Petroleum News
Bakken

page 8 Minority party view on ND O&G bills: stripper wells, tax, more

Vol. 1, No. 22 • www.PetroleumNewsBakken.com | *A weekly newspaper for industry and government* | March 3, 2013

No longer wrapped in parent

Petroleum news

page 3 Murkowski: Alaska has important role in energy self sufficiency

Vol. 18, No. 8 • www.PetroleumNews.com | *A weekly oil & gas newspaper based in Anchorage, Alaska* | Week of February 24, 2013 • $2

February Mining News inside

8 Upper Kobuk tops 6B lbs. copper

10 Fortune sees value in diversity

13 Far North miners post solid 2012

The February issue of North of 60 Mining News is enclosed.

Conoco developing DS-2S in SW Kuparuk after 2012 appraisal

ConocoPhillips is developing a Kuparuk River unit oil field it proved up last year.

The company is applying for a U.S. Army Corps of Engineers permit to build a drill site and access road in the southwest corner of the second largest oil field in North America.

The DS-2S project would develop a discovery ARCO made with the KRU 21-10-08 well in the late 1980s and ConocoPhillips appraised with the Shark Tooth No. 1 well last year.

The two-phase project would begin next winter with ConocoPhillips using nearly 300,000 cubic yards of gravel to

see DS-2S page 21

Canada-US relations strained over upcoming Keystone decision

Within the next three months, President Barack Obama is expected to decide the fate of TransCanada's Keystone XL pipeline — a knotty choice for him between offending environmentalists who contributed so much to his re-election and turning his back on Canada, which is by far the leading external source of United States oil and natural gas imports.

The tension level was raised Feb. 8 when Canada's Foreign Affairs Minister John Baird held the first meeting with newly installed U.S. Secretary of State John Kerry.

Keystone was one of the topics, but all that Baird could extract was a promise from Kerry to reach a fair, transparent and prompt decision, without even hinting at the recommendation he will make to Obama.

see KEYSTONE DECISION page 21

EXPLORATION & PRODUCTION

Resetting Liberty

BP Alaska now aims to begin production from offshore field by end of 2020

By WESLEY LOY
For Petroleum News

BP, with the blessing of federal regulators, is hitting the reset button on its stalled offshore Liberty project.

The Interior Department's Bureau of Safety and Environmental Enforcement, or BSEE, has given BP Exploration (Alaska) Inc. two years to submit a new development and production plan for Liberty.

The company is now shooting to start production from Liberty by December 2020, a BSEE letter indicates.

Originally, BP had hoped to have oil flowing in 2011.

Liberty is located in shallow water, about 20 feet deep, in the Beaufort Sea about six miles offshore and 15 miles east of Prudhoe Bay. BP has estimated the field, discovered in 1997, holds more than 100 million barrels of recoverable oil.

Getting at the oil has proven a challenge.

BP had been working on an ambitious and technically daunting plan to drill into the reservoir from the neighboring Endicott field. Parker Drilling Co. built a monster rig for boring ultra extended-reach wells, and the rig components were barged to the North Slope in July 2009.

The rig was erected, but never went to work.

BSEE, with a Dec. 31 letter signed by Alaska

see LIBERTY page 24

NATURAL GAS

BC taints grand vision

Government views LNG as cash cow it can milk for up to C$260B over 30 years

By GARY PARK
For Petroleum News

British Columbia Premier Christy Clark is tying her flimsy hopes of clinging to power in a May 14 election on natural gas and LNG exports.

Her government issued two grand plans in February forecasting LNG exports could generate C$130 billion to C$260 billion in revenues over 30 years, assuming two large and three smaller-sized LNG plants, along with thousands of jobs.

But, just as quickly, Clark antagonized the industry by disclosing plans to impose a major tax on the exports of natural gas.

The government's strategy papers noted that Australia's natural gas tax and royalty regime is "up to one-third higher" than British Columbia's, noting that new taxes on gas exports could "maximize the benefits to British Columbians" without affecting the province's competitive edge.

A spokesman for the Finance Ministry said discussions are already under way with the industry to see what form a tax might take.

Reminder of Alberta battles

For the Calgary-based producers who dominate the companies holding potential LNG feedstock gas in northeastern British Columbia the prospect of tax hikes creates bitter reminders of the industry's recent battle over royalty increases with the Alberta government that cost billions of dollars in investment and

see BC LNG page 23

FINANCE & ECONOMY

Industry talks changes

No surprise, companies favor end of progressivity; credits needed to counter base

By KRISTEN NELSON
Petroleum News

The elimination of progressivity would be a good first step to reforming Alaska's oil and gas taxation system, but reducing the base rate of 25 percent or credits are needed to counter the high cost of developing resources in the state.

That was the message the Legislature's Resource committees heard from independent and major oil and gas companies Feb. 18 and 20 in hearings on Gov. Sean Parnell's proposed oil tax changes.

The governor has proposed eliminating progressivity, which increases the tax rate as the price of oil increases, along with changes to the existing credit system and the addition of the gross revenue exclusion for barrels of oil from new fields or new participating areas within existing fields.

Progressivity was introduced in changes made to Alaska's oil and gas taxation system in 2006. The previous taxation system was on the gross and is typically referred to as ELF because it contained an economic limit factor, designed to prevent overtaxing fields which were at the end of economic production. While the goal was to prevent early shutdown due to taxation, in application it resulted in very low to no production tax on healthy fields.

The 2006 Petroleum Profits Tax, PPT, effective for North Slope oil fields, was a tax on net profits. It added credits and had a 22.5 percent base tax rate, with progressivity increasing the rate at 0.2

see OIL TAX DEBATE page 22

Attention readers: Petroleum News Bakken goes weekly with this issue, March 3, 2013. Along with a new schedule, the newspaper has a new look — and will be mailed separately from its parent Petroleum News (pictured above). Subscribers will continue to receive both newspapers electronically, but the print editions will be mailed separately and only to their subscribers. If you would like to add the print edition of Petroleum News, which covers Alaska and Northwest Canada, to your subscription package, please contact our circulation department at 907 522-9469 or circulation@petroleumnews.com.

All aboard for Kinder Morgan

Pipeline giant Kinder Morgan has entered a joint venture to build the "first major crude by rail destination facility" in the Houston area — a 210,000 barrel-per-day project expected to come on line in the first quarter of 2014.

Kinder Morgan Energy Partners and Watco Co. LLC have struck a long-term agreement with Mercuria Energy Trading Co. to build the project at Greens Point Industrial Park on the Houston Shipping Channel.

The KW Express venture will open the way for Mercuria to source crude from various locations, including the Bakken shale

see KINDER MORGAN page 22

Cenovus quits Williston Basin

Canadian oil producer Cenovus Energy is quitting Saskatchewan's segment of the Williston basin after deciding it is unable to scale the assets up to a size that would be material to its portfolio.

It said the Bakken and Lower Shaunavon properties are up for sale because of competitive limitations on increasing its land base in the area.

Saskatchewan was once seen as a potential contributor to the company's goal of reaching 75,000 barrels per day of raising tight oil production to about 75,000 bpd by the end of 2016 and had attracted heavy capital spending to raise com-

see CENOVUS page 22

FINANCE & ECONOMY

Up, down or same?

PNB takes a look at how much major producers are spending in the Bakken

By KAY CASHMAN
Petroleum News

■ **Analysis**

When will the Bakken boom subside? Are oil companies reducing their investments in the oil-rich Bakken petroleum system? Do they expect production to decline in 2013 or shortly thereafter?

We aren't going to try to answer all those questions at this time.

But we are going to look to see what the major Bakken well operators are investing in the region in 2013. Is it up, down or the same as last year?

To answer that question we first looked to the three top oil producers — Continental Resources, Hess Corp. and Whiting Petroleum.

Wells they operate produced more than 25 percent of the oil in December from North Dakota's Williston Basin, home of the Bakken petroleum system. (North Dakota produces more than 95 percent of all Bakken oil, including other formations in the play, such as the Three Forks.)

Together, Whiting, Continental and Hess produced 195,954 barrels of oil out of a total daily average of 768,853 barrels in December.

So what did the Bakken's "Big Three" say their capital spending would be in 2013, as compared to 2012? And what are their expectations for Bakken production?

see BAKKEN SPENDING page 17

FINANCE & ECONOMY

When will boom subside?

EIA thinks technology will continue to drive production in 2013, but peak by '14

By ERIC LIDJI
For Petroleum News

The current boom in unconventional oil will eventually become a powerful echo, but only after technological improvements have run their course, according to a U.S. Energy Information Administration analysis of the drivers behind domestic crude oil production.

When that "inflection point" occurs will depend on many factors, but the report from the statistical arm of the U.S. Department of Energy suggests it could be felt as soon as 2014.

Between 2011 and 2012, domestic oil production increased by 790,000 barrels per day, the largest single-year increase since Col. Edwin Drake started the oil industry more than 150 years ago. For the current year, EIA expects production to top that record, increasing by 815,000 bpd over 2012 levels. But in 2014, EIA believes the growth should slow to 570,000 bpd, reaching 7.82 million bpd, the highest average since 1988.

With gains in drilling efficiency, EIA expects the average daily rig count in the Williston Basin to fall over the next two years, to 184 rigs in 2014 from 208 rigs in 2012.

EIA points to technological improvements at

see EIA ANALYSIS page 20

COMPANY UPDATE

QEP's 'pivotal year'

Independent producer to spend more than half its $1.6 to $1.7B capex on Bakken

By RAY TYSON
Petroleum News Bakken

QEP Resources Inc. is calling 2013 a "pivotal year" as it steps up efforts to change from an independent producer dominated by natural gas to one that's more balanced and focused on boosting more desirable oil and natural gas liquids production and reserves.

CHUCK STANLEY

For starters, the Denver, Colo.-based company is planning to spend more than half of this year's capital budget on North Dakota's oil-rich Bakken petroleum system, where QEP holds about 117,000 net acres.

Overall, QEP anticipates that 2013 oil production likely will grow about 70 percent over 2012 levels and that NGL volumes should climb by more than 30 percent, while dry gas output is expected to decline by around 10 percent.

Actually, QEP has been working on its dry-gas dependence problem for several years, but made its first big stride toward the company's ultimate liquids goal in 2012, investing $1.4 billion in last year's third quarter to vastly expand its position in the Bakken play with the acquisition of its South Antelope properties.

QEP to alter gas-liquids mix

QEP also intends to dramatically alter its natural gas-liquids mix in 2013, with oil and NGL

see QEP CAPEX page 21

contents

Petroleum News Bakken

● GOVERNMENT

Helms: ND oil production ‘back on track’

State’s top oil official recently saw an IP report from an oil well in McKenzie County that came in at almost 5,000 bbl a day

By MIKE ELLERD

For Petroleum News Bakken

December 2012 North Dakota oil production reversed the brief downturn observed in November and set yet another production record, putting the state’s production “back on track” according to Lynn Helms, director of the North Dakota Industrial Commission’s Department of Mineral Resources Oil and Gas Division.

LYNN HELMS

Helms discussed the preliminary production data in a Feb. 15 press conference along with a number of other related issues, including: increasing average initial production rates and a new, near record-setting well; economic breakeven; fracking backlog; flaring; outlook for 2013; three-mile laterals; saltwater and other oil and gas-related legislation in the current North Dakota legislature.

Production results

The preliminary production data released on Feb. 15 by the Oil and Gas Division indicate that North Dakota produced an average of 768,853 barrels of oil per day, an increase of 33,791 bpd or 4.6 percent over the 735,062 bpd average production in November. That November production was 2.2 percent below the October production and marked the first production decline in the state in the previous 19 months. (See productions charts, including the Top 50 North Dakota Bakken oil well operators, in the Bakken Stats section of this issue.)

In December 2011, North Dakota average daily oil production was 535,088 bpd. The December 2012 production of 768,853 bpd represents a year-to-year increase of 233,805 bpd, an increase of nearly 44 percent.

Total oil production in December was 23,834,431 barrels. November total production was 22,051,858 barrels of oil.

The preliminary December data also indicate that average daily natural gas production increased to approximately 806 million cubic feet per day, a record high as well as a 2.8 percent increase over the approximately 784 million cfd produced in November.

In addition to production volumes, the number of producing wells increased by 123 in December to a total of 8,224, another record high. However, the rig count actually fell by two from 186 in November to 184 in December. Helms reported that the rig count in January increased by one to 185, but as of Feb. 15 the rig count had dropped down to 182. The all-time high rig count of 218 occurred on May 29, 2012.

More than 95 percent of drilling in North Dakota targets the Bakken and Three Forks formations.

Increasing IPs and near record well

Helms reported that he has seen initial production, IP, numbers generally decline as more wells are added to spacing units and more areas are being explored. The average IP in the state, he said, declined to about 900 barrels per day, but IPs for wells going on production over the last 12 months increased to an average of approximately 1,100 barrels of oil and

US Williston Basin 2012 BOPD

MONTH	ND	E. MT*	SD	TOTAL
January	546,547	59,878	4,915	611,341
February	558,558	62,022	4,891	625,471
March	577,478	60,485	4,776	642,739
April	609,503	64,329	4,725	678,557
May	639,981	63,882	4,941	708,804
June	664,618	61,290	4,864	730,772
July	676,249	65,889	4,743	746,880
August	701,409	67,500	4,645	773,554
September	729,248	68,469	4,640	802,357
October	749,212	71,548	4,561	825,321
November	735,062	70,562	4,647	810,271
December	768,853			--

about 1.5 million cubic feet of gas per day.

However, there are some wells that far exceed those averages, and Helms said he recently saw an IP report from a new well still on confidential status in McKenzie County that came in at almost 5,000 barrels of crude oil and 12 million cubic feet of natural gas per day, and more than 2,000 pounds of fluid pressure.

“It’s a remarkable well,” Helms said. “It’s close to the record. I would say it’s the number two well ever drilled in the Bakken.” He said the well is a typical two-mile long well, but it has more frack stages and a high percentage of high-strength ceramic proppant.

Helms said the geology in the area northwest of Watford City where the well is located has turned out to be “really, really good geology.” It’s the deepest, hottest part of the basin, he said, and added that the Bakken is very mature in that area.

Economic breakeven

Over the last 12 months, Helms has seen the economic breakeven point rise, and he said it now takes an IP rate of more than 400 bpd to achieve a 10 percent rate of return for investors in the well. However, he said he has also seen the number of wells exceeding this higher breakeven point increase and said 90 percent of wells now fall in this category.

Helms said he has not seen a dry hole for well over a year and summarized by saying that the success ratio over the last year is 100 percent for producing oil and 90 percent for economics. These factors, he said, along with an increasing average IP, are good news for Bakken and Three Forks players.

Fracking backlog

According to Helms, there are currently approximately 410 wells waiting to be fracked in the state, one of the highest backlogs the Oil and Gas Division has seen in 24 months. Part of that backlog, he says, is due to winter weather, but part of it, he said, is due to cost saving efforts where operators are waiting to frack wells under their new-year budgets. In addition, he said, operators are pressuring service companies to reduce their costs.

“We had gotten to the point where an $11 million well was more than 50 percent hydraulic fracturing cost, and so there is a huge amount of pressure to cut that part of the completed well cost and that’s what’s happening. So that disrupted the system and gave us a really high number of wells waiting on fracking.”

However, Helms doesn’t see this high backlog continuing. He said he anticipates a big increase in fracking activity beginning in the early spring and continuing into summer, and he expects the frack backlog to eventually fall back to around 200 wells, which he said is pretty normal. “So we’re sitting on about twice the inventory of the unfractured wells as of the end of December as what we consider normal.”

Flaring

Flaring in the state remained steady at 29 percent in December, but Helms said that is still too high. However, he said the good news about that 29 percent number is that the state saw a 4.6 increase in production but no corresponding flaring increase.

Helms was asked if he thought there is disproportionately more flaring in the fringe areas relative to the core areas of the Bakken. He said he doesn’t believe this to be the case. “I don’t think it is disproportionate. I think we’ve got a problem; it is systemic everywhere.” But Helms does believe there are “significant choke points” in the core area, i.e., Dunn, McKenzie and Williams counties, and to a lesser extent, Mountrail County.

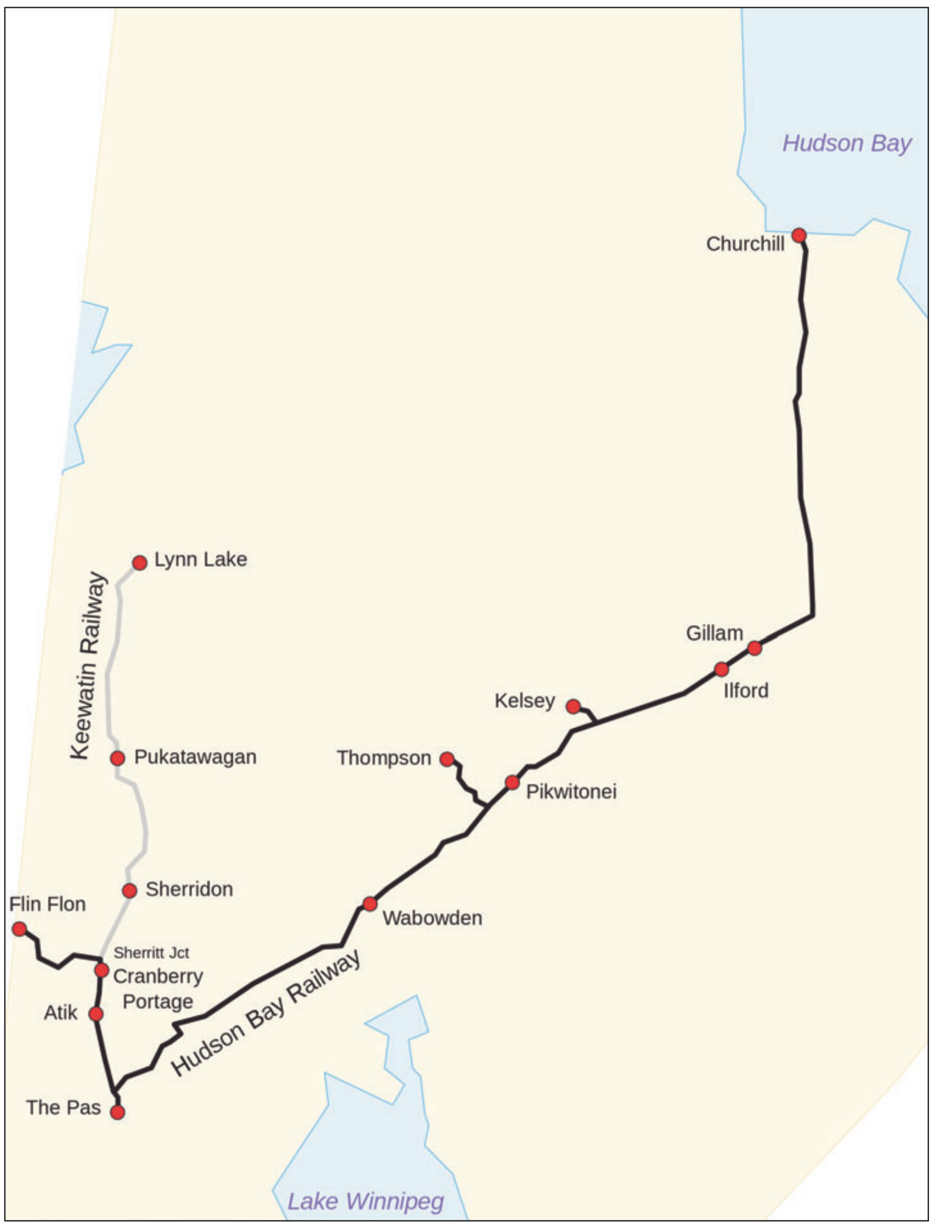
“I think it’s a two-part problem,” he said. “We’re still seeing a build-out in the fringe areas, but the system that we built in the core area is nowhere near large enough.” But he does believe that overall flaring is on a downward trend. Since September 2011 when flaring reached a peak of 36 percent, Helms said there has been a downward trend, and since September 2012 flaring has either held steady or shown some downtick. Month-on-month, he said, flaring has either been very close to the month before or it ticks downwards. “I do think that we’re on a downward trend, but we’ve just got so much work to do in this area to get where we want to be.”

Helms further noted that a well like the 5,000 bpd IP well in McKenzie County that is producing 12 million cfd puts an “enormous strain” on gas gathering sys-

see **ND PRODUCTION** *page 19*

● MOVING HYDROCARBONS

Canada mulls northern route



By GARY PARK

For Petroleum News Bakken

The Bakken formation could fuel short-term plans to ship crude from the Port of Churchill on Canada's Hudson Bay, said the Canadian president of Denver-based OmniTrax, one of North America's largest private railroad and transportation management companies.

Brad Chase told a recent Insight Canadian Oil Sands summit that the seaport, used for decades to export grain during summer months, is part of his company's long-term goal of shipping crude, starting with light, sweet crude, primarily from the Bakken.

"We see five to eight years, as our prediction, of opportunity," he said. "We'd like to be there starting in 2013."

