Final Report

Bakken Roadmap (Phase 1)

Prepared for Petroleum Technology Alliance Canada

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REPORT

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Abstract: This project is aimed at identifying and analyzing the technology opportunities that will arise from unconventional oil and gas activities in the Saskatchewan Bakken play. At the currently low oil pricing environment, facility/operation cost savings and production efficiency improvements have been two key themes in the upstream oil industry. On the basis of a comprehensive literature survey and interactions with oil producers as well as government regulators, eight areas of opportunities have been identified and summarized. While many experiences from the US Bakken can be learned and utilized, the Canadian Bakken poses some unique geological, exploration, and production challenges that need collaboration among oil producers, research organizations, and service companies to be tackled successfully.

EXECUTIVE SUMMARY

Saskatchewan is ranked first in Canada, third in the world, for petroleum exploration and development investment potential, according to the Fraser Institute’s 2014 Annual Global Petroleum Survey. A large portion of the petroleum exploration and production activities take place in the province’s unconventional oil reservoirs, such as the Bakken Formation.

In Canada, the Bakken play covers 62,000 square kilometers (24,800 square miles) of southern Saskatchewan and smaller areas of southwest Manitoba and southeast Alberta. About 1.4 billion barrels of high-quality light oil and 2.9 trillion cubic feet of natural gas are considered economically recoverable from the Canadian Bakken, according to a recent joint assessment by the Saskatchewan Ministry of Economy and Canada's National Energy Board (2015). Although Canada’s Bakken resources were discovered in the 1950s, only since 2004 have they been experiencing a boom, primarily because of the combination of horizontal well drilling and multistage hydraulic fracturing technologies. Bakken is now a big driver of the Western Canadian energy economy. Ed Dancsok, the then assistant deputy minister of the Saskatchewan Ministry of Economy, commented that “we haven’t found the edge of the Bakken yet – the potential is vast.” Even with cumulative production of 160 million barrels to year-end 2014, there are still 1.24 billion barrels of reserves left behind in the reservoirs, and this value can be boosted through future improvements in drilling, completion, and production technologies.

On the US side, the Bakken is much deeper and more costly to develop, but is also greater in the amount of original oil in place. The average well cost, estimated ultimate recovery (EUR), true vertical depth (TVD), lateral length, and fracturing stages on the US side go up significantly. This greatly changes the exploration and production (E&P) practices across the border. Total production from the US Bakken has surpassed one million barrels per day, whereas the Canadian Bakken produces at about one order of magnitude lower. In fact, the Saskatchewan Bakken Formation has started seeing an overall decline in production from its peak in 2012. At the end of 2014, the Bakken in this province produced 61,420 barrels per day, with cumulative total production of over 160 million barrels.

The Canadian Bakken is still more economical to produce than the US side, mainly because its lower productivity is offset by lower well drilling, completion, and operation costs. The average breakeven point of the Canadian Bakken is about $60/bbl West Texas Intermediate (WTI), compared to $65/bbl for the US Bakken.

With a more challenging E&P environment and the much higher daily oil production, US Bakken producers and government regulators have accumulated extensive experience for their Canadian counterparts to learn. For example, over 200 papers published by the Society of Petroleum Engineers shared stories of field E&P and laboratory investigations of the Bakken in North Dakota and Montana. In order to support Bakken oil producers with flaring solution technology, the Energy & Environmental Research Center (EERC) provides a database containing vendor-supplied technical and economic information about gas utilization technologies.

Innovation has proven to be the key factor of the Bakken boom over the last decade. Technology advancements enable oil producers to increase recovery factors while lowering decline rates and capital and operating costs. With the current low oil and gas price environment, it is a lingering question as to how Bakken and other tight oil producers can survive and find opportunities to build sustainable development. The slowdown of drilling and production activities actually gives oil producers opportunities to identify areas that can be optimized and improved through technology innovation.

In the current oil pricing environment, facility/operation cost saving and production efficiency improvement have been two key themes in the upstream oil industry. The purpose of this Bakken Roadmap Project is to identify, for the Saskatchewan Research Council (SRC) and for Saskatchewan regional businesses, the technology opportunities that will arise from unconventional oil and gas activities in the Bakken play. On the basis of a comprehensive literature survey, interviews with several major Canadian tight oil producers, as well as government regulators, eight areas of opportunities have been identified and are listed in chronological order of the E&P process.

1. Reservoir Characterization

Comprehensive understanding of Bakken reservoir characteristics such as reservoir fluid properties, geophysical properties, and geomechanical properties is the key for all follow-up drilling and production operations. Unfortunately, many operators miss obtaining some of these properties due to lack of awareness and/or cost of services.

2. New Drilling and Completion Technologies

The Bakken Formation is a perfect field laboratory in which to test innovative drilling and completion technologies. With extensive capital costs at scales of millions of dollars per well, any breakthrough innovation in this area will be the game-changing factor. The US Bakken and Three Forks producers have embraced advances in drilling and completions and seen their costs drop from an average $10 million/well before 2011 to $7–8 million/well.

3. Production Optimization and Restimulation Technologies

Optimizing existing wells is a more capital-efficient means to increase production efficiency than drilling new wells. Lightstream's optimization involves re-entering an existing wellbore and applying technologies such as millouts, cleanouts, high volume lift installations and casing gas compressor installations. In today's harsh economic environment, the oil industry is particularly looking into cost-effective technologies, such as refracking, to sustain oil production.

4. Enhanced Oil Recovery Technologies

With production declines of 30 to 70% in the first year and ultimate primary recovery of only 10% or less, it is imperative to develop effective enhanced oil recovery (EOR) technologies to tap into the huge amount of residual oil left behind in the reservoir. Mature EOR technologies encounter new challenges upon being used in tight oil reservoirs. Enhanced water flooding and gas flooding are considered the two most promising technologies, which have been piloted at some Saskatchewan Bakken fields with a few innovative variations.

5. Numerical Simulation

The more detailed the reservoir characterization, the more accurate and representative the reservoir models and geological/geomechanic models that can be constructed to study various scenarios of E&P processes.

