakken – Dunn — 14,832
Bicentennial — Bakken — Golden Valley — 395
Buckhorn — Bakken – Billings — 400
Camp — Bakken – McKenzie — 2,400
Cedar Coulee — Bakken – Dunn — 1,555
Charlson — Bakken – McKenzie — 59,494
Corral Creek — Bakken – Dunn — 1,139
Devils Pass — Bakken — MCK/BIL — 51
Elidah — Bakken – McKenzie — 645
Elk — Bakken – McKenzie — 7,465
Elkhorn Ranch — Bakken – Billings — 22
Garden — Bakken – McKenzie — 15,183
Glass Bluff — Bakken – McKenzie — 11,495
Hofflund — Bakken – Williams — 1,731
Indian Hill — Bakken – McKenzie — 2,229

To view this chart in its entirety, please visit: http://bit.ly/Waf9tQ

● FINANCE & ECONOMY

Tight oil sideswipes oil sands

By GARY PARK
For Petroleum News Bakken

Oil sands giant Suncor Energy is displaying more jitters than ever before as it faces the wave of new tight oil production in North America.

The ramping up of volumes from formations such as the Bakken is forcing the company to revise its original schedule for making investment decisions on three projects carrying a combined price tag of about C$40 billion.

Chief Executive Officer Steve Williams said the company's Voyageur project to upgrade oil sands bitumen into synthetic crude is "struggling" to meet its economic threshold and the Fort Hills oil sands mine — both joint ventures with the Canadian unit of France's Total — will probably be delayed at least a year to 2017.

The new volumes of tight oil entering the North American market are effectively increasing the amount of light sweet crude.

"An upgrader just takes advantage of the margin between light crudes and heavy crudes and so it squeezes the margin on an upgrader," he said.

"We are in the process of fully assessing the mid- and long-term consequences of that change in the market and our belief that Voyageur economics are under more pressure than when we initially conceived the project."

Revision of timetable

While decisions on sanctioning had been targeted to occur around mid-2013, reviews are expected to force a revision of that timetable.

With spending delayed, Suncor has chopped 11 percent or C$850 million off its 2012 capital budget and expects the 2013 budget will be stripped of up to C$1.5 billion that Williams now expects will be around C$7.5 billion, down from an earlier target of C$8 billion-C$9 billion.

"At the start of the year, we said that cost and quality metrics would be Suncor's priorities when executing growth projects," he said. "We're delivering on these goals by spending capital efficiently and maintaining a disciplined approach to pre-sanction spending on our operated growth projects."

Shrinking this year's program to C$6.65 billion was achieved by eliminating C$200 million from unidentified small projects, saving C$200 million on Stage 4 of the Firebag in-situ project and imposing tight controls on three joint-venture projects.

Voyageur 'stressed'

The toughest challenge involves the Voyageur project to process 200,000 barrels per day of bitumen, with Suncor holding 51 percent and Total 49 percent. The last cost estimate was C$23 billion.

Voyageur is "stressed" because of "impressive" volumes of tight oil entering the market and Suncor and Total are "working very aggressively" to improve the economics, he said.

However, the two mining projects — Fort Hills and Joslyn — are "looking very attractive — we are pleased with progress being made on scope and costs," although Suncor is not ready to disclose cost thresholds, Williams said.

Fort Hills, with Suncor as 40.8 percent operator, Total holding 29.2 percent and Teck Resources 20 percent, targets 160,000 bpd of bitumen production at an original cost of C$9.6 billion.

Total with 38.25 percent is operator of Joslyn, designed to produce 100,000 bpd, with Suncor holding 26.75 percent, Occidental Petroleum 15 percent and Japan's Inpex 10 percent and carries a cost estimate of C$6 billion.

Williams said Enbridge's planned reversal of Line 9 to displace imported crude for Quebec and Ontario refineries with production from the Alberta oil sands and Bakken play is presenting several options for Suncor's Montreal refinery.

He said the prospect of using "inland" crude for the facility allows Suncor to consider alternatives, including the use of rail to deliver crudes from Western Canada and the United States, adding there will be some action on the project in 2013. ●

Contact Gary Park through publisher@petroleumnews.com

● MERGERS & ACQUISITIONS

Crescent Point reaches out

Bakken player scoops up Utah assets to apply drilling, fracturing technologies; W. Canadian production averages almost 100,000 boe

By GARY PARK
For Petroleum News Bakken

Crescent Point Energy, which has been on the leading edge of technology that has cracked the Canadian Bakken formation, has extended its C$2.5 billion 2012 shopping spree to a light oil resource play in Utah's Uinta Basin.

In an C$861 million deal, including a cash consideration of C$784 million, it has acquired privately held oil and gas producer Ute Energy Upstream Holdings.

"This resource play is a new core area for Crescent Point and is consistent with our strategy of acquiring high-quality, large oil-in-place pools with long-term upside potential," Crescent Point Chief Executive Officer Scott Saxberg said in a release Nov. 1.

He said his company believes it can apply extraction expertise developed in Western Canada and North Dakota to the Uinta, using vertical and horizontal infill drilling and multi-stage fracture stimulation.

Fourth deal this year

The deal, expected to close by the end of November, is Crescent Point's fourth this year, raising its production to 99,500 barrels of oil equivalent per day, with an exit rate for the year targeted at 109,000 boe per day.

Ute Energy has proved plus probable reserves of 55.1 million boe, produces 7,800 boe per day, 88 percent weighted to oil and liquids, controls a net 173,000 acres in Uinta and has 8,800 gross potential drilling locations.

Crescent Point expects closure of the deal will increase its 2012 capital spending by C$150 million to C$1.4 billion.

Exploration and development agreements with the Ute Indian Tribe govern more than 96,000 net acres of the property.

Based on meetings with the tribe, Crescent Point said it is confident that provisions to extend the majority of agreements will give it up to 15 years to develop the inventory.

In a statement, Irene Cuch, chairwoman of the Ute Tribe Business Committee, welcomed "a quality operator of Crescent Point's capabilities and financial strength operating on our lands."

New production record

For the third quarter, Crescent Point set a new average production record of 99,631 boe per day, up 38 percent from the previous quarter and more than 27,000 boe per day from a year earlier, with 15,500 barrels per day coming from the Bakken formation.

Expansion of the company's Stoughton rail facility, due for completion before year's end, will raise shipping capacity out of the area to 40,000 bpd.