Chase said Churchill could also be a shipping point for diluents over the next few years, followed by Alberta's heavier crude products.

He said heavy crudes "really are the long-term plan" allowing shippers to get to tidewater at Churchill "fast and open markets."

Chase said ships move freely through Hudson Bay from mid-July to late October, although the port can handle ships outside that window if users are prepared to pay higher insurance rates.

He said permits and licenses are in place for the port to handle oil, but a third-party engineering firm is consulting with stakeholders to ensure best practices.

Although Churchill would benefit both Alberta and Saskatchewan, the proposed use of rail to ship crude more than 1,200 miles to connect at Delta Junction, Alaska, with the trans-Alaska oil pipeline, shapes up as a more viable option, said Richard Dixon, executive director of the University of Alberta School of Business Center for Applied Research in Energy and the Environment.

He said a route through Alaska connects to existing pipeline infrastructure and facilities, creating an economic advantage.

Dixon said the biggest problem with using Churchill for tidewater access is the restricted shipping season.

He said uncertain weather conditions give no assurance to marketplaces and "that's really the key driver here," noting that crude could be faced with long periods of storage and inaccessibility due to ice.

"Oil markets don't work that way," he said. "With crude oil, it's more the issue that you're trading so much of it every day."

Alberta Energy Minister Ken Hughes has indicated he is open to exploring all options, including a route down the Mackenzie River Valley to the Beaufort Sea, although he said some of the proposals are more long-term or speculative than others.

Dixon said OmniTrax is ready to meet with any provincial or territorial governments who want to examine ways to get crude to new markets.

Hughes said Alberta sees the potential of a regional energy corridor that would allow Manitoba to sell some of its hydroelectricity to Alberta in return for allowing private-sector players to develop the Port of Churchill for the export of petroleum products. ●

Contact Gary Park through publisher@petroleumnews.com

Petroleum News Bakken looking for writers

Prefer experienced reporters, but oil industry knowledge also valued.
Contact Kay Cashman at publisher@petroleumnews.com or 907.561.7517

MESSAGE FROM THE PUBLISHER

Why did you receive Feb. 18 news bulletin?

On Feb. 18 Petroleum News Bakken emailed a news bulletin to all of its readers. The four stories in that bulletin broke after the Feb. 17 edition of Petroleum News Bakken went to press on Feb. 14.

Because one of the articles contained the newly released North Dakota oil production numbers for December, the publisher decided the information should be sent out before March 3, the next scheduled issue of Petroleum News Bakken — and the first issue of the newspaper under its new weekly schedule.

The full version of those four articles, some with subheads and different headlines, and the production charts compiled by Petroleum News Bakken, are reprinted in this issue on the following pages: page 3, Helms: ND oil production 'back on track;' page 12, Enbridge, Energy Transfer launch plan to access E. Gulf for Bakken; page 5, Kringstad: Trains pull increasing share of ND crude; and page 1, Cenovus quits Williston in Saskatchewan.

And the Bakken Stats section, which runs from page 13 through page 17, carries the ND oil production chart by company and the ND Top 50 oil producers — both creations of Petroleum News Bakken.

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Petroleum news

● MOVING HYDROCARBONS

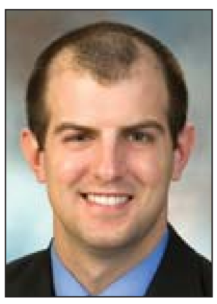
Trains pull increasing share

Kringstad not aware of any new plans for rail terminals, but says that doesn't necessarily mean there won't be any more in future

By MIKE ELLERD

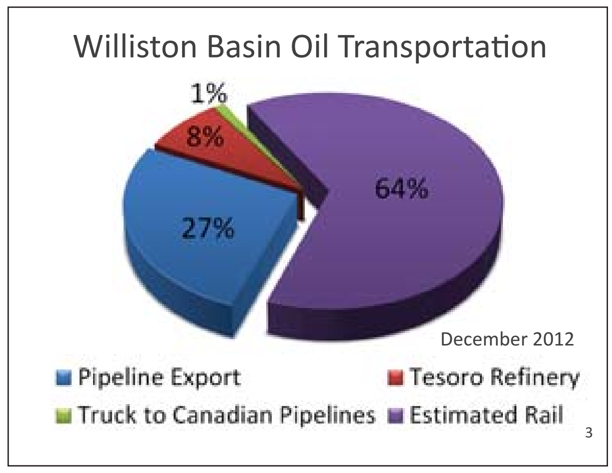
For Petroleum News Bakken

According to Justin Kringstad, director of the North Dakota Industrial Commission's Pipeline Authority, 64 percent of Williston Basin crude oil left the basin on unit trains in December, compared to 27 percent through pipelines. One percent of crude left the basin on trucks headed for Canadian pipelines, and the remaining 8 percent went to the Tesoro refinery at Mandan.


JUSTIN KRINGSTAD

In November, the rail/pipeline percent split was 58/32 percent, and in October that split was 52/38 percent. In April 2012, when the Pipeline Authority first began providing the transportation ratios, the rail/pipeline percent split was 28/56 percent, but ever since, rail has been either holding nearly steady or has gained on pipelines, and in September rail surpassed pipelines for the first time and has been gaining ever since.

Currently between 546,094 and 566,094 barrels of oil



are shipped out of the basin on seven to eight unit trains per day. There are 22 operational rail loading facilities in North Dakota, 17 of which are served by Burlington Northern Santa Fe and the remaining five by Canadian Pacific.

Destination markets favoring rail

During a Feb. 15 press conference held in conjunction with the Oil and Gas Division, Kringstad said the reason for the shift is that current economics for destination sites favor rail transport over pipelines.

"It's attracting a lot of barrels to the rail side," he said.

Kringstad said that the price for Bakken crude oil at Clearbrook, Minn., is nearly on par with West Texas Intermediate or WTI, although Brent crude is still bringing about $20 per barrel more than Bakken crude. He said better pricing at premium markets is what is driving the current advantage that rail has over pipelines because of the access rail has to those destinations.

"If you take a look at it from an overall perspective," Kringstad said, "it's good that we have the optionality here in North Dakota currently to move our crude oil. The shippers have that option if they want to utilize rail while the economics are very attractive in that direction; if they need to switch over to pipeline transportation for other marketing reasons the flexibility and the opportunities are there."

Flaring

On the natural gas side, Kringstad said the number of wells with first-time gas sales was down in December,

see RAIL SHIPPING page 6

● COMPANY UPDATE

Penn West ponders asset sales

Canadian light oil producer seeks greater market for Duvernay holdings; targets 90-130 Spearfish wells in Manitoba's Bakken sector

By GARY PARK

For Petroleum News Bakken

Calgary-based Penn West Exploration is looking to either sell or land a joint-venture partner to develop its liquids-rich gas assets in Alberta's Duvernay play, while turning its main focus to the Spearfish play in southern Manitoba's portion of the Bakken.

Company President Murray Nunns said Penn West has already invested C$100 million in the Willesden Green area of the Duvernay and "would welcome a partner to develop the assets."

"I think our top priority will be looking at some of our early-life projects. A case in point would be the Duvernay. We think there's tremendous value; we don't think there's recognition in the market for that," he said.

"More importantly, we believe an outside source of funding and extraction of some of the value ... is a very good business proposition. So something like that would definitely be on the radar screen," Nunns said.

Penn West said it has a material Duvernay position in the liquids-rich fairway of the Willesden Green area and plans a further stratigraphic test in 2013.

The light-oil-focused producer is also pondering the sale of a "variety of non-core assets that really don't have inventory that has a long-term impact," although there is no desire to erode cash flow too much, he said.

Spearfish tight-oil spending

For 2013, the Spearfish tight-oil play will attract spending of about C$200 million-C$250 million for 90 to 130 wells, encouraged by a reduction in well times to four days from eight days.

Penn West currently has five rigs operating in the Spearfish and plans to introduce a natural gas liquids extraction plant in the second quarter.

Penn West's hopes of shuffling assets coincides with its disclosure that it has added 110 million barrels of oil equivalent of proved plus probable reserves.

Its overall resources include 1.27 billion barrels of light oil and bitumen in Alberta, Saskatchewan and Manitoba, plus 600,000 acres of assets in the Cardium, Viking, Spearfish, Swan Hills and Carbonates plays in Western Canada.

Nunns said the target for 2013 is to produce 135,000-145,000 barrels per day and spend up to C$1.2 billion, regardless of adverse market conditions that stem from unfavorable heavy oil price differentials and restricted pipeline access.

However, Nunns said Penn West is optimistic that new infrastructure projects in the works will allow another 2 million bpd of oil to flow from Canada and the United

see PENN WEST page 6

● DRILLING & COMPLETION

Continental leads in ND Feb. drilling apps

Top producer increasing well densities with over 130 new Bakken, TF wells; SM, Kodiak, XTO, Slawson, others seek well permits

By MIKE ELLERD

For Petroleum News Bakken

Continental Resources submitted numerous applications to the North Dakota Industrial Commission, or NDIC, seeking permission to install in excess of 130 new horizontal wells on existing spacing units in Divide, Dunn, McKenzie and Williams counties with as many as 14 wells on some pads. NDIC's February hearings were scheduled for Feb. 27 and 28.

In Haystack Butte-Bakken field in Dunn and McKenzie counties, Continental filed for authorization to drill 34 new wells on six existing 1,280-acre units, 20 of which will target the Three Forks formation. The remaining 14 will target the Middle Bakken. The spacing units presently have either one or two existing Middle Bakken wells; one has an existing Three Forks well.

Continental is also seeking permission to install another 58 wells in four fields in McKenzie County. In the Antelope-Sanish field, the company is looking to drill a total of 20 new horizontal Bakken and Three Forks wells spread out among three existing 1,280-acre units.

In Haystack Butte-Bakken field in Dunn and McKenzie counties, Continental filed for authorization to drill 34 new wells on six existing 1,280-acre units, 20 of which will target the Three Forks formation. The remaining 14 will target the Middle Bakken. The spacing units presently have either one or two existing Middle Bakken wells; one has an existing Three Forks well.

Continental also wants to install three new Bakken and three new Three Forks wells in one 1,280-acre unit in the Glass Bluff-Bakken field, and the same number of wells in another 1,280-acre unit in the Poe-Bakken field and in each of each of two 1,280-acre units in the Elk-Bakken field.

The company is looking at 14 new wells on an overlapping Elm Tree-Bakken 2,560-acre unit in the Elm Tree-Bakken field.

In Divide and Williams counties, it has filed for NDIC permits to drill 12 wells on two 2,560-acre spacing units in the Stoneview and McGregor-Bakken fields, with another maximum of 14 wells on an overlapping 2,560-acre unit in the Alkali Creek-Bakken field in McKenzie and Mountrail counties.

In Burke County, Continental is seeking authorization to install up to three new Bakken and three new Three Forks wells on a 1,280-acre unit in the Viking-Bakken field.

And the company is seeking permission to drill up to four new Bakken and three new Three Forks wells on a 1,280-acre unit in the Banks-Bakken field in McKenzie and Williams counties.

SM, Kodiak, XTO, American Eagle seek permits

In addition to the applications submitted by Continental Resources, NDIC received numerous other well applications from a variety of operators for consideration during the February hearings.

In McKenzie County, SM Energy is asking to drill nine new horizontal wells on each of three existing 1,280-acre units in the Sivertson-Bakken field. In the Dimmick Lake-Bakken field, also in McKenzie County, the company is seeking permission to drill up to nine horizontal wells on each of two existing 1,280-acre spacing units.

Kodiak Oil and Gas is asking the commission to increase the number of permissible wells from five to eight for six existing 1,280-acre spacing units in the Poe-Bakken field in McKenzie County. Kodiak is also asking the number of wells be increased from four to 12 on eight separate 1,280-acre units in the Pembroke-Bakken field, also in McKenzie County.

In Dunn County, XTO Energy is looking to drill a total of eight wells on an existing 1,280-acre unit in the Killdeer-Bakken field, a total of four wells on an existing 640-acre unit in the Heart Butte Bakken field, and a total of four wells on an existing 320-acre unit, also in the Heart Butte field. In Williams County, XTO is seeking permission to drill a total of eight wells on an existing 960-acre unit in the Tioga-Bakken field.

American Eagle Energy is asking permission to drill up to eight horizontal wells on an existing 800-acre unit, and eight wells on each of two existing 1,280-acre units in the Colgan-Bakken field in Divide County.

Slawson, Petro-Hunt, Oasis file for permits

Slawson Exploration submitted applications requesting authorization to drill five wells on each of two existing 1,280-acre units in the Squaw Gap-Bakken field in McKenzie County.

Petro-Hunt is seeking permission to drill up to eight wells on each 1,280-acre unit the company controls in the Glass Bluff-Bakken field in McKenzie and Williams counties, and up to seven wells on a 640-acre unit in the Stockyard Creek Bakken field in Williams County.

Oasis Petroleum is seeking authorization to drill up to eight horizontal wells on each 1,280-acre unit the company controls in the Squires-Bakken field in Williams County.

Sinclari, True, Flatirons seek permits

Sinclair Oil and Gas is looking to drill a total of four wells on an existing 1,280-acre unit in the Mary-Bakken field in Dunn County.

True Oil LLC is seeking permission to drill up to seven horizontal wells on an existing 1,280-acre unit in the Buffalo Wallow-Bakken field in McKenzie County.

And in Renville County, Denver-based Flatirons Resources LLC is asking to drill up to three wells into the Madison formation on an existing 640-acre spacing unit in the Lake Darling-Madison field. ●

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RAIL SHIPPING

but he said that was in line with the total number of new wells that went into production in December.

"So even though there was a slight downtick, it's still keeping up with the production side, which is very encouraging."

On flaring, Kringstad said he sees two challenges, one being to build the pipeline footprint out farther to reach wells outside of the Bakken core area. But inside that core area, he said, compression is an important issue and how to utilize the existing gas lines to move additional gas.

"So as the infill drilling starts to take place, as we're seeing more and more production from smaller areas, we need to make sure that compression is going to be installed and that those pipelines can handle those larger volumes."

Pipeline maintenance

Kringstad said he has been told that pipeline companies are taking advantage of the reduction in pipeline transport to perform maintenance. When pipelines are "running full and running at full throttle," it's difficult for the companies to keep up with maintenance, he said. But the pipeline companies don't expect the open capacity to be a long-term issue, Kringstad said, and the current open capacity has given them "a little bit of breathing room."

Pipelines in the pipeline

On upcoming pipeline projects in North Dakota, Kringstad said there are a number of projects on several levels. On projects dealing with major export out of the basin, Kringstad said probably the "sizable" project on the federal side is Enbridge's Sandpiper project, which would provide an additional 225,000 barrels per day capacity to the Gulf. But he said there are a number of localized projects to move crude oil within the basin. Kringstad said he is not aware of any new plans for additional rail terminals, but said that doesn't necessarily mean there won't be any more built in the future. ●

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PENN WEST

States to Gulf Coast refineries in 2014.

Cardium asset significant

He said Penn West believes its land holding in the Cardium light oil play is the "most significant asset in the company from a growth and long-term value perspective," although production this year is expected to be "more or less flat" while the focus is on waterflooding and long-term growth.

Rob Wollmann, senior vice president of exploration, said three waterflood projects are expected to be running in the Cardium by the end of 2013, setting the stage for a "much broader program" in 2014.

Penn West also said its first horizontal waterflood pilot in central Alberta's Pembina play yielded a promising 150 bpd from three previously shut-in vertical wells.

The company said an external study completed in 2012 estimated 533 million barrels of light-oil contingent resources in the Cardium properties, which are targeted for a longer-term integrated strategy of primary development with enhanced oil recovery schemes. ●

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● COMPANY UPDATE

North Dakota bolsters Enerplus

Advanced understanding of both Bakken and Three Forks formations; bumped up production by 120% in 2012 to 14,000 boe per day

By GARY PARK
For Petroleum News Bakken

Enerplus is taking a high-spirited view of its drilling activities at Fort Berthold in North Dakota, which has contributed strongly to the Calgary-based company's increase in reserves and production in the final quarter of 2012.

It said an advanced understanding of both the Bakken and Three Forks opportunities in the region raised production by 120 percent last year to 14,000 barrels of oil equivalent per day, with company-wide output increasing to an average of 85,490 boe per day in the fourth quarter.

Along with drilling 26 net operated wells — 19 in the Bakken and seven in three Forks — it participated in 5.1 net non-operated wells.

Based on the results to date, the company projects that ultimate recoveries will vary depending on a number of factors, such as lateral length and the number of fracking stages, plus the number of wells drilled within a drilling spacing unit and what formation the wells are producing from.

Enerplus said it expects ultimate recoveries, EURs, will be lower for wells landed in the Three Forks formations and for the third and fourth wells drilled in a spacing unit.

Taking those factors into consideration, the company said it continues to expect that EURs per long lateral well could range between 500,000 and 800,000 barrels of crude. Because of the weak outlook for natural gas prices, capital investment in Canadian natural gas assets was limited to projects associated with natural gas liquids, the company said.

Activities included delineation of its undeveloped acreage in Alberta's unconventional Cardium and Duvernay plays and additional drilling in the Wilrich. No capital was allocated to shallow natural gas assets.

As a result of the scaled back spending, Canadian natural gas production and reserves declined last year by 9 percent and 12 percent respectively, but the successful drilling results at Fort Berthold were largely responsible for the replacement of more than 190 percent of production last year at "attractive finding and development costs for the second year in a row."

Overall production for the year climbed to 82,098 boe per day from 75,332 boe per day in 2011, while the company posted a net loss for the 12 months of C$155.73 million, due to accounting impairments of C$418 million on oil and gas assets and C4114 million due to expiring undeveloped land rights, mainly in the U.S. Marcellus gas play, compared with net income of C$109.44 million in 2011.

The company reported drilling its first vertical delineation well in the Duvernay late last year, with core and fluid analysis confirming that Enerplus in the liquids-rich fairway. More delineation wells are scheduled for the second half of 2013 to gain a better understanding of the play.

Enerplus also said it is continuing to pursue joint ventures in both the Duvernay and Montney areas given the scale of those opportunities and the chance they present to generate additional near-term funding.

The company said it plans to spend about C$685 million on exploration and development projects this year, down 20 percent from last year, with about 85 percent of capital earmarked for crude oil and liquids-rich natural gas projects, with 75 percent targeted for crude oil specifically.

It anticipates production for the year of 82,000-85,000 boe per day with a 50 percent weighting to crude oil and liquids, with an exit rate for the year of 84,000-88,000 boe per day.

Enerplus said that as natural gas prices declined through 2012, its partners (including Encana) slowed their activities, which saw the company pull 20 percent of its original capital budget of C$154 million.

Chief Executive Officer Gordon Kerr said fourth quarter results enabled Enerplus to "beat the consensus of analysts and virtually all metric, with the growing focus on oil output raising cash flow by 12 percent over the previous year despite a 35 percent plunge in realized gas prices.

Analyst Kyle Preston of National Bank Financial said it was remarkable the company was able to meet its production guidance and cut costs given its operational and financial challenges.

"That helps in pointing to a more sustainable dividend model going forward," he said. ●

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ENERPLUS

At Fort Berthold, Enerplus advanced its understanding of both the Bakken and Three Forks and grew production by approximately 120 percent in 2012, exiting at 14,000 barrels of oil equivalent per day. Total production volumes increased as well, averaging 85,490 boe per day in the fourth quarter.

REFINING

Air quality permit clears way for refinery

The North Dakota Department of Health has issued a critical air quality permit necessary for Dakota Prairie Refining to build a diesel refinery in southwestern North Dakota.

Dakota Prairie is a joint venture between MDU Resources of Bismarck, N.D., and Calumet Specialty Products Partners of Indianapolis, Ind.

"Approval of the air quality permit means that we can begin construction within the next month, and the facility can be operational and helping supply North Dakota's diesel fuel market by late 2014," David L. Goodin, president and chief executive officer of MDU, said Feb. 25.

The facility will process 20,000 barrels per day of Bakken crude oil. The plant will be located on a 318-acre site west of Dickinson in Stark County. It will employ about 100 people. Hiring and training of operating personnel is expected to begin in 2013.

The plant will employ its own plant manager and management team, who will report to a governing board composed of representatives of WBI and Calumet. The facility's engineering and plant design are in the final stages, and Westcon has been selected as the general contractor.

"We appreciate the help of the state's agencies and officials to identify issues and help solve problems in a manner that has brought this project from concept to reality," said Jennifer G. Straumins, president of Calumet's general partner.

—PETROLEUM NEWS BAKKEN

● GOVERNMENT

Minority party perspective on ND O&G bills

Kenton Onstad shares views on stripper wells, extraction tax, relief to counties, flaring and various landowner issues

By MIKE ELLERD
For Petroleum News Bakken

As the minority leader in the North Dakota House of Representatives, Kenton Onstad watches bills in the current legislative assembly, not only from the perspective of his constituents in southeast Mountrail County, but also from the perspective of the House Democratic Non-Partisan League or NPL caucus (North Dakota's national Democratic party affiliate).

