Petroleum news
BAKKEN

page 5 North Dakota continues to confront flaring; examines issue, technologies

Vol. 1, No. 17 • www.PetroleumNewsBakken.com A semi-monthly newspaper for industry and government January 6, 2013

Oasis Well Services hard at work

VERN WHITTEN PHOTOGRAPHY

The frac site above is just over the Montana border from North Dakota, about 5 miles northeast of Bainville, Mont. That's about 15 miles west of Williston, ND. The hydraulic fracturing well work is being done by Oasis Petroleum with its own equipment, which is all new. Oasis had photographer Vern Whitten out early last spring to take some ground photos when it first started doing its own fracing. This photo was taken in December 2012.

Continental asks NDIC for 14 wells on 1,280-acre pad; Hunt files for 18-1,280-acre standups

Among the applications from oil and gas operators received by the North Dakota Industrial Commission in November and December was a request from Continental Resources for the installation of 14 horizontal wells on a 1,280-acre spacing unit in Divide County and a filing by Hunt Oil to establish 18 new 1,280-acre standup well spacings, also in Divide County.

Continental's request was made in December for a spacing unit in the Hayland-Bakken pool. The company currently has two wells in this spacing unit, the Tangsrud 2-1H that produces from the middle Bakken and the Tangsrud 1-1H in the first bench of the Three Forks.

The company wants to drill the additional 14 wells to further target not only the middle Bakken formation member, where most Bakken oil production occurs (90 percent-plus of

see **WELL APPLICATIONS** page 17

Production gush ahead: Kodiak's 2013 capital budget to deliver bigger bang for the buck

Kodiak Oil & Gas Corp. anticipates boosting 2013 Bakken-Three Forks sales volumes by more than 80 percent over 2012 levels on projected annual capital spending that barely exceeds 3 percent compared to 2012.

LYNN A. PETERSON

The Denver-based E&P independent suggested that while difficult to quantify, significantly lower well costs should help keep down operational costs, resulting in more bang for the buck.

"Our experience in the second half of 2012 certainly supports a lower-cost trend for 2013," Lynn A. Peterson, Kodiak's chairman and chief executive officer, said in a recent statement.

$775 million capex for 2013

Kodiak's entire $775 million capital budget for 2013 is

see **KODIAK BUDGET** page 18

E&P REGION

King of the hill

Eagle Ford could replace Bakken as No.1 tight oil producer; $28B 2013 capex

By RAY TYSON

Petroleum News Bakken

Liquids production from the Eagle Ford of South Texas could catch or surpass North Dakota's output from the Bakken petroleum system in 2013, a recent study by EAI Inc. indicates. Meanwhile, a separate report by Wood Mackenzie projects 2013 capital spending in Eagle Ford will total a whopping $28 billion.

"With $28 billion in capex being spent in 2013 and development now in full swing, the excitement in the Eagle Ford and value being extracted from the play continues to exceed expectations," said Callan McMahon, upstream research analyst for Wood Mackenzie.

Behind the Bakken, Eagle Ford is currently the second largest tight oil play in the United States, while also ranking fifth in terms of shale gas production.

Behind the Bakken, Eagle Ford is currently the second largest tight oil play in the United States, while also ranking fifth in terms of shale gas production.

Production numbers published by the U.S. Energy Information Agency in 2012 and analyzed

see **EAGLE FORD** page 19

MERGERS & ACQUISITIONS

Exxon/XTO rise to No. 6

Closing of final phase of Denbury deal bumps companies up the production ladder

By KAY CASHMAN

Petroleum News Bakken

In a deal valued at $2 billion, ExxonMobil and its subsidiary XTO Energy have closed the second and final phase of a purchase and asset exchange with Denbury Resources that gives the mega-major and its Bakken operator an additional 196,000 net acres in North Dakota's Williston Basin and makes them the sixth largest operator of Bakken oil production in the state.

According to the latest oil production numbers released by the North Dakota Industrial Commission, preliminary October output from the Bakken petroleum system put XTO Energy at No. 10 with 19,944 barrels of oil per day and Denbury, at No. 16, with 12,156 bpd.

Also, Denbury, like its E&P peers, drilled wells to hold acreage, which will allow XTO to begin pad drilling — i.e. development — in areas that are very prospective for the middle Bakken member and the first two benches of the Three Forks formation.

Combining the two, the Exxon subsidiary is operating wells that produce approximately 32,100

see **DENBURY DEAL** page 9

TECHNOLOGY

Pad drilling leads way

Multi-well pad drilling revolutionizing Bakken; brings many benefits, few downsides

By MIKE ELLERD

For Petroleum News Bakken

The practice of drilling multiple wells on single pads, commonly known as "pad drilling," is changing the dynamics of exploration and production in the Bakken and by all indications will continue to do so.

Advancements in directional drilling and hydraulic fracturing have made pad drilling feasible. With these advancements, a series of vertical well bores can be drilled in very close proximity, typically 25 to 30 feet apart, followed by long horizontal laterals drilled and fracked in multiple parallel and/or diverging directions, opening up large portions of tight formations from a single surface location. The technique is particularly well suited to plays such as the Bakken where reservoirs are thin but laterally extensive.

VERN WHITTEN PHOTOGRAPHY

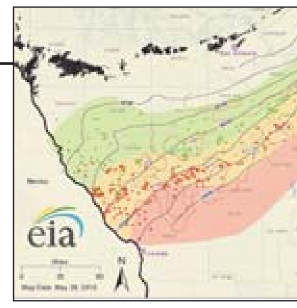
A six well pad

see **PAD DRILLING** page 10

contents

Petroleum News Bakken

ON THE COVER



COMPANY UPDATE

DRILLING & COMPLETION

E&P REGION

FINANCE & ECONOMY

GOVERNMENT

LAND & LEASING

LEGAL

MERGERS & ACQUISITIONS

MOVING HYDROCARBONS

NATURAL GAS

TECHNOLOGY

● E&P REGION

All eyes turning to Duvernay play

Big land grab over, attention shifts to serious evaluation as operators reduce uncertainty; could lead to service sector M&A

By GARY PARK
For Petroleum News Bakken

The roundup is winding down. Now it's payoff time.

Operators secured rights in 2011 to 446 land leases in the Duvernay and Montney plays of Alberta and British Columbia and grabbed the leftovers in 2012.

With those essential pieces in place, the industry is about to establish whether the plays — especially the Duvernay — will rank among the liquids-rich hot spots of North America.

In addition, as the two plays continue to attract investment and interest from producers they could spark a round of merger and acquisition activity in the service sector as multinationals and U.S.-based companies look for a chunk of the action.

BMO Nesbitt Burns oilfield services analyst Michael Mazar anticipates that as plays such as Duvernay and Horn River start to enter full exploitation mode potential service sector heavyweights will look to muscle into the scene.

He said that if long lead-time, world class-type plays such as Duvernay start to take shape, especially if they take a role in LNG exports, that would bring the Horn River, Montney and Liard formations of British Columbia into the spotlight as well.

Companies like Schlumberger, Halliburton and Baker Hughes might then decide they need to expand their presence in Canada after a decade of scaling down their Canadian operations.

Deal making in the upstream sector could involve joint ventures, sales or farmouts.

TAQA North

One of the current market tests covers 96,000 acres of Duvernay rights by TAQA North, Abu Dhabi's national oil company, which cannon balled into Western Canada in 2007 with a C$7.5 billion splash, buying PrimeWest Energy Trust for C$5 billion and Northrock Resources for C$2 billion, moving into the ranks of Canada's top 14 producers.

But it has since calmed the waters looking mostly for organic growth as it adopts a more defensive posture.

Production has dipped over the past two years to 81,930 barrels of oil equivalent per day in the third quarter of 2012, reflecting the sale of 4,000 boe per day of non-core production in March and the shut-in of uneconomic production.

Signaling another course adjustment, TAQA North hired Edward LeFehr, a former senior vice president of Talisman Energy, as its new president to take charge of the company's North American oil and gas operations.

Like most of its peers, the company, which produces about 328 million cubic feet per day of natural gas and holds leases in Horn River, has focused since last winter on oil and liquids rich properties, although its gas outlook is upbeat based on the emergence of LNG export projects in Western Canada and the switch from coal to gas-fired power plants.

On the development front, Bill Gwozd, senior vice president of gas services at Ziff Energy Group, told the Financial Post that the Montney is proven, while the Duvernay is among the continent's top five plays, but will need another five to six years to start taking shape.

Key players

The key players are Canadian Natural Resources and Encana, Canada's two largest natural gas producers who have backed away from their core business and turned to gas liquids to keep their heads above water.

Others holding large land positions are Talisman Energy, Bonavista Energy, Chevron and Celtic Exploration, which is being absorbed by ExxonMobil and Imperial Oil for C$3.1 billion.

Gwozd said that in the midst of doom and gloom for companies relying on gas, prices are not sufficient for producers to cover their costs, making it attractive to unload land "at get their sunk cost at rack rate," leaving them to meet only their operating costs.

That underpinned Encana's move when it sold a 49.9 percent interest in the Duvernay in December to Phoenix Duvernay Gas, a wholly owned unit of PetroChina, for C$2.18 billion, with about half of the property located in the prized Kaybob area.

RBC Dominion Securities analyst Greg Pardy said the Celtic plays could be part of a Pacific Coast LNG scheme that could lead to further joint ventures or acquisitions.

"Given the capital intensity of the play, we expect players to seek partnerships to gain access to capital," he wrote.

"Developing large land positions will require multibillion-dollar investments. We also see the potential for larger players to acquire companies that complement their acreage positions as the play's sweet spots emerge."

Talisman Chief Financial Officer Scott Thomas bolstered that outlook recently, telling a conference has company is mulling the sale of some Duvernay land, while Angle Energy, with 46,720 acres, is exploring joint ventures or other capital funding alternatives for 2013 to get "ideal value" for its properties.

Currently, however, Montney is Canada's leading shale play, with a combination of gas and natural gas liquids production rated as economical at C$2.50 per million British thermal units, while consulting firm Wood Mackenzie estimates the Duvernay is sitting closer to C$3.20.

Duvernay could rival Montney

Wood Mackenzie analyst Hugh Hopewell told the Financial Post that "if you look at the well breakeven costs of the Duvernay, it could soon be rivaling the Montney."

Bernstein Research analyst Neil Beveridge joins several others in comparing the Duvernay to the Eagle Ford, even

see **DUVERNAY** page 6

Petroleum news BAKKEN

www.PetroleumNewsBakken.com

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

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

NEWS
RAY TYSON • 605.343.4031
rtyson@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Julie Bourbeau • 907.229.7547
jbourbeau@petroleumnewsbakken.com
Raylene Combs • 509.290.5903
rcombs@petroleumnewsbakken.com
Ashley Lindly • 907.522.9469
alindly@petroleumnewsbakken.com
Susan Crane • 907.770.5592
scrane@petroleumnews.com
Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX NUMBERS
SOUTH DAKOTA • 713.658.0125
ALASKA • 907.522.9583

Several of the individuals listed above are independent contractors

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

● NATURAL GAS

Hess seeks flaring permits from NDIC

Tioga gas plant expansion 90 million cubic feet per day to 250 mmcf is scheduled for completion by October or November 2013

By MIKE ELLERD
For Petroleum News Bakken

Hess Corp. submitted applications to the North Dakota Industrial Commission in late November requesting permission to allow 41 wells in Burke, Dunne, McKenzie, Mountrail and Williams counties to flow at unrestricted rates and to flare the associated natural gas through Dec. 31, 2013. Then in mid-December Hess submitted similar applications for an additional 49 wells in Williams County. Hess wants the wells to produce unrestricted in order to evaluate reservoir potential, but there is not yet the necessary pipeline infrastructure in place for the capture and transport of the associated natural gas.

Hess is currently working on getting the necessary gathering infrastructure in place, and the gas will either go into Oneok's gas transportation and processing system or to Hess' Tioga gas plant. However, the company is also considering other options, including the feasibility of stripping out liquids and compressing the gas at the well head and transporting it to the Bakken Express pipeline, but the company's ultimate goal is to eventually connect all of the wells to a gathering system.

Some connected soon

Some of the wells, according to Hess, will be connected to a gathering system as early as January 2013, but some are not expected to be connected until early to mid 2014, after the current application period expires.

In November, the commission asked Hess for additional information regarding the proposed gathering pipelines and estimated connection times. The commission also asked for an update at some point in the future on the feasibility of stripping liquids at the well head.

Hess had initially applied for the same exemption for additional wells in Burke, McKenzie and Williams counties. However, those wells have since either been connected or it has otherwise been determined that the extensions are not needed, according to Hess.

Hess told the commission in November that it is also expanding the capacity of its Tioga gas plant from the current capacity of approximately 90 million to 250 million cubic feet per day. That expansion, the company said, is scheduled for completion by October or November 2013. ●

Editor's note: A previous report from Petroleum News Bakken that mentions the Tioga gas plant, "Hess' faith in Bakken paying off," can be found online in the Aug. 5 edition at www.petroleumnews.com/pnads/724367126.shtml

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

GOVERNMENT

Oil and gas on agenda for ND lawmakers

The next session of the North Dakota legislature convenes Jan. 8, with oil and gas expected to be the number one topic.

Whether it's how to spend oil revenue, how to additionally tax the industry, how to regulate it or how to fund repairs and additional infrastructure to support it, the 63rd Legislative Assembly will have just 80 days, by law, to pass a state budget and consider hundreds of new bills before the next session convenes in two years.

The good news is the State of North Dakota is projected to have a $1.6 billion surplus when the current biennium ends on June 30.

For beleaguered lawmakers another piece of good news is that after Jan. 14 representatives can only introduce five more bills each, with that opportunity coming to an end on Jan. 21. Senators have until Jan. 28 to introduce new bills.

Two news reports put the expected number of pre-filed bills close to a thousand.

One of the major focuses of North Dakota's legislative session this year will be adding state employees to deal with rapid growth in the state's oil fields.

Gov. Jack Dalrymple proposed adding 162 new positions across the state in his December budget address, with 155 of those jobs to enhance public safety and respond to population growth in western North Dakota.

Twenty-three of those new positions would be in the state Oil and Gas Division of the Department of Mineral Resources — 13 field inspectors and 10 administrative and geology positions.

The North Dakota Department of Health is slated for 10 new jobs in the governor's proposed budget, including environmental scientists and engineers to handle air quality compliance, oversee oil spill cleanup and monitor new drinking and wastewater facilities.

One of the key issues for western North Dakota that will be under consideration in the upcoming session is the state's oil production tax, in particular how a formula can be applied to the 5 percent tax that will better support the part of the state most impacted by the industry.

Dalrymple wants to change the formula so that it effectively doubles the revenue to oil counties.

The governor's proposed budget also recommends $2.5 billion for statewide transportation systems, plus an additional $1 billion for the North Dakota Department of Transportation.

—PETROLEUM NEWS BAKKEN

NATURAL GAS

ND continues to confront flaring

Pipeline authority-hosted webinar examines the ongoing flaring issue and technologies available to address stranded natural gas

By MIKE ELLERD
For Petroleum News Bakken

The North Dakota Oil and Gas Division and the North Dakota Pipeline Authority hosted a webinar Dec. 18 to address the ongoing issue of natural gas flaring in the state and to offer information on a variety of services available to producers to address stranded gas and reduce or eliminate flaring.