6. Produced Water Recycling

Hydraulic fracturing requires large amounts of water, sand, and chemical fluids that raise sourcing and environmental concerns on waste disposal. A centralized approach can treat and reuse the wastewater throughout the entire lifecycle of well production.

7. **Bakken Oil Transportation**

Increased production from the Bakken, by both Canadian and American producers, comes with its own set of headaches, most notably transportation infrastructure. Pipelines may allay concerns over transporting by truck or rail. Enbridge Bakken has constructed a 124-kilometer (77-mile) pipeline from a new terminal near Steelman, Saskatchewan, to the Enbridge Pipelines Inc. mainline terminal near Cromer, Manitoba.

8. Gas Utilization

In 2011, the then Saskatchewan Ministry of Energy and Resources (ER) passed Directives S-10, Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive, as well as S-20, Saskatchewan Upstream Flaring and Incineration Requirements. They provide regulatory requirements for reducing flaring, incinerating, and venting of associated gas in Saskatchewan. In the future, as more gas processing capacity is installed in the region, the produced gas, which was flared in the past, will become more valuable to the market as natural gas and natural gas liquids or will be re-injected into the reservoirs as an EOR agent.

ACKNOWLEDGEMENTS

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1. INTRODUCTION

1.1 Bakken Formation

The Bakken Formation, with at least 16 billion m^3 (100 billion barrels) of hydrocarbon resources, is one of the largest continuous oil deposits discovered in North America since the 1950s. The 520,000 km^2 formation lies underneath southeast Saskatchewan and southwest Manitoba in Canada, and North Dakota and Montana in the United States. The Bakken, considered "thermally mature" by geologists, produces high-quality light and sweet oil with typical API gravity of 41 to 45°. Since each new tight oil play is unique in nature in terms of geology, lithology, and production mechanism, it is desirable to have a defined strategy for the discovery, development, and decline phases of Bakken.

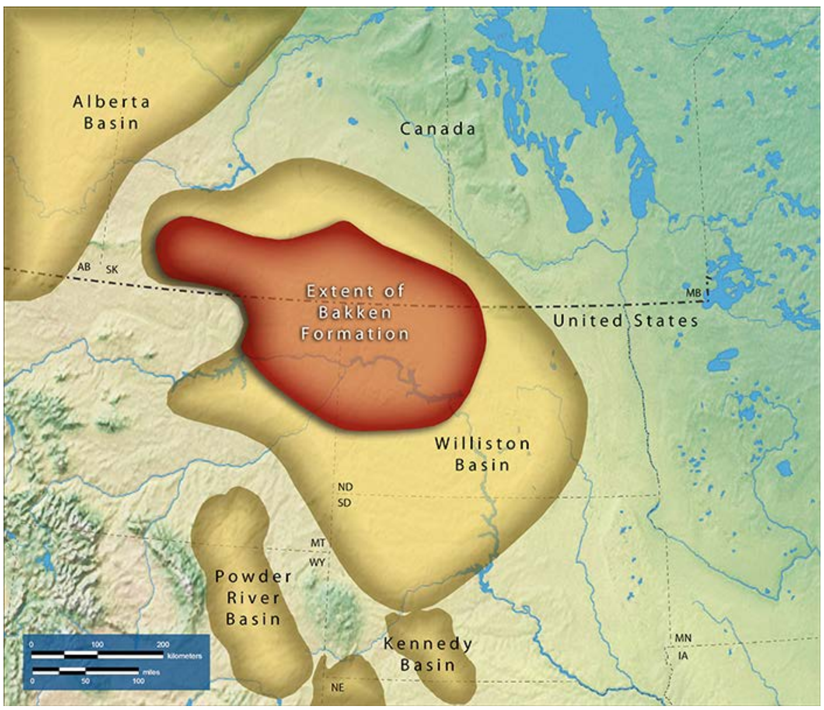

Fig. 1—Map of Bakken Formation in the Williston Basin.
(from EERC, http://www.undeerc.org/bakken/bakkenformation.aspx)

The estimated original oil in place (OOIP) varies. Research conducted by US Geological Survey (USGS) geochemist Leigh Price in 1999 indicated possibly 413 billion barrels of Bakken OOIP. In 2008, a report issued by the North Dakota Department of Mineral Resources estimated 167 billion barrels of OOIP in that state's portion of the Bakken. Nevertheless, the reserves, i.e., the oil can be economically produced with current technologies, range from only one to several percent. In the Canadian portion of the Bakken Formation, the US Energy Information

Administration in the Department of Energy estimated in 2013 that there were 1.6 billion barrels of technically recoverable oil. The USGS commented that the Bakken has the potential to become “the next Saudi Arabia.” Recently, the USGS estimated 7.4 billion barrels of recoverable oil from the Bakken-Three Forks formations jointly.

Reservoirs in the Bakken Formation are characterized as “tight,” with extremely low permeability and porosity (Kreis et al., 2005). While primary oil production can be economical only because of natural fractures creating flow pathways, most places have experienced uneconomical production since the resource’s discovery more than half a century ago. Only since early 2000 has the Bakken been commercially developed thanks to innovative horizontal drilling and multistage fracturing technologies. Now almost all the Bakken wells are under primary depletion, and many new wells are drilled each year to compensate for rapid production decline.

Compared to the more mature and well-known Canadian oil sands, the Bakken has a number of advantages, such as lower breakeven price ($60/barrel for Bakken versus $80/barrel for oil sands), higher oil quality (API 41–43° for Bakken versus 10–15° for oil sands), and faster payout period. More important, technology development in drilling, completion, and production has proven to be the main driver for the Bakken boom in the 21st century.

1.2 Project Objectives

The purpose of this project is to identify, for the Saskatchewan Research Council (SRC) and for Saskatchewan regional businesses, the technology opportunities that will arise from unconventional oil and gas activities in the Bakken play. Such opportunities should be pursued jointly by industry and research institutes, and the products can be utilized by industry to more effectively and rapidly develop the tremendous oil and gas resources in the Bakken. This project is focused on mainly, but not limited to, the Saskatchewan portion of the Bakken Formation.