Onstad, who owns and operates a farm near Parshall, and also does business development for Mountrail-Williams Electric Cooperative, has served in the North Dakota House of Representatives since 2001. He was the assistant minority leader in the 2011 and 2007 sessions, and in the current session was elected by his caucus to the top minority party leadership position. Onstad recently responded to a series of questions posed to him by Petroleum News Bakken regarding some of the important oil and gas-related bills that are moving through the 63rd North Dakota legislative assembly.

> *"Of all the groups we need to satisfy, it is the landowners. They have the most to lose and have least to say. It may well be the deciding factor if we can sustain the current oil and gas development."* **—North Dakota House Minority Leader Kenton Onstad**

Senate Bill 2336

Petroleum News Bakken: One of the more complex oil and gas-related bills in the session is Senate Bill 2336. As currently amended, the bill contains numerous provisions related to oil and gas tax structures, including the following: it requires operators to withhold income taxes on oil and gas royalty payments to nonresidents to ensure the state receives those tax revenues from out-of-state interests; it requires Bakken and Three Forks wells to individually qualify for stripper well status and the associated tax exemptions rather than allowing the entire spacing unit to qualify; it requires Bakken and Three Forks stripper wells to annually recertify for stripper well status; it sets the production volume for Bakken and Three Forks wells to qualify for stripper well status at 40 barrels per day, up from the current volume of 30 bpd; it provides tax incentives for oil companies to explore formations other than the Bakken and Three Forks; it eliminates tax incentives estimated to be as high as $2.1 billion that would kick in if oil prices fall below $52.50 per barrel; and it decreases the oil extraction tax rate from 6.5 percent to 4.5 percent on Jan. 1, 2017, or after a three-month period after that date during which production exceeds 1 million barrels. The amended bill was passed by the Senate Finance and Taxation committee on a 5-2 vote and referred to the Senate Appropriations committee.

KENTON ONSTAD

At this point in the session, some of the provisions do not appear controversial, but others do, in particular the 2.0 percent reduction in the extraction tax that would go into effect on or after Jan. 1, 2017. On one hand it is argued that overall the bill would benefit the state because the legislative council's fiscal analysis indicated the legislation would result in a net fiscal gain to the state of $28.8 million n the 2013-15 biennium, and it eliminates the potential loss $2.1 billion loss to the state should the price of oil fall below $52.80 per barrel. On the other hand, a subsequent fiscal estimate prepared by the legislative council at the request of Sen. Mac Schneider for the five-year period from 2017 through 2012 (the first five years after the 2.0 percent extraction tax reduction is in effect) estimated a total net reduction in extraction tax collections of nearly $596 million.

What are the risks here, i.e., how do you balance an estimated loss of $596 million from 2017 through 2021 against a possible revenue loss of more than $2 billion should the price of oil drop below $52.50 per barrel? What are you views of the other provisions in SB 2336, i.e., would the House Democratic caucus support some or all?

> *"Our caucus would support a bill to lower the extraction tax to our current effective rate of 10.5 percent and remove trigger prices. We would also support a bill to require annual recertification of stripper wells on a well by well basis and give an 11 month holiday to recover costs before they are required to pay the current tax liability."* **—North Dakota House Minority Leader Kenton Onstad**

Q AND A

Onstad: SB 2336 tries to identify several areas of a complicated tax formula. They should have been in a separate bill rather than a comprehensive bill. The two main areas of the bill try to address stripper wells and the trigger price to lower the extraction tax.

We need to address stripper properties versus stripper wells. It is a recognized loophole and if not fixed our effective rate for extraction tax would be essentially zero because once a well is below the production level it pays no extraction tax, and since we do not require recertification of these wells they go on forever with no extraction tax liability. No annual recertification is the problem.

A bigger problem, if we do not remove stripper properties and address wells on an individual basis, is that the larger unit spacing identified with horizontal drilling would allow for all the wells in a unit to be considered stripper status. The state of North Dakota would not receive extraction tax on any of the wells in the unit regardless of production. A huge loophole we need to fix. We are the only state in the union that does not require any type of recertification of these wells. New tertiary techniques, new technology to improve production are being proven every day, and to allow increased production as if it is a new well and to further not allow the state to receive revenue from this onetime resource is not correct. Annual recertification really allows an 11 month holiday to improve those wells, recover costs and put it back on the payroll.

The second problem in SB 2336 is it tries to remove the trigger prices from our incentives and provides a lowering of the extraction tax in return. Trigger prices were put into play when the price of oil fell below the cost of production and created an incentive to continue drilling when prices reached those levels. What is the cost of production? Oil companies do not print out their cost of production to the public because it is an internal number. Competition between companies, publically traded stocks and business reasons are some of the reasons why they are not displayed. Cost of production also depends on barrels produced. When the trigger formula was first presented a typical well produced 100 to 150 barrels of oil per day. Now you have wells recently reported to be producing over 5,000 bopd, a wide variance on what the cost of production on a barrel per barrel basis would actually be.

Sponsors of SB 2336 lead one to believe we need to lower the extraction tax because this is a possibility. All indications from major publications predicting the future price of oil do not reflect the need to lower extraction taxes because of the possibility of lower prices. Security and Exchange Commission quarterly reporting of oil companies in North Dakota all report increasing production to as much as tripling production. They are doing this under the current tax structure in the state. We need to remind the citizens this is a onetime resource and on a state by state comparison of our tax structure is not too high. Oil companies are driven by geology, new technology and the availability of oil.

Our caucus would support a bill to lower the extraction tax to our current effective rate of 10.5 percent and remove trigger prices. We would also support a bill to require annual recertification of stripper wells on a well by well basis and give an 11 month holiday to recover costs before they are required to pay the current tax liability.

Extraction tax reduction

Petroleum News Bakken: House Bill 1234 would incrementally reduce the oil extraction tax by 0.5 percent, but also takes away stripper well tax exemptions for Bakken and Three Forks wells. The legislative council's fiscal analysis estimated that removing the stripper well exemption for Bakken and Three Forks wells would increase revenue by $84 million, but the reduction in the extraction tax would reduce revenue by $240 million, resulting in a net revenue loss of $156 million in the 2013-15 biennium.

North Dakota has seen its revenues increase substantially in recent years as a result of the current oil boom. Do you believe that the state is bringing in suffi-

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● DRILLING & COMPLETION

Corinthian looking at 120 new Spearfish wells

By MIKE ELLERD

For Petroleum News Bakken

Corinthian Exploration (USA) Corp. is asking the commission to establish a total of 10 320-acre spacing units in the Spearfish formation in Bottineau County and is seeking permission to drill up to 12 horizontal wells on each 320-acre unit for a possible maximum of 120 new wells. Corinthian Exploration (USA) is based in North Dakota with an office in Souris, but is a wholly owned subsidiary of Calgary-based Corinthian Exploration Corp. Most of Corinthian's activities are in the North Souris field and one confidential well in the Northeast Landa field. Both fields are located along the Canadian border in northern Bottineau County.

According to information compiled by Julie LeFever of the North Dakota Geological Survey, the Spearfish formation consists of three members and underlies half of North Dakota, but it is the uppermost member, primarily consisting of quartzose sandstones interbedded with shales, that is productive. That member overlies the Madison formation in north-central North Dakota and southern Manitoba. In that area of North Dakota, the depth of the Spearfish formation varies from approximately 2,900 feet to 3,400 feet and ranges in thickness from approximately 125 feet to 220 feet. According to LeFever, the production history of the Spearfish is similar to that of the Bakken dating back to 1952.

North Dakota Industrial Commission Department of Mineral Resources Oil and Gas Division records indicate the first wells in North Souris field date back to 1955, but those wells targeted the Madison formation. One of those early wells is still producing, and through January 2013 the well has produced a total of 250,411 barrels of oil with an initial production rate of 232 barrels per day.

Since 2007, Corinthian has drilled some 33 wells in the North Souris field, all of which target the Spearfish formation and some additionally target the Madison formation. Seven of these wells are on confidential status and some are not yet producing. Production data for the producing wells indicate initial production rates ranging from 189 bpd to as low as 3 bpd. The company has one well in the Northeast Landa field, which is also on confidential status. ●

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ONSTAD Q&A

cient revenue and that a 0.5 percent reduction in the extraction tax is reasonable?

Onstad: HB 1234 is in the right direction to correct stripper well loophole. As I mentioned earlier, if we do not require recertification, we do not correct the major problem. HB 1234 limits itself to Bakken and Three Forks Wells only. This limitation again opens the door to a major loophole. Do you realize the size of the Williston Basin and the number of zones that are now economically feasible to produce? I disagree to limit to two zones the tax exemption. If you want to lower the extraction tax, let's fix the stripper well situation. This is a trade-off for a partial fix.

Relief to oil counties

Petroleum News Bakken: Increasing funding to oil counties has been a priority in the current legislation session, and one bill that addresses this is HB 1318, a bill you are sponsoring and informally known as the "catch up and plan initiative." That bill would provide for a one-time, two-year increase in the percentage of the production tax money going to impacted counties, which according to the legislative council's fiscal analysis would amount to nearly $1.5 billion. Another bill providing relief to oil counties is HB 1358, which would provide additional state funding to oil-impacted counties ($292.9 million), hub cities ($85.5 million) and schools ($30.5 million), and would also add $50 million to the impact grant fund. The legislative council's fiscal analyses on these bills indicate both would negatively impact the state's general and other funds. HB 1358 was passed by the House Finance and Taxation committee with amendments on a 14-0 vote, and HB 1318 is still in that committee.

In your opinion, how do these two bills compare and how much redundancy is there in them. Is one more likely to get through the legislature than the other or might provisions from each be combined into a final bill?

Onstad: It is only fair to look at all funding bills to the oil producing counties together. There are good parts in all of the bills and I would hope they would be considered together. They are obviously not and from a public perspective the best relief bill will not be created.

"The downside is the socioeconomic effects of the development. Traffic has increased so much it scares many people from driving, mostly senior citizens. The costs of groceries, hardware, building supplies and clothing have all taken a major increase. Rent, costs of homes and many other items have increased to a level where they become unaffordable. That is very unfortunate." **—North Dakota House Minority Leader Kenton Onstad**

The needs in western North Dakota are enormous. This time in history is unprecedented in the impacts created to the State of North Dakota. It is also unprecedented in the increases of benefits the state has realized. We have created some good things, Legacy Fund is one example. We need to further vision for the state of North Dakota what do we want the state to look like when the development starts to slow down. We have a wonderful opportunity to address the needs for western North Dakota along with the entire state. The state of North Dakota has to address their responsibility and further focus on the future of the state. I have concerns we are staying with a maintenance approach and not establishing a long range plan for the state.

Flaring bills

Petroleum News Bakken: Flaring of natural gas is an important issue facing North Dakota and in December flaring was at 29 percent, lower than the all-time high of 36 percent in September 2011 but still far above the ideal level of approximately 5 percent that the state would like to achieve. Three bills have been introduced that address flaring in the current legislative session. SB 2315 would have completely eliminated royalty and tax exemptions from the one-year flaring rule, but that bill was defeated in the Senate. HB 1134 provides tax incentives for operators to find alternate uses for natural gas and that bill passed the House on a vote of 93-0 and has moved to the Senate. SB 2370 provides tax incentives for the installation of gas gathering pipeline systems. That bill was amended and the amendments were adopted by the Senate Finance and Taxation Committee and referred to the Senate Appropriations Committee, although many of the amendments were technical in nature and dealt with pipeline diameters and operating pressures.

Analyses on the fiscal effects these two bills would have on revenue by the legislative council indicate that HB 1134 would result in a reduction in tax revenues to the state totaling approximately $32 million in the 2013-15 biennium, and SB 2370 would reduce revenues by approximately $16 million in the same biennium.

What are your views on HB 1134 and SB 2370, and do you believe the potential benefits these bills justify the potential losses in revenue?

Onstad: Flaring is a terrible waste of a one-time revenue. It is a feel good approach that doesn't solve the problem. The average flaring is 1 percent across the nation. There is absolutely no reason we are at 30 percent. Many states do not allow flaring at all, along with Canada, and if they do it is a shorter period of time than allowed in North Dakota. I think we need to further restrict the flaring rule. I will support the intent but hope we could further reduce the flaring.

Landowner issues

Petroleum News Bakken: HB 1333 is a landowner easement bill that contains a number of provisions, including giving the Industrial Commission more authority to regulate saltwater disposal and expands the commission's duties related to pipeline reclamation. The bill also allows for the North Dakota mediation service to mediate pipeline easement disputes. Another bill, HB 1349, establishes new surface reclamation requirements.

What are your thoughts on these bills and on landowner issues in general as they relate to oil and gas development in North Dakota?

Onstad: Landowners are the biggest entity impacted by oil and gas development. They are also the largest group that has very little assistance to address their prob-

see **ONSTAD Q&A** *page 10*

● COMPANY UPDATE

DeeThree hikes Bakken activities

Plans 20 wells in southern Alberta Bakken play; has yet to define western edge of Ferguson Alberta Bakken, drilling 1 or 2 wells

By GARY PARK

For Petroleum News Bakken

Calgary-based DeeThree Exploration has the southern Alberta Bakken play squarely in its sights for 2013, with plans to spend the largest chunk of its C$150 million capital budget on drilling 20 wells in the formation.

The company said it expects significant production gains while adding to the resource potential of both its key oil resource plays — the Alberta Bakken and Belly River in central Alberta's Brazeau area.

It said 2012 acquisitions of 32,640 net acres that offset its Alberta Bakken holdings and 21,760 net acres in the Belly River play are highly prospective for further exploration and development.

DeeThree said it hopes 2013 production will average 6,800-7,000 barrels of oil equivalent per day (76 percent crude oil and liquids and 24 percent natural gas), with a targeted exit rate for the year of 8,500-9,000 boe per day (81 percent crude and liquids and 19 percent gas). Its 2012 output averaged 4,230 boe per day (65 percent crude and liquids and 35 percent gas).

The company said it plans to build this year on its 2012 drilling program, which resulted in the discovery of a significant oil pool in the Alberta Bakken property and confirmation of the multi-zone potential of its Belly River light oil resource play.

DeeThree said the well had initial production over 30 days of 448 barrels per day, confirming the geological and seismic modeling — results that prompted the company to acquire 3,840 acres offsetting the eastern portion of its Alberta Bakken land base.

Its final 2012 Alberta Bakken well was a 3.2 kilometer horizontal extension to the east of its existing Ferguson Bakken oilfield. The well encountered "excellent pay-and-gas detection through to the end of the horizontal leg and significantly extended the known limits of the oil pool to a 103-square-kilometer fairway."

DeeThree said the well had initial production over 30 days of 448 barrels per day, confirming the geological and seismic modeling — results that prompted the company to acquire 3,840 acres offsetting the eastern portion of its Alberta Bakken land base.

Additional wells planned

The immediate plan is to drill additional wells in the area to further delineate the trend over the 9,600 acres of the company's eastern land.

DeeThree said it has yet to define the western edge of its Ferguson Alberta Bakken pool, where it acquired 12,160 acres last year of highly prospective land on trend to the west of its Alberta Bakken development area.

The company plans to drill one or two wells on the acquired acreage this year, aiming to extend the identified size of its Ferguson Alberta Bakken pool.

DeeThree said it has completed an internal geological and geophysical study of its 32,000-acre land base, including 10,880 acres of acquired land, situated to the north of its existing core development area.

Two to four wells are expected to be drilled on these lands in 2013, with any drilling success qualifying as significant because no oil resource potential has been assigned to the lands.

The company said it has invested significant facility infrastructure on its Alberta Bakken property, where oil processing facilities are currently operating close to capacity. A second main battery will be commissioned in the second quarter to boost capacity to 8,000 bpd.

Funds flow from operations for 2013 is projected at about C$100 million. Currently the company has 1,500 boe per day of crude oil hedged at an average floor price of US$90 per barrel West Texas Intermediate. ●

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ONSTAD Q&A

lems. The laws in North Dakota to develop mineral interests put the surface owner at a terrible disadvantage. Negotiations are one sided. Damages are all they have and that is not a true reflection of the losses they will receive over the age of any well.

I am very supportive of landowner issues and see a growing dislike for the industry from surface owners, not in a distasteful way but they see the Oil and Gas Division taking industry side and not as a fair regulator. Even though many are receiving royalty payments, the intrusion on their way of life is huge. Farming practices, effects on ranching, the impacts on roads, dust accumulation and water quality are only a handful of the concerns our landowners raise. Of all the groups we need to satisfy, it is the landowners. They have the most to lose and have least to say. It may well be the deciding factor if we can sustain the current oil and gas development.

Heart of the Bakken

Petroleum News Bakken: You live in the heart of the Bakken and you represent constituents that are affected first hand by both the positive and negative impacts of the current oil boom. As a legislator, what are the most important issues facing you as you represent the diversity of interests in your district?

Onstad: Residents in my district are on one hand supportive of the oil and gas development because they knew what the alternative is — dying. The amount of impact in such a short span has most wondering what are the benefits as many see none to very little.

Businesses are flourishing and have provided many job opportunities for residents. There is more wealth in our area than ever before and the Tribal members are benefiting from the development as well.

The downside is the socioeconomic effects of the development. Traffic has increased so much it scares many people from driving, mostly senior citizens. The costs of groceries, hardware, building supplies and clothing have all taken a major increase. Rent, costs of homes and many other items have increased to a level where they become unaffordable. That is very unfortunate.

Crime has increased, volunteer rural ambulances and fire departments are swamped, law enforcement, daycare, schools, city commissions and county officials are overwhelmed in such a way we are losing the volunteerism spirit of our communities.

They look at it as a change in how we live and quality of life. They want to make sure that the current impacts leave the countryside a better place. Many traditions, hunting, fishing and others are kept to a minimal impact. We recognize the benefits for the State of North Dakota and providing property tax relief, additional funding for infrastructure, more dollars to fund other projects. They are just tired of being the sacrificial lamb for the state and want the due respect and recognition of what western North Dakota is going through. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

• COMPANY UPDATE

Newfield looks to double US oil in 3 years

By RAY TYSON

Petroleum News Bakken

A confident Newfield Exploration is shifting into high gear with an aggressive three-year, $4.4-$4.7 billion investment plan to double its U.S. oil and liquids production by year-end 2015. It's the first time the company has stepped out so far with such a forecast.

"It highlights the confidence we have in the depth and quality of our domestic portfolio and our ability to execute," Lee K. Boothby, Newfield's chairman, president and chief executive officer, told analysts Feb. 20 during Newfield's fourth quarter and year-end 2012 earnings conference call.

Newfield unveiled its lofty production goal about a week earlier, on the same day it separately disclosed that it would be looking at "strategic alternatives" for its international assets, including a possible sale, to focus on developing its four liquids-driven domestic resource plays, including the Williston Basin's oil-rich Bakken petroleum system.

Newfield's international holdings consist of offshore oil and natural gas developments in Malaysia and China.

"Any future international growth would've come at the expense of not fully accelerating our domestic oil and liquids plays. We simply cannot do both," Boothby said in the conference call.

Projecting oil growth

Newfield is looking to boost U.S. oil production from 11.1 million barrels in 2012, to 13-14.5 million barrels in 2013, to 16.8-19 million barrels in 2014, and to 20.6-25.3 million barrels in 2015, while increasing natural gas liquids production over the same years from 2.3 million barrels, to 4.2-4.7 million barrels, to 7.2-8.0 million barrels, and upward to 8.5 million barrels in 2015.

"We have more than 11,000 potential liquid drilling locations, which at our current pace of drilling activity, equates to decades of inventory," Boothby said, noting that by 2015, two-thirds of total company production would be liquids. About half is currently liquids.

In contrast, Newfield is looking to reduce production of its less desirable U.S. natural gas, which has been under pricing pressure for years, from 140 billion cubic feet in 2012, to 115-125 bcf in 2013, to 114-132 bcf in 2014, to 112-136 bcf in 2015.

"The three-year plan that we put out, that's a first for Newfield," Boothby told analysts.

A robust capex program

Meanwhile, North Dakota's Williston Basin, the Uinta Basin in Utah, Cana Woodford in Oklahoma and Eagle Ford in Texas are to receive about 80 percent of Newfield's $1.7-to $1.9 billion in capital spending this year, or roughly $1.4-$1.5 billion, the company said. An additional $1.5-$1.6 billion in domestic spending is earmarked for 2014 and again in 2015.

Williston's slice of the spending pie will increase to $230 million. With that Newfield plans to drill about 45 new wells in the Bakken and Three Forks formations in 2013, resulting in about a 15 percent production increase over 2012 averages of about 10,500 barrels of oil equivalent per day.

A fourth company-operated drilling rig was expected to join the Williston fleet in early March, and the company said production would likely jump another 25 percent in 2014.

"Our Williston team could easily receive the most improved award for 2012," Boothby said. "They successfully tackled industry issues with innovative solutions and lowered well cost, reduced the timing of rig release to first oil sales and transitioned to an efficient development program."