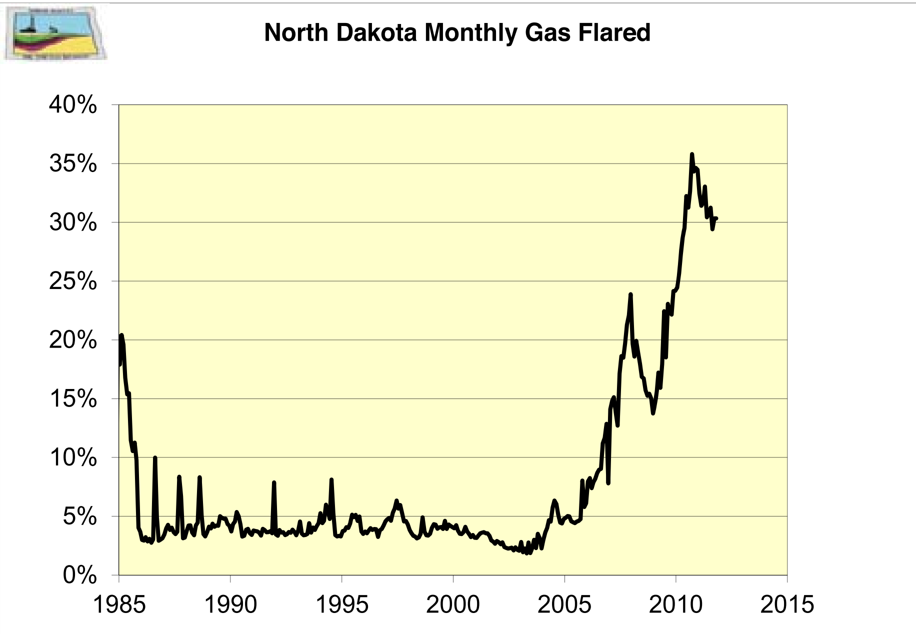
In his opening remarks, division Director Lynn Helms said that 30 percent of the natural gas produced in North Dakota was flared in October, and with gas production reaching a total of 796 million cubic feet for the month, that amounts to just under 240 million cubic feet of gas flared per day in the state. Flaring reached a peak of 36 percent in September 2011, but by August 2012 flaring fell to 29 percent before rising back up to the 30 percent flared in October 2012.


LYNN HELMS

Without a reduction in flaring, the problem will only get worse as production increases. Helms said North Dakota would like to reduce flaring to below 10 percent. However, by the time flaring is reduced to 10 percent, production projections indicate the state will be increasing production to between 2 million and 2.5 million cubic feet of natural gas, which puts the flared volume back upwards of 250 million cubic feet per day. It would be "great," Helms said, if the state could reduce flaring to 5 percent, which would lower the flared volume down to the 100 million to 125 million cubic feet per day range. "So short-term and long-term, there's tremendous opportunity in the utilization of flared gas."

ND Regulations

The North Dakota Industrial Commission has jurisdiction over the field rules. Helms says that typically under field rules, wells are allowed to produce unrestricted for 60 days in order to test the wells, but after the initial 60 days, production is limited to 200 barrels per day for the next 60 days, then to 150 barrels per day for another 60 days, and finally down to 100 barrels per day thereafter.



High: 36%, September 2011 Recent Drop: 29%, August 2012

But according to Helms, the Commission has not rigorously enforced that rule because of the large differential between oil and gas value and concern that enforcing the rule would potentially reduce the net present value of a Bakken well to 25 percent, which he said "would be a significant economic hit to the industry." However, Helms says the commission is eager to more rigorously enforce the field rule policies as flaring solutions are developed and made available.

Flaring itself is also regulated by the commission. The flaring rule states that produced gas can be flared for a period of one year, after which the well must be capped, connected to a gas gathering system or connected to an electrical generator that consumes at least 75 percent of the gas. If the producer violates the rule, taxes are imposed on the producer, and the producer must pay royalties to the royalty owners.

However, there is also a flaring exemption rule in North Dakota which allows continued flaring without the imposition of gas taxes and royalty payments if a producer can demonstrate that it would not be economically feasible to connect to a gathering system or to a generator,

Operators have been requesting "increasingly lengthy" exemptions to the field and flaring rules, according to Helms, and the commission has "tightened up" and is currently issuing only six month extensions. The commission, he said, is aware that new technologies are continually being developed, and is also aware of such other issues as changing oil prices as well as changing well economics. The commission, therefore, does not want to make long-term commitments based on short-term economics.

New legislation

Helms said he believes there will be "some pretty significant amendments" to these and other gas statues that deal with flare gas solutions in the upcoming legislative session.

Flaring reached a peak of 36 percent in September 2011, but by August 2012 flaring fell to 29 percent before rising back up to the 30 percent flared in October 2012.

He said Rep. Todd Porter of Mandan has already submitted a bill which he says will "change the landscape" in terms of tax exemptions, production exemptions, how utilization of flared gas is reported to the commission and how that reporting will relieve some liability concerns that operators have.

"And of course we're open to new ideas and new thoughts to make that the best possible piece of legislation it can be. We only get a chance to work on it every two years, so this will be a big piece of the puzzle of working on North Dakota's flare gas," Helms concluded.

Options for stranded gas

Eight firms that have developed or are developing technologies to address stranded natural gas at the wellhead were invited to share information on their specific areas of expertise during the Dec. 18 webinar.

Blaise Energy Inc., of Bismarck, offers a variety of solutions for wellhead gas. The company employs generators at the wellhead and uses wellhead gas to generate electricity that can either be used for site power or can to fed directly into the electrical grid. The company also provides an option for larger-scale electrical generation to power such operations as gas plants. It also can separate natural gas liquids, and is working on developing a process that converts methane to methanol.

Expansion Energy is a technology development company whose business model is to develop technologies and then license those technologies to other parties for implementation. It recently entered into a manufacturing partnership with Dresser Rand, and is developing a mobile

see GAS FLARING page 6

● COMPANY UPDATE

Gibson sets wide-ranging budget

By GARY PARK

For Petroleum News Bakken

Calgary-based Gibson Energy, a fast-expanding midstream service provider, has the Bakken on its long list of capital spending targets for 2013, having set a budget of C$304 million for internal growth investments and the upgrading and replacement of existing assets.

STEWART HANLON

Of the total, C$270 million is directed towards internal spending as the company aligns its budget towards what Chief Executive Officer Stewart Hanlon said is a "long-term objective of generating stable and growing cash flow for shareholders through an attractive dividend and a growing asset base."

He said the spending is heavily weighted towards the terminals and pipeline segment, "which should enable our integrated oil-levered assets to provide diversified cash flow and stability through various commodity and drilling cycles."

The strategic objectives for 2013 including expanding integrated service offerings in growing North American oil plays such as the Western Canada Sedimentary Basin, Bakken, Niobrara, Granite Wash, Eagle Ford, Tuscaloosa Marine and Gulf of Mexico regions.

The terminals and pipelines spending is primarily related to the construction of tanks at the Hardisty terminal in central Alberta, including the development of unit train and manifest crude rail loading facilities.

Budget could be modified

Significant investment is also planned for Gibson's environmental services segment, with the emphasis on the environmental and fluid handling business in the United States and expansion of current facilities and additional facility locations in Canada. The new business segment combines the Omni Energy Services U.S. assets with the Canadian Custom Treating and Terminals assets.

Gibson said the budget could be modified in response to business and economic conditions.

The company said it estimated capital growth spending for 2014 will be in excess of C$200 million, with about 60-65 percent allocated to the terminals and pipelines segment.

The strategic objectives for 2013 including expanding integrated service offerings in growing North American oil plays such as the Western Canada Sedimentary Basin, Bakken, Niobrara, Granite Wash, Eagle Ford, Tuscaloosa Marine and Gulf of Mexico regions.

That includes building and expanding on an investment platform stemming from the acquisitions of Palko Environmental and Omni Energy in emulsion treating, water disposal and oilfield waste management, while exploring alternatives to expand the terminal and pipelines business in the United States and expanding truck transportation to meet growing demand. ●

Contact Gary Park through publisher@petroleumnews.com

continued from page 5

GAS FLARING

liquid natural gas production system known as "VX Cycle," which is estimated to be commercially available by the third quarter of 2013.

LPP Combustion LLC is a fuel technology and equipment supply company with interests in using flare gas and natural gas liquids for onsite power generation. The company has a patented process for converting flare gas and natural gas liquids into a substitute natural gas for application in gas turbines, reciprocating engines, and duct and boiler burners onsite without having to separate out the liquids.

Wellhead Energy Systems LLP is a company that works in cooperation with Ohio-based EnerFab, an energy engineering, fabrication, field erected and maintenance services firm. Wellhead Energy employs mobile modular units that use natural gas to generate electricity which can be used onsite or transferred to an electrical grid.

Boewulf N-Flex LLC has a proprietary technology that converts methane to ammonia fertilizer at the wellhead. In this process, the natural gas liquids are separated out and the methane is converted to anhydrous ammonia. In November, Boewulf N-Flex received a $1 million grant from the North Dakota Industrial Commission to help the company get the company's first units into operation.

BX Energy of Billings, Mont., is a company that focuses on capturing and transporting gas to gathering pipelines. The company compresses gas and associated liquids at the wellhead and then transports the compressed mixture via truck to gathering pipelines.

G2G Solutions of Billings, Mont., utilizes refrigeration technology to separate natural gas liquids from produced gas at the wellhead. The units are fully integrated, mobile and scalable and can typically be moved from one location to another in less than a day.

Alternative Gas Processing Inc. is a manufacturer's representative firm whose primary principles are Tucker Gas Process Equipment and the midstream firm NGL Energy Partners. Collectively these firms offer an associated gas recovery, transport and marketing service.

The webinar can be heard on the North Dakota Pipeline Authority's website, and all of the presenter's slides are also available at that website. ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

Net acres held by major landholders in the Duvernay

Canadian Natural Resources	500,000 acres
Encana/Phoenix Duvernay Gas	445,000 acres
Talisman Energ	350,000 acres
Bonavista Energy	256,000 acres
Chevron	220,000 acres
Athabasca Oil	192,000 acres
Sinopec Daylight Energy	130,000 acres
PetroBakken	121,600 acres
ExxonMobil/Imperial Oil	110,000 acres
Husky Energy	55,000 acres
Angle Energy	46,700 acres
Bellatrix Exploration	27,500 acres

continued from page 3

DUVERNAY

though the Canadian play's costs remain about double those of its more-advanced Texas competitor because of the formations greater depth and location.

However, the Duvernay is overtaking British Columbia's Horn River, which is favored because of its distance from British Columbia ports for LNG exports, but whose drier gas puts breakeven costs at about C$4 per thousand cubic feet.

Gwozd said that because of a very high liquids content in part of the Duvernay the net value of the play could add C$3 for the liquids to C$3 for gas.

Following a recent speaking trip to Asia, he forecast that interest in the Horn River, Montney and Duvernay will be especially high in Malaysia, Vietnam, Singapore, India and the Philippines, which could lead moves to establish joint ventures to gain LNG exports.

Hopewell said the liquids content of the Duvernay means that play could provide diluents to thin oil sands bitumen for pipeline transportation, allowing Western Canada's tight gas and shale gas potential to edge ahead of the prolific Eagle Ford and Marcellus plays in the U.S.

The Alberta government's Energy Resources Conservation Board has estimated the Duvernay holds 443 trillion cubic feet of gas and 61.7 billion barrels of oil in place.

But not everyone is ready to climb aboard the booster bandwagon.

Canadian Natural President Steve Laut told a conference call the Duvernay is still short of the production rates required to yield a "very economic return on capital. So we are being cautious and taking our time to make sure we understand what's going on."

"The rates are a little less than what we would expect to see in a very economic return on capital," he said.

Service sector

In the service sector, Mazar said that while some large service companies have a "sprinkling" of assets and involvement in Western Canada, their fastest way to ramp up would likely be through acquisitions and offering an integrated service package including drilling, fracturing and well tie-ins.

He does not foresee a rush among Canadian service companies to join forces.

"I see Canadian companies looking abroad and looking to establish a foothold in some attractive international markets where it's a far lower risk to do an acquisition than it is to do organically," he said.

Scott Treadwell, TD Securities' vice president of equity research, oil and gas services, agreed with Mazar that as the Canadian E&P landscape changes so will the business realities of the sector.

"I think you're going to see consolidation driven partly by the sellers where the little guys see that they're just going to be (living off) table scraps from the big guys and also from the international integrated service companies," he said.

Treadwell suggested that as potentially large-scale resource plays emerge in Western Canada and as the Duvernay and LNG projects start to advance the region will gain in strategic importance among multinationals. ●

Contact Gary Park through publisher@petroleumnews.com

● FINANCE & ECONOMY

Economic uncertainty undercuts confidence

Energy company CFO survey shows increasing pessimism in regard to accessing sources of financing for 2013 capital investments

PETROLEUM NEWS BAKKEN

Sixty percent of U.S. oil and gas chief financial officers, CFOs, who responded to a national survey say they feel more pessimistic this year than last on the state of the U.S. economy and its impact on demand for oil and gas.

This is reflected in a drop in sentiment about accessing capital and credit. In 2011, 73 percent of CFOs felt positive about accessing additional sources of financing, compared to just 59 percent this year.

The survey found that 31 percent of U.S. energy companies plan to increase their capital investments for 2013 in non-conventional areas, including shale, while only 26 percent plan to invest in more environmentally friendly exploration and processing technologies.

These are among the findings from the 2013 BDO Energy Outlook Survey, which examined the opinions of 100 CFOs at U.S. oil and gas exploration and production companies. BDO USA LLP, a self-described leading U.S. accounting and consulting organization, conducted the survey in September and October.

Counting on shale plays

Companies are banking on a combination of continued development of shale plays, an increase in prices and new production technologies to help turn their investments into a profit, the survey found.

Hydraulic fracturing issues remain companies' biggest environmental concern for a second year, as cited by 44 percent of CFOs, followed by 25 percent who view spills and pollution cleanup as their top concern.

As shale production in the United States continues at a rapid pace, 77 percent of the CFOs surveyed expect the domestic supply of oil to increase in 2013. In addition, 69 percent of CFOs also see natural gas supplies on the rise.

"The marketplace opportunity promised by the continued development and production of non-conventional energy sources is at perhaps its highest level in years," said Charles Dewhurst, practice leader in the natural resources industry group at BDO. "Shale resources are at the center of this opportunity and, today, energy companies have actively begun to embrace shale and have made it a central component of the U.S. oil and gas industry's growth strategy for the future."

Doubts over economy grow

However, only 50 percent of CFOs expect demand for oil to increase in step with supply, concerns said to be fueled in part by ongoing doubts about the strength of the U.S. economy.

Additional findings from the 2013 BDO Energy Outlook Survey include:

A plurality of CFOs (44 percent) say ongoing turmoil in the Middle East, more than fears of a double dip recession (22 percent) or the European debt crisis (16 percent), will have the greatest impact on oil prices in the coming year.

"This demonstrates the extent to which U.S. oil and gas companies have adapted to the economic push and pull of the last several years, as well as challenging geopolitical dynamics at home and abroad," Dewhurst said. "Yet they retain optimism the industry will be able to surmount these ongoing uncertainties."

Government regulation continues to be on the minds of industry leaders, with 63 percent reporting that regulations have resulted in delays or terminations of projects during the past 12 months, compared with 56 percent a year prior. As the next Congress convenes in January, 36 percent fear more restrictive government regulation in 2013, followed by 28 percent who think tax proposals targeting the energy sector, including possible corporate tax hikes, lie ahead.

Legislative issues big concern

Half of the CFOs surveyed say legislative issues will be the biggest factor inhibiting growth of the sector moving forward. And, for the fourth consecutive year, more CFOs (37 percent) see legislative changes posing the sector's greatest financial challenge heading into 2013, ahead of low prices (36 percent) and access to capital and credit (17 percent).

"There was a lot of talk about the need to be energy independent during the recent election," said Clark Sackschewsky, a partner in BDO's natural resources practice. "Now that politicking is over and the legislative process resumes, companies are anxiously looking to see the extent to which Congress addresses the important energy issues that lie ahead."

As an independent member firm of BDO International Ltd., BDO USA LLP, a Delaware limited liability partnership, is the U.S. member of BDO International, a UK company. BDO serves multi-national clients through a global network of 1,204 offices in 138 countries. ●

Editor's note: The Bakken petroleum system is often, albeit mistakenly, referred to as a shale play, even though 99.9999 percent of its production comes from tight, non-shale, sands.

MOVING HYDROCARBONS

Targa closes Saddle Butte buyout

On Jan. 2 Targa Resources Partners announced that it closed on its acquisition of Saddle Butte Pipeline's ownership in Saddle Butte's Williston Basin crude oil pipeline and terminal system as well as Saddle Butte's natural gas gathering and processing operations. The $950 million deal was first announced in November. The new business will be known as Targa Badlands.