For its properties in southeast Saskatchewan and Manitoba, the company logged 66 gross wells and claimed a 100 percent success rate. Of that total, 44 gross wells were drilled horizontally in the Bakken play and 22 were horizontal wells in conventional zones.

Crescent Point also converted six additional Viewfield Bakken producing wells to water injection wells, ending the quarter with a total of 41 producing water injection wells.

It said production from those wells continues to surpass its expectations and has demonstrated the field-wide applicability of waterflood to the play, with potential partners and the Saskatchewan government involved in discussing that prospect.

Crescent Point said it continues to pursue multiple applications of new technologies to maximize recoveries and improve efficiencies, including re-entering existing wells in the Saskatchewan Bakken that

see CRESCENT POINT page 17

● COMPANY UPDATE

SM Energy reports strong 3Q production

Third quarter Bakken/TF production up 96 percent over third quarter 2011; operated four rigs and completed nine wells

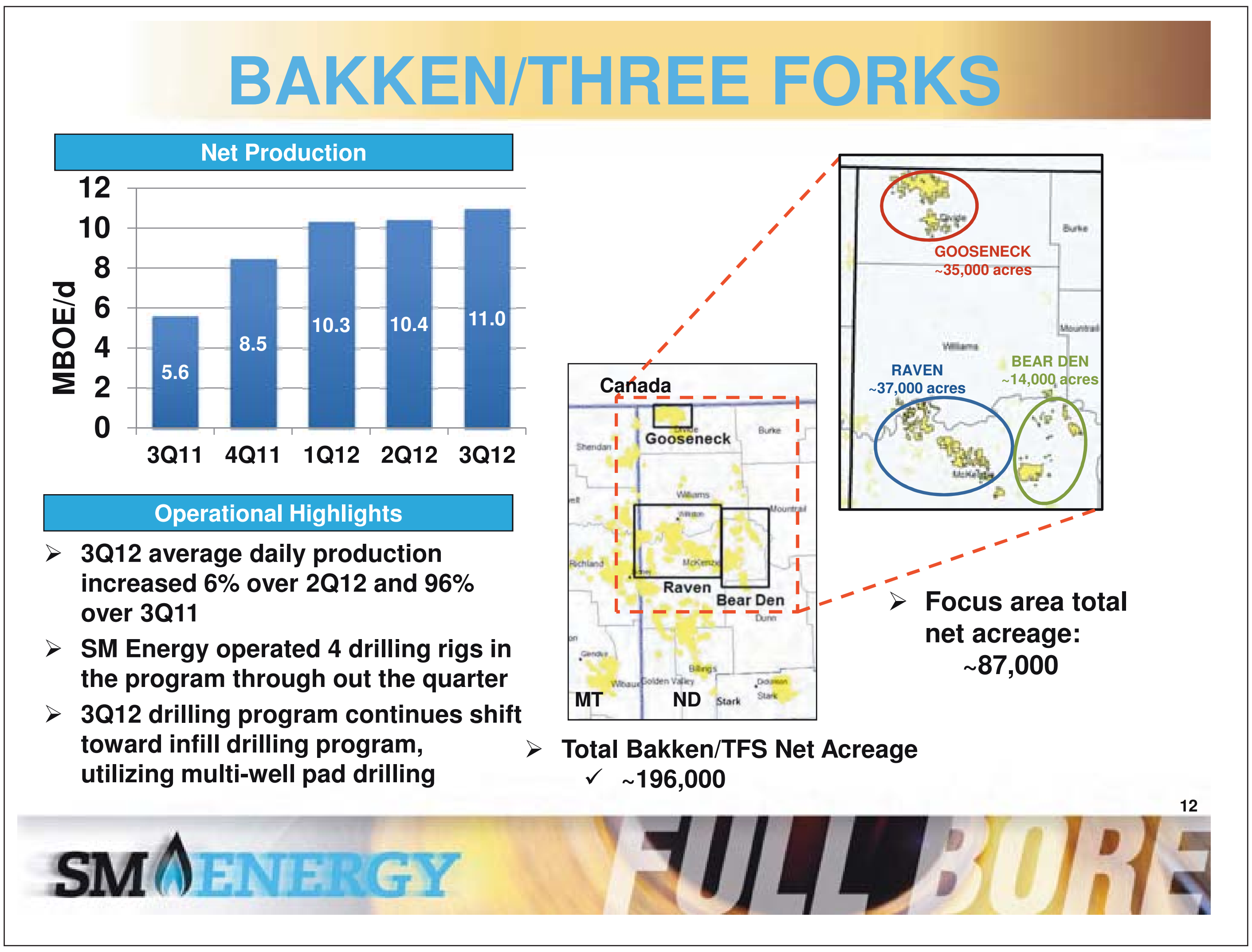
By MIKE ELLERD

For Petroleum News Bakken

SM Energy reported quarterly production of 9.5 million barrels of oil equivalent, a production increase of 13 percent over the previous quarter. While most of this production was driven by the company's Eagle Ford rich gas play, production in its Bakken and Three Forks assets was 11,000 barrels of oil equivalent per day, an increase of 6 percent over the second quarter 2012 and a 96 percent increase over the third quarter 2011.

The company transitioned most of its drilling and completion activity in the basin to multi-well pad infill drilling in the first two quarters of the year.

SM Energy operated four drilling rigs in the Williston Basin during the third quarter, and it plans to continue to operate those four rigs through the fourth quarter. Three of these rigs are focused on the Bakken and Three Forks in its Raven and Bear Den prospects in McKenzie and Williams counties, and the fourth rig is targeting the Three Forks formation in its Gooseneck prospect in Divide County.



Multi-well, infill drilling

The company transitioned most of its drilling and completion activity in the basin to multi-well pad infill drilling in the first two quarters of the year. During the third quarter, SM Energy completed nine operated wells in its Bakken and Three Forks pools.

"During the third quarter, we operated four drilling rigs, with one rig in the Gooseneck area and the other three in our Raven and Borden prospect areas," said SM Energy President and Chief Operating Officer Javan Ottoson in a Nov. 1 conference call. "This program continues to deliver strong production growth and reported a 6 percent increase in sequential production growth from prior quarter up to 11,000 barrels of oil equivalent per day and nearly double quarterly production volumes from the third quarter of 2011," Ottoson said.

Focus Bakken, Three Forks

While SM Energy has approximately 196,000 net acres in the Williston Basin, the primary focus of its activities in the basin is on the oil-producing Bakken and Three Forks formations in the Raven, Bear Den and Gooseneck areas where it has approximately 87,000 net acres. In the Nov. 1 conference call, Ottoson also said that essentially all of this acreage is currently held by production.