Newfield's Three Forks acreage

He said that while most of Newfield's current development efforts in the Williston are focused on the Middle Bakken, the company has more than 40,000 net acres that also are prospective for the Three Forks.

"In addition, we'll also be investigating the various deeper benches within the section," Boothby said.

This year Newfield plans to invest about $360 million in the Cana Woodford where it has "fast-tracked" more than 45,000 acres into development and an additional 100,000 acres continue to be assessed. Newfield, which projects 200 percent production growth in 2013, plans to operate up to six rigs in the play this year.

$380 million goes to Uinta

Drilling in vertical and horizontal plays in the Uinta Basin and development of the Greater Monument Butte, GMBU, waterflood calls for an investment of about $380 million this year. More than 200 wells are planned for the ongoing GMBU project. On other Uinta fronts, the company plans to spud the first of four multi-well pads to test the Uteland Butte with "super-extended" laterals of about 9,800 feet. Horizontal drilling is also under way in the Wasatch formation. Uinta oil production is expected to grow about 10 percent in 2012 and 20 percent in 2014.

And about $275 million is planned for investment in the Eagle Ford. The development program includes the drilling of about 35 wells. Development drilling in 2013 will focus on an approximate 25,000-acre footprint in the West Asherton and Fashing fields. Net production from the region in 2013 is expected to increase about 75 percent over 2012 levels.

International gets up to $400 million

The remaining 20 percent of Newfield's 2013 capital expenditure budget, or about $300-to $400 million, will go to international assets, primarily to ongoing oil developments. About $150 million of the total is related to the Pearl development offshore China, with first production scheduled for early 2014.

However, international liftings are expected to decline 25-30 percent compared to 2012. The impending decrease was attributed to natural field declines, limited investment in new exploration and exploitation opportunities and changes in the economic sharing of production under Newfield's production sharing agree-

see NEWFIELD page 24

● MOVING HYDROCARBONS

Race to the US Gulf Coast

New partnership of Enbridge, Energy Transfer Partners, launches plan to access eastern Gulf for Bakken, Western Canadian crude

By GARY PARK

For Petroleum News

A new joint venture by Enbridge and Energy Transfer Partners, ETP, is zeroing in on the Eastern Gulf Coast crude market, with plans to spend up to $3.4 billion to deliver as much as 660,000 barrels per day of crude from the Bakken and Western Canada.

Enbridge views the 3 million bpd capacity of the Louisiana market as an "excellent fit with our broader market access initiatives."

Steve Wuori, president of liquids pipelines at the Calgary-based company, said there is ample opportunity for crude on the 700-mile link from Flanagan, Ill., to displace imported crude in the Gulf Coast region.

Enbridge Chief Executive Officer Al Monaco said the eastern Gulf refineries are "configured nicely for a market that is screaming out for heavy crude" to offset the declining volumes from Mexico and Venezuela.

He said Enbridge's comprehensive bundle of projects will "go a long way" to ease price discounting "that Western Canadian and Bakken producers currently are facing as well as to meet the demand of North American refiners seeking reliable domestic supply."

Addressing crude bottlenecks

ETP President Marshall McCrea said the joint-venture project, which needs approval from the Federal Energy Regulatory Commission to reverse a portion of natural gas trunkline from Patoka, Ill., to St. James, La., would address crude bottlenecks on the North American pipeline network.

He said ETP looks forward to working with Enbridge to establish a "key transportation conduit to link a diversified slate of reliable, long-term crude oil reserves to refineries along that eastern Gulf Coast."

If FERC approval is received later this year, the new 30-inch diameter system could be in service by early 2015, with Dallas-based ETP as operator.

In the western Gulf, Enbridge and its partner Enterprise Products Partners recently reversed the 400,000 bpd Seaway pipeline from Cushing, Okla., and are working on a number of initiatives to debottleneck the downstream end of Seaway, although the partnership is not yet ready to estimate the eventual run rate for the pipeline.

For Enbridge, it is also part of a strategy to recapture Bakken crude that is now being carried by rail.

The use of that option contributed to a 16 percent decline in the fourth quarter of 2012 in shipping volumes on the Enbridge pipeline system in North Dakota that is operated by subsidiary Enbridge Energy Partners, EEP.

EEP President Mark Maki told analysts earlier in February that the company`s strategy, including its Light Oil Market Access Program to access refineries in the U.S. Midwest, Ontario, Quebec and possibly farther east in the US and Canada, will remedy that loss of volumes "in due course."

Surge in rail movements

Wuori conceded that Enbridge in 2012 saw a "real surge in rail movements, especially out of North Dakota and somewhat out of (the Williston basin) in Saskatchewan," lowering utilization on the North Dakota system to 74 percent.

He said that to move discounted crudes like those found in the Bakken by rail to the St. James refinery hub costs $12-$17 per barrel, although a rail shipper still has a "better netback than on pipe."

Tudor Pickering Holt estimates that more than 60 percent of total Bakken production is leaving the basin by rail, but said that another 500,000 bpd of pipeline capacity to Louisiana and Texas would strengthen the thesis that after 2013 only minimal crude will be carried by rail from the Bakken to both the eastern and western Gulf Coast, while shippers use rail to access the eastern and western seaboards of the U.S.

Wuori noted that the tremendous demand in the St. James/New Orleans market for Bakken crude currently accounts for 400,000 bpd arriving by rail.

Seaway reversed

In the western Gulf, Enbridge and its partner Enterprise Products Partners recently reversed the 400,000 bpd Seaway pipeline from Cushing, Okla., and are working on a number of initiatives to debottleneck the downstream end of Seaway, although the partnership is not yet ready to estimate the eventual run rate for the pipeline.

RBN analyst Sandy Fielden warned that if TransCanada's proposed 830,000 bpd Keystone XL application is turned down by the Obama administration, the Enbridge-ETP pipeline would "create additional space from Canada. If Keystone goes ahead (the joint venture project) is already looking shaky."

He said shipper commitments in an open season expected to be held before mid-2013 would likely be limited pending a verdict on Keystone XL's fate.

The desire by Enbridge-ETP to go ahead was indicated in Monaco's comment that commitments or only 250,000 bpd, or "a bit less," would be needed in an open season to make the project economically feasible, although Enbridge said it has the ability to install less horsepower on the line to match the initial level of interest by shippers and enable the "project to proceed at a lower commitment level than would normally be the case." ●

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BAKKEN Stats

IPs for ND Bakken wells

February 12 – 25, 2013

This chart contains initial production rates, or IPs, for active wells that were filed as completed with the state of North Dakota from Feb. 12 to Feb. 25, 2013 in the Bakken petroleum system, which includes formations such as the Bakken, Three Forks and Birdbear. The completed wells that are missing either haven't been tested or were awarded tight-hole status, so the IP rate is not yet available. This chart also contains a section with active wells that were released from tight-hole status during the same period, Feb. 12 to Feb. 25. The information was assembled by Petroleum News Bakken from daily activity reports from the North Dakota Industrial Commission's Department of Minerals, Oil and Gas Division, website and other sources. The name of the well operator is as it appears in state records, with the loss of an occasional Inc., LLC. or Corporation. Some of the companies, or their Bakken assets, have been acquired by others. In those cases, the current owner is in parenthesis, such as ExxonMobil in parenthesis behind XTO Energy.

LEGEND

The well operator's name is on the upper line, followed by individual wells with data in this order: NDIC file number; well name; field; location; spacing; county, wellbore type; total depth; IP test date; IP oil flow rate. (IP stands for initial production; in this chart it's the first 24 hours of oil production.)

IPs for completed North Dakota wells

BTA Oil Producers
21614; 9215 JV-P Snow-B-1R; Little Knife; SESW 11-143N-98W; SEC; Billings, horizontal; 13570; 4/8/2012; 15 bbl

Continental Resources
21979; Alpha 3-14H; Camp; SWNE 14-152N-100W; 4SEC; McKenzie, horizontal; 19567; 1/19/2013; 338 bbl
23180; Buddy 1-27H; East Fork; NWNE 27-156N-99W; 2SEC; Williams, horizontal; 20692; 1/28/2013; 833 bbl
22720; Grant 1-16H; Corinth; NENW 16-159N-97W; 2SEC; Williams, horizontal; 19491; 11/2/2012; 23 bbl
21977; Florida 3-11H; Camp; SWNE 14-152N-100W; 4SEC; McKenzie, horizontal; 23614; 1/17/2013; 1,016 bbl
23181; Donindgo 1-22H; East Fork; NWNE 27-156N-99W; 2SEC; Williams, horizontal; 21241; 1/13/2013; 318 bbl

Enerplus Resources
22727; Needle 149-93-05AH; Mandaree; LOT1 5-149N-93W; E2; Dunn, horizontal; 15595; 1/18/2013; 664 bbl

Hess
23059; LK-M Elisabeth 147-97-1522H-3; Little Knife; SESW 10-147N-97W; 2SEC; Dunn, horizontal; 21400; 1/24/2013; 664 bbl
23058; LK-M Elisabeth 147-97-1522H-2; Little Knife; SESW 10-147-97W; 2SEC: Dunn, horizontal; 21185; 1/26/2013; 860 bbl

Kodiak Oil and Gas
22660; P Bibler 155-99-15-31-30-2H; Epping; SWSE 31-155N-99W; 2SEC; Williams, horizontal; 20,509; 1/19/2013; 1,554 bbl

Liberty Resources
23534; J. Garvin Jacobson 150-101-8-5-1H; Pronghorn; SESW 8-150N-101W; 2SEC; McKenzie, horizontal; 20,414; 2/12/2013; 589 bbl

Slawson Exploration
21596; Coyote 2-32H; Big Bend; LOT3 5-151N-92W; ICO; Mountrail, horizontal; 15,439; 1/2/2013; 703 bbl

Whiting Oil and Gas
23772; Verne Hagey 13-12TFX; Sanish; NWSW 12-154N-92W; ICO; Mountrail, horizontal; 20,150; 1/21/2013; 531 bbl
23758; Lillian Viola 14-12TFX; Sanish; SWSW 12-154N-92W; ICO; Mountrail, horizontal; 19,137; 1/18/2013; 630 bbl
23562; Roggenbuck Federal 41-24TFX; Sanish; NENE 24-153N-93W; ICO; Mountrail, horizontal; 20,555; 1/18/2013; 1,147 bbl

IPs for ND wells released from tight-hole status

Abraxas Petroleum
22996; Jore Federal 2-11-3H; North Fork; LOT2 2-149N-97W; 2SEC; McKenzie, horizontal; 20,610; 10/24/2012; 761 bbl

Brigham Oil and Gas (Statoil)
23034; Allison 23-14 1H; East Fork; SESW 23-156N-100W; 2SEC; Williams, horizontal; 20,300; 11/22/2012; 2,850 bbl
22929; Vachal 3-34 2TFH; Alger; SWSW 3-155N-93W; 2SEC; Mountrail, horizontal; 20,490; 12/10/2012; 1,898 bbl

Burlington Resources (ConocoPhillips)
22753; Iron Horse 41-2TFH; Union Center; LOT1 2-152N-96W; 2SEC; McKenzie, horizontal; 21,302; 11/1/2012; 1,964 bbl
22791; Morgan 21-28TFH 3NH; Pershing; NENW 28-150N-96W; 4SEC; McKenzie, horizontal; 21,865; 1/10/2013, 2,084 bbl
23030; Walter 31-29MBH; Haystack Butte; NWNE 29-148N-98W; 2SEC; McKenzie, horizontal; 21,261; 12/8/2012; 2,966 bbl
23250; Lovaas 11-1MBH; Blue Buttes; LOT4 1-150N-96W; 2SEC; McKenzie, horizontal; 19,630; 12/16/2012; 2,806 bbl

Continental Resources
22927; Butch 1-29H; Stoneview; NENW 29-161N-94W; 2SEC; Burke, horizontal; 18,800; 12/3/2012; 262 bbl
22812; Flying W 1-25H; Blacktail; NENW 25-144N-99W; 2SEC; Billings, horizontal; 21,050; 12/3/2012; 202 bbl
23086; Norfolk 2-1H; North Tobacco Garden; LOT1 1-151N-99W; 2SEC; McKenzie, horizontal; 20,851; 12/14/2012; 894 bbl
23351; Missoula 2-21H; Camp; SWSW 21-152N-100W; 2SEC; McKenzie, horizontal;20,724; 12/31/2012; 921 bbl
21151; Mack 5-2H; Antelope; LOT2 2-152N-94W; SEC; McKenzie, horizontal; 15,650; 11/9/2012; 446 bbl
23352; Missoula 3-21H; Camp; SWSW 21-152N-100W; 2SEC; McKenzie, horizontal; 20,891; 1/2/2013; 424 bbl
23349; Sverdrup 1-36H; Frazier; SWSE 36-161N-97W; 3SEC; Divide, horizontal; 18,972; 11/2/2012; 743 bbl

EOG Resources
20578; Bear Den 18-21H; Spotted Horn; NWNE 21-150N-94W; 2SEC: McKenzie, horizontal; 15,719; 9/26/2012; 1,667 bbl
20577; Bear Den 19-2116H; Spotted Horn; NWNE 21-150N-94W; 2SEC; McKenzie, horizontal; 16,165; 9/9/2012; 1,886 bbl
21688; Bear Den 103-21H; Spotted Horn; NWNE 21-150N-94W; 2SEC: McKenzie, horizontal; 15,564; 9/26/2012; 957 bbl
22208; Sidonia 45-0409H; Clear Water; LOT4 4-158N-90W; 2SEC; Mountrail, horizontal; 18,499; 8/27/2012; 823 bbl

Enerplus Resources
22748; Chokecherry 149-93-21A-22H; Mandaree; SENE 20-149N-93W; 2SEC; Dunn, horizontal; 21,023; 11/15/2012; 729 bbl
23166; Bullhead 149-93-15D-16H TF; South Fork; NWSE 14-148N-93W; 2SEC; Dunn, horizontal; 20,464; 11/28/2012; 983 bbl

Fidelity Exploration and Production (MDU)
23144; Lee 19-20-29H; Sanish; NENW 19-154N-92W; 4SEC; Mountrail, horizontal; 21,920; 9/3/2012; 484 bbl
22667; O Bach 29-32H; Green River; NENW 29-140N-98W; 2SEC; Stark, horizontal; 20,311; 10/19/2012; 170 bbl

GMX Resources
21544; Akovenko F24-34-2H; Ranch Creek; SESW 34-146N-99W; 2SEC; McKenzie, horizontal; 20,997; 11/5/2012; 2,496 bbl

Hess
23192; Bl-Myrtrice-156-96- 2536H-1; Beaver Lodge; NWNW 25-156N-96W; 2SEC; Williams, horizontal; 19,270; 12/26/2012; 1,085 bbl
23284; En-Belik 156-93-0607H-3; LOT 4 6-156N-93W; 2SEC; Mountrail, horizontal; 19,595; 11/19/2012; 849 bbl
23039; En-Horst S-154-93- 1003H-5; SESW 10-154N-93W; 2SEC; Mountrail, horizontal; 19,294; 12/28/2012; 450 bbl
23040; En-Horst S-154-93- 1003H-6; SESW 10-154N-93W; 2SEC; Mountrail, horizontal; 19,236; 1/6/2013; 521 bbl
23038; En-Horst S-154-93- 1003H-4; SESW 10-154N-93W; 2SEC; Mountrail, horizontal; 16,431; 12/29/2012; 515 bbl

Hunt Oil
23322; Sioux Trail 1-1-12H; LOT2 -160N-101W; Divide, horizontal; Wildcat; 18,496; 12/29/2012; 160 bbl
23323; Alexandria 1-33-28HTF; LOT3 1-160N-101W; Divide, horizontal; Wildcat; 19,472; 1/2/2013; 233 bbl

Kodiak Oil and Gas
22462; Moccasin Creek 16-26-27-12H; Moccasin Creek; SESE 26-148N-93W; 2SEC; Dunn, horizontal; 20,044; 1/5/2013; 1,941 bbl
22465; Moccasin Creek 16-26-27-13H3; Moccasin Creek; SESE 26-148N-93W; 2SEC; Dunn, horizontal; 19,955; 12/21/2012; 2,095 bbl
23390; P Bibler 155-99-15-31-7-15H3; Stockyard Creek; SWSE 31-155N-99W; 2SEC; Williams, horizontal; 21,399; 1/22/2013; 1,521 bbl
19962; P State 154-97-3-16-21-13H3; Truax, NENW 16-154N-97W; 2SEC; Williams, horizontal; 20,178; 12/23/2012; 2,059 bbl
21391; Smokey 15-7-6-2H; Pembroke; SWSE 7-149N-98W; 2SEC; McKenzie, horizontal; 20,810; 12/6/2012; 1,500 bbl

Legacy Oil and Gas
21887; Legacy Etal Berntein 13-7H; Red Rock; SWSW 7-163N-76W; S2; Bottineau, horizontal; 7,150; 11/4/2012; 182 bbl
21922; Legacy Etal Bernstein 13-17H; Red Rock; SWSW 17-163N-76W; S2; Bottineau, horizontal; 7,038; 10/26/2012; 94 bbl

Liberty Resources
22401; Likenbill 155-101-11-2-1H; Cow Creek; SWSE 11-155N-101W; 2SEC; Williams, horizontal; 20,715; 9/17/2012; 876 bbl
21680; Nygaard 150-101-28-33-1H; Pronghorn; NWNE 28-150N-101W; 2SEC; McKenzie, horizontal; 20,860; 9/4/2012; 800 bbl

Marathon Oil
22911; Pearl 41-13H; Big Bend; SWSE 22-144N-96W; 2SEC; Mountrail, horizontal; 20,352; 10/23/2012; 1,538 bbl
23106; Schmalz 34-22H; Murhy Creek; SWSE 22-144N-96W; 2SEC; Dunn, horizontal; 20,525; 11/6/2012; 1,047 bbl

Newfield Production
23275; Darlene Federal 152-97-13-24-2H; Westberg; NENE 13-152N-97W; 2SEC; McKenzie, horizontal; 20,625; 1/14/2013; 2,102 bbl
23277; Darlene Federal 152-97-13-24-3H; Westberg; NWNE 13-152N-97W; 2SEC; McKenzie, horizontal; 1/10/2013; 2,000 bbl
23276; Darlene Federal 152-97-13-24-10H; Westberg; NWNE 13-152N-97W; 2SEC; McKenzie, horizontal; 19,920; 1/9/2013; 921 bbl
23207; Orvis State 150-99-21-16-2H; South Tobacco Garden; SESE 21-150N-99W; 2SEC; McKenzie, horizontal; 20,707; 10/4/2012; 1,539 bbl

Oasis Petroleum
22347; Basey 5300 44-12T; Crazy Man Creek; SESE 12-153N-100W; 2SEC; Williams, horizontal; 21,050; 9/10/2012; 2,621 bbl
22304; Celia S 5300 41-12T; Crazy Man Creek; SWSW 12-153N-100W; 2SEC; Williams, horizontal; 20,891; 10/12/2012; 1,364 bbl
22348; Kovars 5300 44-12B; Crazy Man Creek; SESE 12-153N-100W; 2SEC; Williams, horizontal; 20,950; 9/20/2012; 2,661 bbl
22303; Thomas S 5300 41-12B; Crazy Man Creek; SWSW 12-153N-100W; 2SEC; Williams, horizontal; 20,870; 10/2/2012; 1,952 bbl

Oxy USA
21913; Bill Cody 1-20-29H-141-96; St. Anthony; NWNE 20-141N-96W; 2SEC; Dunn, horizontal; 20,290; 8/5/2012; 138 bbl
22150; Richard Jablonsky 1-13-24-141-97; SWSE 12-141N-97W; 2SEC; Dunn, horizontal; 20,245; 8/24/2012; 503 bbl
22519; Ward Lake 1-5-6H-160-91; Dimond; NENE 5-160N-91W; 2SEC; Burke, horizontal; 17,900; 6/28/2012; 10 bbl