All of the assets are located in McKenzie, Dunn, and Mountrail counties, and include approximately 155 miles of crude oil pipelines, the Alexander Terminal with storage capacity of 30,000 barrels, and the Johnsons Corner Terminal with a storage capacity of 20,000 barrels that is being expanded to 40,000 barrels. Also included are approximately 95 miles of natural gas gathering pipelines and the Little Missouri plant which had an initial capacity of 20,000 cubic feet per day, but is being expanded to 40,000 cubic feet per day.

—MIKE ELLERD

COMPANY UPDATE

Abraxas says production may be up 28%

Abraxas Petroleum Corp. expects 2013 daily production to average between 4,900-5,200 barrels of oil equivalent, a hefty 21-28 percent increase over average daily output of 4,300-4,500 boe in 2012.

The San Antonio, Texas-based producer anticipated its 2012 production exit rate to be substantially higher than fourth quarter average volumes, based on the expected completion of four wells in Abraxas' continuous drilling program in the Bakken and Eagle Ford plays.

Abraxas also recently adopted a preliminary 2013 capital expenditure budget of $70 million, the same amount initially approved for 2012, before any budget adjustments during the year.

All of the $70 million in capital spending currently earmarked for 2013 is focused on new wells in Abraxas' core basins — $47.7 million for the Bakken, $21.6 million for Eagle Ford, and $700,000 for the Permian. Abraxas said it plans to keep one drilling rig continuously operating in the Bakken and Eagle Ford throughout 2013.

Assets being marketed

Meanwhile, Abraxas continues to market numerous assets, which it deems non-core, assets with a low working interest or assets with little associated production. The company recently netted about $22 million on the sales of its non-core Nordheim Eagle Ford and Alberta Basin properties.

"Our business plan, capex schedule and recent asset sales exemplify the strides we are making in executing on our stated plan of refocusing the portfolio on our core basins, delivering the balance sheet and growing the production base off high working interest wells in our core basins," said Bob Watson, president and chief executive officer of Abraxas.

"Furthermore, our divestiture activity and schedule remains quite active and ongoing. We look forward to updating the market regularly as we continue to execute on our stated business plan."

—RAY TYSON

MERGERS & ACQUISITIONS

Bakken helps Enerplus reshape portfolio

Enerplus Corp. has closed the acquisition of additional working interests in Montana Bakken property for US$119 million including estimated closing adjustments. The assets in the Sleeping Giant area in the Elm Coulee field in Montana's Richmond County include about 6.2 million barrels of oil equivalent of proved plus probable reserves and production of 1,500 boe per day.

The deal consolidates the company's working interest to about 90 percent in the operated leases, giving Enerplus net output of 7,300 boe per day.

The Calgary-based company also announced it has closed the sale of crude oil assets in Manitoba for C$216 million. They were producing 1,600 boe per day of crude oil under waterflood and had an estimated 8.4 million boe of estimated proved plus probable reserves.

Enerplus said the transactions are consistent with its strategy of focusing its portfolio through the sale of non-core assets and consolidating its interests in core areas.

By reinvesting about half the proceeds from the Manitoba sale, the company said it has replaced the sold production, improved the concentration of its asset base and improved its operating metrics.

—GARY PARK

LAND & LEASING

Enterprise acquires Montana leases

The wholly owned U.S. subsidiary of Vancouver-based Enterprise Energy Resources has completed the acquisition of 46,000 net acres of oil and gas leases in Cascade Country, Mont., that it hopes will demonstrate values in common with the nearby Southern Alberta Bakken and the main Bakken play in the Williston Basin further to the east, where most of the production comes from western North Dakota.

The deal by Evolution Oil Group with an arm's length third party carries an aggregate purchase price of $2.1 million, or $45 per net mineral acre.

The terms include a disposition bonus equal to about 30 percent of net realized profits that Evolution will pay to the seller, plus a production bonus equal to $1.5 million from any commercial production on the leases.

Enterprise President and Chief Executive Officer Geoff Carrington said the acreage is "on trend with recent, successful wells" in the emerging Southern Alberta Bakken (in adjacent Montana counties of Lewis and Clark and Teton) and has "similar characteristics" to the North Dakota Bakken.

In July Evolution sold 100 percent of oil and gas leases covering 15,971 net mineral acres in the Montana portion of the Williston Basin to an arm's length third party for $19 million, leaving Evolution with a 100 percent working interest (80 percent net revenue interest) in another 14,000 acres.

—GARY PARK

● TECHNOLOGY

Technology reverses Alberta oil output

By GARY PARK
For Petroleum News

More innovations in the use of leading-edge drilling and completion technology will unlock billions of barrels of crude oil in Western Canada, raising output for at least the next five years, industry leaders forecast.

The turnaround is already evident in Alberta where unconventional methods have raised conventional production from 459,000 barrels per day to an expected 600,000 bpd in 2012, with more gains in sight, said a report by the Canadian Association of Petroleum Producers.

The report said the combination of horizontal drilling and hydraulic fracturing is yielding results in the most advanced plays in the Cardium, Beaverhill Lake Carbonate and Viking formations.

CAPP predicted that stepped up drilling activity in the Southern Alberta Bakken, Duvernay and Montney plays will offset what would otherwise have been a sharp decline in conventional volumes, which posted a steady decline over the four years from 2006.

BMO Capital Markets analyst Gordon Tait said early results from the Cardium have pointed to a reversal of annual production for the whole basin.

"Current reserve numbers and production forecasts do not reflect the true potential of development of the old and new plays such as the Cardium and Bakken," he wrote.

"With new drilling technology, producers are able to recover more of the oil-in-place," adding to the current recovery of 25 percent-30 percent, he said.

That optimism is echoed by producers such as Enerplus Resources and Baytex Energy.

Enerplus has tagged 81 percent of its 2013 capital budget of C$685 million for development drilling and well completions, while Baytex said technology has boosted its output by 20 percent over the past year to 21,350 bpd from a key asset in the Peace River region of northwestern Alberta.

> *"Current reserve numbers and production forecasts do not reflect the true potential of development of the old and new plays such as the Cardium and Bakken."*
> —BMO Capital Markets analyst Gordon Tait

Marginal drilling increase

The Petroleum Services Association of Canada forecast a marginal increase in cross-Canada drilling to 11,400 wells in 2013 from an expected 11,240 in 2012, with Alberta accounting for 7,050 wells, 87 percent oil-related and the rest targeting natural gas.

Alberta Energy Minister Ken Hughes is confident there are "still a few prizes to be won" in his province's conventional sector.

He said the game-changing role of technology "is a phenomenon that will not go away soon," as Alberta benefits from what is learned across North America.

However, regardless of the upbeat views, drilling activity in Western Canada has been sluggish as the industry enters its traditional peak period.

Surveys indicate that only 48 percent of 792 rigs were active in 2012, compared with 57 percent of 802 rigs in 2011, although the utilization rate was still the second highest since 2066 when 63 percent of rigs were at work.

The sharpest drop was in gas-prone British Columbia where the rate fell 31 percent to 38 rigs from 55 active rigs in 2011.

Alberta recorded a 12 percent decline to 269 rigs from 307 rigs in 2011 as operators shifted their attentions to oil wells, while Saskatchewan also reported a 12 percent decline to 71 rigs.

The utilization rate in Western Canada in mid-December reached 53 percent or 433 rigs, with Husky Energy leading the drillers at 29 rigs, followed by Encana at 20 and Canadian Natural Resources at 18. ●

Contact Gary Park through publisher@petroleumnews.com

COMPANY UPDATE

SM Energy allots $290M for Bakken

SM Energy announced its 2013 capital expenditure budget and performance guidance on Dec. 19, and the company says it expects to invest $290 million in Bakken and Three Forks drilling and completion in the coming year.

The focus in the Bakken will be on the SM Energy's Bear Den, Raven and Gooseneck prospects in McKenzie, Williams and Divide counties. The company will operate approximately 80 percent of the capital earmarked for the Bakken program in 2013 and is planning on 40 flowing completions in the operated portion of the program.

SM Energy will begin the year with four operating drill rigs, but with pad drilling efficiencies it expects to average three and a half rigs throughout the year.

Overall, SM Energy is planning to spend a total of $1.2 billion on drilling and completion in a number of plays. The largest allocation is $650 million in the Eagle Ford, followed by the Bakken at $290 million and the Permian at $170 million. Combined, spending in these three plays constitutes approximately 90 percent of the company's total 2013 drilling and completion budget.

"Our 2013 capital program positions the company for another year of record production while generating strong returns from our key projects," said Chief Executive Officer Tony Best. "The capital budget is anchored by our high return Eagle Ford and Bakken/Three Forks development programs, with additional investments being made in emerging oil programs in the Permian Basin. Our production mix will continue to shift from lower value natural gas to higher value liquids throughout the year."

The company anticipates 2013 production to increase 20 percent over 2012, which will be a mix of 50 percent natural gas, 29 percent oil and 21 percent natural gas liquids.

—MIKE ELLERD

continued from page 1

DENBURY DEAL

bpd of oil, bumping Marathon Oil out of the sixth position with 29,313 bpd, and coming in behind Brigham Oil & Gas, a subsidiary of Statoil, which operates North Dakota Bakken wells that produce an average of about 45,597 bpd.

The top four North Dakota Bakken oil producers in October were Continental Resources at approximately 66,155 bpd; Whiting Oil and Gas at 63,126 bpd; Hess at 60,137 bpd; and EOG Resources at 47,847 bpd.

Again, these numbers represent oil produced from wells operated by these companies; the monthly update from NDIC's Department of Minerals, Oil & Gas Division, does not identify the percentage of Bakken system oil (including Three Forks) that is owned by the operator, nor does it identify the amount of oil that is produced from wells operated by others in which these companies have an interest.

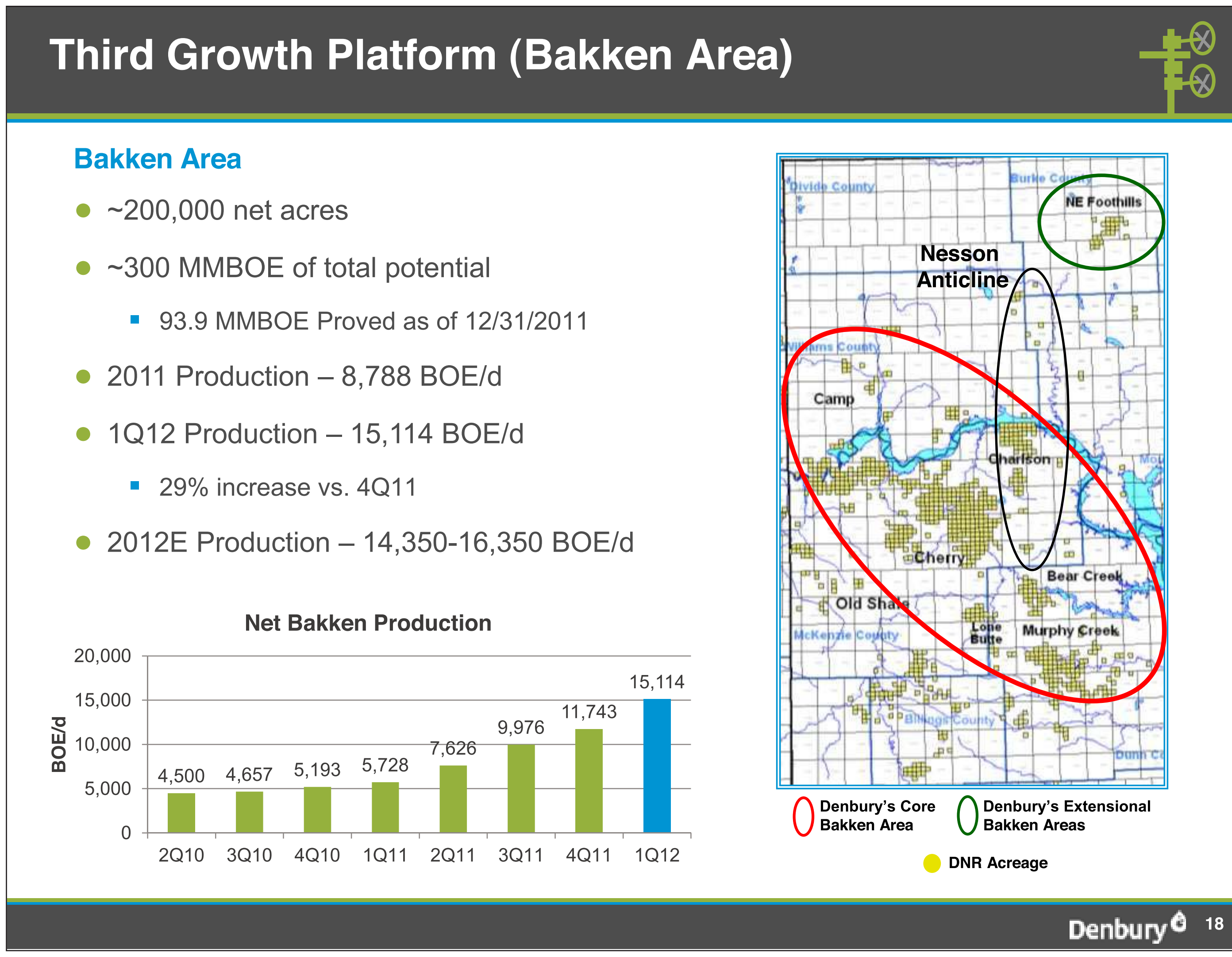
The ranking and output by company from NDIC's numbers, which are organized by field, is done monthly by Petroleum News Bakken.

What Exxon and Denbury have provided in written and verbal statements was the barrels of oil equivalent involved in the transaction, which would result in a slightly higher number since natural gas, a relatively small part of Bakken output, is included.

When the deal was announced in September the companies said that when it closed at the end of the year it would increase XTO's output from approximately 32,000 barrels of oil equivalent per day in second quarter to 47,000 boe per day by including Denbury's anticipated oil and gas year-end output of 15,000 boe per day — a notable difference from NDIC's preliminary October number of 32,100 bpd of oil when XTO/Exxon and Denbury output was combined.

The difference was likely due to a significant percentage of non-operated oil in Exxon's estimate.

While the numbers supplied by Bakken producers might or might not include gas, be broken down by month, or even separate out vertical wells that seldom include Bakken petroleum system production, Continental Resources periodically provides a list of the top oil producers in the U.S. Williston Basin, which put five companies at the top of the list for the third quarter. They were ranked as Continental, No. 1; Hess, No. 2; Whiting, No. 3; EOG, No. 4; and Statoil/Brigham, No. 5. The only difference from the preliminary October NDIC figures as interpreted by Petroleum News Bakken was that Hess and Whiting's positions were reversed.



This slide is from a Denbury corporate presentation in June 2012. Its deal with ExxonMobil and XTO was announced in September.

Growth by acquisition and drill bit

It's reasonable to assume from what Exxon has said about XTO's work on the 400,000 net acres they owned prior to the

see **DENBURY DEAL** *page 12*

continued from page 1

PAD DRILLING


VERN WHITTEN PHOTOGRAPHY

Williston Basin energy corridor with 14 multi-well pads

Although pad drilling has only come into widespread application in the Bakken in the last two to three years, the method dates back to the early days of production in Prudhoe Bay, according to Denny Smith, director of corporate development for Nabors Drilling, the largest drilling contractor in the Williston Basin. Smith said true commercial pad drilling began in Prudhoe Bay in response to environmental concerns and the need to minimize surface impacts.


"My sense is that for the total population of wells out there it's relatively early, but it's emerging fast." —Denny Smith, Nabors Drilling

While the same fundamental method is used for offshore production, Smith said for years it simply was not cost effective on land in the Lower 48 states. However, as technologies advanced, pad drilling eventually became more feasible and found application in places like the Piceance Basin of Colorado where wells were clustered on single pads in rough, mountainous terrain.