In other operations, SM Energy reported an 18 percent increase in its rich gas Eagle Ford play, and that oil production in its non-operated Eagle Ford assets also increased from the previous quarter. In the Permian Basin, the company operated four drill rigs in the quarter and added 10,300 net acres bringing the total Permian Basin acreage to 125,600 net acres. SM Energy also operated three rigs in its Granite Wash program and one rig in the Powder River Basin. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

continued from page 16

CRESCENT POINT

were originally completed with 8-stage and 16-stage cemented liners and increasing them to 25-stage and 30-stage completions. Another 90 wells have been identified as candidates for this process.

In addition, the company said it drilled three two-mile horizontal wells in the Flat Lake Bakken play and achieved 100 percent success.

Shaunavon injection

In southwestern Saskatchewan, it drilled 20 gross wells at a 100 percent success rate, 11 of them drilled in the Shaunavon area.

Crescent Point is now injecting water into seven horizontal wells in the Lower Shaunavon and has been "encouraged" by results to date.

Through acquisitions completed this year, it has add 17 injection wells in the Upper Shaunavon formation and expects to have as many as 30 water injections wells in the play by year-end.

In the latest quarter, the company completed preparation of its rail-loading facility in the Dollard area and delivered its first loads in October. Current capacity is 4,000 bpd and expansion is planned for 2013.

In North Dakota, Crescent Point participated in drilling 30 oil wells, 14 of them targeted in the Three Forks formation. The success rate was reported at 100 percent.

It aims to drill up to 16 net wells in the Bakken and Three Forks zones this year and is working with service providers to reduce capital costs that have seen upward pressure due to high industry activity levels in North Dakota.

According to the state's Department of Minerals, Oil and Gas Division, Crescent Point's U.S. subsidiary operated wells that produced 2,694 bpd in August.

Calculations by Petroleum News Bakken rate the company as the 28th largest oil producer in the Bakken system of North Dakota, including the Three Forks formation. ●

Contact Gary Park through publisher@petroleumnews.com

● IN OTHER NEWS

Rail buildout ahead to handle 1M bpd

Time for natural gas to replace diesel as locomotive fuel? OPEC first to feel the squeeze from US, Russian crude production?

COMPILED By STEVEN MERRITT
For Petroleum News Bakken

In Other News

Despite its phenomenal growth in recent years, especially in the northern Plains, rail transport for crude oil will not replace the need for more pipelines, Continental Resources chief financial officer told an investor conference earlier in November.

According to a recent Platts report, Continental CFO John Hart said the production forecast for the Williston Basin alone "will require a full platform of infrastructure buildout."

"There will definitely be a need for pipelines," Hart said. "The production growth forecast is in excess of 1.5 million barrels per day, and could reach 2 million to 2.5 million bpd."

According to Platts, Hart said that regional rail infrastructure to handle more than 1 million barrels per day is in the works, which will create a "huge shift" in markets in the coming years as well as affect the price differential between West Texas Intermediate and Gulf Coast crudes.

Currently, Continental is shipping 65 percent of its Bakken crude by rail.

Platts cited Hart's mention of two pipeline projects — the reversed Seaway pipeline and TransCanada's Gulf Coast Project — as vital to bringing Plains crude south. The Seaway pipeline began delivering Cushing, Okla., crude shipments to the Gulf Coast last June, and, according to the Platts report, could reach a capacity of 400,000 bpd in early 2013. Plans also are in the works to double capacity by mid-2014.

TransCanada's Gulf Coast line, originally part of its Keystone XL design, is slated for a mid-to-late 2013 startup with an initial 700,000 bpd capacity that will deliver crude from Cushing to Nederland, Texas, according to Platts.

■ Read more here:
http://bit.ly/Sqs7C4

Time for natural gas to replace diesel as locomotive fuel?

THE BOOMING PRODUCTION of natural gas from resource plays coupled with prices that are forecast to remain low and stable in the coming years have railroad executives revisiting a decades-old question for the industry: is it time for natural gas to replace diesel as a means for fueling locomotives?

According to a recent article in the Houston Chronicle, although rail firms have been publicly quiet about the potential of natural gas-powered locomotives — citing unproven technology and a lack of real-world examples of gas-powered trains — they are giving the idea serious consideration.

"It has to be something that the whole industry is going to be moving on to, but our projection is that, yes, it will be eventually moving on to (gas)," Normand Pellerin, assistant vice president for environment and sustainability for Canadian National Railways, told the Chronicle. "That's because we don't see how diesel prices will come down over the years. It's all about pricing."

Canadian National currently runs a natural gas-powered test train in Alberta.

According to the Chronicle, rising diesel prices pushed Union Pacific Railroad's fuel and utilities costs to \$3.6 billion in 2011, which accounted for 26 percent of its overall expenses. That ongoing expense has prompted railroads to invest in engine and software upgrades in an effort to trim total fuel usage, which can top 1 billion gallons annually for industry mainstays like Union Pacific and BNSF, according to the Chronicle. Currently, natural gas sells for \$1 to \$2 per gallon less than an equivalent amount of diesel.

But getting from concept to reality will involve myriad factors.

A switch to natural gas would involve modifying diesel-electric locomotives at a cost of \$600,000 to \$1 million each, which would be expected to fall with increased application and interest from companies, according to the Houston newspaper.

Also, the challenge of storing and moving liquefied natural gas for refueling trains will involve new regulations, infrastructure and logistics. According to the Houston Chronicle article, the idea of bringing back the tender car has emerged. Instead of wood or coal, the railcar directly behind the locomotive would be filled with LNG.

■ Read more here:
http://bit.ly/RV7qkU

OPEC first to feel squeeze from US, Russia crude production?

FOR YEARS, CHALLENGERS and incumbents for national office in the U.S. have emphasized a "do more with less oil" from the Organization of the Petroleum Exporting Countries. And according to a recent Wall Street Journal piece, the U.S. boom, coupled with a robust production effort in Russia could have OPEC feeling the market pinch.

According to The Journal, imports are expected to account for less than 40 percent of U.S. oil consumption next year for the first time since 1991.

"This flood of U.S. crude is likely to put oil prices and OPEC output under downward pressure next year," The Journal quoted Leo Drollas, chief economist of the U.K.-based Centre for Global Energy Studies. The article also cited an Energy Information Agency report that sees a small drop of 490,000 barrels a day in OPEC supply next year, as it cuts output to support prices.