The objectives of the project are:

- To understand the opportunity presented by the Bakken Formation based on its geology and the engineering technologies available to recover gas, condensate and oil from it.
- To map the historical and present situation of the Saskatchewan Bakken play and prepare a set of likely development and production scenarios, including potential demand for water, sand, chemicals and other commodities and services, and including learning from the neighboring Bakken play in North Dakota.

- To identify technology challenges that will be faced in the development of the Bakken play, as well as potential technology solutions.
- To scope 5 to 10 specific technology opportunities that could be pursued by technology providers, including SRC, by leveraging the PTAC Tight Oil and Shale Gas Innovation Network.
- To deliver industry workshops and a final report.

2. GEOLOGY OF THE BAKKEN FORMATION

2.1 General Geology

The Bakken Formation takes its name from Henry Bakken, owner of a Montana farm where a geologist, J.W. Nordquist, described the formation in North Dakota's Nesson Anticline (Beaver Lodge field) in 1953. Nordquist (1953) made the following observations about the formation. The late Devonian-early Mississippian Bakken Formation was deposited about 360 million years ago. It spreads in the central and deeper portion of the Williston Basin, which is a large, roughly circular depression on the North American craton. The thickest area of the Bakken Formation reaches 145–150 feet at southeast of Tioga, North Dakota, where it is located at the eastern base of the Nesson Anticline. The formation generally thins evenly toward the margins of the Williston Basin. The formation is over 11,000 feet in depth at the center of the formation and rises to 3000 feet at the Canadian side. The Bakken Formation has three members: black, organic-rich shales for the Upper and Lower Members, which are generally one to ten meters thick, and siltstones and sandstones in the Middle Bakken Member. The productive middle member mainly contains very fine to fine grained, argillaceous, dolomitic sandstone to siltstone. Matrix permeability is in the range of 0.01 to 0.5 md and porosity is from 5% to 12%. The upper and lower black shale members were deposited under anoxic conditions in a shelf environment, while the middle siltstone and sandstone members were deposited in shallow to marginal marine environments (Halabura et al., 2007).

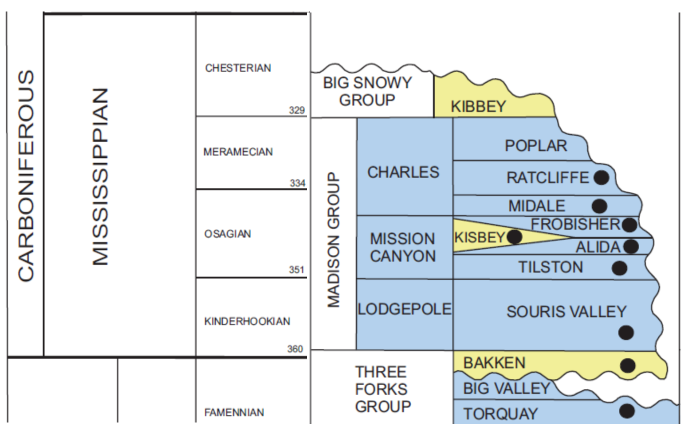

Fig. 2—Southeast Saskatchewan Stratigraphy (Late Devonian Early Mississippian).
(from Saskatchewan Ministry of Economy)

The Bakken shale consists of dark-gray, brownish-black to black, massive to fissile, varied organic rich (average total organic content in the range of 3–20%) mudstone. The lithology sequence indicates a change from highly oxidizing conditions during Three Forks time to highly anoxic conditions (i.e., offshore marine environment during sea-level rise) in lower Bakken time. The anoxic conditions continued until middle Bakken time as coarser clastics deposited. The presence of pyrite, high concentrations of organic matter (marine algae) and a few benthic fossils indicate a deep marine depositional environment (LeFever, 1991; Smith and Bustin, 2000). Similarly, the upper shale indicates anoxic conditions followed by oxygenated water conditions during the Lodgepole time.

The Bakken Formation is regionally overpressured because of hydrocarbon generation, and such overpressure has been suggested to cause natural fractures in the formation (Meissner, 1978; Pitman et al., 2001; Nordeng and LeFever, 2008; Sonnenberg and Pramudito, 2009). Multiple fracture types have been reported to occur on a macroscopic and microscopic scale in the Bakken Formation, and are most abundant in the lower and middle members. In the sandstones and siltstones in the middle member, the vast majority of these fractures have been reported to be open (nonmineralized), discontinuous features oriented subparallel to bedding (Pitman et al., 2001). Horizontal expulsion fractures have been reported in the Bakken shales in clay- and organic-rich intervals (Carlisle et al., 1992; Pitman et al., 2001).

The biggest Bakken reservoir in southeast Saskatchewan is the Viewfield. It is bioturbated, dolomitic siltstone and sandstone. The siltstone can be slightly argillaceous, which is related to burrowing, with up to 11% clay contents. Finely disseminated pyrite is commonly seen and can be up to 3% in the area. Permeability is in the range of 0.01 to 1 md, with porosity of 8 to 12%.

The Lodgepole Formation

The Mississippian Lodgepole formation, which conformably overlies the Bakken, lies in central and the east half of Montana, southern Saskatchewan and Manitoba, and North and South Dakota. The lithology is mainly light to dark lime mudstones with thin black shale partings in the lower portion, fossiliferous in the upper portion. This is considered to represent change from shallow to deep water deposition.

The Torquay Formation

In addition to Bakken, Saskatchewan's Torquay oil (known as Three Forks in the US) discovery has gained increasing attention. The upper Devonian Torquay formation is present throughout much of the Williston Basin. Its northern limit is the west-northwest-trending post-Mississippian erosional edge in central Saskatchewan (south of Saskatoon). The thickness of the formation is consistently 45–50 m, except in southwestern Saskatchewan, in where it reaches a maximum of

65 m, and in southeastern Saskatchewan, where, by contrast, the thickness is reduced to 20 m locally (Kreis and Costa, 2005). The lithology in the Torquay Formation is recognized as interbedded weathered brown carbonates (mainly dolomite), dolarenties, dolomitic mudstones, and minor amount s of anhydrite. In eastern Saskatchewan, the Bakken lower member is absent so that the productive middle member is in direct with the underlying Torquay Formation. Interest in this formation is growing because it is believed that the original oil in place (OOIP) in Torquay Formation may actually be larger than in Bakken due to its thickness. Crescent Point in Canada and Continental Resources in United States are two pioneers in exploration of the Torquay Formation. Currently, Saskatchewan Torquay production takes place in two areas—the Flat Lake area along the US border near Oungre, and the Ryerson area near the Manitoba border.