Now, coupled with North Dakota's standard 1,280-acre spacing unit, pad drilling is facilitating production while minimizing surface impacts in the Bakken.

ND's 1,280-acre spacings

Alison Ritter, public information officer for the Oil and Gas Division of the North Dakota Industrial Commission, said North Dakota set standardized, north-south 1,280-acre well spacings in early 2010, not only to minimize surface impacts but also to organize those impacts. She said knowing that laterals can be successfully drilled up to two miles long, it made sense for the state to set the spacing units that combine two sections in a one- by two-mile unit.


"If you're just randomizing where you're placing these 1,280 acres, you're probably not going to have the best desired outcome on the landscape." —Alison Ritter, North Dakota Oil and Gas Division

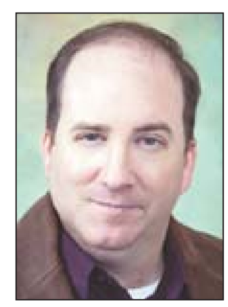
But Ritter said it also made sense to arrange those two-section spacing units into an organized grid. The state's preference was to configure two sections, one on top of the other, into a single 1,280-acre "standup" spacing unit. The standups were then arranged in side-by-side patterns and accessed either from the north or the south via east-west trending service roads.

"If you're just randomizing where you're placing these 1,280 acres, you're probably not going to have the best desired outcome on the landscape. But if you can take a giant puzzle and put the pieces together first, and then go back and draw your picture, you have a better idea of how things are going to look when everything's done." Ritter uses several aerial photographs of energy corridors and multi-well pads to illustrate this concept when she gives presentations to the public.

Ritter said the reduction of surface impacts is one of greatest benefits of pad drilling. With conventional drilling, surface impacts from oil production were almost 10 percent of a spacing unit, but with pad drilling, she said, those impacts can now be less than 0.4 percent. Being able to maximize the recovery of oil while minimizing impacts on the landscape is part of North Dakota's mission statement, she said, adding "we want to realize the greater good from this resource, but we want to minimize the impact that it has on our landscape and our people."

Allowing for green spaces

Drew Combs of North Dakota's Trust Lands Minerals Management Division agrees that pad drilling is a good management plan for energy corridors that allow for large green spaces. "The Industrial Commission is managing not only for the producers but also for the people that utilize the surface." The larger spacing units, Combs said, allow for the production of oil from a tract while maintaining a minimal surface footprint. "Smaller footprint, more production," he said.


"Smaller footprint, more production." —Drew Combs, North Dakota Trust Lands

Combs said he sees 1,280-acre spacing continuing as the trend for future production, but he said his concern is for areas where those spacings are not feasible due to terrain constraints such as in the Bad Lands. Where feasible, Combs said, he would promote larger spacing units in such areas.

Maximizing recovery

Rick Muncrief, senior vice president of operations for Continental Resources, said his company worked with the North Dakota officials to develop spacing units that would maximize recovery. In conventional plays, Muncrief said, "setbacks" or buffer zones are implemented to prevent a producer in one spacing unit from extending into and draining the reservoir from an adjacent spacing unit. A setback of 600 feet, which is not uncommon in conventional plays where oil is mobile, results in 1,200 total feet of reservoir that is not developed.


Being able to drill two miles down and three out and have successful completions is another step change in oil and gas production. "It just shows you the power of the technology with horizontal drilling." —Rick Muncrief, Continental Resources

However, Muncrief said North Dakota had the foresight to realize that in tight, unconventional reservoirs such as the Bakken where the oil is immobile, reservoir drainage from an adjacent spacing unit was not the issue it is within conventional reservoirs, and he said the state regulators worked with all the stakeholders to deliver appropriately reduced setbacks to allow as much of the reservoir to be drained as possible within the confines of a single spacing unit.

Continental was one of the first companies to employ pad drilling and coined the term "ECO-Pad" accounting for the ecological advantages from minimizing the surface footprint, as well as the economic benefits associated with centralized locations. The ECO-pad, Muncrief said, "gives you a relaxed setback, and that's what differentiates it from other pad drilling in more traditional development."

Statoil's Lance Langford, vice president for development and production in North America, agrees that one of the biggest reasons for pad drilling on larger spacings is a much smaller surface footprint. Langford said that Statoil is currently looking to drill up to seven wells per pad in some areas, and that a seven well pad is only approximately 1.7 times the area of a single well pad. Having seven wells with less than twice the additional surface disturbance of a single well provides additional efficiency, according to Langford.


"Even in slow times, the preference for operators will be for the new walking rigs, so that's incentive for drilling contractors as well." —Lance Langford, Statoil

Another added efficiency, according to Langford, is that twice as much reservoir can be accessed in a 1,280-acre unit as in a 640-acre unit, with the only additional cost drilling the extra approximately 5,000 feet of lateral, which he said is "fast drilling."

Less infrastructure

Not only does pad drilling result in a smaller surface footprint, but it can also result in less infrastructure, according to the Oil and Gas Division's Ritter. She said pad drilling on a large spacing unit allows producers to install infrastructure such as pipelines and electricity only once rather than having to install multiple lines to multiple locations in the unit, "dotting all over the landscape."

According to Statoil's Langford, a further advantage is that oil is often transported from the wellhead to major transportation hubs via truck, but with multiple wells in close proximity there can be sufficient volumes of oil to justify installation of gathering pipelines. The same can hold true for water, and at many sites, Langford said, Statoil brings fresh water in and takes production water out through pipelines.

Langford also said that more contiguous acreage helps to justify the cost of

see **PAD DRILLING** *page 11*

continued from page 10

PAD DRILLING

installing pipelines. The most favorable economics, he said, result from a combination of having multiple wells on single pads and having multiple pads in a given geographic area.

Langford pointed out that with such pipelines in place, the number of truck service trips decreases significantly over the lifetime of a well. He said with the oil and water pipeline systems that Statoil has installed to date, the company has eliminated more than 100 round truck trips per day in the basin. That number, he said, is growing and he is hopeful that by the end of 2013 Statoil will be able to eliminate upwards of 300 truck trips a day.

And another advantage that Smith of Nabors saw with pad drilling in Prudhoe Bay was the positive economics associated with downspacing as well as with additional exploration. As production in an area matures, companies begin looking at capturing more of the marginal resources, whether that is through downspacing or looking at shallower or deeper sources. With all of the infrastructure and processing capability already in place, Smith said, the additional cost to develop those other resources becomes economically feasible.

Zipper fracking

Another benefit to pad drilling is in what Statoil's Langford calls "zipper" fracking, where one crew fracks multiple wells on a pad in a single operation by manifolding the wells together. With this process, Langford said, four wells can be fracked in the time it used to take to frack a single well.

In zipper fracking, the first zone in the first well is perforated and fracked after which the well is isolated from the other wells with the manifold. Then the first zone in the second well is perforated and fracked. While the second well is being fracked, a plug is placed in the first well so that the second zone in the first well can be fracked. These simultaneous tasks continue in succession until all zones in all wells are fracked. According to Langford, this zipper fracking process has been one of the biggest cost savings associated with pad drilling.

Specialized rigs

Efficient pad drilling also requires specialized "walking" rigs that can readily move from one well location to another on a pad, according to Smith. Only a small percentage of the rigs currently operating in the U.S. have that specialized design, but Smith believes that as pad drilling becomes the norm, more and more specialized rigs will be built. He said Nabors currently has approximately 90 drills either in service or being built that are capable of pad drilling, most of which are true walking rigs. A large number of these rigs, he said, are in or headed to the Williston Basin.

Continental's Muncrief said his company currently has 20 contract drill rigs operating in the basin, about two thirds of which are walking rigs. While there will probably always be some market for conventional drill rigs, Muncrief believes that over time the drilling contractors that have the walking capabilities "are the ones that are going to truly provide producers with the flexibility that they need and the efficiency that they need."

Backup of rig orders

In his monthly webinar on Dec. 17, Oil and Gas Division Director Lynn Helms said there are large numbers of walking

NABORS DRILLING

A modern walking drill rig

rigs currently under construction. Several operators with whom he has spoken said they plan to replace conventional rigs with walking rigs over the next few months. He added that there is a backlog of rig orders but those new walking rigs should be delivered in the next six to 12 weeks.

Most walking rigs have stationary "backyards," the part of the rig that houses such ancillary equipment as electrical generators, fuel tanks, water tanks and mud pumps. These rigs, according to Helms, can drill a maximum of four wells without having to stop, break down and move the backyard. He added that one company is already looking at a walking rig with a mobile backyard that walks with it.

Helms estimated that approximately 50 percent of the rigs currently operating in the Bakken are walking rigs. "Most of the companies want to get to the point where they only have one or two conventional rigs in their portfolio, and all of the rest walk." He said by the end of 2013 the goal of many operators is to be at 75 percent walking rigs, and eventually reach 80 or 90 percent by sometime in 2014.

More wells and longer laterals

According to Muncrief, Continental continues to increase the number of wells per pad and just started on its first 14-well pad with plans for another 14-well and a 16-well pad in 2013. In addition, Continental is experimenting with three-mile laterals and has already drilled and completed one three-mile lateral in Montana, which is now on production. Continental is currently drilling two other three-mile laterals in North Dakota.

Being able to drill two miles down and three out and have successful completions, Muncrief said, is another step change in oil and gas production. "It just shows you the power of the technology with horizontal drilling."

Downsides

According to Ritter, while the good definitely outweighs the bad, there are some downsides, the biggest of which she said is for people living on service roads. On an east-west road where an energy corridor is being developed there are traffic impacts "that, you cannot escape." She said the larger spacings are the best management strategy, "but try telling that to somebody who lives there."

Another issue with pad drilling according to Muncrief is that a single well can go on production as soon as it is completed. With multiple wells on a single pad, however, they all have to be drilled and completed before any go on production, resulting in some delay, although Muncrief said that is really a minor issue and he doesn't see any significant downsides to pad drilling.

Langford said a potential downside that he sees is in having sufficient takeaway capacity for all the wells on a pad when they all come on production at the same time and initial production rates are high. He said if there isn't sufficient pipeline capacity, then trucks have to be used to handle the initial volumes.

The way of the future

Increasingly, other Bakken operators are moving to pad drilling as well. For example, Oasis Petroleum is transitioning to pad drilling and is looking for full pad development in 2013; Hess Energy announced in its third quarter 2012 production results that the company is transitioning to pad drilling; WPX Energy is converting is drill rig fleet for pad drilling; SM Energy began transitioning to pad drilling early in 2012; and Pioneer Drilling is planning to add 10 walking rigs to its fleet in the coming year.

Statoil's Langford believes that multi-well pads will be the norm, even though, as he said, they are a huge capital investment. By early 2013, Statoil hopes that all of its 12 contract Bakken rigs will be walking systems. "Even in slow times, the preference for operators will be for the new walking rigs, so that's incentive for drilling contractors as well."

Continental's Muncrief said he believes the drilling technologies being used in the Williston Basin are driving the technological advances in pad drilling, and he also believes that pad drilling will become the norm in the Bakken. "We're to the point we're getting far enough down the road where the pad-type drilling will be more of the norm as you go forward."

Smith of Nabors also agrees and believes pad drilling will become the norm in the Bakken and similar plays. "My sense is that for the total population of wells out there it's relatively early, but it's emerging fast." ●

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

DRILLING & COMPLETION

Oasis proposing Cottonwood-Bakken expansion

Oasis Petroleum filed an application with the North Dakota Industrial Commission in late November to extend the outline of the Cottonwood-Bakken pool in Burke and Mountrail counties, and to establish 23 new 1,280-acre spacing units with up to eight horizontal wells per pad for a possible maximum of 184 new wells. (See related story about other such applications on page 1 of this issue.)

The existing spacing in the area consists of a mix of 640-acre units as well as on-pattern and off-pattern standup and laydown 1,280-acre units. The proposed new spacing would consist of 20 standup and 3 laydown 1,280-acre units. Oasis says the new spacings would result in less surface footprint and would not only be more economical for the company but also better for the landowners.

The new wells would target both the Middle Bakken and the Three Forks with the wells split approximately evenly between the two reservoirs. The Middle Bakken in the area ranges from approximately 35 to 50 feet thick with an average of approximately 40 feet thick, according to Oasis.

Estimated ultimate recoveries are estimated at 425,000 barrels for the Middle Bakken and 400,000 barrels for the Three Forks, and corresponding recovery factors of 2.89 and 5.69 percent, respectively. Gas-to-oil ratios are estimated at 930 cubic feet per barrel in the Bakken and 700 cubic feet per barrel in the Three Forks.

Oasis estimates that the Bakken wells will cost approximately $10 million each, and the Three Forks wells approximately $10.2 million.

—MIKE ELLERD

MOVING HYDROCARBONS

Seaway expansion nearly complete

Seaway Pipeline announced Jan. 2 that it is in the final stages of increasing capacity on its 500-mile, 30-inch crude oil pipeline running from Cushing, Okla., to the Gulf Coast. The capacity is being increased from approximately 150,000 barrels per day to approximately 400,000 bpd.

Transportation on the pipeline was temporarily suspended in order to make final pump station connections. Service is expected to resume by Jan. 11.

Seaway is a joint venture between Enbridge and Enterprise Products Partners. The pipeline includes a terminal and distribution hub in Texas City, Texas, that provides crude oil from the pipeline to Houston-area refineries. The Seaway provides Enbridge customers with access to Gulf Coast refineries.

—MIKE ELLERD

continued from page 9

DENBURY DEAL

Denbury addition, that Exxon will not only grow Bakken production from acquisitions but also from XTO drilling.

XTO's production from the Bakken petroleum system more than doubled between mid-2010, when Exxon entered the Williston Basin with its acquisition of the independent, and mid-2012, an Exxon executive said July 26.

"We have moved into a development phase across our roughly 400,000 net acre leasehold. In the first half of 2012, we turned 40 wells to sales, nearly double the pace of 2011. In the second quarter of 2012, our gross operated Bakken production increased by 60 percent over the prior year quarter. Since our entry into the play, we have more than doubled gross operative production to approximately 32,000 oil equivalent barrels per day," David Rosenthal, Exxon vice president of investor relations, said in a second quarter earnings call.

From an "Exxon Mobil perspective, I can tell you as we move out of these delineation appraisal and valuation of programs into full development, you'll continue to see the ramp-up … particularly in places like the Bakken," Rosenthal said, per a presentation transcription provided by www.SeekingAlpha.com.

In a Nov. 1 third quarter earnings call, Rosenthal talked about Exxon's commitment to increase its liquids production in places such as the Bakken.

He also said the Denbury acreage was "located close to current XTO development areas generating further efficiencies." (The majority of Denbury's leases are in northeast McKenzie and northwest Dunn counties per the adjacent Denbury map.)

In the two years it owned Bakken assets, Denbury focused on reducing costs which critics say hurt production. Also, Denbury, like its E&P peers, drilled wells to hold acreage, which will allow XTO to begin pad drilling — i.e. development — in areas that are very prospective for the middle Bakken member and the first two benches of the Three Forks formation.

According to press releases from Exxon and Denbury some of the acreage that changed hands is in Montana, although that is not reflected in Denbury's Bakken map and neither company said how much was in Montana.

Doing what they do best

The deal with Exxon and XTO allows Denbury to focus on what its President and CEO Phil Rykhoek thinks it "does best" — flooding older oil fields with CO_2 to extract the oil left behind.

"We acquired our Bakken assets in the 2010 Encore acquisition. We are pleased with our development activities in the Bakken. … This trade allows us to … leverage our Bakken position to acquire two of the top oil fields in our core operating regions that are candidates for CO_2 flooding, while also adding incremental CO_2 resources in the Rocky Mountain region," Rykhoek said Sept. 20, referring to the Webster field in Texas and Hartzog Draw field in Wyoming and the CO_2 reserves in Wyoming that Denbury received in the deal.

While Denbury is focused on tertiary oil recovery operations, Exxon subsidiary XTO has a 25-year track record of investing in and understanding how unconventional resource bases can be profitably commercialized — a perfect fit for the productive tight oil reservoirs in the Bakken petroleum system.