Meanwhile, the Centre for Global Energy Studies reported that the output boost will reduce global demand for OPEC's crude in 2013 by about 670,000 barrels a day — about 2 percent of its current crude production of about 31

see **IN OTHER NEWS** *page 19*

MOVING HYDROCARBONS

Rail will 'be here for a while'

Crude transportation by rail will remain an "essential market link" for many years as Midcontinent production outpaces the introduction of new pipelines, Mike Jennings, chief executive officer of independent refiner HollyFrontier, told a third-quarter earnings conference call.

He said rail shipments will "be here for a while," meaning it will likely be many years before U.S. crude price differentials relative to Brent reflect only the cost of pipeline transportation.

The Association of American Railroads captured the rapid acceleration in the use of rail to deliver from inland production fields to Gulf Coast refineries, reporting that for the week ended Sept. 18, rail transportation of petroleum products rose 64.2 percent over a year earlier.

Jennings said rising Midcontinent volumes will likely continue for years to outstrip pipeline capacity, with domestic crude price differentials to Brent continuing to reflect the cost of both pipeline and rail transportation.

Costs widening

He said the cost of getting inland-produced crude to coastal refining regions has widened those differentials against waterborne crudes in recent years because rail costs especially are more expensive than pipes.

Jennings said HollyFrontier's forward view of oil price differentials reflects the consensus position that pipe transport will "ultimately" set prices for many differentials.

He said pipeline tariffs are not currently setting crude differentials, a situation that is likely to continue as output rises in such fields as the Bakken in North Dakota and Montana, the Permian Basin in West Texas and the Mississippi Lime in Oklahoma/Kansas.

Jennings noted that Magellan's conversion of the former Longhorn pipeline, which the midstream company is reversing to carry 135,000 barrels per day from Crane, Texas, to the Houston area by mid-2013, "will drain a significant volume of crude out of the Permian, but Permian production is growing by 150,000 bpd," so the line fills less than a single year's output.

—GARY PARK

continued from page 1

APACHE WELL

ference call.

"The good news is we've had good oil shows from the logs in the formations that we were targeting," he said.

The horizontal wells in the Williston Basin would be targeting the middle Bakken and upper Three Forks members, Apache previously said.

"We're currently in the completion phase of our initial wells in each of these plays and we'll be experimenting with our frack designs to give us optional results," Farris said.

For the horizontal well in Daniels County, where Apache acquired about 300,000 net acres in the first half of 2012, Farris said the company was in the process of hydraulic fracturing its first well and drilling its second well, which he put at 2,700 feet as of Nov. 1.

Although Apache had expected to drill as many as five wells by the end of the year, Farris since it would have "two wells down" by that time.

When asked if Apache was still picking up acreage in the area, Farris essentially repeated what company vice president for exploration and new ventures, John Bedingfield, said in mid-June when the Houston-based company announced its entry into the Williston Basin and its 300,000-acre acquisition.

The leasing is done, Bedingfield said.

"Some will trickle in, but the big leasing is done."

Farris also noted that "there have been some other operators … not right next door … that have announced pretty good results. I mean, the play is moving that way (northwest), so hopefully, it moves all our way. We're going to find out here pretty quick."

Bedingfield said in June that if 2012 drilling was successful Apache would ramp up drilling in the area in 2013.

In response to a request for an update on Apache's first two wells in Daniels County, a company spokesman said, "we'll have more to say next year after the data are analyzed, and we're in a better position to comment on their impact."

Daniels County is known for producing conventional oil from the Ratcliff, Madison, Mission Canyon and McGowan formations.

Although Apache is initially focusing on the middle Bakken and the upper Three Forks, from which almost all Bakken petroleum system crude is currently being produced, Bedingfield said "there are a number of other plays" throughout Apache's Daniels County acreage: "The Madison section above us, Lodgepole and others. … And below in the Devonian, there's other Devonian plays, the Birdbear, for example, which also has oil pay."

During third quarter Farris said Apache "accelerated our drilling momentum across our portfolio and we've got excellent results. In the U.S. we continue to step off our play activity and now run 63 rigs (nearly 100 worldwide) — 50 percent more than we had at the beginning of the year."

The buying spree Apache started two and a half years ago has since slowed down because the company now has identified thousands of drilling locations worldwide, including 1,900 potential locations in Daniels County.

Farris said the company had a $10 billion exploration and development budget in 2012, and planned to expand drilling in 2013 throughout its portfolio,

Apache's oil production as of Nov. 1 was 800,000 barrels a day, Farris said.

Worldwide, Apache received an average of $102.62 per barrel of oil in the third quarter, a slight increase from $101.71 per barrel in the prior-year period.

—KAY CASHMAN

continued from page 12

KODIAK GROWTH

"The increase (in wells) is directly related to our improvement in drilling time caused largely by more pad drilling and efficiency gains," Peterson said.

He said that through efficiencies, the average cost of drilling a well is now about $10.5 million, down from nearly $12 million earlier this year.

Peterson noted that Kodiak would be in the final stages of fracture stimulation work over the next couple of weeks. "This activity level demonstrates our completion work progress and a road map for our production growth," he added.

For the third quarter of 2012, Kodiak reported $112.1 million in revenue, compared to revenue of $28.5 million in the third quarter of 2011. Third-quarter net income ($3.5 million) includes an unrealized loss of $36.7 million related to derivative instruments used for commodity hedging and $4 million in deferred income tax benefits.

Per its website, Kodiak "owns and controls approximately 155,000 net acres" in Western North Dakota and Eastern Montana in the Williston Basin, where its primary target is the Bakken petroleum system's middle Bakken and Three Forks formations. The company has more than 800 net locations prospective for Bakken production. ●

Editor's note: Kodiak's secondary leasehold area is the Green River Basin in the Vermillion Basin, where the company believes there is natural gas trapped in various sands, coals and shales at depths ranging from 2,000 feet to nearly 15,000 feet. The primary target of its current efforts in this area is the over-pressured Baxter Shale at depths to approximately 13,000 feet. Per its website, Kodiak will "continue to monitor and evaluate this prospect before allocating further capital to this area. As of Dec. 31, 2011, we owned a non-operated interest in approximately 35,000 gross (12,000 net) acres in this geologic basin that is prospective for multiple gas bearing reservoirs including the Almond Sandstone and the Baxter Shale."

Contact Ray Tyson at rtyson@petroleumnewsbakken.com

continued from page 18

IN OTHER NEWS

million barrels a day.