In the US, the Three Forks Formation (equivalent of Torquay Formation in Canada) underlies the Bakken Formation, separated by the Sanish Formation. The Three Forks Formation is estimated to have 20 billion barrels of oil in place, with 10% recoverable reserves. The oil reservoirs mainly consist of silty dolostone that are interbedded with green chloritic mudstone. The porosities are generally <8% and permeabilities are <0.1 md.

2.2 Lithology

LeFever (2005) made the following observations of the Bakken Formation's lithology. The upper and lower members are organic-rich and marine in origin, and are considered rich source rocks for oil and natural gas. The middle Bakken member includes siltstones and sandstones, and can be further divided into three units and five lithofacies (LeFever, 2005, Kreis and Costa, 2005, National Energy Board and Sakatchewan Ministry of Economy, 2015). From bottom to top, Unit A is massive, mostly medium grey to dark greenish grey, calcareous, argillaceous, pyritiferous siltstone characterized by abundant bioturbation. It covers about 38,000 km^2 and is typically 1 to 12 m thick, thinning to zero at its northern and eastern edges. Unit B is typically light to medium grey, calcite-cemented, very fine to fine-grained sandstone to oolitic calcarenite. It contains conventional oil in southeast Saskatchewan where a "trap" exists to hold that oil in place. Where it is present, conventional oil in Unit B can be produced with vertical wells. Unit C is aerially more extensive, covering about 62,000 km^2. It has an average thickness of 3 m and thins to zero at its northern edge. It is recognized by laminated dolomitic siltstone and very fine grained sandstone. Bioturbation and other soft sediment deformation are very prevalent in Unit C.

The middle member has highly variable lithology with generally well-sorted, well-cemented, and light to medium gray sandstone and siltstone. All lithologies within the middle member have low primary permeability and porosity. In North Dakota, LeFever (2005) reported five lithofacies in the Middle Bakken member, from bottom to top. Lithofacies 1 is argillaceous siltstone;

lithofacies 2 can be determined as greenish gray argillaceous siltstone to brownish gray silty sandstone; lithofacies 3 is dark gray, fine-grained sandstone to medium gray limestone; lithofacies 4 is lower argillaceous packstone to fine-grained sandstone and upper interbeds of dark gray shale and buff silty sandstone; lithofacies 5 is siltstone. In southeast Bakken, Staruiala et al (2013) identified eight lithofacies in the studied area: shale, silty dolostone, dolomitic siltstone, interbedded sand-silt-shale, dolomitic/calcitic sandstone, sandy/silty grainstone, interbedded sandstone and siltstone, and silty wackstone.

Natural fractures were created by superlithostatic pressures that were formed due to increased fluid volumes in the source rocks during hydrocarbon generation (Pitman et al., 2001). They play a big role in producing oil from the Bakken, since they have permeabilities one to several orders of magnitude larger than the rock matrix.

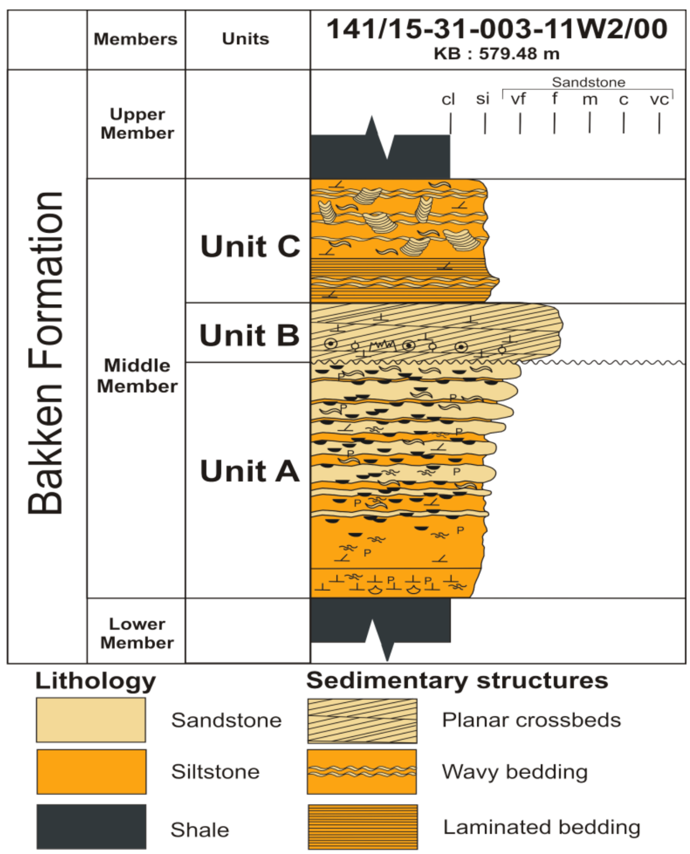

Fig. 3—Bakken Lithology in the Viewfield Field, Southeast Saskatchewan.
(Saskatchewan Geological Survey Open File 2013-1)

3. Bakken Production

3.1 Historical Production

Although the Bakken play was discovered in the 1950s, it was considered as marginal, if not sub-marginal. Until the introduction and application of innovative drilling and completion technologies, the Bakken was generally considered uneconomic. Since 2000, drilling activities have increased significantly. At present, all wells in the tight Bakken are drilled horizontally and normally completed with an uncemented slotted or pre-perforated liners. Most completions consist of isolated multistage fracturing treatments.