While the purchase and asset exchange between Exxon/XTO and Denbury is a win-win for those companies, the deal should also prove beneficial for North Dakota because of Exxon and XTO's commitment to increasing liquids production and their record of quickly building needed infrastructure, such as natural gas plants and pipelines. ●

Contact Kay Cashman at publisher@petroleumnews.com

North Dakota Well Operator Transfers/Changes November & December 2012

November 6
From: Denbury Onshore, LLC
To: Encore Energy Partners Operating LLC
#06992 — Federal 5-33A, SWNW 33-143N-100W, Billings Co.

November 7
From: North Plains Energy, LLC
To: XTO Energy Inc. (operates ExxonMobil's Bakken assets)
#23104 — Hartsoch 15-35-1H, SWSE 35-157N-96W, Williams Co.

November 8
From: Upton Resources U.S.A. Inc.
To: Williston Exploration, LLC
#15126 — Davis Creek 1-28H, SWSW 28-139N-100W, Billings Co.
#15024 — Tracy Mountain Federal 10-1H, NENE 10-138N-101W, Billings Co.
#15100 — Tracy Mountain Federal 12-2, NWSW 2-138N-101W, Billings Co.
#16010 — Federal 13-2H, NWSW 2-138N-101W, Billings Co.
#12078 — Sun 10-7, NWSE 7-138N-99W, Stark Co.
#14878 — Upton Et Al S. Fryburg 2, SESW 6-138N-100W, Billings Co.
#14994 — Tracy Mountain Fryburg 3-1H, SESE 3-138N-101W, Billings Co.
#15053 — Tracy Mountain Federal 3-2H, SESE 3-138N-101W, Billings Co.
#15087 — Davis Creek 1-32H, SWSW 32-139N-100W, Billings Co.
#14770 — Tracy Mountain Federal 10-3, NWSE 3-138N-101W, Billings Co.
#15116 — Rocky Hill 1-7H, SWSW 7-138N-99W, Stark Co.
#15120 — Davis Creek 2-32H, NESE 32-139N-100W, Billings Co.
#15198 — Davis Creek 2-8H, NENW 8-138N-100W, Billings Co.
#15209 — Federal 2-13, NESE 13-138N-102W, Billings Co.
#15261 — Federal 3-13H, NESW 13-138N-102W, Billings Co.
#15283 — Rocky Hill 1-6H, SESW 6-138N-99W, Stark Co.
#15305 — Rocky Hill 1-18H, NWSW 18-138N-99W, Stark Co.
#16450 — Davis Creek 1-27H, SWSW 27-139N-100W, Billings Co.
#16526 — Tracy Mountain Federal 1-18H, NESE 13-138N-102W, Billings Co.
#90098 — Davis Creek SWD 1, NESE 32-139N-100W, Billings Co.

From: Eland Energy, Inc.
To: Ulmer Energy, LLC
#11578 — Habermeyer 33-13 1, NWSE 13-153N-102W, Williams Co.

From: Ulmer Energy, LLC
To: Williston Exploration, LLC
#10385 — Cameron 1-20, NESW 20-139N-102W, Billings Co.

November 16
From: CCS Midstream Services, LLC
To: Tervita, LLC
#01156 — KT Enterprises 24-19 SWD, SENE 19-152N-95W, McKenzie Co.
#09081 — KT Enterprises 33-23 SWD, NESE 23-152N-96W, McKenzie Co.
#90189 — CCS Midstream Services SWD 1-18, SWSW 18-152N-101W, McKenzie Co.

From: Marathon Oil Company
To: Resolute Natural Resources Company, LLC
#19718 — Forest USA 14-2H, SWSW 2-147N-98W, McKenzie Co.

November 28
From: New Millennium Resources
To: Missouri Basin Well Service
#08984 — Dolyniuk 1-35, N2SE 35-140N-99W, Stark Co.

December 3
From: Moxie Disposal Systems, LLC
To: Cypress Energy Partners - Bakken, LLC
#90208 — Ashton Dawn SWD 1, SWSW 15-155N-91W, Mountrail Co.

December 13
From: Helis Oil & Gas Company, L.L.C.
To: QEP Energy Company
#17722 — Henderson Federal 4-26/35H, NWNW 26-150N-95W, McKenzie Co.
#21052 — Moberg 15-22/15H, SWSE 22-149N-95W, McKenzie Co.
#20780 — Henderson 1-28/33H, NENE 28-150N-95W, McKenzie Co.
#20591 — Jones 4-15/22H, NWNW 15-150N-95W, McKenzie Co.
#20226 — Moberg 4-20/21H, NWNW 20-149N-95W, McKenzie Co.
#19898 — Gabbert 3-3/10H, LOT 3 3-149N-95W, McKenzie Co.
#19894 — Gabbert 4-2/11H, LOT 4 2-149N-95W, McKenzie Co.
#19680 — Johnson 1-4/9H, NENE 4-149N-95W, McKenzie Co.
#19678 — Moberg 15-18H, SWSE 18-149N-95W, McKenzie Co.
#19379 — Kirkland 13-23/14H, SWSW 23-149N-95W, McKenzie Co.
#19104 — Henderson 16-34/27H, SESE 34-150N-95W, McKenzie Co.
#21054 — Veeder 1-27/34H, NENE 27-149N-95W, McKenzie Co.
#18361 — Dodge 4-6/7 HR, LOT 4 6-149N-95W, McKenzie Co.
#19323 — Thompson 1-29/32H, NENE 29-150N-95W, McKenzie Co.
#17266 — Jones 4-24H, LOT 4 13-150N-95W, McKenzie Co.
#17261 — Henderson 4-1H, LOT 1 1-149N-95W, McKenzie Co.
#17260 — State 4-36H, LOT 1 36-150N-95W, McKenzie Co.
#17254 — Henderson 4-25H, NWNW 25-150N-95W, McKenzie Co.
#17251 — Levang 4-13H, NWNW 13-150N-95W, McKenzie Co.
#16960 — Jones 4-23H, NWNW 23-150N-95W, McKenzie Co.
#16959 — Jones 16-14H, SESE 14-150N-95W, McKenzie Co.
#16929 — Levang 4-28H, NWNW 28-150N-95W, McKenzie Co.
#16856 — Peterson 15-15H, SWSE 15-149N-95W, McKenzie Co.
#16689 — Linseth 4-8H, NWNW 8-149N-95W, McKenzie Co.
#16652 — Levang 3-22H, NENW 22-150N-95W, McKenzie Co.
#18448 — Andrecovich 5-17/16H, SWNW 17-149N-95W, McKenzie Co.
#18973 — State 1-16/21H, NENE 16-150N-95W, McKenzie Co.
#21331 — Foreman 5-2/1H, SWNW 2-150N-95W, McKenzie Co.
#23472 — P. Levang 4-14/23H, NWNW 14-150N-95W, McKenzie Co.
#22880 — Bert 2-2/11H, LOT3 2-149N-95W, McKenzie Co.
#22879 — Gabbert 4-2/11HR, NWNW 2-149N-95W, McKenzie Co.
#22194 — Moberg 13-17/16H, SWSW 17-149N-95W, McKenzie Co.
#22193 — Kummer 1-6/7H, LOT1 6-149N-95W, McKenzie Co.
#21564 — Levang Federal 14-21/16H, SESW 21-150N-95W, McKenzie Co.
#21521 — Dailey 4-12/13H, LOT1 12-150N-95W, McKenzie Co.
#21465 — Tat 15-33/28H, SWSE 33-149N-95W, McKenzie Co.
#22371 — Hazel 13-34/27H, SWSW 34-150N-95W, McKenzie Co.
#21437 — Lawlar 16-8/5H, SESE 8-149N-95W, McKenzie Co.
#21456 — Tat 13-35/26H, SWSW 35-149N-95W, McKenzie Co.

From: Triangle USA Petroleum Corporation
To: Caliber Midstream, LLC
#90222 — Lewis 150-101-25-1 SWD, SWSW 25-150N-101W, McKenzie Co.

From: Ballard Petroleum Holdings, LLC
To: Murex Petroleum Corporation
#15031 — Stiletto 21-16, NENW 16-143N-98W, Billings Co.

From: Armstrong Operating, Inc.
To: Missouri Basin Well Service, Inc.
#14442 — Beaudoin 36-1, E2SW 36-144N-97W, Dunn Co.

December 14
From: Continental Resources, Inc.
To: SM Energy Company
#19303 — Seattle 1-35H, SWSE 35-152N-100W, McKenzie Co.

December 17
From: Moxie Disposal Systems, LLC
To: Cypress Energy Partners - Bakken, LLC
#90202 — Piper SWD 1, NESE 12-155N-101W, Williams Co.

From: RDT Properties, Inc.
To: Midcon Energy Operating, Inc.
#04074 — A. Legein 1, NENE 20-162N-95W, DIVIDE CO.
#03899 — C. W. Cater 1, NWNW 28-158N-95W, Williams Co.

December 19
From: DRD Saltwater Disposal, LLC
To: Waterworks Eask Fork, LLC
#90215 — Irgens SWD 1, SWSW 22-156N-100W, Williams Co.

From: RM Resources, LLC
To: QC Environmental Services, Inc.
#12840 — Masters Enterprises 1, SESE 27-143N-96W, Dunn Co.

From: Citation Oil & Gas Corp.
To: Missouri Basin Well Service, Inc.
#13666 — Rieder 1-9R, NWNW 9-155N-101W, Williams Co.

Note: Information compiled by Petroleum News Bakken and derived from the online daily activity reports of the North Dakota Industrial Commission.

The previous operator transfer took place on Oct. 17 and appeared in a chart on page 9 of Petroleum News Bakken's Oct. 21 edition. It can be found here: http://www.petroleumnews.com/bkpdfarch/655139528.pdf

● DRILLING & COMPLETION

Montana weekly oil activity reports, Dec. 14-Dec. 27

COMPILED By DARRYL L. FLOWERS
For Petroleum News Bakken

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

Week of 12/14 to 12/20

New locations — horizontal wells

Two horizontal wells were approved in Richland County, both aiming for the Bakken formation. Continental Resources Inc. was green lighted for the Charlotte Federal 3-14H, with an SHL at SW SE 14-25N-52E (200 FSL/2480 FEL) and a PBHL of 18,711 feet at NW NE 11-25N-52E (660 FNL/2200 FEL); Kraken Operating LLC was given the go ahead for the Fisher 20 1H, with an SHL at NE NW 20-25N-51E (225 FNL/1761 FWL) and a PBHL of 12,924 feet at SW SE 20-25N-51E (660 FSL/1760 FEL).

Re-issued locations

In Richland County, two permits were issued to Continental Resources Inc.: the Georges 1-4RR, with an SHL at SE SE 4-25N-55E (400 FSL/400 FEL) and a PBHL of 19,133 feet at SE SE 4-25N-55E (200 FSL/1000 FEL) will aim for the Red River C formation while the Westbrook 1-22H, with an SHL at SE SW 22-27N-56E (610 FSL/1800 FWL) and a PBHL of 19,251 feet at NE NW 15-27N-56E (200 FNL/1980 FWL) will bore into the Bakken formation.

In Sheridan County, L & H Resources LLP was issued a permit for the Meyer 1H. The well has an SHL at NE NW 23-37N-56E (1260 FNL/2310 FWL) and a PBHL of 14,420 feet at NW NW 22-37N-56E (1260 FNL/700 FWL). The well will aim for the Bakken formation.

Completions

In Richland County, Continental Resources Inc. reported the completion of the Kane 1-10H. The Bakken formation well has an SHL at NE NW 15-26N-54E (295 FNL/1735 FWL) and a BHL of 19,961 feet at NE NW 3-26N-54E (233 FNL/1967 FWL). The reported IP was 309 BOPD; 293 MCFPD of gas and 289 BWPD.

In Roosevelt County, Whiting Oil and Gas Corp. reported the completion of the Christoffersen 24-20TFH. The well has an SHL at SE SW 20-30N-56E (345 FSL/1980 FWL) and a BHL of 18,906 feet at NE NW 17-30N-56E (720 FNL/1906 FWL), tapping into the Three Forks formation. The reported IP was 130 BOPD, 115 MCFPD of gas and 247 BWPD.

Week of 12/21 to 12/27

Completions

In Richland County, Continental Resources Inc. reported the completion of the Wagner 1-17H. The well has an SHL at NW NE 17-26N-55E (300 FNL/1625 FEL) and a BHL of 19,905 feet at SW SE 20-26N-55E (233 FSL/1965 FEL). The well reported an IP of 239 BOPD; 150 MCFPD of gas and 450 BWPD. The well taps into the Bakken formation. ●

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

● LEGAL

Bakken bunk: plea deal reached in oil scam

THE ASSOCIATED PRESS

A California woman faces a likely prison sentence after reaching a plea deal with prosecutors for her role in a scam to dupe investors into sinking money into fictitious oil and gas projects on Montana's Fort Peck Indian Reservation, her defense attorney said Dec. 27.

Dana Yvonne Kent of Santa Ana, Calif., has agreed to plead guilty to a single count of investment fraud by wire, documents show. In exchange, prosecutors said they would drop charges of conspiracy to commit fraud and investment fraud by mail.

Kent remains in federal custody.

An affidavit earlier submitted by an FBI agent said that beginning in 2009, dozens of people across the country invested about $673,000 into a drilling project promoted by Kent and five co-defendants.

Co-defendants reject plea deals

The remaining defendants, also California residents, refused offers of plea deals, according to filings from prosecutors. The deadline for plea agreements is Jan. 11.

Kent's attorney, Carl Jensen, said Dec. 27 she probably faces about a year-and-a-half in prison based on federal sentencing guidelines.

But U.S. District Judge Sam Haddon in Great Falls will have the final say. He scheduled a change of plea hearing for Jan. 2.

"Obviously the judge can do whatever he wants to do," Jensen said.

A September indictment suggested other defendants played a more prominent role in the scam, but said that Kent "assisted the other conspirators in the promotion of the scheme."

The fictitious projects promoted by the defendants were linked to the booming Bakken oil industry of western North Dakota and eastern Montana, according to authorities. Investors were promised lucrative returns, with initial investments to be repaid within six months and then regular monthly checks flowing to investors thereafter.

To make the story more believable, the defendants presented a copy of a 2006 letter from the federal Bureau of Indian Affairs approving three oil and gas leases on land owned by a Fort Peck tribal member.

The northeastern Montana reservation is situated along the shallower western flank of the Williston Basin, which contains the Bakken petroleum system. The Bakken has become one of the richest oil producing regions in the U.S.

Authorities said the two companies created by the defendants — Domestic Energy Solutions and U.S. Oil and Gas LLC — never really pursued an oil and gas project, which was also said to include a refinery, pipelines and other infrastructure.

The leases had been canceled for nonpayment in 2007, court documents show.

The defendants were arrested in California in August.

The five who refused plea deals — Mike Campa, Suzette Gal, Andras Zoltan Gal, Krisztian Zoltan George Gal and Steven Carpenter — are slated to go to trial Feb. 12. They have pleaded not guilty.

Campa and Carpenter remain in custody, while the Gals have been released pending trial.

Suzette Gal is married to Campa, according to court documents. Andras and Krisztian Gal are her sons from a prior marriage.

Past convictions

Campa pleaded guilty to two counts of wire fraud in 1994 in a telemarketing fraud case targeting the elderly. Carpenter was convicted and sentenced in 1994 to 30 months in prison in California on charges including conspiracy to commit mail fraud.

More recently, Campa has been linked by authorities to investment schemes in Pennsylvania, Missouri, Colorado, Kansas, Texas and Washington state, according to court filings by prosecutors.

Attorneys for Campa and the Gals objected to details of those prior schemes being introduced as evidence in the Montana case, on grounds that it could prejudice the case.

Campa's public defender, Hank Branom, said Dec. 27 that some of the schemes involved companies that Campa did not work for or had already left.

"They're not related and they're not relevant and the danger of confusing the jury is great if they were to be admitted," Branom said.