Besides the U.S. juggernaut of production, The Journal cites an intensive Russian drilling program that is sending production (10.46 million barrels a day in October) to levels not seen since the 1980s.

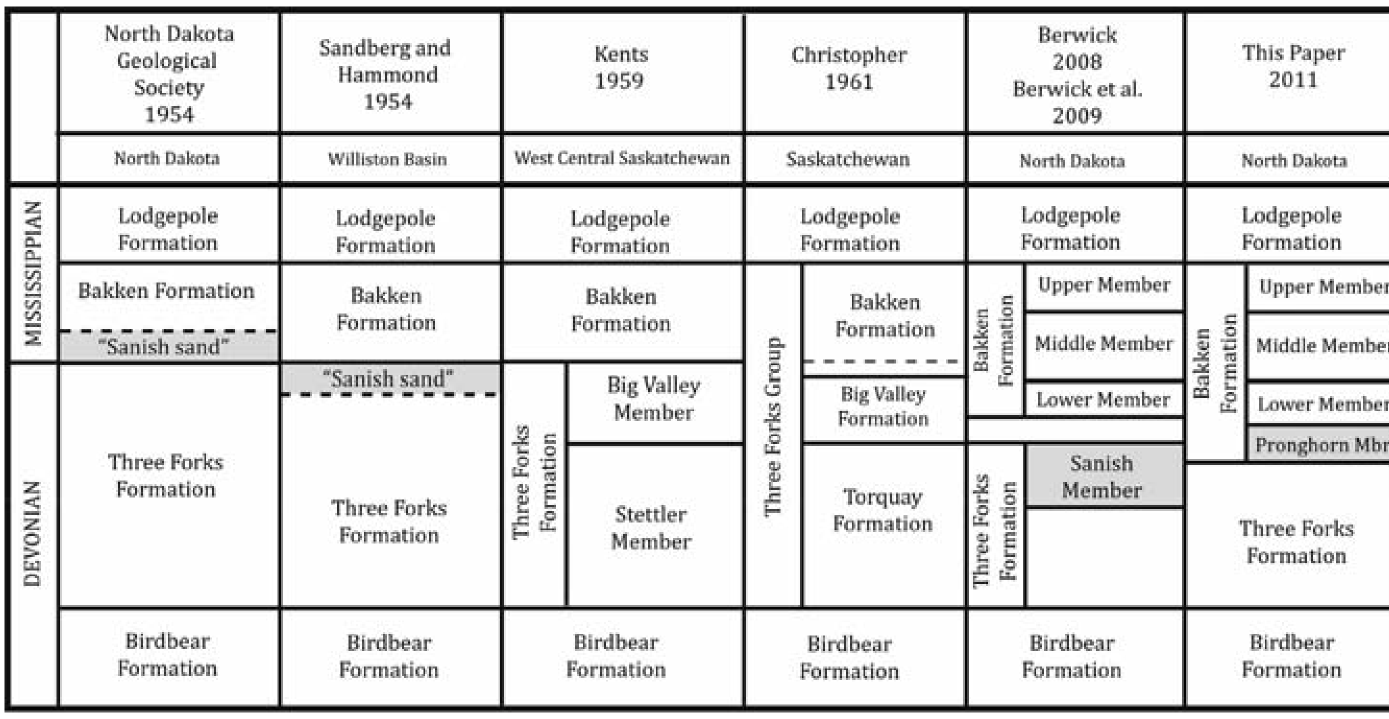
And while Russia has promised closer ties with OPEC, observers say it would be unlikely to coordinate production cuts with the cartel to bolster prices.

"For us to join in production cuts, OPEC would have to offer us something very attractive that would compensate all the risks. I haven't seen any such offers," Igor Sechin, chief executive of OAO Rosneft, told The Journal.

■ Read more here: http://on.wsj.com/UEQJgs

continued from page 1

UNIT DEFINITION



mation. The section was called the Sanish sand based on Stanolind Oil Co.'s #1 Woodrow Starr well, which produced from that member. NDGS considered the Sanish to be part of the Bakken formation.

The unit was later described by C.A. Sandberg and C.R. Hammond as a fine-grained sandstone and coarse siltstone ranging from five to 15 feet in thickness. Sandberg and Hammond considered the unit as part of the Three Forks formation.

Over the years the unit appeared and disappeared in texts as an understanding of the Bakken and Three Forks formations evolved from the 1950s to 2009, but where it was referenced, the unit was commonly referred to as the Sanish sand unit and was generally considered to be part of the Three Forks formation.

Then in 2009, Anschutz drilled its No. 24-14H Sadowsky well in far southern Dunn County and cut a core 88 feet in length from the eight feet above the bottom of the Lodgepole down to nine feet into the top of the Three Forks formation. From that core, NDGS Core Library Director Julie LeFever, along with Richard LeFever of the University of North Dakota and Stephan Nordeng of NDGS, was able to finally and definitively describe the Pronghorn member.

The Pronghorn identified in that core was 43 feet thick, extended from 10,491.5 to 10,534.5 feet, and unconformably overlies the Three Forks and is unconformably over-

LeFever said she is currently mapping the Pronghorn unit. Completion of the project, she said, depended on the availability of adequate well data.

lain by the lower Bakken, they said.

In a paper published by the Rocky Mountain Association of Geologists in 2011, LeFever and her colleagues formally argued for redefining the Sanish unit as the Pronghorn member, and to also formally include the Pronghorn as a member of the Bakken formation.

In that paper, LeFever and her colleagues said, "We consider the Pronghorn member to be part of the Bakken formation for two reasons. First, where present, the member lies above a recognizable unconformity, which probably has regional extent. Second, the succession from the Pronghorn member upward to the lower Bakken shale strongly resembles the succession from the middle member to the upper Bakken shale," from which a large majority of Bakken oil is produced.

In an interview with Petroleum News Bakken, LeFever reiterated the similarity of the Pronghorn with the middle Bakken, and that the argument for including it in the Bakken formation is the fact that it sits on a major unconformity between the Three Forks and the Bakken.

"It's that placement of that unconformity at the top of the Three Forks that I think really pushes it into the Bakken," LeFever said.

LeFever also said that where the Pronghorn is producing, the lower Bakken shales are gone and the Pronghorn is overlain by the upper shales in most areas. So where one generally sees the Pronghorn, she said, the lower shale is gone.

According to LeFever, the Pronghorn member is predominant in Stark, southern Dunn, southern McKenzie, and northern Billings counties, as well as touching a small part of the east side of Golden Valley County.