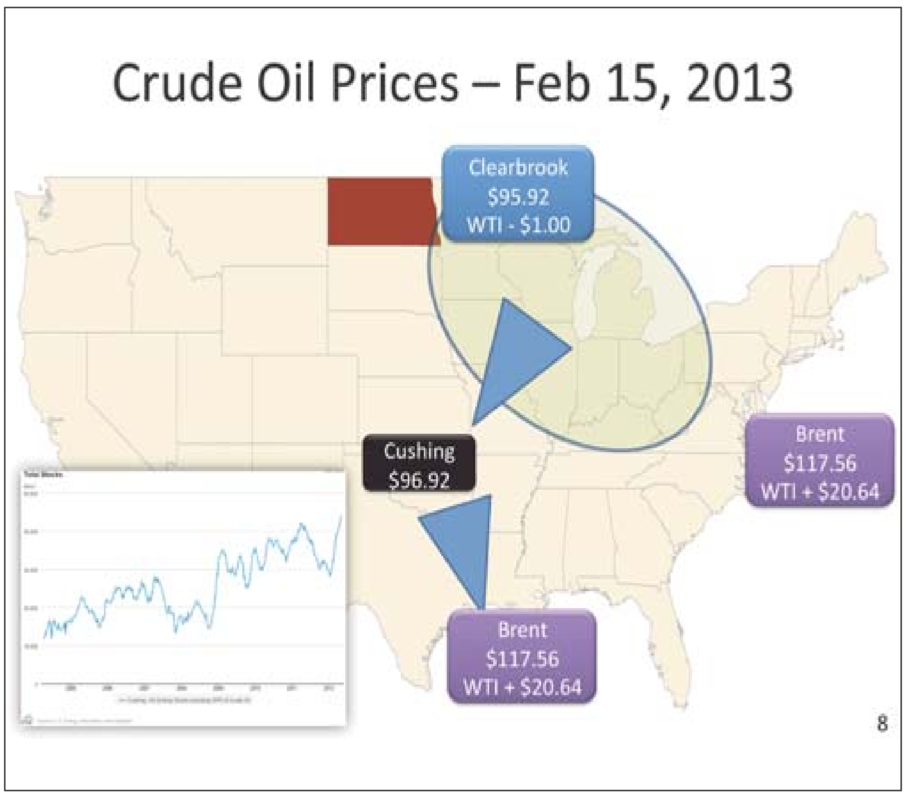
QEP Energy
22028; MHA 2-32-29H-150-91; Heart Butte; SESW 32-150N-91W; ICO; Dunn, horizontal; 20,100; 11/26/2012; 2,737 bbl
22372; P. Levang 4-14/23H; Blue Buttes; NWNW 14-150N-95W; 2SEC; McKenzie, horizontal; 20,720; 11/15/2012; 1,734 bbl

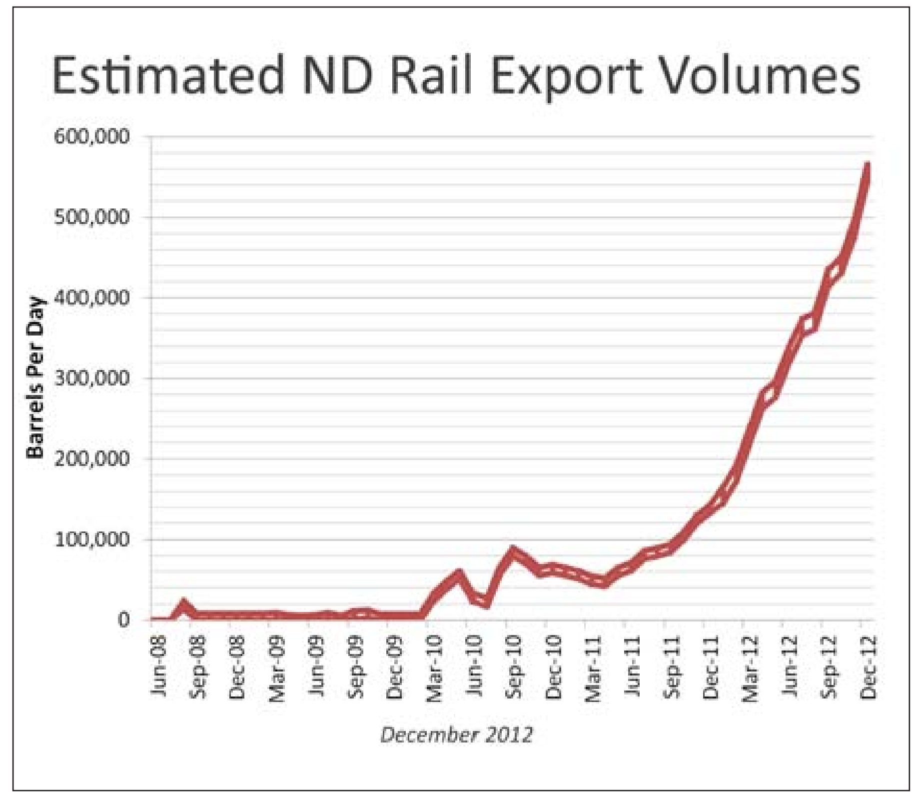
see **ND IPS** *page 14*

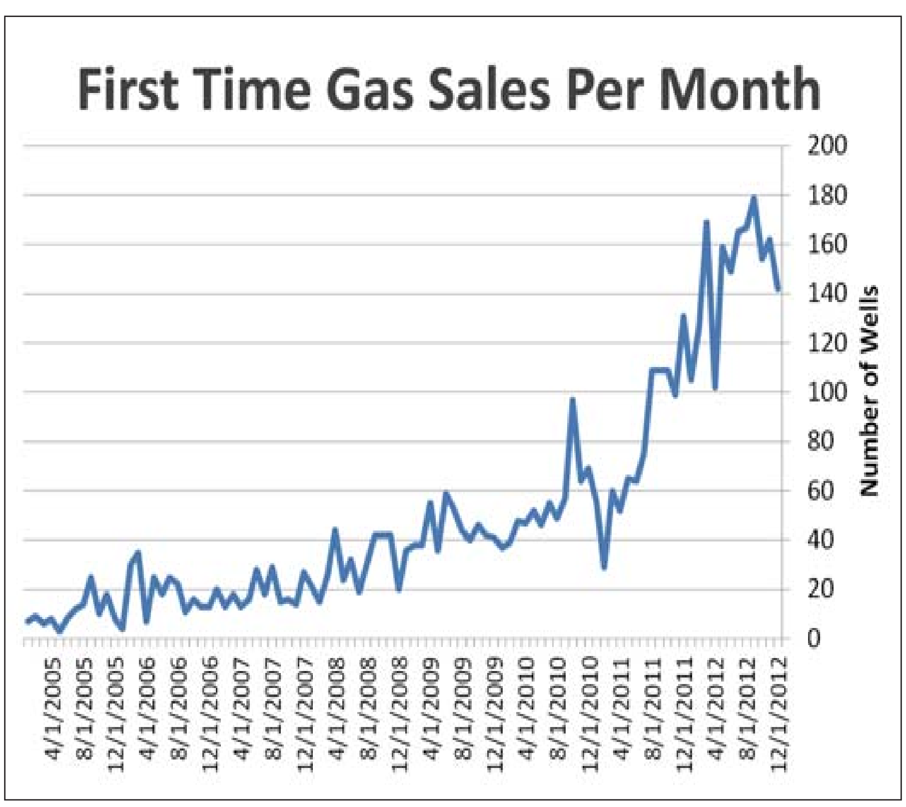
Petroleum News Bakken

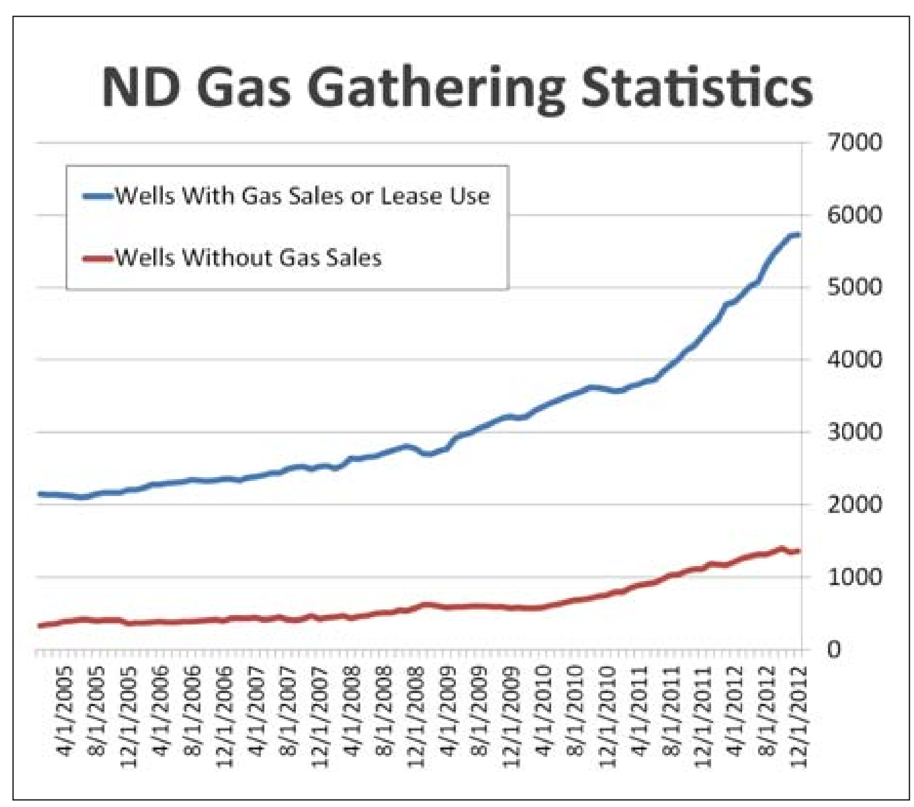
North Dakota Pipeline Authority

Monthly update February 15, 2013









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ND IPS

Samson Resources (KKR & Co.)
23509; Nomad 0607-2TFH; West Ambrose; LOT4 6-163N-99W; 4SEC; Divide, horizontal; 17,791; 12/14/2012; 770 bbl
23508; Nomad 0607-1H; West Ambrose; LOT 4 6-163N-99W; 4SEC; Divide, horizontal; 17,779; 12/12/2012; 669 bbl

Sequel Energy
21022; Louie 24-24H-2536-16095-MB; North Tioga; SESW 24-160N-95W; 2SEC; Divide, horizontal; 19,406; 11/17/2012; 573 bbl

Slawson Exploration
21427; Sniper Federal 2-6-7H; Big Bend; NENW 6-151N-92W; 2SEC; Mountrail, horizontal; 20,256; 10/25/2012; 1,502 bbl
23105; Lunker Federal 2-33-4H; Van Hook; NWNW 33-152N-91W; 2SEC; Mountrail, horizontal; 19,536; 10/25/2012; 778 bbl

SM Energy
23348; August 4-26HN; Colgan; NWNW 26-163N-101W; 2SEC; Divide, horizontal; 18,506; 10/16/2012; 385 bbl

Triangle USA Petroleum
22625; Triangle 149-101-1-12-1H; Antelope Crek; SESW 36-150N-101W; 2SEC; McKenzie, horizontal; 21,615; 1/18/2013; 638 bbl
22627; Triangle 149-101-1-12-3H; Antelope Creek; SESW 36-150N-101W; 2SEC; McKenzie, horizontal; 21,440; 1/17/2013; 551 bbl

True Oil
23406; Hagen Federal 41-25 25-30H; NENE 25-148N-101W; ICO; McKenzie, horizontal; 14,198; 1/4/2013; 57 bbl

Whiting Oil and Gas
21077; BSMU 1707; Big Stick; NESW 17-142N-100W; U; Billings, directional; 9524; 11/12/2012; 0 bbl
22947; Norgard 41-14H; Ellsworth; NENE 14-149N-100W; 2SEC; McKenzie, horizontal; 20,975; 8/23/2012; 1,648 bbl

WPX Energy
22651; Charles Blackhawk 31-30HB; Heart Butte; SESW 31-148N-92W; 2SEC; Dunn, horizontal; 19,042; 11/21/2012; 219 bbl
23216; Corn Stalk 20HC; Squaw Creek; NWSW 20-149N-94W; S2; McKenzie, horizontal; 15,618; 1/13/2013; 783 bbl
23254; Coyote Necklace 24HD; Reunion Bay; SWSE 13-150N-93W; ICO; Mountrail, horizontal; 15,710; 10/2/2012; 494 bbl

XTO Energy (ExxonMobil)
22275; Rose Federal 34X-34C; West Capa; SWSE 34-155N-97W; 2SEC; Williams, horizontal; 20,574; 1/13/2013; 1,672 bbl
23431; Flatland 11X-2E; Sand Creek; LOT 4 2-153N-97W; 2SEC; McKenzie, horizontal; 20,509; 11/7/2012; 1,464 bbl
23404; Unni 21X-27B; Midway; NENW 27-157N-96W; 2SEC; Williams, horizontal; 19,957; 12/10/2012; 856 bbl

—Compiled by Kay Cashman

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MT weekly oil activity reports, Feb. 8 – Feb. 21

COMPILED BY DARRYL L. FLOWERS
For Petroleum News Bakken

Week of 2/8 to 2/14

New locations — horizontal wells

In Richland County, Continental Resources Inc. was approved for the Fabian Federal 1-10H. The Bakken formation well has a SHL at SW SW 10-26N-55E (275 FSL/1260 FWL) and a PBHL of 20,104 feet at NE NW 3-26N-55E (200 FNL/1980 FWL).

Completions

Slawson Exploration Co. Inc. reported the completion of two Richland County wells, both tapping into the Bakken formation. The Villain 1-12H, with an SHL at NE NE 12-23N-52E (200 FNL/920 FEL) and a single lateral of 13,462 feet at SE SE 12-23N-52E (680 FSL/717 FEL), reported an IP of 344 BOPD, 371 MCFPD and 147 BWPD. The Rogue 1-36H, with an SHL at SE SE 36-24N-52E (550 FSL/800 FEL) and a BHL of 13,429 feet at NE NE 36-24N-52E (250 FNL/808 FEL) turned in an IP of 220 BOPD, 242 MCFPD and 30 BWPD.

In Roosevelt County, Brigham Oil & Gas LP turned in a completion report for the Crusch 12-1 1H. The Bakken formation well has an SHL at SW SE 12-28N-58E (300 FSL/1400 FEL) and a BHL of 20,172 feet at NW NE 1-28N-58E (235 FNL/1759 FEL). The Crusch turned in an IP of 973 BOPD, 719 MCFPD and 5,953 BWPD.

Week of 2/15 to 2/21

New locations — horizontal wells

Three new wells were approved in Richland County. Whiting Oil and Gas Corp. was given the go-ahead for two wells: the Sundheim 31-2-1H, with a SHL at NE 2-25N-57E (280 FNL/2400 FEL) and a PBHL of 21,148 feet at SW SW 11-25N-57E (240 FSL/660 FWL) and the Skov 31-28-1H, with an SHL at NW NE 28-25N-59E (281 FNL/1735 FEL) and a PBHL of 21,789 feet at SW SW 33-25N-59E (240 FSL/660 FWL). Slawson Exploration Co. Inc. was green lighted for the Python 3-4MLH. The well has an SHL at SW SW 4-23N-53E (279 FSL/350 FWL) and has two laterals, with PBHLs of 14,027 feet at SE SE 4-23N-53E (250 FSL/750 FEL) and 14,022 feet at NW NW 4-23N-53E (250 FNL/750 FWL).

In Sheridan County, Epyon Oil Inc. won approval for the Bubba 3558 41-24H. The Bubba has an SHL at SW SW 24-35N-58E (250 FSL/250 FWL) and a PBHL of 15,831 feet at NE 24-35N-58E (250 FNL/550 FEL).

All of the horizontal wells will target the Bakken formation.

Re-issued locations

In Rosebud County, a permit was issued to Fidelity Exploration & Production Co. for the Grebe 24-28H. The Heath formation well has an SHL at NW NE 33-11N-33E (242 FNL/2281 FEL) and a PBHL of 10,452 feet at NW NW 28-11N-33E (330 FNL/330 FWL).

Permit modifications/corrections

In Richland County, Continental Resources Inc. was approved for a Permit Modification / Correction on the Earl-Reimann 4 HSU. The well has an SHL at SE SE 14-23N-55E (240 FSL/298 FEL) and a PBHL of 20,606 feet at EL SE 26-23N-55E (200 FSL/0 FEL. The target is the Bakken formation.

Completions

In Petroleum County, Central Montana Resources LLC turned in a completion report for the Snowmane 6. The well, which taps into the Heath formation, is located at NE NW 8-13N-29E (710 FNL/1933 FWL) and has a TD of 4,244 feet. The well reported an IP of 125 BWPD.

Abbreviations & parameters

With a few exceptions, the Montana weekly oil activity report includes horizontal well activity in the Bakken petroleum system in the eastern/northeastern part of the state within the Williston Basin. It also includes what is referred to as the South Alberta Bakken fairway in northwestern/west-central Montana, which is at least 175 miles long (north-south) and 50 miles wide (east-west), extending from southern Alberta, where the formation is generally referred to as the Exshaw, southwards through Montana's Glacier, Toole, Pondera, Teton and Lewis & Clark counties. The Southern Alberta Bakken, under evaluation by several oil companies, is not part of the Williston Basin.

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

In Richland County, Whiting Oil and Gas Corp. reported the completion of three Bakken formation wells. The Double Bar M 24-32H has an SHL at SE SW 32-27N-57E (310 FSL/2280 FWL) and a BHL of 20,031 feet at NE NW 29-27N-57E (244 FNL/1985 FWL). The Double Bar reported an IP of 375 BOPD; 233 MCFPD and 320 BWPD. The Kittleson Federal 34-23-1H has an SHL at SW SE 23-26N-57E (840 FSL/1645 FEL) and a BHL of 21,554 feet at NW NW 14-26N-57E (243 FNL/613 FWL). The Kittleson reported an IP of 564 BOPD, 128 MCFPD and 933 BWPD. The Kittleson Federal 24-24-1H, with an SHL at SE SW 24-26N-57E (583 FSL/1545 FWL) and a BHL of 19,135 feet at NW NW 13-26N-57E (1169 FNL/640 FWL). The well reported an IP of 558 BOPD, 45 MCFPD and 1,451 BWPD.

Continental Resources Inc. reported the completion of the Helen 3-19H in Richland County. The well has an SHL at SE SW 19-25N-55E (270 FSL/2450 FWL) and a BHL of 19,675 feet at NW NE 18-25N-55E (232 FNL/2654 FWL). The reported IP was 642 BOPD, 342 MCFPD and 459 BWPD. The well targets the Bakken formation. ●

Petroleum News Bakken

North Dakota well operator transfers

February 14 – 22, 2013

LEGEND
Date of well operator transfer
Well(s) transferred from
Well(s) transferred to
NDIC well file number — well name — well type — pool — field — IP (initial production) test date — IP oil rate in barrels — location — county

February 20, 2013

From: BTA Oil Producers, LLC
To: Petro-Hunt, LLC
15917 - 20411 JV-P Koufax 1423, horizontal , Bakken, Stoneview, 12-5-05, 32 bbl, NENW 14-160N-95W, Divide Co.
15846 - 20501 JV-P Battleview 1621 1-H, horizontal, Bakken, North Tioga, 11-21-05, 118 bbl, NENW 16-159N-94W, Burke Co.
15755 - 20411 JV-P Melgaard 211 1-H, horizontal, Bakken, Stoneview, 7-8-05, 190 bbl, NWNW 2-160N-95W, Divide Co.

February 20, 2013

From : Phillip D. Armstrong
To: Ballantyne Oil, LLC
90054 - Kjonaas 1 SWD, vertical, Dakota, Glenburn, (no IP info. listed, drilled to 3,200 feet, completed 1983, saltwater disposal), NENW 30-158N-81W, Renville Co.
08383 - Kjonaas-Baker 4, vertical, Madison, Glenburn, 6-5-81, 43 bbl, SENW 30-158N-81W, Renville Co.
07617 - Colcord Estate 4, vertical, Madison, Glenburn, 6-22-80, 43 bbl, NWNE 25-158N-82W, Renville Co.
07582 - Colcord Estate 3, vertical, Madison, Glenburn, 6-19-80, 60 bbl, SENE 25-158N-82W, Renville Co.
07581 - Kjonaas-Baker 3, vertical, Madison, Glenburn, 6-21-80, 83 bbl, NWNW 30-158N-81W, Renville Co.
04405 - Colcord Estate 2, vertical, Madison, Glenburn, 4-16-68, 108 bbl, SWNE 25-158N-82W, Renville Co.
04398 - Colcord Estate 1, vertical, Madison, Glenburn, 4-16-68, 125 bbl, NENE 25-158N-82W, Renville Co.
04393 - Kjonaas-Baker 2, vertical, Madison, Glenburn, 4-14-68, 72 bbl, SWNW 30-158N-81W, Renville Co.
04354 - Kjonaas-Baker 1, vertical, Madison, Glenburn, 12-5-67, 83 bbl, NENW 30-158N-81W, Renville Co.

Note: The information in this chart was compiled by Petroleum News Bakken from the online daily activity reports of the North Dakota Industrial Commission, or NDIC. The operator names in this report are as they appear in State of North Dakota records, even though some of the companies, or their Bakken assets, might have been purchased by other companies. XTO Energy, for example, is now a subsidiary of ExxonMobil.

Petroleum News Bakken

North Dakota Bakken oil production by company

December 2012

Derived from the preliminary December 2012 Oil & Gas Production Report published by the North Dakota State Industrial Commission, Department of Minerals, Oil and 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 and other formations within the system) that is owned by each company or its partners, so it may differ from what each company reports. Also, the daily average was derived from dividing the total production by the number of days in December, versus the number of days the well was actually producing. There are a few wells that did not produce for the entire month.