Haddon has yet to rule on the defendants' request to exclude the prior schemes. ●

● COMPANY UPDATE

Triangle on target, but 3Q not up to par

With production rising, Bakken-focused Triangle Petroleum is poised to meet annual production goals and sets 2013 capex

By MIKE ELLERD
For Petroleum News Bakken

In December Denver-based Triangle Petroleum Corp. announced that its average daily Bakken production throughout its fiscal third quarter ending Oct. 31 was 1,389 barrels of oil equivalent per day, representing a quarter-over-quarter sequential growth rate of approximately 20 percent. For the quarter, total production was 127,783 boe, up from 104,660 boe the company produced in its second quarter and 62,700 boe in its first quarter.

The company ended its third quarter with an estimated net daily Bakken production of 2,022 boe per day, up from the net daily production of 1,120 boe per day that the company reported at the close of its second quarter ending in July, and the 696 boe per day at the close of its first quarter ending in April.

While this production keeps Triangle on track to meet its year end average production guidance of between 2,600 and 3,200 boe per day, the company says the third quarter production was lower than it had expected.

Triangle President and Chief Executive Officer Jonathan Samuels said in a Dec. 10 conference call that one of the "key drivers" in the production statistics is the time it takes to get all wells on a multi-well pad online. In that call, Samuels said that "multi-well pads drive operational and cost efficiencies in the drilling and completion side of bringing wells online. It also results in higher downtime in the early days of a well's life."

Samuels explained that with multiple wells, "whenever you conduct any sort of operation on one of those wells, whether you're flow back testing and you want to shut in, whether you're drilling out plugs, safety pretty much depends that you shut in all wells on that pattern."

New acreage

Triangle also acquired an additional approximately 1,600 net acres in its third quarter. This acreage included 1,200 net acres acquired through swaps, primarily in McKenzie County, for an average price of $2,765 per acre.

Next year's budget

For its next fiscal year, Triangle has set a total budget of $190 million, of which $128 million is earmarked for the company's two-rig operated drilling program with another $27 million for its non-operated drilling program. The company has also budgeted $15 million for infrastructure construction, $6 million for expanding and maintaining acreage, $5 million for its fracking subsidiary Rock Pile Energy Services, and $9 million for other capital expenditures.

Core area and deep targets

Triangle's core area is in central McKenzie and Williams counties where it holds approximately 21,000 and 15,000 net acres, respectively. The company is targeting both Bakken and Three Forks formations.

Samuels said his company is excited about the geology and the reservoir quality in the company's core areas. "Our target formations are deeper and hotter here than just about anywhere else in the basin, which does mean costs are higher, but we also think we're ultimately going to get a lot more wells per 1280 than other folks are going to get in other parts of the basin."

Samuels went on to say that ultimate recoveries from Triangle's acreage will be higher on a percentage basis than seen in other areas, mainly because the acreages will support higher well densities.

"We continue to study our downspacing and what the appropriate well spacing is, but as of today with well spaced just as little as 600 feet apart, we see no communication between these well bores which is very encouraging for us as we both move horizontally across the 1,280, meaning more Bakken wells in the unit and as you move vertically, meaning Bakken Three Forks and other benches of the Three Forks as well," Samuels explained.

Montana acreage

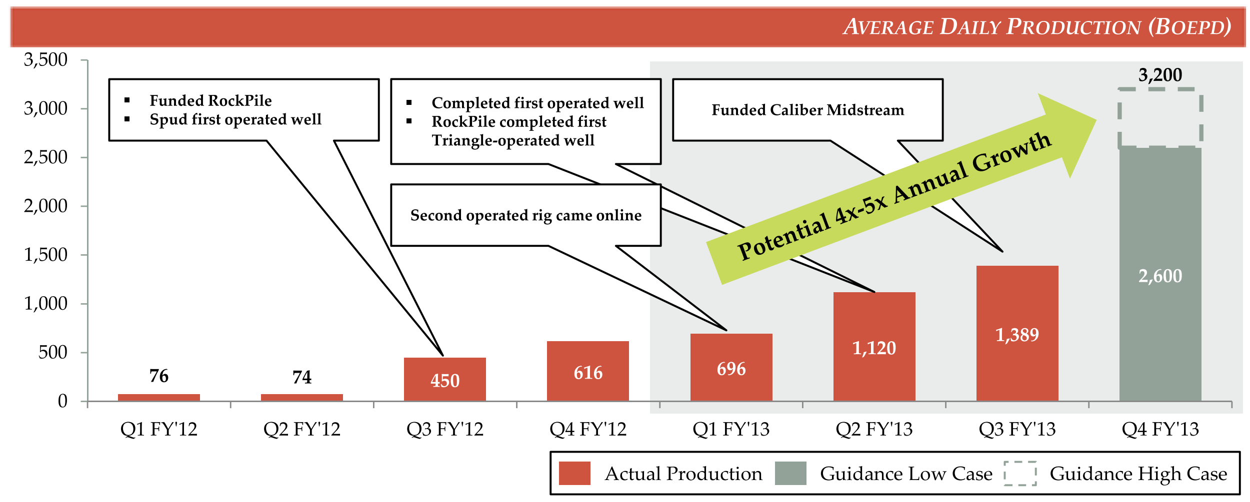
In northeast Montana, Triangle holds approximately 50,000 acres in its Station

see TRIANGLE PETROLEUM page 18

TRIANGLE HIGHLIGHTS

PRODUCTION AND DRILLING INVENTORY

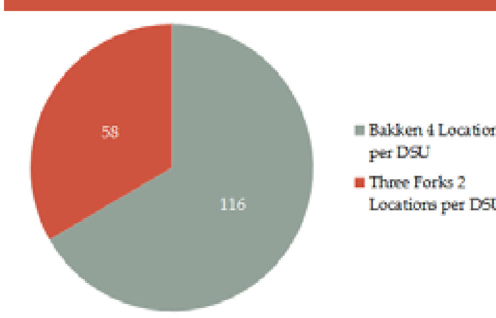
AVERAGE DAILY PRODUCTION (BOEPD)



SUBSTANTIAL PRODUCTION GROWTH FROM OPERATED PROGRAM

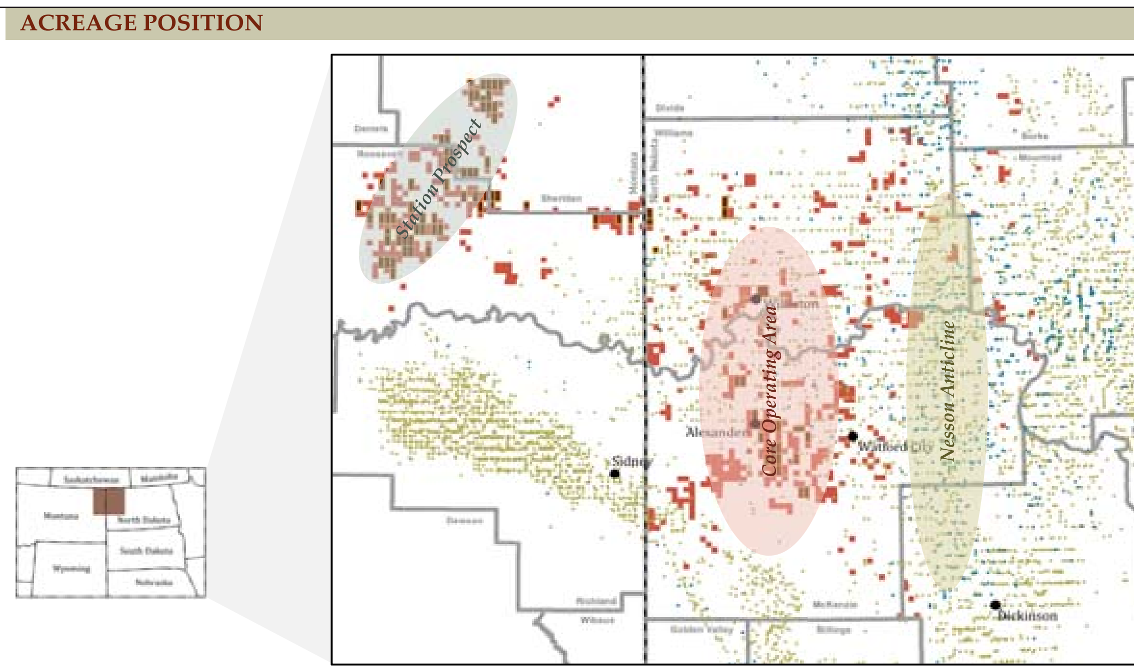
- FY'13 exit rate guidance of 2,600 – 3,200 Boepd represents approximately 4x-5x annual growth
- 174 operated drilling locations in Core Area, providing 9 years of inventory
- Potential for additional locations from Bakken downspacing and deeper benches of the Three Forks
- Station Prospect potentially adds approximately 350 locations to operated inventory

DRILLING INVENTORY



TRIANGLE HIGHLIGHTS

ACREAGE POSITION

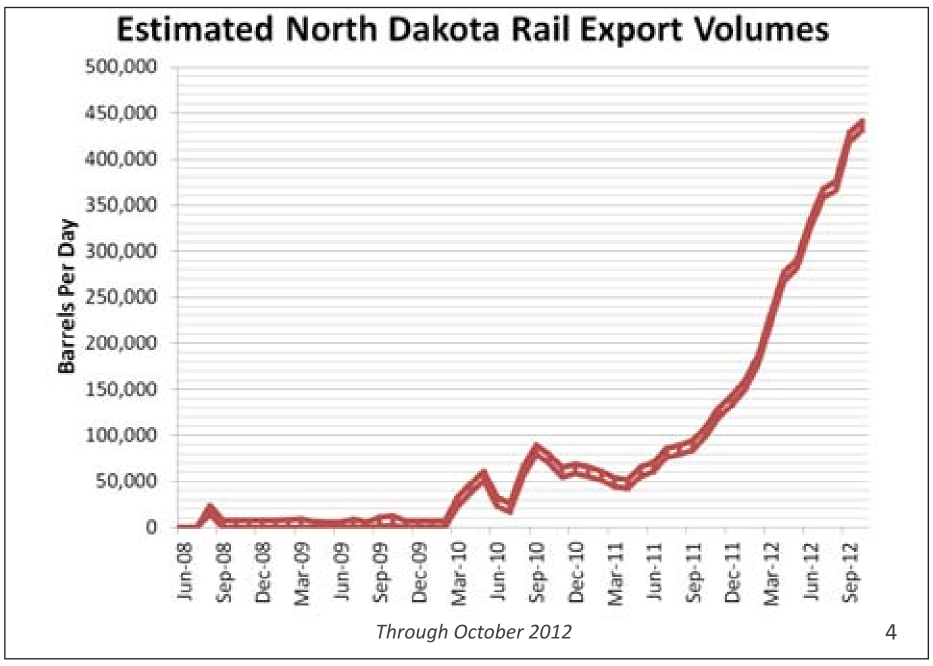


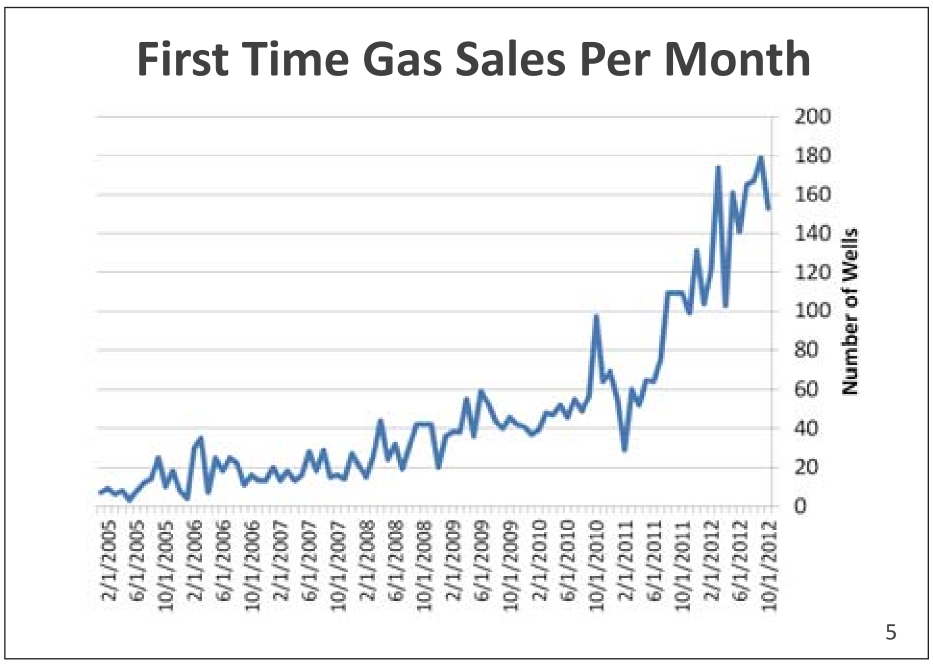
DETAILS	MCKENZIE COUNTY	WILLIAMS COUNTY/OTHER CORE	STATION PROSPECT (3)
NET ACREAGE	~21,000	~15,000	~50,000
PERCENT OPERATED (%) (1)	42%	50%	70%
BAKKEN DRILLING LOCATIONS (2)	64	52	236
THREE FORKS DRILLING LOCATIONS (2)	32	26	118

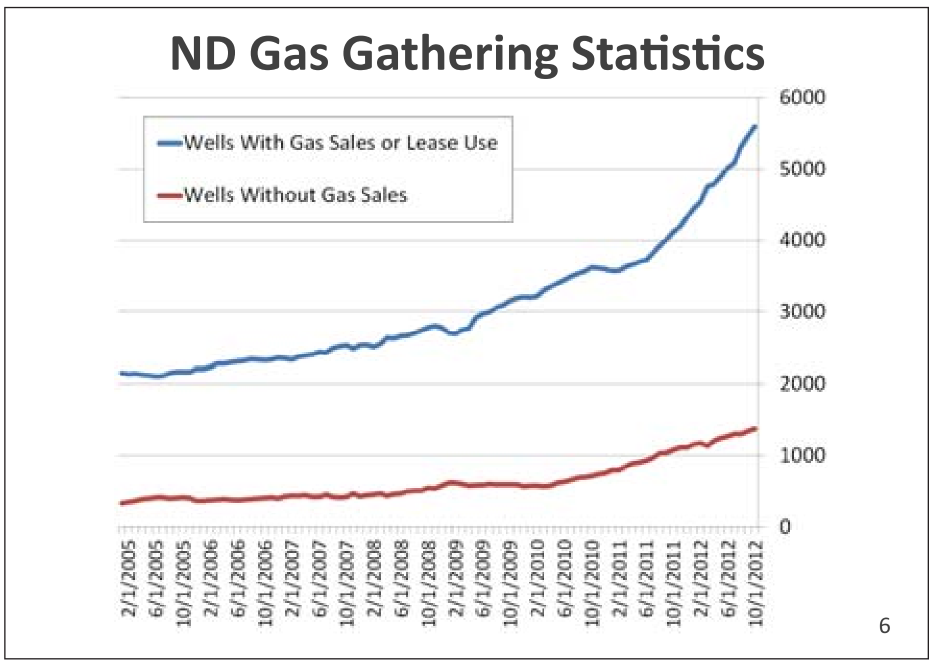
Source: Triangle Petroleum Corporation and North Dakota Industrial Commission, 2012.
(1) Operated assumes 30% or greater working interest.
(2) Based on 4 Bakken/2Three Forks wells per unit.
(3) Station Prospect is an exploratory area.