Why is term 'Sanish' a problem?

According to LeFever and her colleagues, the term Sanish, while "well embedded in the literature," as describing a sandstone bed at the base of the Bakken formation, has since been adopted as a regulatory pool name, and is also the name of a field that produces from both the Three Forks and the Bakken formations. Therefore, LeFever and her colleagues recognized the need for a formal clarification and nomenclature change.

According to LeFever and her colleagues, the term Sanish, while "well embedded in the literature," as describing a sandstone bed at the base of the Bakken formation, has since been adopted as a regulatory pool name, and is also the name of a field that produces from both the Three Forks and the Bakken formations.

A definite pay zone for Whiting

Regardless of what it is called, the Pronghorn unit has proven to be very productive.

For example, in announcing its third quarter 2012 financial and operating results, Whiting Petroleum said net production from its Lewis & Clark/Pronghorn prospects that focus on the Pronghorn unit, averaged 12,190 barrels of equivalent per day in the third quarter of 2012, an increase of 19 percent over the 10,275 barrels of equivalent per day in the second quarter of 2012.

Whiting said a typical Pronghorn well is its Solberg 14-11PH in Stark County, which flowed at an initial rate of 1,825 barrels of equivalent per day from the Pronghorn Sand on Sept. 17, 2012.

Whiting also cited results of two other wells completed in the Pronghorn unit and tested in late September; its Buckman 34-9PH well flowed at an initial rate of 1,964 barrels of equivalent per day, and its Buckman 44-9PH was completed flowing 1,545 barrels of equivalent per day.

Will the name stick?

Whether or not the new nomenclature will be universally adopted is yet to be seen.

LeFever told Petroleum News Bakken a speaker at a recent conference argued for continued use of the term Sanish.

"We proposed this," LeFever said, "and now it's open to discussion," but went on to say that generally she believes it has been accepted.

LeFever said she is currently mapping the Pronghorn unit. Completion of the project, she said, depended on the availability of adequate well data. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

continued from page 1

ALBERTA RESOURCES

the radical industry shift from conventional operations to horizontal drilling and hydraulic fracturing.

Andrew Beaton, one of the report's authors, said the numbers fall roughly into line with the Eagle Ford and Marcellus shales and approximate numbers reported so far by companies exploring the shale prospects in Alberta.

Potential beyond oil sands

The findings bolster the view that Alberta has immense hydrocarbon potential beyond its oil sands, rated as the world's third-largest deposit at 170 billion barrels of proven reserves and an ultimate potential of 1.7 trillion barrels.

The Duvernay and Montney have already attracted strong investments from Encana, Chevron and Talisman Energy, with ExxonMobil joining the scramble in October by negotiating a C$2.6 billion takeover of Celtic Exploration, while a host of mostly state-owned Asian companies have stakes out minority positions.

The study says the Duvernay formation, which cuts across much of north-central Alberta, contains 61.7 billion barrels of oil, 11.3 billion barrels of liquids and 443 tcf of gas, while the Muskwa in northwestern Alberta has 115.1 billion barrels of oil, 14.8 billion barrels of liquids and 419 tcf of gas.

Western Alberta's Montney — which also extends into a major exploration area in northeastern British Columbia — has estimated resources of 136.3 billion barrels of oil, 28.9 billion barrels of liquids and 2,211 tcf of gas.

However, the Montney is not strictly rated as a shale target because it is dominated by siltstone and has been included because it is a target for unconventional resources.

The findings also cover a preliminary assessment of the Colorado, Wilrich and Rierdon units as well as a summary of the Bantry shale unit.

Technical snapshot of Exshaw findings

The basal Banff/Exshaw resource assessment was limited to southern Alberta "due to data availability and current industry focus", the report said.

In addition to sourcing conventional reservoirs the Exshaw shale is recognized as a major source rock for heavy oil and bitumen deposits in northern Alberta. The combined interval of the Exshaw formation and the basal shale of the Banff formation is stratigraphically equivalent to the Bakken formation in the Williston Basin, the study said.

The combined interval of the Exshaw formation and the basal shale of the Banff formation is stratigraphically equivalent to the Bakken formation in the Williston Basin. … "For this project," the findings noted, "the terms lower shale, middle unit, and upper shale correspond to the Exshaw shale (lower Bakken), the upper Exshaw (middle Bakken), and the lower Banff basal black shale (upper Bakken), respectively."

Extending into northern and northwestern Montana, the play is often referred to as the southern Alberta Bakken or the southern Alberta Bakken basin by industry

"For this project," the findings noted, "the terms lower shale, middle unit, and upper shale correspond to the Exshaw shale (lower Bakken), the upper Exshaw (middle Bakken), and the lower Banff basal black shale (upper Bakken), respectively."

The basal Banff/Exshaw has a large variation in primary lithologies. The upper and lower shales are dominated by dark grey to black, fissile, hard-to-soft, calcareous to noncalcareous, organic-rich shale.

The middle unit consists of various lithologies, including calcareous sandstone, argillaceous sandstone, dolomitic siltstone, calcareous siltstone, silty lime-mudstone, limestone, and dolostone.

The variation in primary lithologies, the report said, "may indicate that the Exshaw and basal Banff merit a more detailed stratigraphic study to determine erosional boundaries and confirm stratigraphic equivalence to the Bakken."

In the study area, depth to the top the basal Banff/Exshaw ranges from 500 meters (1,640 feet) near the subcrop erosional edge to about 4000 meters (13,123 feet) along the deformed belt.

The upper and lower shales are both thin. The thickness of the lower shale ranges from 4 to 13 meters, or 13 to 43 feet. The upper shale is more difficult to correlate and has a smaller aerial extent than the lower shale. The upper shale ranges from <1 to 2.3 meters, or <3 to 7.6 feet, thick.

The gross isopach of the middle unit in southeastern Alberta ranges from zero to 40 meters, or zero to 131 feet, along a roughly northeast-to-southwest trend.

Four wells were selected for a cross-section that displays the stratigraphic relationship of the three units and the correlation to the Bakken.

A porosity-thickness, or Phi-h, map of the basal Banff/Exshaw was constructed for the study, using density-porosity logs calibrated to a grain density of 2.74 g/cm3 with no porosity cutoff and a >75 API gamma-ray–log cutoff.

The gamma-ray cutoff excluded any lithology, such as sandstone or limestone that was relatively free of argillaceous material.