Because of different geology and reservoir conditions, exploration and production in Bakken oil fields can be very different within the Williston Basin. The southeast Saskatchewan Bakken reservoirs are located at a shallower depth and in localized pools with lower pressure and temperature than the Bakken in the US. The direct consequence is that Saskatchewan Bakken oil production is easier and cheaper, but with a lower production rate and estimated ultimate recovery (EUR). In 2014, production from North Dakota exceeded 1.1 million barrels per day, while the Saskatchewan Bakken produced at a more modest rate of approximately 60,000 barrels per day. While for the US Bakken, average wells are 3,000 m TVD with 3,000 m laterals. The EUR is of 500,000 BOE scale. The lower productivity from Canadian Bakken wells is somehow offset by their lower drilling, completion, and operation costs. The average breakeven of the Canadian Bakken is about $60/bbl West Texas Intermediate (WTI), compared to $65/bbl for the US Bakken.

In Canada, Bakken activity has been relatively new and more limited, starting only in 2004 with about seven rigs working continuously. During that time, different oil companies were using different drilling and completion techniques, which also yielded widely different results. Although Bakken activity has transformed Saskatchewan to a petro-province and Manitoba to an exploration destination, the wells drilled in these two provinces are generally less profitable than those in North Dakota and Montana.

Bakken oil production has already declined in 2015. The major reasons are the reduction of drilling activity and decline of current production wells. It is generally accepted that there is a three-month delay between when a horizontal well is drilled and when it starts producing. The lag is due to the fact that each horizontal well also has to be fracked and then tied into pipelines. As a result, it is expected that this decline is going to accelerate significantly in the next couple of months.

The ultimate recovery in the Bakken for primary production is expected to be 1 to 10% of OOIP, while for good areas, or "sweet spots" in the Bakken, the recovery can reach 5 to 15%. The variation depends on many factors like porosity, permeability, fracture length and density, and well spacing.

3.2 Production in Saskatchewan

The Bakken Formation in Saskatchewan spans 62,000 square kilometers (24,800 square miles) in the southeast of the province. The first Bakken tight oil production in southeast Saskatchewan was in the Roncotte field in the middle member sandstone in 1956. Primary production is often related to natural fractures (LeFever et al., 1991; Piché et al., 2002). Thermal maturation created "overpressures" to develop naturally occurring fracture systems. Oil flow during primary production is dependent on the transmissibility and connectivity of these natural fractures that intersect with production wells (Halabura and Andreas, 2010). In the early years, Saskatchewan's Bakken oil production was limited to several pools such as the Rocanville-Welwyn, Viewfield, Ceylon, Hummingbird, and Roncott pools. In recent years, the drilling activities have been focused on the Viewfield–Midale region and spreading to other fields.

The boom in Saskatchewan Bakken production activity generally started in mid-2000, which was triggered by application of long horizontal wells, which allow maximum exposure to the reservoir, and new conceptual stackfrac techniques, which allow fracturing of siltstone along the extent of the wellbore. At the largest Viewfield field in the Saskatchewan Bakken, the average true vertical depth (TVD) is 1,500 m and lateral length is 1,600 m. The average EUR is 110,000 barrel of oil equivalent (BOE). **Fig. 4** shows that the Saskatchewan Bakken production has climbed sharply since 2005 and peaked in October 2012 with 70,000 bbl/d. Cumulative total production to date is about 160 million bbl. **Fig. 5** shows the corresponding statistics for Torquay production. **Fig. 6** is statistics of current producing wells in Bakken, Torquay, and Lodgepole Formations in southeast Saskatchewan. In 2015, the forecast was for roughly 2700 wells to be drilled in Saskatchewan, among which 800 to 900 shall be drilled within the Williston Basin, aiming to produce oil from the Bakken and Torquay Formations, especially in the Ryerson and Flatlake area. Drilling activity in 2015 is down until now, due to the lower oil price.

In a recent report published by Saskatchewan Ministry of the Economy and the National Energy Board (2015), about 1.4 billion bbl of oil and 2.9 trillion cubic feet of natural gas are economically recoverable from the Canadian Bakken. With cumulative production of 160 million barrels up to the end of 2014, there are still 1.24 billion barrels of recoverable oil remaining based on today's technology. History always proves that advancements in drilling, completion, and completion technologies will further add to these reserves.

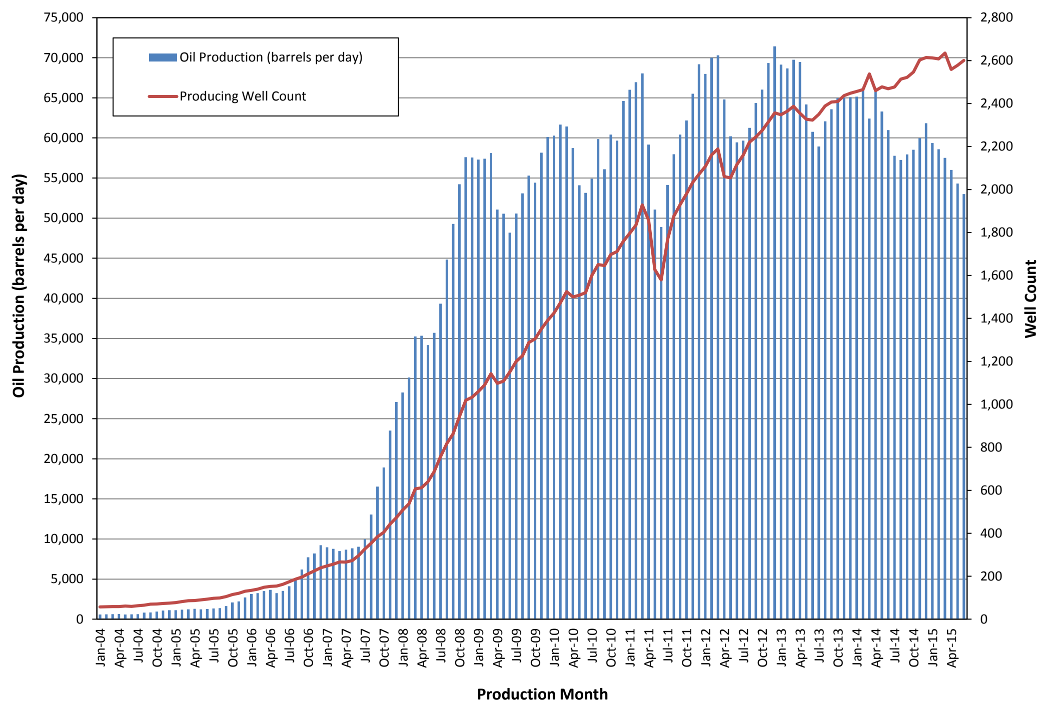

Fig. 4—Southeast Saskatchewan Bakken Oil Production and Producing Well Count Statistics.
(Statistics from geoSCOUT)