7 TRIANGLE PETROLEUM CORPORATION

Updates from North Dakota Pipeline Authority







US Williston Basin 2012 BOPD

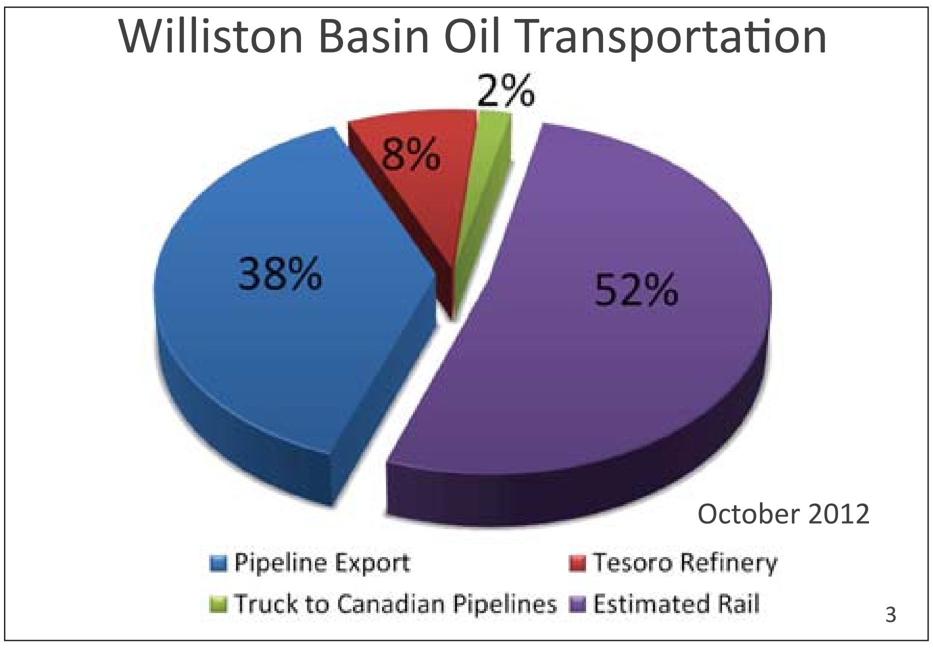
MONTH	ND	E. MT*	SD	TOTAL
January	546,547	59,561	4,915	611,023
February	558,558	61,708	4,891	625,157
March	577,478	60,179	4,776	642,432
April	609,503	63,968	4,725	678,196
May	639,981	63,521	4,941	708,444
June	664,618	60,872	4,864	730,354
July	676,249	65,300	4,743	746,292
August	701,409	67,084	4,645	773,137
September	729,248	67,807	4,640	801,695
October	747,239	68,907		--
November				--
December				--

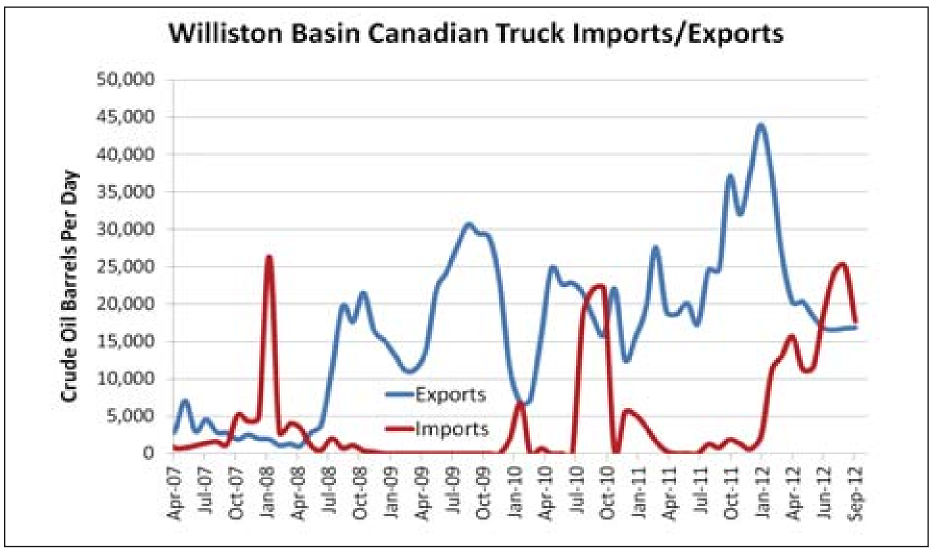
ND Oil Production

Month	Month Total	Avg. BOPD
September 2012 - Final	21,877,429	729,248
October 2012 - Prelim.	23,164,406	747,239

ND Gas Production

Month	Month Total	Avg. MCFD
September 2012 - Final	23,874,169	795,806
October 2012 - Prelim.	24,677,309	796,042





Note: The above information is from the North Dakota Pipeline Authority, which is headed by Justin Kringstad. The authority can be reached at : (701)220-6227. Supporting documents and previous monthly updates can be found online at http://northdakotapipelines.com/directors-cut/

continued from page 1

WELL APPLICATIONS

North Dakota's oil production), but also the first, second and third benches of the Three Forks formation.

Three of the proposed 14 wells will target the middle Bakken, two will target the first bench of the Three Forks, four the second bench and the remaining three the third bench.

The company estimates ultimate recoveries of 370,000 barrels of oil per well.

Rather than drill all 14 wells back to back, Continental will begin by drilling four wells in early 2013, one of which will test the middle Bakken, one the second Three Forks bench and two the third Three Forks bench.

The company will look at drilling the remaining wells following testing of the first four.

All of the new wells will connect to the Highland gas gathering system.

With the efficiency of pad drilling, Continental said it estimates each of the new wells will cost $8.5 million.

The company also asked the commission to expand the field boundary of the Cedar Creek-Ordovician Pool in Bowman County and establish one 640-area spacing unit in the expanded pool. Continental wants to drill up to two horizontal wells on that spacing.

Hunt seeks 18 new 1,280-acre standup spacing units

Hunt asked the commission in a December application to extend the field boundaries for the West Ambrose, Musta and/or the Smokey Butte-Bakken pools in southern Divide County and establish and include in the new boundaries 18 new 1,280-acre standup spacing units, allowing it to drill one horizontal well in each unit.

The company plans to target both the middle Bakken and the first bench of the Three Forks. Hunt said if the company opts to pursue other Three Forks benches it will come back before the commission at a later time.

Hunt estimates the wells will cost $7.9 million each.

The company told the commission that it is talking to several companies about getting gas connections, but presently there is no nearby gas gathering infrastructure. Hunt is actually running gas engines on its pumping units in the area.

However, Hunt said its intent is to get all wells connected as soon as infrastructure is available.

The company estimates recoverable oil at 400,000 barrels from each of the 18 wells.

Hess asks for overlapping 2,560-acre units

Hess also filed applications in December requesting the commission establish several new overlapping 2,560-acre spacing units in Mountrail and Williams counties.

The company requested the establishment of one overlapping 2,560-acre unit from two existing standup 1,260-acre units in the Beaver Lodge-Bakken pool in Williams County. Hess wants to drill one or more horizontal wells across existing 1,280-acre standup units in order to recover oil that would not otherwise be recovered in the setbacks. Wells in this spacing unit would be limited to the Bakken formation.

In Mountrail County, Hess asked the commission to establish one overlapping 2,560-acre unit from two existing 1,280-acre standups, and two overlapping 2,560-acre units from two existing 2,560-acre units where a center 1,280-acre standup would be common to both of the new 2,560-acre units. Wells in these spacing units would target both the middle Bakken and Three Forks formations.

Hess estimates recovery factors for these wells in the 2.4 to 2.5 percent range, with ultimate recoveries of 536,000 barrels each.

Wells are estimated to cost $10.5 million each.

Approved: Kodiak Oil and Gas applied for authorization to drill up to 12 horizontal wells on two 1,280-acre units, one in Williams and the other in McKenzie County. Kodiak also asked the commission to amend the stratigraphic definition of the Bakken pool to include 50 feet above the top of the upper Bakken shale member to the top of the Birdbear formation for these new wells.

Commission approves reserve pits for Enduro

Enduro Operating requested authorization from the commission in November to construct and use reserve pits for drilling wells in the Mouse River-Madison pool in Renville County, and in mid-December the commission approved the request.

The company argued that the depth of the Madison formation in the area is less than 5,000 feet and the use of reserve pits would lower drilling costs by 10 percent in the shallow, conventional play where marginal recoveries and economics result in additional costs.

In its approval, the commission specified that the reserve pit must be lined and that it is not to be used until a commission inspector has given approval following an onsite inspection.

The reserve pit is to be reclaimed within 90 days of well completion.

Enduro said the reserve pits would lower drilling costs by 10 percent.

Kodiak to amend Bakken stratigraphic definition

In November, Kodiak Oil and Gas applied for authorization to drill up to 12 horizontal wells on two 1,280-acre units, one in Williams County and the other in McKenzie. Kodiak also asked the commission to amend the stratigraphic definition of the Bakken pool to include 50 feet above the top of the upper Bakken shale member to the top of the Birdbear formation for these new wells.

These requests have since been approved by the commission.

The company estimates Bakken recovery factors of 3.9 percent in McKenzie County and 4.7 percent in Williams County, and ultimate recoveries of 570,000 and 630,000 barrels of oil in the two counties, respectively.

For the upper Three Forks, Kodiak's recovery factors are estimates at 8.5 percent in McKenzie County and 12 percent in Williams County. Estimated ultimate recoveries for the Three Forks are 455,000 barrels in both counties.

Wells will cost approximately $10 million each, the company said.

Kodiak also requested in November the establishment of two new 1,280-acre spacing units in Dunn County and permission to drill up to two horizontal wells on each.

Continental prevails over landowner re. Truax-Bakken pool

In November, Continental Resources applied to the commission for an order amending field rules to alter the definition of the stratigraphic limits of Truax-Bakken pool in McKenzie and Williams counties in order to more fully develop the oil resources in the pool. The stratigraphic limits of Truax-Bakken pool were defined as the interval from 50 feet above the top of the Bakken formation to 100 feet below the top of the Three Forks formation.

Continental argued that oil in the lower portion of the Three Forks is part of the Bakken petroleum system and requested the limits of the Traux-Bakken pool be redefined as the interval from 50 feet above the top of the Bakken formation to above the top of the Birdbear formation in order to access more of the Three Forks in the pool.

The application had been protested by the mineral owner who is opposed to vertical expansion of the lower Bakken pool limit to include the Three Forks, but the commission found that the mineral owner did not effectively demonstrate that Continental's request should be denied.

On Dec. 13 the commission approved the application.

Burlington applies for nine 2,560 spacing units

Burlington Resources, part of ConocoPhillips, filed applications in November for the establishment of eight new overlapping 2,560-acre spacing units in McKenzie County and one new 2,560-acre unit in Dunn County in order to drill inline wells in areas that would not otherwise be accessed because of the setbacks between existing 1,280-acre units.

All of the new wells will be in the middle Bakken formation, which is what most wells target when the application says Bakken since its tight sands currently produce more than 99.9 percent of Bakken formation oil.

Burlington estimates recovery factors between 1.6 and 2.7 percent, and primary oil recoveries of 325,000 and 500,000 barrels of oil.

Wells are estimated to cost approximately $10 million each.

Burlington is planning to have gas gathering infrastructure in place before the wells go into production.

Cornerstone requests Woburn field expansion

In November, Cornerstone Natural Resources requested an expansion of the Woburn field in Burke County along with two temporary 1,280-acre spacings in order to develop a pool recently discovered by three of its horizontal wells targeting the Bakken and Three Forks formations.

The three wells are the company's Ingerson #2-12-1H, Ingerson #7-13-24H and Mertes #6-22-15H.

The company estimates original oil in place at approximately 7.1 million barrels in the Bakken formation and 2.6 million barrels in the Three Forks, and found primary recovery factors of 0.8 and 6.7 percent from the two Ingerson wells targeting the Bakken and Three Forks, respectively, with recoverable oil estimates are 59,965 barrels from the Bakken and 174,910 from the Three Forks.

Wells are estimated to cost approximately $6.5 million.

Cornerstone also asked the wells be allowed to produce unrestricted for 90 days until they can be connected to gas gathering systems.

see **WELL APPLICATIONS** *page 20*

Petroleum news BAKKEN

Oil Patch Bits

Larson Electronics introduces swing arm light

Larson Electronics' Magnalight.com said Dec. 17 that it has unveiled the HBLP-1MLED-SWAM stainless steel swing arm mounted explosion proof light for waste water treatment plant applications. Built with 316 stainless steel and equipped with a Class 1 and Class 2 Division 1 10,000 lumen LED light, this adjustable hazardous area light is designed for corrosive environments.

The HBLP-1MLED-SWAM is used to position the explosion proof LED light to address maintenance tasks, and then pushed aside for storage. Similar in functionality to a dock light, this high powered LED light is rated for use in Class 1 and Class 2 Division 1 areas. The 316 stainless steel hinge and mounting arm are corrosion resistant and applicable for food grade applications. Priced around $3,500, the HBLP-1MLED-SWAM is available with one week or less lead time.

"We have expanded our welding fabrication to include stainless steel configurations, because more of our customers in highly corrosive or food processing require it," said Rob Bresnahan with Larson Electronics' Magnalight.com. "This explosion proof LED light with stainless steel swing arm is the first of several products designed to meet the needs of operators in those industries."

Larson Electronics' Magnalight.com produces a wide range of innovative and durable implementations of portable hazardous location lighting. You can learn more about Larson Electronics at www.Magnalight.com.

Flermoen completes executive fire officer training

The City of Grand Forks, N.D., said Dec. 17 that the Grand Forks Fire Department Battalion Chief Kelli Flermoen has successfully completed the prestigious Executive Fire Officer program, offered by the U.S. Fire Administration's National Fire Academy.

see OIL PATCH BITS page 20

Bakken Players

continued from page 1

KODIAK BUDGET

allocated to Williston Basin oil and gas activities. However, the projected tally may change depending on market conditions, oilfield services and equipment availability, commodity prices and drilling results, Kodiak said. The company's final budget for 2012 was adjusted to $750 million.

Of the preliminary $775 million budgeted for 2013, $600 million is allocated for the drilling and completing of 75 gross (61 net) operated wells; $140 million to non-operated drilling and completion activities for 14 net wells; and $35 million for other items including water disposal systems, well connections, and acreage acquisitions.

"While we modeled nearly $10 million per well for drilling and completions costs in our 2013 (budget), we expect to achieve lower well costs as we move through 2013," Peterson said.

The 2013 drilling program is designed to provide flexibility in identifying suitable well locations and in the timing and size of capital investment, the company noted.

Kodiak to operate six rigs

As part of the 2013 budget, Kodiak expects to operate six drilling rigs during the majority of 2013. However, the company's rig termination schedule allows Kodiak to adjust the budget in reaction to economic conditions. Kodiak expects to primarily use one dedicated full-time, 24-hour completion spread, while maintaining the option to add a second 24-hour crew on an as-needed basis.

About a third of Kodiak's 2013 drilling budget is dedicated to its North Dakota Polar and Smokey pilot projects, designed to test the full potential of the Bakken and underlying Three Forks reservoirs using tight well spacing on 1,280-acre units.

No capital expenditures were allocated to the Green River Basin in Southwestern Wyoming where Kodiak has a non-operated working interest in 30,000 gross acres (7,000 net acres). Participation in future wells in the Green River Basin is subject to prevailing Rocky Mountain liquids and natural gas prices at time of election, the company said.

Kodiak expects to finance it 2013 capital spending budget from existing working capital, operating cash flow and availability under its existing revolving credit facility agreement. As of Dec. 18, the company's borrowing base and total commitment for the revolving credit facility was $450 million.

Budget reflects confidence

"The 2013 budget reflects our continued confidence in the development of our Williston Basin leasehold," Peterson said. "We are very fortunate to be investing capital in a world-class oil play where we are achieving excellent rates of return."

Kodiak said it had two gross (1.6 net) wells on flowback, four gross (three net) wells being completed, and anticipated that completion activities would begin on four gross (three net) additional wells by year-end 2012.

Based on the company's anticipated 2012 exit rate, combined with activities contemplated under its 2013 capital budget, Kodiak projects to average 29,000-to 31,000 barrels of oil equivalent per day in sales volumes for the full-year 2013, which would exceed 80 percent versus 2012's sales volume growth. The projected exit rate for 2013 sales volumes is expected to range from 38,000-to 40,000 boe per day, the company said.

2012 exit rate reaffirmed

After assessing production volumes for the first nine-months of 2012, and taking into account anticipated fourth quarter completions activities, the company reaffirmed its previously disclosed projected 2012 exit rate of 27,000 boe per day. Kodiak now believes its average daily production will be in the range of 15,500-to 17,500 boe per day for the full-year 2012. The new range compares to previous disclosure of 17,000-to 21,000 boe per day average production for 2012.