The map shows high porosity-thickness values in the northeast near the erosional edge. Current hydrocarbon exploration is concentrated in the southwest corner of the study area.

The grain density used to determine porosity accounted for the presence of total organic carbon by converting TOC to kerogen and counting it as a mineral component. The methodology used works well, the findings said, when the TOC content range spans only a few weight per cent.

"The TOC content of the upper and lower shale, however, is quite variable which may cause significant error in the calculation of the porous volume of shale in our methodology," the report said. "For the present resource estimation, we chose not to include the porous volume of the shale. A well-by-well evaluation of the data is necessary to achieve a reliable estimate of shale porosity. However, because the upper and lower shales are quite thin, the resource estimate may not change dramatically by this exclusion."

The resource estimate for the basal Banff/Exshaw "is based on the adsorbed gas content of the upper and lower shales, as well as the porous volume of the middle unit, which is the primary production unit

see **ALBERTA RESOURCES** *page 22*

Oil Patch Bits

Larson Electronics introduces portable work light

Larson Electronics LLC said Nov. 13 that it has announced the addition of the 6000 watt CM-4X15M-25-480V-3P for operators looking for portable 480 volt work site lighting. Equipped with four 1500 watt adjustable metal halide light heads, this Magnalight work site lighting system can be used from the ground or elevated via crane for work site area illumination.

Larson has begun shipping the CM-4X15M-25-480V-3P 6000 watt portable work site lighting system. Equipped with four 1500 watt metal halide lights that can independently be positioned in any direction, this industrial lighting system can be powered with 480 volts, Larson said. Constructed of heavy duty aluminum tubing, this work area floodlight system is built for durability and demanding conditions. The design of the light enables the operator to pick the light system with a crane as easily as using it from the ground, since the light heads can be pointed directly up or down.

"Our new CM-4X15M-25-480V-3P work site illumination system is designed to be positioned within, above or below the work area for optimal coverage," said Larson's Rob Bresnahan. "The 480 volt ballasts don't require any kind of transformer or power distribution. Instead operators can tie off directly to their 480V panel and get the lighting they require."

For more information visit www.magnalight.com.

Companies involved in the Bakken, Three Forks and related plays

continued from page 21

ALBERTA RESOURCES

in the Bakken play in the Williston Basin."

The TOC content ranges from 0.1 to 16.9 weight percent in the findings, based on 75 samples from 13 wells. The TOC content of the middle unit is generally <1.0 wt. % in the southern area.

"There is some indication that the northern area may contain a higher content of TOC," the report said. "The thermal maturity of the basal Banff/Exshaw source rocks, based on vitrinite reflectance data, exhibits increased maturity to the southwest, corresponding to an increased depth below the surface."

Using Dean Stark analysis and helium pycnometry on select samples, the laboratory calculated water saturation.

"The distribution of values for the basal Banff and Exshaw formations in the southern area shows dominance in the range of about 10 percent to 50 percent, which we used as P90 and P10 constraints in our resource evaluation," the report said.

Constraints not considered

The report cautioned that the numbers represent "endowment of hydrocarbons" and that geological and engineering constraints along with economic, social and environmental considerations will eventually determine the volumes that can be recovered.

Co-author Dean Rokosh said the operators will be in the best position to say which plays are economic.

"It's still a learning stage in every one of these formations," he said.

Data and information produced by the study may help in the evaluation, exploration and development of the resources and can be used by industry to help identify shale gas prospects, plan effective drilling and completions strategies and guide land acquisition decisions.

In Alberta, 15 formations have the potential for shale and/or siltstone-hosted hydrocarbons, which may represent a valuable resource for the province, the report says.

Estimates for the total amount of gas in Alberta shale vary from 80 tcf to 100 tcf, pointing to the "great potential size of the resource, which can contribute to economic benefits and energy security for Alberta."

The Energy Resources Conservation Board launched its study of shale- and siltstone-hosted hydrocarbons in 2006, initially focusing on shale gas in the formations which had attracted industry interest, such as the Colorado shales and the Banff/Exshaw.

As the study moved ahead, the ERCB found that many of the formations it was analyzing also contained significant quantities of natural gas liquids and oil, prompting it to expand the assessment.

In total, 3,385 samples were analyzed, including duplicates and standards for quality control.

Samples were collected from 65 outcrops and core samples were taken from 316 wells. Of the total samples collected, 2,746 were from core, 440 were from outcrops and 199 were standards and duplicates. Some of the data generated by the ERCB's resource appraisal group will be presented in future digital databases.

Read the full report at http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_2012_06.pdf

—GARY PARK

Editor's note: The text under the subhead "Technical snapshot of Exshaw findings" was compiled by Kay Cashman.

Contact Gary Park through publisher@petroleumnews.com

continued from page 1

LEASE AUCTION

Petroleum News Bakken. Combs said the acreage available for the lease auctions in what he referred to as the "proven area" is decreasing, and that, he said, might be reflected in the higher prices.

Top price by Diamond Resources

The top price of $15,300 per acre in the November 2012 auction was paid by Diamond Resources of Williston for a 5.03 acre parcel in McKenzie County. Diamond Resources was also the high acreage buyer, successfully bidding on a total of 3,783 acres in Billings (77), Burke (1,083), Dunn (eight) and McKenzie (2,615) counties. The average price per acre paid by Diamond Resources was $1,050 in Billings County, $237 in Burke County, $1,100 in Dunn County, and $5,968 in McKenzie County.

Denver-based QEP Energy purchased two parcels totaling 214 acres in McKenzie County for $8,000 per acre. Black Ridge Oil and Gas of Minnetonka, Minn., paid $1,800 per acre for 80 acres in Mountrail County, and also purchased a total 160 acres in Mountrail County at $1,800 per acre, and 160 acres in Burke County with an average of $206 per acre.

Other successful bidders at the November auction: Houston-based Hess Corp. (20 acres in McKenzie County at $4,100 per acre); American Land Services LLC of Bismarck (six acres in McKenzie County at $1,300 per acre); LSM Energy Inc. of Mandan (eight acres in Billings County with an average of $1,250 per acre); Empire Oil Co. Williston (971 acres in Billings County with an average of $509 per acre); Northern Energy Corp. of Bismarck (480 acres in Burke County at $25 per acre, 160 acres in Dunn County with an average of $157 per acre, 80 acres in Mountrail County at $500 per acre, and 160 acres in Stark County at $125 per acre); Gary Warnke dba Warco Oil Co. (120 acres in Bowman County with an average of $475 per acre); White Butte Resources of Bismarck (1,919 acres in McKenzie County with an average of $82 per acre); Great Northern Energy LLC of Bismarck (780 acres in Bowman County with an average of $49 per acre); and H. Kermit Anderson and/or Rebecca Ann Hilton Anderson of Ronan, Mont. (80 acres in Bowman County with an average of $55 per acre, 160 acres in Renville County at $36 per acre, and 80 acres in Ward County at $26 per acre).