LEGEND
Field - pool - county - daily average barrels of oil
Daily average barrels for all fields combined

Also note: The operator names used in this chart are exactly as they appear in State of North Dakota Oil & Gas Division records, but some of the companies and/or their Bakken assets might have been acquired by others. The ones we caught were Burlington Resources Oil & Gas Company, LP, which is owned by Conoco Phillips; Brigham Oil & Gas, L.P., owned by Statoil; XTO Energy, Inc., owned by ExxonMobil, and Samson Resources Company, owned by KKR & Co. Please let us know if you see any others by emailing Kay Cashman at publisher@petroleumnews.com.

Abraxas Petroleum Corp

Demores - Bakken - Billings	398
North Fork - Bakken - McKenzie	7,242
Roosevelt - Bakken - Billings	588

Daily average 265.4

American Eagle Energy Corporation

Colgan - Bakken - Divide	34,666

Daily average 1,118.3

Arsenal Energy USA, Inc.

Stanley - Bakken - Mountrail	23,860

Daily average 769.7

Baytex Energy USA Ltd

Ambrose - Bakken - Divide	35,983
Blooming Prairie - Bakken - Divide	5,158
Burg - Bakken - Divide/Williams	2,171
Garnet - Bakken - Divide	4,707
Lone Tree - Bakken - Williams	3,854
Lone Tree Lake - Bakken - Williams	2,273
Moraine - Bakken - Divide	1,902
Musta - Bakken - Divide	2,242
Plumer - Bakken - Divide	7,324
Skabo - Bakken - Divide	1,193
Smoky Butte - Bakken - Divide	4,988
West Ambrose - Bakken - Divide	17,410
Whiteaker - Bakken - Divide	20,196
Wildcat - Bakken - Williams	2,282

Daily average 3,602.7

Brigham Oil & Gas, LP (Statoil)

Alexander - Bakken - McKenzie	15,289
Alger - Bakken - Mountrail	565,112
Avoca - Bakken - Williams	11,443
Banks - Bakken - McKenzie	134,579
Briar Creek - Bakken - McKenzie	15,652
Buford - Bakken - Williams	3,939
Bull Butte - Bakken - Williams	31,688
Camp - Bakken - McKenzie	63,061
Catwalk - Bakken - Williams	11,425
Cow Creek - Bakken - Williams	32,043
East Fork - Bakken - Williams	84,145
Elk - Bakken - McKenzie	37,449
Foreman Butte - Bakken - McKenzie	6,564
Glass Bluff - Bakken - McKenzie	2,106
Kittleson Slough - Bakken - Mountrail	8,545
Lake Trenton - Bakken - Williams	3,806
Last Chance - Bakken - Williams	22,264
Nameless - Bakken - McKenzie	6,618
Painted Woods - Bakken - Williams	61,533
Parshall - Bakken - Mountrail	403
Patent Gate - Bakken - McKenzie	5,611
Poe - Bakken - McKenzie	21,366
Ragged Butte - Bakken - McKenzie	46,109
Rosebud - Bakken - Williams	9,873
Ross - Bakken - Mountrail	254
Sakakawea - Bakken - McKenzie	5,866
Sandrocks - Bakken - McKenzie	12,860
Spring Creek - Bakken - McKenzie	7,147
Squires - Bakken - Williams	38,973
Stony Creek - Bakken - Williams	74,179
Sugar Beet - Bakken - Williams	10,525
Todd - Bakken - Williams	172,636
Wildcat - Bakken - McKenzie/Williams	4,420
Williston - Bakken - Williams	32,577

Daily average 50,324.5

BTA Oil Producers, LLC

Bicentennial - Bakken - Golden Valley	221
Elkhorn Ranch - Bakken - Billings	40
North Tioga - Bakken - Burke	123
Pierre Creek - Bakken - McKenzie	168
Stoneview - Bakken - Divide	1,059

Daily average 52.0

Burlington Resources Oil & Gas Company, LP (ConocoPhillips)

Bailey - Bakken - Dunn	24,512
Banks - Bakken - McKenzie	10,559
Bennett Creek - Bakken - McKenzie	1,162
Blue Buttes - Bakken - McKenzie	50,450
Bully - Bakken - McKenzie	4,852
Cabernet - Bakken - Dunn	14,521
Camel Butte - Bakken - McKenzie	17,602
Charlson - Bakken - McKenzie	23,001
Clear Creek - Bakken - McKenzie	8,492
Corral Creek - Bakken - Dunn	29,357
Croff - Bakken - McKenzie	6,404
Crooked Creek - Bakken - Dunn	6,343
Dimmick Lake - Bakken - McKenzie	4,259
Elidah - Bakken - McKenzie	36,605
Fayette - Bakken - Dunn	4,042
Hawkeye - Bakken - McKenzie	8,766
Haystack Butte - Bakken - McKenzie	77,044
Jim Creek - Bakken - Dunn	5,146
Johnson Corner - Bakken - McKenzie	6,846
Keene - Bakken/Three Forks - McKenzie	55,655
Killdeer - Bakken - Dunn	7,723
Little Knife - Bakken - Dunn	39,987
Lone Butte - Bakken - Dunn	2,181
Mondak - Bakken - McKenzie	2
Morgan Draw - Bakken - Golden Valley	599
Murphy Creek - Bakken - Dunn	43,823
North Fork - Bakken - McKenzie	9,406
Pershing - Bakken - McKenzie	4,411
Pierre Creek - Bakken - McKenzie	2
Sand Creek - Bakken - McKenzie	33,750
Twin Valley - Bakken - McKenzie	627
Union Center - Bakken - McKenzie	55,464
Westberg - Bakken - McKenzie	16,921
Wildcat - Bakken - McKenzie	0
Willmen - Bakken - Dunn	3,211

Daily average 19,797.6

Carl H. Nordstrand

Pierre Creek - Bakken - McKenzie	104

Daily average 3.4

Charger Resources, LLC

Buckhorn - Bakken - McKenzie	118
Johnson Corner - Bakken - McKenzie	164
Morgan Draw - Bakken - Golden Valley	188
Pierre Creek - Bakken - McKenzie	0

Daily average 15.2

Chesapeake Operating, Inc.

Wildcat - Bakken/Three Forks - Stark/Golden Valley	0

To view this chart in its entirety, please visit: http://bit.ly/12Z30Qf

Petroleum News Bakken

Looking for a rig report?

Montana
Drilling Ahead at **www.drillingahead.com/USARigReport** offers a U.S. Drilling Rig Report that includes Montana.

North Dakota
The best list for North Dakota is updated daily by the North Dakota Oil and Gas Division at **www.dmr.nd.gov/oilgas/riglist.asp**

Saskatchewan
Weekly drilling activity report from the government of Saskatchewan:
www.economy.gov.sk.ca/Daily-Well-Bulletin-Weekly-Drilling-Reports

Manitoba
Weekly drilling activity report from the government of Manitoba:
www.manitoba.ca/iem/petroleum/wwar/index.html


PHOTO COURTESY CONTINENTAL RESOURCES

Petroleum News Bakken

Bakken producers' stock prices

Closing prices as of Feb. 27, along with those from previous Wednesday

Company	Exchange	Symbol	Closing price	Previous Wed.
Abraxas Petroleum Corp.	NASDAQ	AXAS	$2.00	$2.12
Arsenal Energy USA, Inc.	TSE	AEI	$0.54	$0.60
Baytex Energy Corp.	NYSE	BTE	$42.20	$42.80
Brigham Exploration Co. (Statoil)	NYSE	STO	$25.34	$25.65
Burlington Resources Co. (ConocoPhillips)	NYSE	COP	$58.04	$57.67
Continental Resources, Inc.	NYSE	CLR	$83.97	$82.43
Crescent Point Energy Corp.	TSE	CPG	$38.80	$38.72
Enerplus Resources USA Corp.	NYSE	ERF	$13.32	$12.35
EOG Resources, Inc.	NYSE	EOG	$126.92	$127.39
Fidelity Exploration & Production (MDU)	NYSE	MDU	$23.97	$24.06
G3 Operating LLC (Halcon Resources Corp.)	NYSE	HK	$7.16	$7.27
GMX Resources, Inc.	NYSE	GMXR	$2.21	$2.80
Hess Corp.	NYSE	HES	$65.68	$66.01
Kodiak Oil & Gas (USA), Inc.	NYSE	KOG	$8.83	$9.00
Legacy Reserves Operating LP	NASDAQ	LGCY	$26.17	$26.27
Marathon Oil Company	NYSE	MRO	$33.42	$34.57
Newfield Production Company	NYSE	NFX	$23.24	$24.75
Oasis Petroleum, Inc.	NYSE	OAS	$35.98	$36.06
OXY USA (Occidental Petroleum Corp.)	NYSE	OXY	$82.23	$84.51
QEP Resources, Inc.	NYSE	QEP	$30.88	$29.98
Resolute (Resolute Energy Corp.)	NYSE	REN	$9.53	$9.53
Samson Resources Company (KKR & Co.)	NYSE	KKR	$18.02	$17.58
SM Energy Company	NYSE	SM	$59.03	$58.32
Triangle USA Petroleum Corp.	NYSE	TPLM	$6.48	$6.77
Whiting Oil and Gas Corp.	NYSE	WLL	$49.16	$48.59
WPX Energy, Inc.	NYSE	WPX	$14.50	$14.90
XTO Energy, Inc. (ExxonMobil)	NYSE	XOM	$89.53	$88.97

continued from page 1

BAKKEN SPENDING

Whiting, which averaged 66,156 barrels of oil per day in December from wells it operates, expects its capital expenditures to be about the same in 2013 as they were last year.

It allocated $1.142 billion for the "Northern Rockies," which includes the western and southern Williston Basin, the Sanish field and Red River units. The number excludes, however, company-wide exploration spending of $82 million, facilities investment of $178 million and $150 million for well work, some of which will make its way to the Bakken.

Whiting is looking at drilling 148 wells in 2013 and is currently running 17 drilling rigs in the region.

And what are the expectations of the company's leadership?

Praising three Williston Basin prospects for generating "excellent results" in 2012, Whiting's Chairman and CEO James J. Volker said Feb. 27, "For the foreseeable future, our objective is to generate double-digit production growth while spending close to our discretionary cash flow. Our 2013 capital budget of $2.2 billion (company-wide) is expected to yield year-over-year production growth in the 12 percent to 16 percent range."

How can you spend the same and get more? The standard answer is that Bakken has moved into development mode, drilling and completion costs have come down and Bakken oil prices are expected to get stronger as differentials improve.

Continental spending more

Continental, which averaged 65,141 barrels of oil daily from the wells it operates in North Dakota, is looking at increasing its capital expenditures for the Bakken.

Its 2013 capex is set at $2.622 billion, with $2.1 billion for North Dakota, $427 million for Montana, plus $63 million for its Red River units.

The company's 2012 capex was about $2.25 billion.

Approximately 18 percent of the wells Continental operated and completed in 2012 were drilled from ECO-Pads. At Feb. 15, 67 percent of its 21 operated rigs in the Bakken were capable of ECO-Pad drilling and 14 rigs were actively drilling pad locations.

In 2013 it expects to drill 226.2 net wells. In 2012 it completed 173 net wells and drilled 204 net wells.

Hess spending a lot less

Hess, which averaged 64,657 barrels of oil per day from wells it operated in North Dakota in December, has set its Bakken capex at $2.2 billion, which is a whopping 29 percent down from 2012 when it was $3.1 billion.

But Hess executives are quick to point out that they drove drilling and completion costs down by more than 30 percent in 2012.

In 2012, the company completed 206 net wells, but actually drilled 176 net wells.

In 2013, it plans to drill 185 net wells but complete 175 of them.

Currently, the company has 15 rigs in the basin.

In a Jan. 30 conference call with analysts, John B. Hess, chairman and chief executive officer, said North Dakota Bakken net production averaged 56,000 barrels of oil equivalent per day in 2012, and is likely to average between 64,000 and 70,000 boe per day in 2013.

"We have built a strong position in the Bakken, which is arguably one of the best shale oil plays in the world," he said.

Statoil, EOG both spending more

The next two ranking Bakken producers by operated wells are EOG Resources and Statoil, owner of Brigham Oil & Gas.

Their production — averaging 50,326 barrels of oil per day for Statoil and 46,091 barrels for EOG — combined with the Big Three, represents almost 40 percent of the oil from North Dakota's Bakken system.

Both companies plan to spend more in the region in 2013; and they are expecting an increase in production.

Together with the top five, the next 20 companies produce nearly 75 percent of the oil from the Bakken. All but three responded, and their comments ranged from "We can't tell you, we're privately owned," to "We don't break out our Bakken numbers," to "same" or "up" from 2012. Only two firm's financials showed they planned to spend less in 2012.

Even those that were privately owned or don't break out Bakken capex, were mostly upbeat about their plans.

So although it was not a perfect score for the optimists, our assessment is that they prevailed. Investment in the region is still strong. ●

Contact Kay Cashman at publisher@petroleumnews.com

IN OTHER NEWS

What makes the Bakken the best?

Aimee Duffy and Tyler Crowe talk about the Bakken play in a Feb. 25 video featured on The Motley Fool website.

EOG Resources top executive, Mark Papa, predicts that the Eagle Ford will overtake the Bakken in production in two years, says the introduction to the video.

Crowe disagrees with Papa, citing the 225,000-barrel increase in Bakken production per day in 2012. The Eagle Ford only produces 350,000 barrels per day, so it has a ways to go to catch up to the Bakken, contends.

Although a 2008 USGS study estimated the Bakken's recoverable reserves at 5 billion barrels, the CEO of the American Petroleum Institute recently estimated that there are 20 billion barrels in the Bakken, the piece says, continuing: "Takeaway capacity and problems with low prices are limiting proven reserves in the Bakken, but the Enbridge mainline extension with a Bakken spur will provide pipeline capacity, as will the Keystone XL pipeline from Canada. Rail investments, such as those spearheaded by EOG Resources, are additional positive signs. Note that reserves can only be proven when they are commercially viable. Better takeaway capacity should bump prices up and hence bump reserves up, too."

Furthermore, Crowe notes, "if Valero, Tesoro, and Phillips 66 have their way with their rail investments," Bakken oil may "supplant" pricier Alaska and Brent crude in both East Coast and West Coast refineries.

In short, "the Bakken is a beast."

Read more here: http://bit.ly/XBopbu

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Its purpose, per its website: To Help The World Invest. Better.

Its core value: Be Foolish!

Petroleum News Bakken

December 2012

Top 50 North Dakota Bakken oil producers

Company	BDP*
1 Whiting Oil and Gas Corporation	66,155.7
2 Continental Resources, Inc.	65,141.2
3 Hess Corporation	64,656.7
4 Brigham Oil & Gas, LP (Statoil)	50,324.5
5 EOG Resources, Inc.	46,090.9
6 XTO Energy Inc. (ExxonMobil)	33,148.2
7 Marathon Oil Company	31,194.4
8 Petro-Hunt, LLC	25,743.0
9 Slawson Exploration Company, Inc.	21,058.4
10 Kodiak Oil & Gas (USA), Inc.	20,423.0
11 Oasis Petroleum North America LLC	20,012.6
12 Burlington Resources (ConocoPhillips)	19,797.6
13 QEP Energy Company	17,520.7
14 WPX Energy Williston, LLC	17,043.4
15 Oxy USA, Inc.	15,187.3
16 SM Energy Company	12,664.5
17 Zavanna, LLC	10,990.8
18 Enerplus Resources USA Corporation	10,567.8
19 Hunt Oil Company	9,954.9
20 Newfield Production Company	9,437.4
21 Murex Petroleum Corporation	8,509.4
22 Zenergy, Inc.	7,931.7
23 Fidelity Exploration & Production (MDU)	7,801.2
24 Samson Resources Company (KKR & Co.)	7,574.2
25 Baytex Energy USA Ltd	3,602.7
26 Liberty Resources, LLC	3,416.0
27 G3 Operating, LLC (GeoResources)	3,000.3
28 Crescent Point Energy US Corp.	2,858.6
29 Sinclair Oil and Gas Company	2,051.6
30 Triangle USA Petroleum Corporation	1,581.0
31 Cornerstone Natural Resources, LLC	1,454.2
32 American Eagle Energy Corporation	1,118.3
33 Arsenal Energy USA, Inc.	769.7
34 True Oil, LLC	609.6
35 GMX Resources, Inc.	447.3
36 Sequel Energy, LLC	291.7
37 Abraxas Petroleum Corp	265.4
38 Windsor Energy Group, LLC	230.9
39 Gadeco, LLC	220.7
40 Resolute Natural Resources Company, LLC	190.5
41 Resource Drilling, LLC	176.3
42 Legacy Reserves Operating LP	131.1
43 Prima Exploration, Inc.	113.9
44 SHD Oil & Gas, LLC	94.2
45 BTA Oil Producers, LLC	52.0
46 Petro Havester Operating Company, LLC	43.8
47 Texakota, Inc.	42.9
48 Encore Energy Partners Operating, LLC	17.8
49 Peregrine Petroleum Partners, LTD	16.5
50 Charger Resources, LLC	15.2

*Barrels of oil per day

Numbers derived from the preliminary December 2012 Oil & Gas Production Report published by the North Dakota State Industrial Commission, Department of Minerals, Oil and 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.

● DRILLING & COMPLETION

Bakken Hunter leads for Feb. spacing units

Sizes run the gamut from 2,560 acres down to 160; well densities range from one per 2,560 acres to as high as 16 per 1,280

By MIKE ELLERD

For Petroleum News Bakken

The North Dakota Industrial Commission received numerous requests for the establishment of new drill spacing units that are on the commission's February hearing docket, and the requests were led by Bakken Hunter LLC, Continental Resources and Burlington Resources. Combined, these three companies are asking for more than 50 new spacing units of varying acreages, although numerous other Williston Basin operators are also seeking new spacing units from NDIC. The hearings were scheduled for Feb. 27 and 28.

Seeking the most new spacing units was Bakken Hunter, a wholly owned subsidiary of Magnum Hunter Resources Corp., which is requesting the commission establish a total of 23 new spacing units, all in the Bounty School-Bakken field in Divide County.

Bakken Hunter

Seeking the most new spacing units was Bakken Hunter, a wholly owned subsidiary of Magnum Hunter Resources Corp., which is requesting the commission establish a total of 23 new spacing units, all in the Bounty School-Bakken field in Divide County. Of these 23 new spacing units, 13 are 640-acre units and the remaining 10 are 1,280-acre units. Bakken Hunter is also seeking permission to install up to eight horizontal wells on the 640-acre spacing units and up to 16 horizontal wells on the 1,280 acre units.

Continental Resources

In the Stoneview, Sauk and Oliver-Bakken fields in Divide and Williams counties, Continental Resources is asking that the commission establish three overlapping 2,560-acre units on which it wants to drill "multiple" wells. In Divide County, Continental is requesting the commission establish four new 1,280-acre spacing units, four 1920-acre spacing units and two overlapping 1,920 units in the Juno, Kimberly, Baukol Noonan and/or Noonan-Bakken fields and allow the company to drill one well on each. Continental is also asking the commission to establish a 1,280-acre unit in the Stoneview or Leaf Mountain-Bakken field and allow the drilling of a single well.

In McKenzie and Mountrail counties, Continental is asking for an additional 1,280-acre spacing unit in the Sanish or Four Bears-Bakken field on which it wants to drill up to eight horizontal wells. In Williams County, the company is asking for a single 640-acre unit in the Painted Woods or Todd-Bakken field to drill a single horizontal well.

Burlington Resources

Burlington Resources, now part of ConocoPhillips, asked that the commission establish eight new overlapping 2,560-acre spacing units in the Camel Butte, Clear Creek, Blue Buttes, Johnson Corner, Pershing Croff and North Fork-Bakken fields in McKenzie County and allow the company to drill one or more horizontal wells between the existing 1,280-acre units. Burlington is also asking the commission to establish one new 1,280-acre unit in the MonDak-Bakken field, and three new 1,280-acre units in the Pierre Creek and Covered Bridge-Bakken fields and be allowed to drill a horizontal well on each.

Hess, Petro-Hunt and Slawson

Hess Corp. submitted requests for the commission to establish three overlapping 2,560-acre units in the Manitou-Bakken field in Mountrail County and allow it to drill one or more horizontal wells between the existing 1,280-acre units. The company is also asking for an overlapping 2,560-acre unit in Blue Buttes-Bakken field in McKenzie County for the same purpose.

Hess is also asking the commission establish a 1,280-acre spacing unit in the Alkali Creek-Bakken field in Mountrail County where the company wants to drill up to 10 new horizontal wells. Additionally, Hess is asking for a 1,280-acre unit for the Beaver Lodge-Bakken and Beaver Lodge-Devonian fields in Williams County where it wants to drill up four horizontal wells targeting the Three Forks formation.