Peterson said that with the majority of Kodiak's acreage held by production, the company could now focus on efficient multi-well pad development drilling where it can continue to drive down costs.

"Of added advantage, much of our infrastructure is already in place which further improves operations," Peterson said. "While our 2012 growth in proven reserves, production and cash flow was significant, we planned our 2013 (spending) program to again deliver meaningful growth for Kodiak and its shareholders."

—RAY TYSON

Contact Ray Tyson at rtyson@petroleumnews.com

continued from page 15

TRIANGLE PETROLEUM

Prospect in Roosevelt and Sheridan counties. In the Dec. 10 conference call, Samuels told analysts that the company is keeping an eye on this exploratory area. "This is part of our portfolio that gets very little attention, very little value accredited to it. But we're monitoring activity in the area as I'm sure a lot of you are as well and there are some big boys out there sniffing around. You've got Apache, Southwestern, Whiting, Samson Resources, all drilling wells, leasing acres and it's going to be something to keep an eye on next year."

Other ventures

Triangle's majority-owned fracking subsidiary Rock Pile Energy Services, which began operations this year, recently completed its eighth Triangle-operated well and anticipates completing four additional Triangle-operated wells by the end of January. Triangle reported that Rock Pile has successfully initiated 24-hour field operations and completed a 62-stage zipper frack in less than 11 days.

And in October 2012, Triangle announced Caliber Midstream Partners joint venture with First Reserve Corp. Caliber is currently constructing pipelines for crude oil, natural gas, fresh and produced water, and has broken ground on a centralized processing facility west of Watford City near Alexander in McKenzie County.

Triangle says it is a Bakken-focused, growth oriented company that holds approximately 86,000 net acres in the Williston Basin, of which approximately 60 percent is operated. It has over 170 operated drilling locations within its Bakken core area in McKenzie and Williams counties. ●

Editor's note: Per the latest oil production report published by the North Dakota State Industrial Commission, Triangle-operated Bakken petroleum system wells produced an average of about 1,524 barrels of oil per day in October, making it the 31st largest Bakken oil producer in the state.

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

continued from page 1

EAGLE FORD

by private researchers, such as Bentek Energy, showed that Eagle Ford daily output was closing in on the Bakken and that Eagle Ford might soon overtake the Bakken. This has not yet happened.

Eagle Ford versus Bakken

However, research firm EAI, Energy Analysts International, recently stepped forth with its own forecast: "Eagle Ford production is likely to rival Bakken production levels in 2013." EAI said it based the forecast on its latest "North American Shale Fairway Crude Supply, Logistics, Refining and Pricing Outlook" study update and basin production tracking.

Specifically, EAI estimated average daily Eagle Ford production in December of about 560,000 barrels of liquids (crude and condensate), and projected the play would exit 2012 at 610,000-660,000 barrels per day, increasing to 800,000-900,000 bpd in 2013.

North Dakota production, which is dominated by the Bakken, was averaging 747,239 bpd in October 2012, the last month for which statistics were available, and EAI forecasts that North Dakota daily production will approach 900,000 barrels during 2013.

However, the span between Eagle Ford and Bakken production is actually much closer considering that North Dakota production is made up of roughly 10 percent conventional oil, bringing the 900,000-bpd North Dakota target down to around 810,000 barrels, when taking into account only the Bakken petroleum system, which includes both Bakken and Three Forks formation production.

North Dakota's production estimates

The production numbers grow even tighter based on the North Dakota Department of Minerals Resources' own projections for 2013. Director Lynn Helms told reporters in a recent conference call that the department expects North Dakota production to grow to around 830,000 bpd by the middle of the year and to 850,000 bpd by year-end. That equates to year-end Bakken only volumes of about 765,000 bpd, compared to the 800,000-900,000 bpd of Eagle Ford liquids projected by EAI.

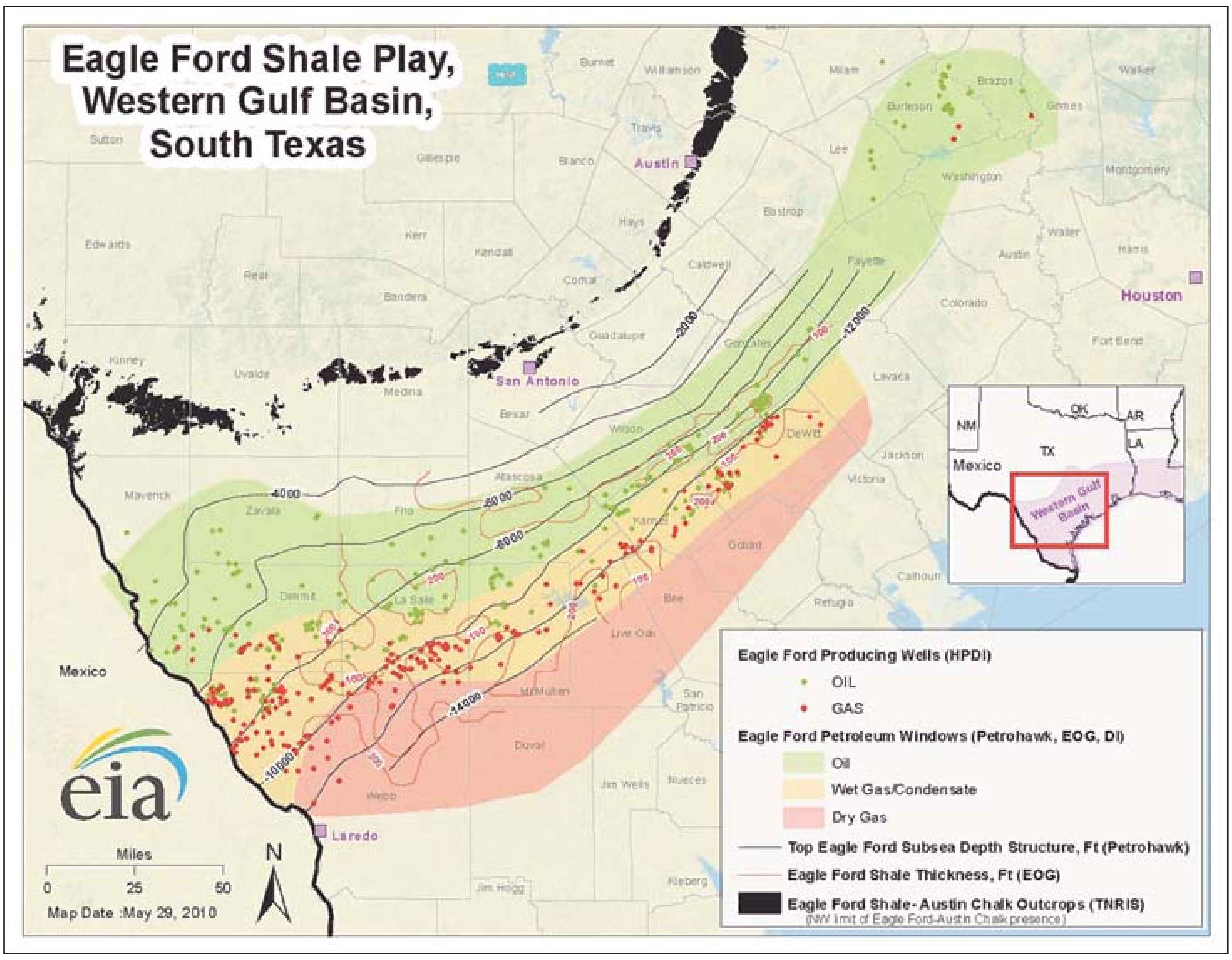
And though North Dakota production is expected to return to a 3-4 percent monthly growth, it registered only a 2.5 percent increase in October, due to less drilling and a substantial backlog in hydraulic fracturing jobs. Though some of the slowdown was attributed to temporary setbacks, it also may have signaled a departure from boom times to more stable economic growth.

Investment to exceed $116 billion

On the investment side, industry is likely to sink more than $116 billion in the Eagle Ford between 2012 and 2015 — more than the cost of developing the Kashagan offshore field in Kazakhstan, which has been called the world's most expensive standalone energy project, Wood Mackenzie said. With $28 billion in anticipated capital spending in 2013 alone, Eagle Ford will represent 27 percent of the total capital expenditure of the onshore Lower 48 total.

Wood Mackenzie said Eagle Ford growth has been driven by a number of factors, including: operators have successfully delineated acreage; well productivity has increased because of both technology and experience; and depressed natural gas prices have continued the diversion of capital to liquid-rich plays such as the Eagle Ford.

"In tandem, the capacity constraints faced earlier in the play's development have been eased, as midstream and service companies invest aggressively to capitalize on the growth in production," Wood Mackenzie said.



Eagle Ford's leading players

According to Wood Mackenzie, there is no substitute for core acreage in resource plays, and the Eagle Ford is no exception. Today, most operators have moved into the development phase and the quality of acreage positions is being realized. The leading players — EOG Resources, BHP Billiton and ConocoPhillips — not only hold core acreage positions, but also hold a larger quantity of the quality acreage. The three companies have a combined remaining value in the Eagle Ford of around $30 billion.

Wood Mackenzie estimates that for EOG, the Eagle Ford holds 38 percent of the company's upstream value.

"EOG was one of the first companies to shift its strategic focus to liquids, a decision that has been well rewarded in the Eagle Ford," McMahon said.

BHP Billiton's Eagle Ford assets, acquired through the takeover of Petrohawk, now represent 20 percent of the company's entire upstream global portfolio.

ConocoPhillips also targeted the liquids-rich core area of the play early on, enabling a substantial acreage position to be built at a lower entry cost.

The larger capital budgets have enabled these big companies to progress further along in their development programs increasing overall valuations, while smaller players are able to leverage joint venture and cost-carry agreements to maximize on a value per acre basis, Wood Mackenzie said.

Rigs to target liquids areas

The counties with crude and condensate exposure are expected to drive Eagle Ford growth, as 74 percent of the future drilling rigs likely will be assigned to target liquids-rich areas, Wood Mackenzie said.

"The pace of growth in the Eagle Ford shows no sign of slowing down, and our analysis indicates that Gonzalez, DeWitt and Karnes counties have established themselves as the sweet spots of the play, and now account for over 50 percent of daily liquids production," McMahon said.

There are multiple, rapidly growing unconventional oil and gas plays across the United States, but according to industry analysts, the Eagle Ford stands above most because of its heavy liquids content, sprawling existing and proposed infrastructure, high initial oil production rates and proximity to some of the largest energy markets in North America.

Moreover, Eagle Ford's geology is said to be favorable for rapid development. Its production is near many existing processing and fractionation plants and multiple pipelines and other infrastructure. Its drilling costs also are low compared to many other unconventional plays because of abundant liquids, high production rates and rapid drill times. ●

Contact Ray Tyson at rtyson@petroleumnews.com

continued from page 17

WELL APPLICATIONS

Whiting gets one approval

Whiting Oil and Gas Corp. requested amendments in November allowing the company to drill up to five horizontal wells each on two adjacent 1,280-acre spacing units, and to establish an overlapping 2,560-acre spacing unit so that one or more wells can be drilled between the 1,280-acre units. The request is for two separate 2,560-acre units in McKenzie County, one of which has since been approved by the commission.

The company estimates recoveries of 10 and 12 percent from the Bakken and Three Forks formations, respectively, resulting in estimated ultimate recoveries of just over 1 million barrels and approximately 759,000 barrels from the two formations, respectively.

Wells are estimated to cost approximately $8 million.

Whiting said there is gas infrastructure in place and the company plans to immediately begin selling produced gas.

American Eagle files for two 800-acre standups

American Eagle Energy asked that field rules be amended so that two 800-acre standup spacing units could be established in the Colgon-Bakken pool in Divide County. American Eagle also requested that up to four horizontal wells be allowed on each spacing unit.

Marathon estimates middle Bakken recovery between 3.2 and 3.8 percent, and ultimate middle Bakken recovery at 330,000 barrels of oil per well.

The company estimates original oil in place at slightly over 4 million barrels and a single-well recovery factor of 8 percent, which would result in estimated single-well reserves of 321,000 barrels and four-well recovery reserves of 1,284,000 barrels.

The shorter lateral wells are estimated to cost approximately $5.9 million each, and American Eagle is planning to target both the Bakken and Three Forks formations from multi-well pads. The company anticipates a gas gathering system will be in place within six months.

Zenergy wants laydown configurations

Zenergy Inc. asked the commission in November to approve two laydown 1,280-acre spacing units and one overlapping 2,560-acre spacing unit, all in McKenzie County.

The reason for the laydown configurations as opposed to the standard North Dakota standup configurations is because of controlling interests the company has in adjacent lateral acreages. Zenergy said that as far as the geology is concerned the company has no preference for north-south or east-west drilling. Zenergy indicated there would be no problem in connecting the proposed well to a gas gathering system.

The 2,560-acre spacing unit was requested so the company could drill longer diagonal laterals across it.

The company is targeting both the Bakken and Three Forks formations.

Zenergy estimates Bakken recovery factors between 3 and 7 percent, and ultimate recoveries of 500,000 barrels. The Three Forks recovery factor is estimated at 2 percent and ultimate recovery of 500,000 barrels.

Wells are estimated to cost $9.3 million each.

Marathon submits apps for 1,280-acre units

In December, Marathon Oil applied for the establishment of a 1,280-acre spacing unit and drilling up to four wells on that unit and four wells on three existing 1,280-acre units in Dunn County, all of which will target the middle member of the Bakken formation.

In November, Marathon applied for an amendment allowing up to seven horizontal wells on 1,280-acre spacing, also in Dunn County.

Marathon estimates middle Bakken recovery between 3.2 and 3.8 percent, and ultimate middle Bakken recovery at 330,000 barrels of oil per well.

Several requests for increasing well densities

Baytex Energy USA, GMX Resources, Liberty Resources, Newfield Production, PetroGulf Corp., Samson Oil and Gas USA, XTO Energy and Triangle USA Petroleum all submitted applications to the commission in November and December for orders authorizing the drilling, completion and producing of additional wells on existing spacing units.

XTO filed for up to eight wells on each of 45 existing 1,280-acre spacing units in Burke, Dunn, Williams and Billings counties, for a total maximum of 360 wells.

Baytex is requesting up to seven wells on each of 27 existing 1,280-acre spacing units in Divide County, for a total maximum of 189 wells.

Liberty applied for up to eight wells on each of 19 existing 1,280-acre spacing units in McKenzie and Williams counties for a total maximum of 189 wells.

GMX filed for up to four wells on each of four existing 1,280-acre spacing units in Billings and McKenzie counties.

Newfield requested up to seven wells on an existing 1,280-acre spacing unit in the Sand Creek-Bakken pool in McKenzie County.

PetroGulf applied for authorization to drill up to eight wells on an existing 1,280-acre spacing unit in McKenzie County.

Samson asked for authorization to drill up to seven wells on each of two overlapping 1,280-acre spacings in Williams County.

Triangle asked to drill up to four wells on two existing 1,280-acre spacing units in McKenzie County.

—MIKE ELLERD

Contact Mike Ellerd at mellerd@petroleumnewsbakken.com

continued from page 18

OIL PATCH BITS

Flermoen is the first to complete the program in the Grand Forks Fire Department and one of a select few firefighters in North Dakota to do so. The program is designed to provide senior fire officers an understanding of the need to transform fire organizations from being reactive to proactive — with an emphasis on leadership development, prevention and risk reduction.

"This is a tremendous plus for the Grand Forks Fire Department," said Grand Forks Fire Chief Peter O'Neill. "I admire Battalion Chief Flermoen's dedication to the educational process and applaud her efforts."

The program consists of a unique series of four courses — each two weeks in length — that span a four-year period. Following each course, the participant has to complete an applied research project that relates to their organization.

Flermoen, who has been with the Grand Forks Fire Department since January, 1996 has been a battalion chief since May 2011.