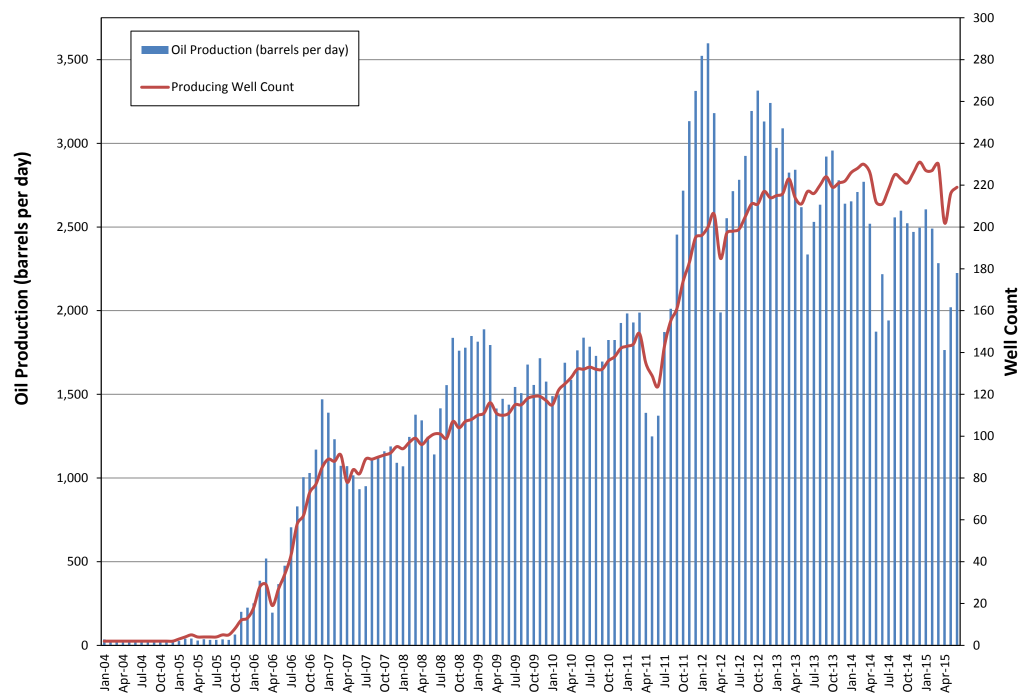

Fig. 5—Southeast Saskatchewan Torquay Oil Production and Producing Well Count Statistics.
(Statistics from geoSCOUT)

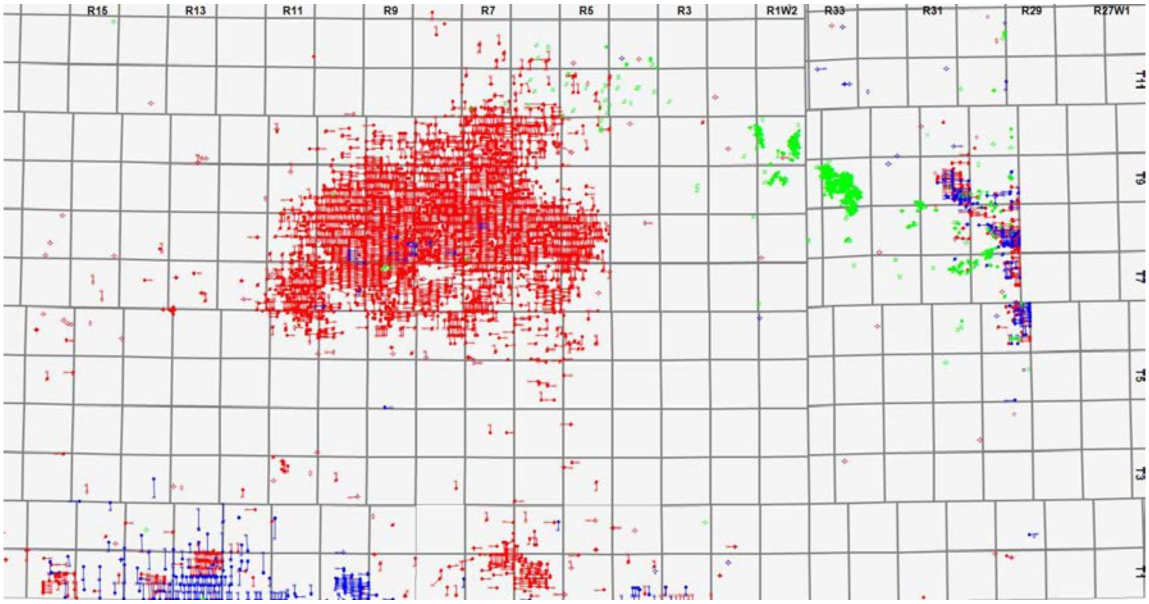

Fig. 6 Current Active wells in Bakken, Torquay, and Lodgepole Formations in southeast Saskatchewan (Red: Bakken; Green: Lodgepole; Purple: Torquay)

3.3 Production in Other Provinces and the United States

3.3.1 Production in Alberta

The Exshaw formation is stratigraphically equivalent to the Bakken formation that extends through south Alberta and into northeastern British Columbia. Alberta's Bakken activity is still at an early stage. There are currently about 34 Canadian companies and 11 US companies trying to produce oil from the 110 mile long and 25 mile wide zone from southern Alberta into northern Montana. Two of the largest players in the Alberta Bakken are DeeThree Exploration and Legacy Oil & Gas Limited. DeeThree Exploration holds 280 sections of Bakken land in southern Alberta. Legacy has 115 sections and more than 1200 net horizontal drilling locations in the Alberta Bakken.