Petro-Hunt is asking the commission to establish a 2,560-acre unit and authorize the drilling of up to 10 wells, or to establish a new 1,280-acre unit and authorize the drilling of up to five wells on that new unit and five wells on an existing 1,280-acre unit in Stoneville-Bakken field in Divide County. Petro-Hunt is also asking the commission to establish four overlapping 2,560-acre units in the Charlson, Phelps Bay-Bakken fields and the Keene-Bakken/Three Forks fields in McKenzie County and allow for the drilling of one horizontal well on each. In addition, the company is seeking permission to drill up to eight wells on each 1,280-acre unit the company controls in the Glass Bluff-Bakken field in McKenzie and Williams counties, and up to seven wells on a 640-acre unit in the Stockyard Creek Bakken field in Williams County.

Yet another producer, Slawson Exploration, is requesting the commission establish a variety of new spacing units in Mountrail County. In the Van Hook-Bakken field the company is requesting the commission establish a 3,200-acre unit and authorize the drilling of one well on the unit. Slawson is asking the commission establish three overlapping 1,280-acre units, also in the Van Hook-Bakken field, and another 1,280-acre unit in the Big Bend-Bakken field where it wants to drill up to five wells on each. And in McKenzie County, Slawson is asking for the establishment of a 640-acre spacing unit in Squaw Gap-Bakken field on which it wants to drill up to five wells.

Statoil, Whiting, SM, XTO, WPX, Sequel

Meanwhile, Statoil is asking the commission to establish an overlapping 2,560-acre unit in the Briar Creek-Bakken field in McKenzie and Williams counties on which it wants to drill up to 15 wells, and that another 2,560-acre unit be established for the Alger-Bakken field in Mountrail County where the company wants to drill up to 10 wells.

Whiting Oil and Gas is asking the commission to establish a 1,280-acre unit in the Roosevelt-Bakken field in Billings County for drilling of up to four wells. In the Camel-Hump-Red River and/or the Delhi-Red River fields of Golden Valley County, Whiting is asking for a 320-acre unit for the drilling of a single horizontal well, and is also requesting the establishment of two 160-acre units for the drilling of one vertical well on each.

SM Energy is asking the commission to establish three overlapping 2,560-acre units in McKenzie County in the Poe, Johnson Corner, Dimmick Lake and Sivertson-Bakken fields and that it be allowed to drill one or more horizontal wells between the existing 1,280-acre units on each new 2,560-acre unit.

XTO Energy is requesting a single 1,280-acre unit be established in Lindahl-Bakken field in Williams County for the drilling of one horizontal well.

WPX Energy Williston LLC is asking for a 640-acre unit in the Reunion Bay-Bakken field in Mountrail County in order to drill one well.

Sequel Energy is asking for a 2,560-acre unit in Pierre Creek-Bakken field in Burke, Divide and Williams counties for the drilling of six horizontal wells. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

GOVERNMENT

ND flaring requests continue in February

While North Dakota grapples with an ongoing natural gas flaring problem, the North Dakota Industrial Commission continues to receive numerous requests from operators for unrestricted well production and flaring beyond the 60 days allowed under current NDIC field rules. Hearings on these requests were scheduled for Feb. 27 and 28, as this edition of Petroleum News Bakken went to press (see write up in the March 10 issue, which will be available online March 8).

In December, flaring in North Dakota was at 29 percent, the same as it was in November but still far above where state officials want it to be (see related story on page 3).

Hess Corp. requested continued flaring for all of its wells in the Beaver Lodge-Bakken field in Williams County, and in the Hawkeye-Bakken field in McKenzie County. According to the NDIC's Department of Mineral Resources Oil and Gas Division records, Hess has 128 wells on active status and three on confidential status in the Beaver Lodge field, and 24 active and nine confidential wells in the Hawkeye field. Hess is currently working to secure contracts for installation of gas gathering infrastructure and is asking for the continued flaring to extend through December.

Marathon Oil Co. is requesting continued flaring through June for its wells in the Lost Bridge-Bakken field Dunn County, in the Deep Water Creek Bay-Bakken field in Dunn and McLean counties, and in the Strandahl-Bakken field in Williams County because presently there is no gas gathering system in those fields. Oil and Gas Division records indicate that Marathon currently has two active and five confidential wells in the Lost Bridge-Bakken field, 12 active and two confidential wells in the Deep Water Creek Bay field, and eight active and two confidential wells in the Strandahl field.

Slawson Exploration Co. is asking permission to continue flaring for its wells in the Alger-Bakken field in Mountrail County until the wells can be connected to a gas gathering system. Oil and Gas Division records indicate that Slawson currently has five active and one confidential well in the Alger field, although Slawson indicated it may drill additional wells in the field.

Baytex Energy USA is requesting flaring be allowed to continue at six wells in the West Ambrose-Bakken field in Divide County. Samson Resources Co. is asking to continue flaring at two of its wells in Ellisville-Bakken field in Williams County.

—MIKE ELLERD

● COMPANY UPDATE

SM Energy sets new production record

By MIKE ELLERD

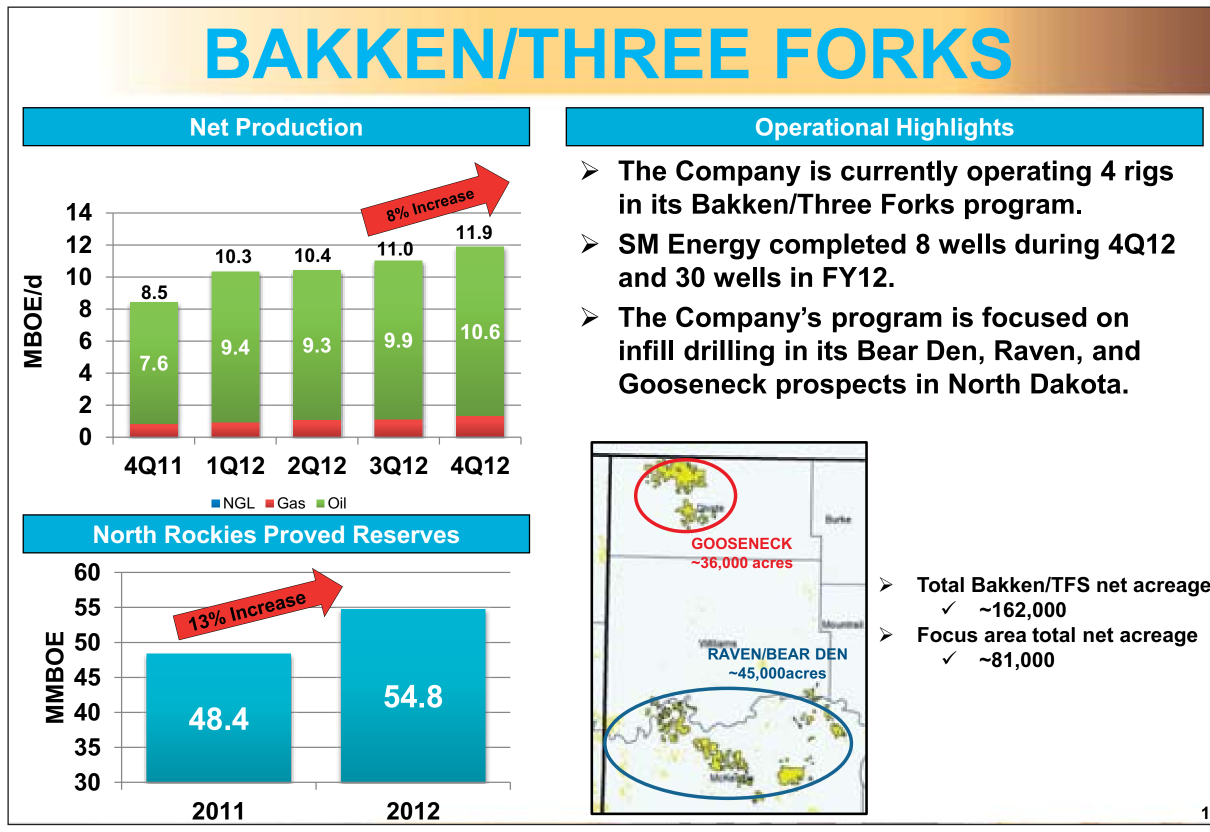
For Petroleum News Bakken

SM Energy announced its fourth quarter and year end 2012 production results on Feb. 20, and said its net Bakken/Three Forks production in the fourth quarter was 11,900 barrels of oil equivalent per day, up 8 percent from its third quarter average daily production of 11,000 boepd, and up 40 percent over the 8,500 boe the company produced per day in the fourth quarter 2011.

All of its operations combined resulted in an overall 2012 average daily production of 110,000 boepd, a 6.8 percent increase over the third quarter average daily production of 103,000 boepd, and an increase of 18 percent over the fourth quarter 2011 average daily production of 93,000 boepd. In terms of gross production, SM Energy produced a company record of 36.5 million boe in 2012, which exceeded company guidance and represents an annual gross production increase of 29 percent. In addition to the Bakken, SM Energy has major operations in the Eagle Ford and Permian Shales plays.

The company also reported total proved reserves of 293 million boe at the end of 2012, a 40 percent increase over year-end 2011 reserves. Fifty-three percent of those reserves are liquids.

see **SM ENERGY** *page 24*



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ND PRODUCTION

tems and could kick other wells off the system and return them to flaring.

2013 outlook

"One of the things we've learned from the November-December experience was about how many wells it takes to sustain production in North Dakota."

In November, Helms said, only 76 new wells were brought on production, and the state saw a production decline, whereas 123 new wells were brought on production in December and the state saw a production increase. He said the Oil and Gas Division is now able to estimate that it takes about 90 new wells a month to maintain 769,000 barrels a day, and that more than 100 new wells per month will be necessary to grow production to the levels that are being used for 2013-15 revenue forecasts.

Helms said he is very confident that the state is going to sustain the production level of approximately 770,000 barrels per day. He said the only scenario where that production would not be sustained is one in which the Bureau of Land Management would issue restrictive federal fracking rules, the Environmental Protection Agency would issue restrictive fracking guidelines, Congress would strip away the intangible drilling costs and depletion allowance, and at the same time oil prices would drop significantly. He does not, however, foresee that happening. In fact, he said "we're pretty confident it's going to grow and actually meet or exceed the revenue forecast number of the 850,000 this next biennium."

Regarding rig count, Helms said he has been told by operators that with current crude oil pricing and the transportation mechanisms, drilling activity will increase and he expects to see it back in the 200 range, about a 10 percent increase over the current count of 182. That, he said, will escalate oil production by 2 to 4 percent month-on-month. However, Helms said 200 rigs is about 10 percent less activity than seen in May 2012 (a record rig count of 218 was set on May 29, 2012).

"So we think that we're going to settle in somewhere right between where we're at now and where we were in May and June of 2012."

Continental's 3-mile laterals

Continental Resources is experimenting with three-mile laterals, and Helms was asked in the press conference if there are any issues with the longer laterals. He said the drilling has gone much better than expected. What it not known at this point, he said, is how effectively the longer laterals can be fracked.

"There have been some difficulties with fracking that far away stage and we don't know how well it's going to produce." He said a few more months of data are needed from those longer lateral wells to determine whether they are actually going to give up more oil.

Salt water legislation

During the press conference, Helms was asked if the Oil and Gas Division has begun drafting new rules required under House Bill 1333, a bill that would provide additional reclamation standards for pipelines and contains a provision whereby the North Dakota mediation service may mediate pipeline easement disputes. Several amendments were added to the bill by the House Energy and Natural Resources committee on Feb. 12, including the addition of saltwater disposal wells and associated facilities and abandoned oil and gas wells. The amendments were approved by the full House on Feb. 13 and the amended bill was referred to the Appropriations Committee.

Helms said the Oil and Gas Division has not begun drafting those new rules. The North Dakota Industrial Commission's jurisdiction in regard to saltwater disposal wells has always been limited since North Dakota took primacy from the EPA in 1983, he said, and the commission essentially dealt only with formation geology and well construction and testing. While the commission has had some rules in place over the past 10 years that deal with saltwater disposal facilities, HB 1333 would significantly expand the commission's jurisdiction into the transportation of saltwater, according to Helms.

Other O&G legislation

Concerning other legislation, Helms said his group has been tracking 41 oil and gas-related bills thus far in the current session. He said his group thought they might be tracking somewhere between 75 and 100, so tracking on 41, he said, "sounds like it ought to be some relief," but he added that "they have not been easy bills." He said the Oil and Gas Division is trying to deal with surface owner concerns, well placement, saltwater spills and flaring. Those, he said, "are very, very difficult processes to tackle" and there are a lot of ideas out there.

He said he is starting to see the bills come together. In all of those arenas, he said, there are three to four different bills, and he expects the "best parts" in each set of related bills to come together into a single bill, and in total he expects to see the 41 bills consolidated into 10 or 15 "good bills and good ideas." ●

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EIA ANALYSIS

tight oil formations in North Dakota and Texas, a continental pipeline system adjusting to the new geography of oil production, and production increases from a slate of new Gulf of Mexico developments.

While noting that future technologies could further improve the economics of tight oil, EIA expects the growth of unconventional production to slow as economics of scale reduce and companies deplete the sweet spots. Still, EIA noted, "It is difficult to predict when that inflection point will be reached because it can be pushed father into the future by increases in the number of drilling rigs and further technological change."

While noting that future technologies could further improve the economics of tight oil, EIA expects the growth of unconventional production to slow as economics of scale reduce and companies deplete the sweet spots.

Tight oil driving growth

The recent growth comes primarily from three basins, according to EIA.

They are the Williston Basin of North Dakota and Montana (home to the Bakken petroleum system and prolific middle Bakken formation member); the Western Gulf Basin of south Texas (home to the Eagle Ford formation); and the Permian Basin of west Texas (home to the Spraberry and Wolfcamp formations), with promising results also coming out of the Denver Basin of Colorado and Wyoming, and the Anadarko and Arkoma basins of north Texas, Oklahoma and Arkansas.

Of the 1.26 million bpd of total forecasted production growth between November 2012 and December 2014, EIA expects some 1.13 million bpd to come from onshore plays.

"While oil production from other sources will continue to account for most of the country's output, production volumes from tight formations such as the Bakken, Eagle Ford and Spraberry are forecast to steadily increase tight oil's production share, reaching about one third of total U.S. oil production by 2014," EIA concluded in its report.

With gains in drilling efficiency, EIA expects the average daily rig count in the Williston Basin to fall over the next two years, to 184 rigs in 2014 from 208 rigs in 2012.

This, in turn, should cause production growth to slow as well. EIA is forecasting production will increase from 720,000 bpd in 2012, to 950,000 bpd in 2013, to 1.13 million bpd in 2014 and close out 2014 at just less than 1.19 million bpd. Additionally, as companies deplete sweet spots, EIA expects 30-day initial production rates to fall over the near term, from 458 bpd in 2012, to 435 bpd in 2013, to 414 bpd in 2014.

With winter weather impacting Bakken developments to a much greater degree than tight oil operations in Texas, though, EIA expects production to "surge" in the spring.

More efficiency gains to come?

While the combination of horizontal drilling and hydraulic fracturing is responsible for making these formations economic at current oil prices, EIA points to a range of technologies responsible for bringing down the cost of tight oil development, and therefore increasing production this past year and likely for the next two years, as well.

Those technologies include: multi-well pads that create economies of scale for both drilling and completion activities, horizontal laterals up to two miles long that contact a larger portion of oil-bearing formations, micro-seismic imaging that improves the understanding of formations, drill bits designed specifically for shale and tight formations, and "walking" rigs that decrease the time to move from one well to another on a pad.

And EIA sees the possibility for additional technologies to further improve the economics of tight oil, including "selective fracturing" along horizontal laterals, which would avoid sections of a formation believed to have lower or no production value.

Optimizing operations

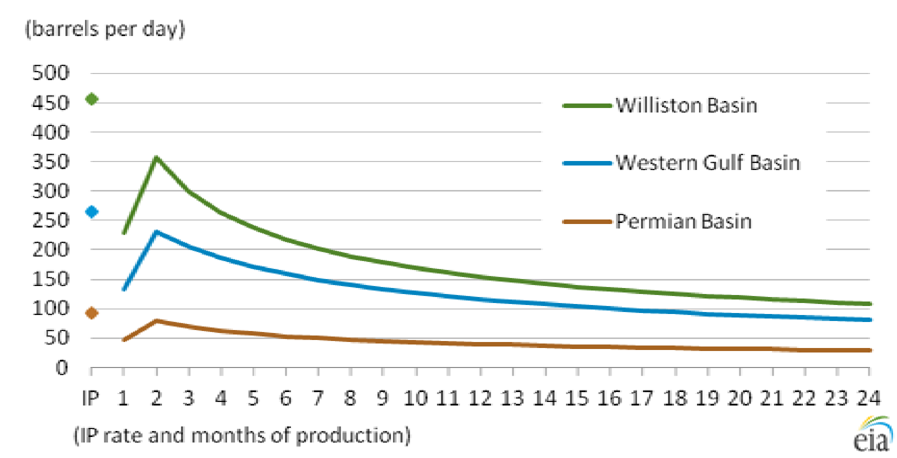
Even without additional improvements, producers are gaining efficiency.

Because of the steep decline curves common for tight oil wells, unconventional growth follows drilling activity to a much greater degree than in conventional plays and economies of scale come when producers find the optimal use for existing technologies.

In the Bakken, for instance, the average horizontal lateral is currently 10,000 feet long with 30 fracturing stages. By coming into contact with more of the formation, these longer laterals reduce risk and increase production, which in turn

see **EIA ANALYSIS** *page 21*

Figure 4. Production profile of average wells in three key basins, 2011 to present



Source: U.S. Energy Information Administration (EIA) analysis of DrillingInfo data

In the Western Gulf Basin, the rig count declined during the second half of 2012, but is forecast to increase moderately during 2013 and 2014 (Table 1). While a rig typically takes longer than a month to drill a new well, the increased use of pad drilling, as described below, is expected to increase rig efficiency to about one well per rig per month in 2013 and 2014. Based on the rig count rising to about 360 in 2014, about 8,400 total new wells would be drilled in 2013 and 2014 in the Western Gulf Basin.

Table 1. Forecast assumptions for liquids production in three key basins

	2012	2013	2014
Western Gulf Basin			
Average Drilling Rig Count	352	338	361
Rig Efficiency (wells/rig-year)	9	12	12
New Well Count	3,042	4,061	4,337
Well Initial Production (bbl/d)	331	290	269
Production (million bbl/d)	0.89	1.28	1.58
Permian Basin			
Average Drilling Rig Count	506	492	523
Rig Efficiency (wells/rig-year)	10	10	10
New Well Count	5,063	4,925	5,228
Well Initial Production (bbl/d)	93	93	93
Production (million bbl/d)	1.18	1.29	1.37
Williston Basin			
Average Drilling Rig Count	208	196	184
Rig Efficiency (wells/rig-year)	10	12	12
New Well Count	2,079	2,348	2,213
Well Initial Production (bbl/d)	458	435	414
Production (million bbl/d)	0.72	0.95	1.13

Source: U.S. Energy Information Administration

U.S. Energy Information Administration | STEO Supplement: U.S. Crude Oil Production Outlook 7

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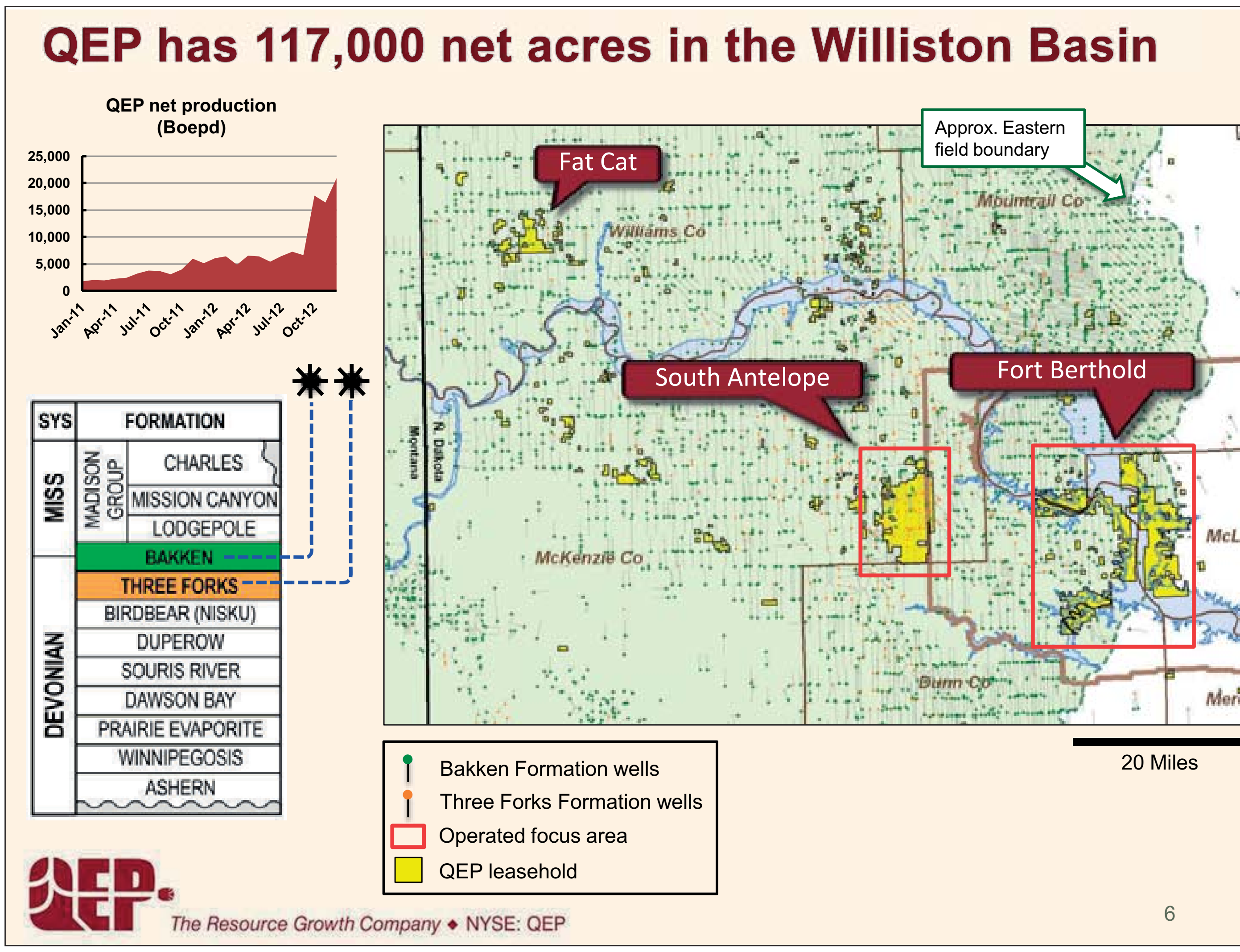
QEP CAPEX



making up 32 percent of total production, compared to 22 percent in 2012, 14 percent in 2011, and 11 percent in 2010.