Next auction in February

The Minerals Management Division is currently accepting nominations for the next lease auction, which is tentatively scheduled for Feb. 5. The nominations deadline is Dec. 14. The location for the February auction has not yet been determined.

Combs told Petroleum News Bakken that he has a few holdover parcels from the November auction that will be available at the February auction, but otherwise he doesn't know what to expect in terms of nominations for the February sale. However, he said he typically doesn't see many nominations this far in advance of an auction, and most nominations are received in the last two days of the nomination period. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

continued from page 1

MEGA DEALS

properties for $650 million. The property includes leasehold of roughly 120,000 net acres, primarily in Divide and Williams counties, N.D., and production of about 6,500 barrels of oil equivalent per day.

Continental is currently the largest leaseholder in the Bakken, with 984,040 net acres as of Sept. 30. If completed, the proposed acquisition will increase this total to 1.1 million net acres. The Oklahoma-based company operates a large portion of the acreage that it's acquiring, and more than half of it is held by production.

In addition, Continental said it has entered into an agreement to sell its producing crude oil and natural gas properties and supporting assets in its East Region for $125 million in cash, using the proceeds to help pay for the Bakken acquisition. The East Region primarily includes properties east of the Mississippi River, including the Illinois Basin and the state of Michigan, among other areas. Production from the properties included in the sale agreement averaged about 1,100 boe per day during this year's third quarter.

"We are divesting non-core, conventional assets and re-investing the proceeds in an attractive acquisition that further builds our strategic, core position in the Bakken," Hamm noted.

Transaction closes at year-end

If the Bakken acreage acquisition is completed as planned, the company said it expects additional 2013 drilling capital expenditures will be largely offset by incremental cash flow from the acquired properties. Both transactions are expected to close prior to year-end 2012.

Continental reported strong production on average for the third quarter of 2012, setting an overall record of 102,964 boe per day, 55 percent above third quarter 2011 output and 9 percent above this year's second quarter. September production was 105,874 boe per day, the company reported.

Bakken-Three Forks production, which represents just over 60 percent of Continental's total output, was 62,453 boe per day for the third quarter, a whopping 81 percent increase over the 2011 third quarter and 17 percent higher than this year's second quarter, the company said.

In terms of operated wells, Continental completed 46 gross (34 net) wells in the Bakken in the third quarter of 2012, with 41 gross (29 net) wells in North Dakota and five gross (five net) wells in Montana.

Wells averaged 1,076 boepd

Company-operated wells completed during the third quarter averaged 1,076 boe per day for North Dakota Bakken wells and 886 boe per day for Montana wells in their initial one-day test-periods. Twenty-two of Continental's 41 gross operated wells in North Dakota had initial production test rates of more than 1,000 boe per day, while two of its five operated Montana wells surpassed that level in the third quarter of 2012.

Bakken well performance continues to meet the company's expectations, Continental said.

A notable project completed during the recent quarter was the Antelope-Bohmbach ECO-Pad in McKenzie County, consisting of the Antelope 3-23H and 4-23H and the Bohmbach 3-35H and 4-35H wells. The four wells tested at an aggregate initial rate of 6,240 boe per day in total, for an average of 1,560 boe per day per well, with average flowing tubing pressure of 3,800 psi. Continental has an 85 percent working interest in the wells.

In October the company announced a new five-year plan to triple production and proved reserves by year-end 2017.

"2013 is shaping up as another year of production growth with efficiency gains," Hamm said. "We expect 30-to 35 percent production growth next year, the first year in our new five-year plan. …"

Big plans for SCOOP

Continental also has big expansion plans for the so-called SCOOP play of southern Oklahoma, in helping to attain its triple growth strategy. Production there during the third quarter was 5,183 boe per day, a 327 percent increase over last year's third quarter and 64 percent above this year's second quarter output.

Meanwhile, efforts by Continental to develop new opportunities to market Bakken oil to refineries and other markets on the East, West and Gulf coasts, are paying off in big ways.

"Additional pipe and rail infrastructure has broken the logjam of Bakken oil, and we are marketing our barrels directly to refineries on all three coasts, as well as in Canada," Hamm said. "This has resulted in reduced oil price differentials … in the third quarter."

Winston Frederick Bott, Continental's president and chief financial officer, said several third-quarter operating trends should help the company increase production more cost efficiently in 2013, and continue to build cash flow.

More equipment available

"Firstly, we are starting to see increased availability of drilling and completion equipment and crews in the Bakken," he said. "The supply of services and equipment is starting to come in line with demand."

Moreover, he said 45 percent of the company's operated drilling fleet is situated on multi-well pads, versus 10 percent in the first quarter, allowing the drilling of second and third production wells in a single spacing unit. Because pad drilling minimizes rig moves, he added, the average cost per rig move has been reduced 17 percent this year.

"Pad drilling helps reduce drilling cycle times," Bott said, noting that currently, the company is saving 10 percent per well on its ECO-Pad projects.

And though day rates for newer upgraded rigs are higher, "we're offsetting the higher cost with faster cycle times," he added.

Wells per rig increased

For example, he said the average number of wells drilled per rig increased 33 percent to 1.2 wells per rig month in the third quarter compared to the first quarter. Average days in the lateral, the most critical part of the hole, dropped 18 percent through a combination of greater efficiency, improved execution and accuracy.

Continental recently demonstrated its execution capabilities with the North Dakota-Lewisville well, which set a Williston Basin depth record, drilling to a total depth of just over five miles in 26 days.

"So I think the headline is if you take our drilling cycle spud-to-spud, well costs are 25 percent lower in the third quarter compared to the first quarter of the year, in large part because of these drilling efficiencies," Bott said. "This is on top of the 12 percent improvement in spud-to-spud well costs that we had last year."

On the financial side, Continental's third-quarter earnings before interest, income taxes, depreciation, depletion, amortization and accretion, property impairments and exploration expenses, EBITDAX, were 492.3 million, a 46 percent increase compared to the 2011 third quarter. ●

Contact Ray Tyson at rtyson@petroleumnewsbakken.com