3.3.2 Production in Manitoba

In several papers, Fox and Martiniuk (1992, 1994, 1997) described the geology and reservoir characteristics of producing horizons in Manitoba. They outlined exploration and development (E&P) opportunities and activities in Manitoba, and discussed various factors that influence these opportunities.

In Manitoba, first Bakken production was in the Daly field, southwestern Manitoba in 1985 (LeFever, et al., 1991). The shallower depth (average 874 m for the middle member) and high quality (40.2º API) made the Bakken production prospective. In 2014, out of 464 wells drilled, 64 were drilled into the Bakken Formation. Many wells were drilled and completed into multiple zones. In 2015, total expenditure by the oil and gas industry was planned to be $700 million. This includes drilling of 280 wells, targeting annual oil production of 47,000 bbl. Generally, drilling will be slowed down by 25% compared to 2014.

3.3.3 Production in US

The US Bakken production occurs from 8,000 to 11,000 feet vertical depth, at pressures of 5,500 to 6,000 psi and temperature of about 260°F. The API gravity for the Bakken oil is typically from 39 to 46°. US Bakken production is from all three members, while Saskatchewan Bakken production is primarily from the Middle sandstone and siltstone member (LeFever et al., 1991; Piché et al., 2002). **Figs. 6 and 7** show the Bakken oil production and producing well counts for Montana and North Dakota, respectively.

The production of Bakken oil in the US can be divided into three stages: a) vertical well production prior to 1985; b) implementation of horizontal well drilling, which increased the daily production to 11,790 bbl, followed by production decline back to 2000 bbl/d up to 2004; 3) incorporating of the horizontal well, or even multilateral well, into fracturing technology, by which the production was boosted to 70,000 bbl per day since 2004.

The Elm Coulee field, discovered in 2000 in Richland Country, Montana, and Mountrail County, North Dakota, was among the first commercial scale Bakken production in the US from modern stimulation technologies.

The estimated ultimate recovery (EUR) for North Dakota can range, on the lower side, from 250,000 to 400,000 BOE per well, to the highest EUR of over 700,000 BOE.

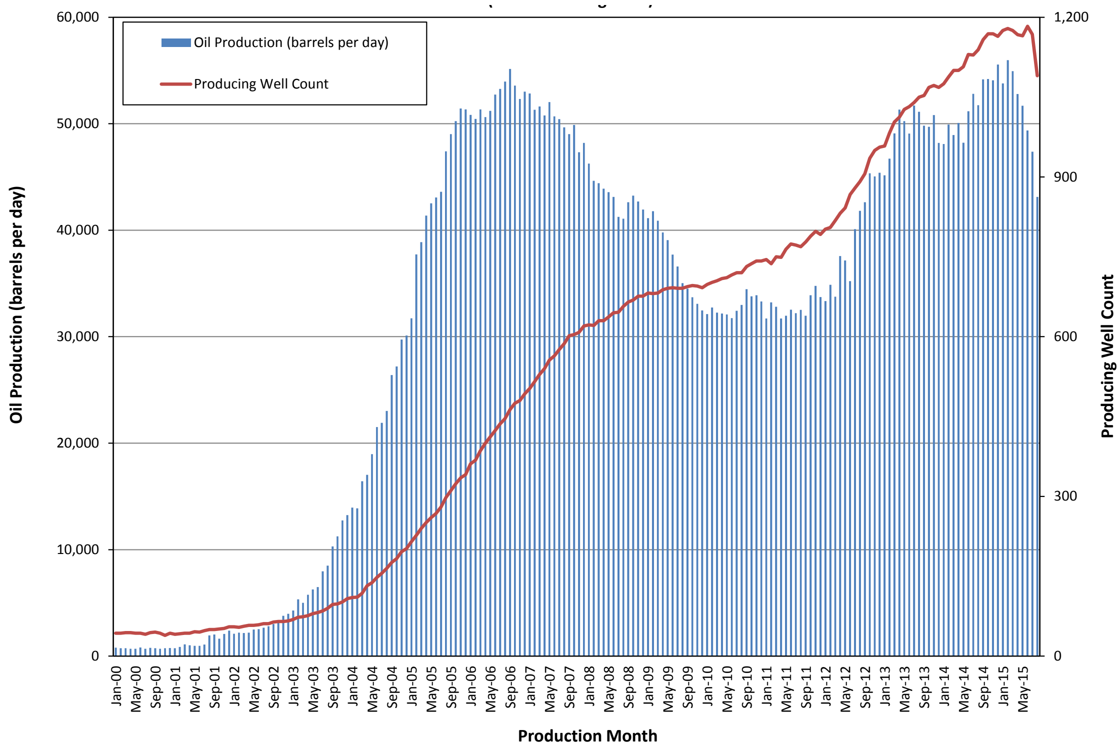

Fig. 7—Montana Bakken Oil Production and Producing Well Count Statistics.
(Statistics from geoSCOUT)