Still, QEP continues to struggle with downward pressure on earnings, posting substantially lower net income for the fourth quarter and year-end 2012, compared to the same periods in 2011, in large part because of the weak economics surrounding its nearly 80 percent reliance on natural gas.

Even before adjusting the numbers downward to reflect property impairments and other "extraordinary" items, QEP's net income for the 2012 fourth quarter was just $59.8 million versus $104.6 million for the same quarter the prior year. Profit for full-year 2012 was $227.9 million compared to $316.2 million for 2011.

QEP attributed the lower adjusted net income primarily to lower natural gas and NGL prices, lower midstream NGL sales volumes and prices, and other expenses.

$23.1 million Q4 loss

However, when plugging in the extraordinary items, including non-cash charges, litigation and losses and gains on property sales, QEP actually lost $23.1 million in the fourth quarter, compared to "no earnings" for the quarter a year earlier. For the full year 2012, QEP reported net income of $128.3 million versus $267.2 million for the previous year.

"In spite of headwinds with regards to natural gas and NGL prices, for the full year 2012, we posted record results in a number of important areas," Richard J. Doleshek, QEP's chief financial officer, told analysts during the company's Feb. 20 earnings call.

That's largely because the company's exploration and production arm, QEP Energy, financially outperformed the company's gathering and processing arm, QEP Field Services.

Overall production jumps 16 percent

QEP Energy grew overall production 16 percent in 2012 to a record 319.2 billion cubic feet of gas equivalent, or an average of 872 million cubic feet per day, "driven by good results across our entire operation," said Chuck Stanley, QEP Resources' chairman, president and chief executive officer.

Fourth-quarter production, also a record, jumped 14 percent to 83.9 bcfe, compared to 73.9 bcfe for the same period in 2011. Of particular note, oil production rocketed nearly 100 percent and NGL nearly 40 percent, while less desirable natural gas increased just 1 percent. Moreover, oil and NGL revenues together increased a whopping 52 percent from the 2011 fourth quarter.

"We're making excellent progress in growing our crude oil production … thanks, in part, to our North Dakota acquisition," Stanley said. "And that growth is accelerating."

Oil output rockets 97 percent

Oil production totaled 6.3 million barrels in 2012 compared to 3.7 million barrels in 2011, a 69 percent increase, he said, adding that for the fourth quarter, QEP produced 2.3 million barrels, a 97 percent increase over the 1.2 million barrels produced in the previous year's fourth quarter.

QEP Energy's estimated proved reserves totaled 3.9 trillion cubic feet of gas equivalent at year-end 2012, up 9 percent from year-end 2011. And about 33 percent of proved reserves at year-end 20122 were oil and NGL compared to 24 percent at year-end 2011.

QEP's North Dakota Bakken acquisition in last year's third quarter alone added 313.8 bcfe to the company's total reserve base.

"The positive impact of our North Dakota acquisition is clear," Stanley said, noting that crude oil alone represented 17 percent of QEP Energy's production in the fourth quarter of 2012, compared to just 10 percent in the prior year period and 11 percent in the third quarter of 2012.

Drilling pace to pick up

Meanwhile, QEP Resources said it intends to pick up the drilling pace considerably in 2013, dedicating 53 percent of its forecasted $1.625-to $1.725 billion capital expenditure budget on the company's Bakken and Three Forks development, spread between operations on the Fort Berthold Reservation and its recently acquired South Antelope properties.

The 53 percent of capex allocated to the Bakken for 2013 compares to 28 percent in 2012 and 17 percent in 2011.

"This program assumes we ramp up to an eight-rig drilling problem on the Williston Basin assets by mid-year," Stanley said, noting that four of the seven rigs currently working the region are located in South Antelope. He said a fifth rig is planned this year for South Antelope.

During the fourth quarter, the company completed and put on stream two QEP-operated Three Forks formation horizontal wells on the South Antelope property. Both wells met pre-drill expectations, with average 24-hour initial production, IP, rates of 2,175 boe per day. QEP estimates ultimate recoverable reserves on these two wells of more than 1 million boe.

Well design change at Antelope

"We've made changes in well design in South Antelope that we believe will allow us to deliver $11 million gross completed or lower well cost going forward on this property," Stanley said.

On its Fort Berthold acreage, he added, QEP completed and put on line nine wells during the fourth quarter — four Middle Bakken and five Three Forks. He said seven of the wells were drilled on the Independence Pad in the northwest corner of the company's acreage, "and all of them had excellent 24-hour IPs of 2,400 to 2,900 boe per day."

However, the two remaining Fort Berthold wells were drilled on the eastern edge of QEP's acreage and produced lower IPs of around 900 boe per day. "That's not surprising given their location toward the margin or the pinch out of the Bakken and Three Forks on the eastern part of our acreage," Stanley explained.

Well costs at Fort Berthold

He said that during the fourth quarter, the company was able to deliver completed well costs of about $11 million on its Fort Berthold acreage.

Most of the remaining half of QEP's

see **QEP CAPEX** *page 22*

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EIA ANALYSIS

lowers average finding and development costs.

But, as EIA noted, because horizontal wells are more expensive per foot than vertical wells "there are diminishing returns to ever longer laterals." And, according to a report from the oil field services giant Schlumberger, 30 stages of hydraulic fracturing appears to be the optimal amount for 10,000-foot laterals.

Some efficiency gains have nothing to do with technologies.

EIA pointed out that in the Eagle Ford and the Bakken, leaseholders have started swapping out acreage to create contiguous land positions that cover less ground and therefore require lower mobilization costs. The agency also praised the North Dakota Industrial Commission for unitizing leases in a grid of small equal plots, which "should create long term infrastructure efficiencies whereby service roads are oriented along the axes."

By bringing down the cost of production, these gains have improved the economics of sweet spots and also increased the potential tight oil resource base by making more areas economic, but EIA believes "the rate of change in efficiency improvements is expected to slow down in the future and become more representative of the overall rate of technological improvement experienced by the oil and gas industry as a whole." ●

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Petroleum News Bakken

Oil Patch Bits

Larson Electronics offers new dual colored light bar

Larson Electronics said Feb. 20 that it has released a high intensity LED light configured to allow operators to produce red or blue light output from the same fixture. The LEDLB-24-VISRED LED light bar features rugged waterproof construction designed for extreme conditions and a dual color LED design that allows this unit to serve in multiple applications.

The LEDLB-24-VISRED LED light bar features four rows of LED emitters, two rows producing white light and two rows producing red, these light bars are ideal for law enforcement, security, and hunting applications where colored light is often desired. These high output LED lights are fitted with dual pigtails with Deutsch connectors to provide secure wiring connections and have an IP68 rated waterproof housing and unbreakable polycarbonate lens to withstand abusive weather conditions and handling.

The Cree LEDs used in these units provide more than 50,000 hours of operational life and high power output that surpasses that of comparable halogen lights while using less power. Since these lights are LED, they draw far less current than incandescent lamps and produce more than 4,000 lumens while drawing only 72 watts at 6 amps from a 12 volt electrical system. For more information visit www.larsonelectronics.com.

Bakken Players

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QEP CAPEX

2013 capital budget is being distributed among the company's other oil and liquids-rich plays in Wyoming, Utah, Texas and Oklahoma. Pinedale will get roughly 14 percent of the budget. Granite Wash, along with the Cana, Tonkawa and Marmaton programs, will receive about 17 percent of total capital, "driven in large part by the high level of anticipated non-operated drilling activity in these plays," the company said, while the Uinta Basin will attract about 6 percent of QEP's total capital.

"We continue development of Lower Mesaverde liquids-rich natural gas play and Green River formation oil development," Stanley said.

Haynesville dry gas to plunge

With no drilling activity planned this year for QEP's Haynesville natural gas development in northwest Louisiana, the company is forecasting a 30 percent decline in dry gas production from this area alone, from about 110 bcfe in 2012 to about 75 bcfe in 2013.

"We view that this is a pivotal year for QEP, as we dramatically shift the production mix from one dominated by natural gas to one that's more balanced between natural gas, oil and NGLs," Stanley said. ●

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CENOVUS

bined Bakken and Lower Shaunavon output exiting 2012 of 7,000 bpd, up 9 percent from a year earlier.

Cenovus hopes to complete the sale this year.

6,000 bpd by rail

In releasing results for the fourth quarter of 2012, Cenovus said it is currently moving 6,000 bpd of production by rail and hopes to add another 4,000 bpd, with the possible addition of insulated rail cars.

Don Swystun, executive vice president of refining, marketing and transportation, said the company is currently moving about 40,000 bpd of its 100,000 bpd of oil sands volumes and 77,000 bpd of conventional crude to tidewater

About 11,500 bpd moves on Kinder Morgan's Trans Mountain system to Vancouver for shipment to California and Asia and 20,000 bpd is carried on the Pegasus pipeline to the Gulf Coast.

He said Cenovus has committed a combined 175,000 bpd to Enbridge's proposed Northern Gateway pipeline and the planned Trans Mountain expansion, although both projects are facing stiff opposition.

Swystun said Cenovus plans "significant participation" in TransCanada's expected open season this year to establish a crude pipeline from Alberta to Ontario and Quebec refineries and possibly extending to the Atlantic Coast.

—GARY PARK

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KINDER MORGAN

area, Western Canada, Cushing, Okla., and West Texas.

The crude will be delivered by rail to the shipping channel for distribution to refineries by pipeline and barges.

It will have the capacity to unload and load up to three unit trains per day of crude oil and condensate as well as provide for up to 100,000 bpd of barge loading capacity.

KW Express will own 85 percent of the project and, along with Watco, construct and operate the facility once it is completed. Mercuria will own the remaining 15 percent.

Counting on continuing spread

Kinder Morgan Terminals President John Schlosser said the project will "provide U.S. and Canadian producers with much needed market access and optionality to deliver their crude oil production."

Traders expect the crude-by-rail plan will count on a continuing wide price spread between Brent and West Texas Intermediate crudes that will offer an incentive to move WTI-priced crudes to the Gulf Coast.

But some analysts are withholding judgment pending the introduction of TransCanada's 700,000 bpd Cushing to Nederland, Texas, pipeline and expansion of the Enterprise Product Partners-Enbridge Seaway line to 850,000 bpd, both scheduled to start service in 2014.

Mercuria was launched in 2004 and has become one of the largest integrated energy and commodity trading companies in the world. It trades from hubs in Geneva, London, Singapore, Shanghai, Chicago and Houston.

—GARY PARK

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● COMPANY UPDATE

Abraxas Petroleum back on track

Lousy weather, gas plant issues cut into Texas independent's fourth-quarter production, focused on Bakken and Eagle Ford

By RAY TYSON

Petroleum News Bakken

Abraxas Petroleum Corp.'s production was back on course in February after bad weather in January caused delays in well completions in the Williston Basin of North Dakota and Montana, and plant issues throughout January in Texas' Eagle Ford relegated the company to flair natural gas.

Production in the 2012 fourth quarter averaged a sluggish 4,147 barrels of oil equivalent per day. But output returned to more "normalized levels" of 4,400-4,600 boe per day in February, even before the recent completion of wells in the Bakken and Eagle Ford.

Abraxas, an E&P independent based in San Antonio, Texas, said Feb. 20 that given the strong base production and incremental production anticipated from the recent well completions, the company was reiterating its production guidance of 4,900-5,200 boe per day for 2013.

Meanwhile, drilling continued in the Bakken on the Lillibridge East PAD with intermediate casing set on the 1H, 2H, 3H and 4H, Abraxas said, noting that the company also was preparing to drill the lateral on the 4H, after which the rig would move to drill 3H, 2H and 1H laterals. Abraxas owns holds a 34 percent working interest in the Lillibridge East PAD.

Also in the Bakken, Abraxas said it completed the Ravin 3H and was finishing the fracture stimulation of the Ravin 2H. Flowback was expected to begin soon after. Abraxas owns a 49 percent working interest in both the Ravin 2H and 3H.

In McMullen County, Texas, Abraxas said it successfully completed the Corvette C 1H with a 20-stage fracture stimulation and that it was flowing at rates above the company's "type curve." Moreover, the well was drilled, completed and turned to sales for about $6.1 million, or almost $2 million below originally projected cost.

Also in the Eagle Ford, the Gran Torino A 1H was being fracture stimulated with a 19-stage completion, Abraxas said, adding that the Mustang 3H was recently drilled and cased to a total depth of 15,007 feet, with an anticipated fracture stimulation date in March. Abraxas said it was preparing to spud its next well at WyCross, the Mustang 2H.

Abraxas owns a 25 percent working interest in the Corvette C 1H and an 18.75 percent working interest in the Gran Torino A 1H, Mustang 3H and Mustang 2H.

The company said its proved reserves at year-end 2012 stood at 30.1 million boe, a net increase of 84,000 boe over year-end 2011 proved reserves of 29.3 million boe. The reserves consisted of about 58 percent oil, 9 percent natural gas liquids and 34 percent natural gas. Forty-eight percent of the reserves were classified as proved developed.

Marketing non-operated Bakken assets

Abraxas said it hired E-Spectrum Advisors to market its non-operated Bakken and Three Forks assets in North Dakota and Montana. The potential divestiture consists of about 435 boe per day and 14,502 net acres. Proceeds would be used to pay down the company's credit revolver and then redeploy them to core-operated Bakken and Eagle Ford assets, the company said.

Bob Watson, Abraxas' president and chief executive officer, characterized 2012 as a "momentous" year for the company, as Abraxas continued to shift its reserve base from natural gas to oil, moved the company-owned rig to the Bakken, and began an active Eagle Ford drilling program.

Bob Watson, Abraxas' president and chief executive officer, characterized 2012 as a "momentous" year for the company, as Abraxas continued to shift its reserve base from natural gas to oil, moved the company-owned rig to the Bakken, and began an active Eagle Ford drilling program.

Watson pointed out that in spite of a significant divestiture of Eagle Ford reserves and the loss of the remainder of its proved undeveloped gas reserves due to down pricing, Abraxas still managed to achieve a roughly 3 percent increase in total reserves and a substantial increase in oil reserves.

"Our business plan for 2013 remains simple: focus capex on our core basins primarily in the Eagle Ford and Bakken (and) rationalize our portfolio by divesting low working interest, non-operated and non-core assets," he said.

"And, most importantly, grow our production on an absolute basis with oil volumes. Recent production and well performance accompanied by the efficiency gains we are witnessing in our Eagle Ford program gives us confidence that each goal is readily achievable." ●

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ASSOCIATIONS

PRINCESS CRUISES

The Diamond Princess is the sister ship to the Sapphire Princess that will be taking chamber members to Alaska in September.

Here comes the crew from North Dakota

From the Alaska Cruise Association's February newsletter:

Here's an interesting twist: over the past few years, many Alaska companies have moved their operations to North Dakota, where there's a huge oil boom under way.

Now, North Dakota businesses are coming north to Alaska — via cruise ship.

The Greater North Dakota Chamber is hosting a cruise Sept. 11-21 that includes a visit to Denali and a cruise through Prince William Sound and the Inside Passage.

"The Greater North Dakota Chamber is proud to host this Alaskan tour and provide an opportunity for North Dakotans to travel together to this magical destination," according to a chamber flyer.

If you're interested, fares start at $1,750.

Note: The chamber flyer mentioned above can be found online at www.ndchamber.com/wp-content/uploads/2012/12/alaska-cruise-brochure.pdf

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SM ENERGY

"SM Energy had a record-breaking year in 2012 with new highs for proved reserves and annual production, completing the year with record quarterly production," said Chief Executive Officer Anthony Best in a Feb. 20 press release. "These results were driven by our high rate of return oil and liquid-rich programs in the Eagle Ford shale and Bakken/Three Forks, which are expected to continue to drive our growth in 2013."

> *"SM Energy had a record-breaking year in 2012 with new highs for proved reserves and annual production, completing the year with record quarterly production."*
> **—SM Energy CEO Anthony Best**

The Denver-based independent also announced that it completed a total of 30 wells in its Bakken/Three Forks operations in 2012, eight of which were completed in the fourth quarter. SM Energy is currently operating four drill rigs and is focusing on infill drilling in its Raven, Bear Den and Gooseneck prospects in McKenzie, Williams and Divide counties. The company plans to switch two of those rigs over to walking rigs later in 2013 to enhance pad drilling efficiency.

In its Gooseneck Three Forks prospect, the company reports expected estimated ultimate recoveries of 380,000 boe per well (93 percent oil and 7 percent gas). In the Bear Den/Raven area, it reports an expected Bakken EUR of 458,000 boe per well (88 percent oil and 12 percent gas), and an expected Three Forks EUR of 395,000 boe per (85 percent oil and 14 percent gas).

For 2013, SM Energy has budgeted approximately $1.5 billion for capital expenditures, of which $1.2 billion is earmarked for drilling and completion. Of that $1.2 billion, $290 is allocated to the company's Bakken/Three Forks program. ●

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NEWFIELD

ments.

The Texas-based E&P independent has a successful track record of selling non-strategic assets, raising more than $1 billion over the last two years. Proceeds were used to help finance drilling programs, and returns from the sale of any international properties likely would be used to enhance domestic drilling, Newfield indicated.

Spending exceeds cash flow

Still, though Newfield said it carefully considered the "financing applications" of its "laser-focused" domestic drilling program, the company will end up spending more than it will generate through operations.

"Yes, we will outspend cash flow in 2013," Boothby said. "But we are confident that the potential returns in the cash flow growth embedded within our four domestic plays warrants our plan."

However, Newfield's 2012 financial statement was marred by non-cash charges totaling about $2 billion, which "made the comparison to First Call estimates a little difficult," Boothby conceded.

The largest contributor ($1.5 billion) to the write-down was attributed to lower natural gas prices, which removed from Newfield's books more than 600 billion cubic feet of proved natural gas reserves at year-end 2012.

The second charge is related to a company decision to "repatriate" the accumulated profits from Newfield's international subsidiaries.

"We repatriated international cash … and used the funds to reduce short-term borrowing," Boothby explained, noting that this action was the primary component of a $550 million non-cash tax charge.

$1.4 billion net loss

These non-cash charges resulted in a reported net loss of $1.4 billion for the fourth quarter of 2012, compared to net income of $68 million for the same period in 2011. Income for the quarter was $304 million when excluding charges and other liabilities.

Newfield generated $646 million in revenue for the 2012 fourth quarter, down from $677 million in the fourth quarter of 2011. Revenue for the year was $2.5 billion, up slightly from the prior year's $2.4 billion.

Fourth quarter and full-year 2012 production also reflected the impact of about $630 million in asset sales during the year, including the October 2012 closing on the sale of its deepwater Gulf of Mexico assets.

11.9 million boe in Q4

Newfield's total production in the fourth quarter of 2012 was 11.9 million boe, or about 129,300 boe per day, made up of 47 percent oil, 6 percent natural gas liquids and 47 percent natural gas. Of the total, International production accounted for 2.8 million boe, or 31,000 boe per day.

For the full-year 2012, Newfield's liftings totaled 50 million boe. Adjusted for the impact of asset sales during the period, liquids production in 2012 increased about 35 percent over 2011. Newfield's full-year 2012 international liquids production increased about 50 percent over 2011.

Substantially all of Newfield's capital over the last three years has been allocated to liquids production, which has grown at more than a 20 percent compounded average growth rate since 2009. ●

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