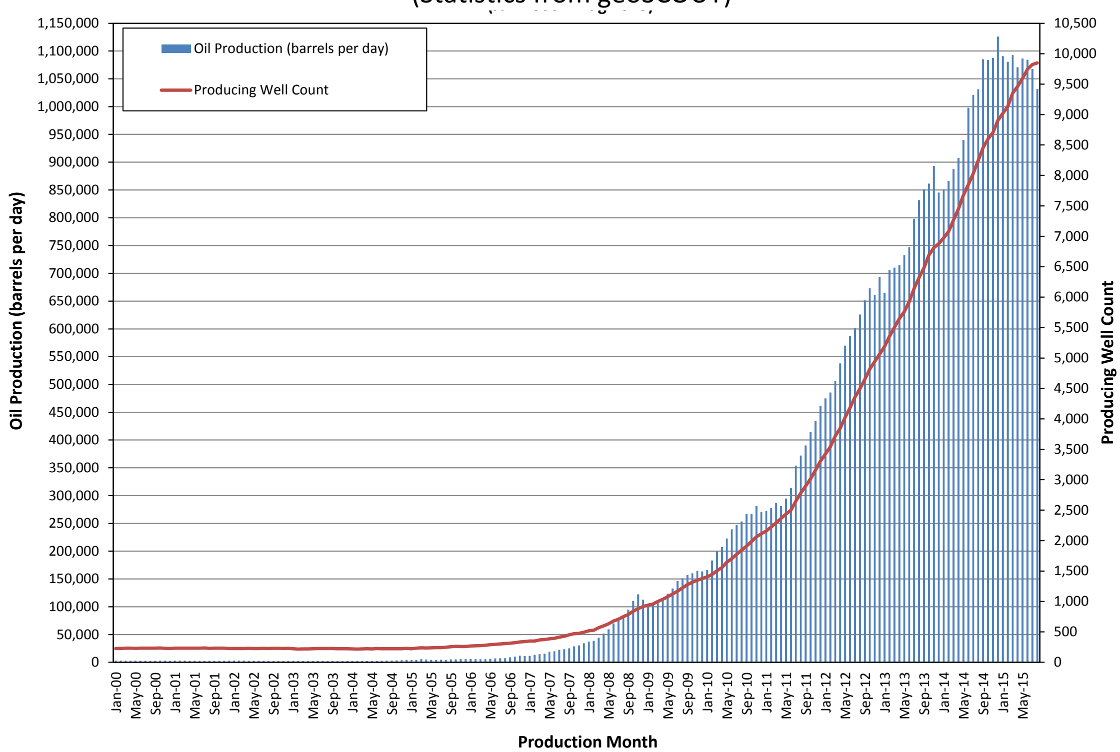

Fig. 8—North Dakota Bakken Oil Production and Producing Well Count Statistics.
(Statistics from geoSCOUT)

4. Technology Opportunities

Until the wide application of innovative technologies such as horizontal drilling and multistage fracturing, the Bakken Formation had been generally considered uneconomical before early 2000s. Technologies have evolved dramatically in recent years, which is reflected in booming Bakken oil production. In 2002, a Saskatchewan-based geoscience and engineering consulting firm, North Rim, conducted an unpublished study for a large oil company to examine exploration potential for the Bakken (Piché and Halabura, 2002). Although multistage hydraulic fracturing was still in its infancy, the conclusions was made that large-scale Bakken oil production would be mainly from areas with either naturally or artificially developed fractures. In their updated 2010 report (Halabura and Andreas, 2010), North Rim concluded that the Saskatchewan Bakken oil boom would continue as exploration pushed to coarser, more porous and more permeable sand as well as tighter, less permeable siltstone and shale parts towards the center of the Williston Basin. There is still potential for new discoveries of Bakken reservoirs in Saskatchewan, particularly along the migration pathways and within the traps of various mechanisms such as salt dissolution and structural traps.

Unconventional resources have a track record of technology development and innovation in the upstream oil industry, particularly since the year 2000. Two major motivations are:

(1) Increased facility/operational efficiency: technologies to reduce drilling and completion time and costs, and to reduce the operation cost.

(2) Increased recovery: technologies that increase initial production (IP) rates, well productivity, and ultimate estimated recovery (UER).

A large number of research activities have been conducted for tight oil formations by oil producers, research institutes and universities, and service companies across North America and the rest of the world. Whereas many research initiatives were conducted for the Bakken Formation in other provinces/states or other tight oil formations, this chapter aims at summarizing all the research activities and provides general guidance on how they can be applied to Saskatchewan Bakken reservoirs. In total, eight technology opportunities were identified in this report based on previous literature surveys and interviews with several major Canadian tight oil producers. They could be pursued by technology providers, such as SRC, by leveraging the PTAC Tight Oil and Shale Gas Innovation Network (TOGIN).

4.1 Reservoir Characterization

Reservoir characterization provides important geological and engineering parameters for economically evaluating and exploring the Bakken Formation. The Bakken reservoir rocks are highly complicated and variable (Grau and Sterling, 2011). There are many stratigraphic targets and sweet spots for lateral drilling around the basin. Variables such as thermal maturity and facies distribution are primary controls on the distribution of the overall play. Natural fracturing of the reservoir is also key to success, and ranges from microfracturing, to diagenetically enhanced fracturing, to hydraulic fracturing due to hydrocarbon generation, and finally to tectonic fracturing of brittle rock types. Facies controlled lithologies and subsequent diagenesis also play a role in reservoir quality. Finally, reservoir pressure and water saturation play a role in the ultimate recoveries. Understandably, these variables yield a wide range of reservoir targets and production characteristics around the Williston Basin.

Gangiredla and Westacott (2014) collected a wide range of geologic and engineering data from public information sources to develop an integrated subsurface database for Bakken reservoir characterization studies: Reservoir Characterization of the Bakken Petroleum System: A Regional Data Analysis Method. The database built with Geographix® software has several features: (1) modern open database connectivity (ODBC) – compliant geographic information system (GIS) data functionality; (2) rapid import of a wide range of data formats; (3) significantly reduced technical training time; (4) rapid multiwell data analysis; (5) multi-user networked resource for knowledge sharing; and (6) integrated engineering, petrophysical, geological, geophysical, and geospatial applications.

In their Phase I study, Gangiredla and Westacoot generated a workflow to normalize data and perform a regional petrophysical analysis. In Phase II, the aim was to further characterize the Bakken reservoirs through (1) geological modeling of Middle Bakken facies; (2) reservoir pressure modeling; (3) mechanical properties, anisotropy, and fracture gradients; and (4) natural fracture swarms.

4.1.1 Reservoir Fluid Properties

Fluid Properties

Traditional pressure/volume/temperature (PVT) measurements and equation-of-state (EOS) modeling are conducted without considering any effects of confinement (e.g., porous media) and surface thermodynamics of the fluid. When the pore size reduces to nanometer level for shale or ultra-tight reservoirs, capillary pressure caused by a curved liquid phase and molecular interactions between fluid and rocks will result in a shift of the following PVT and surface properties:

1. Bubblepoint pressure and lower dewpoint pressure decrease, while upper dewpoint pressure increases
2. Critical pressure and critical temperature decrease
3. Capillary pressure increase
4. Interfacial tension decrease
5. Minimum miscibility pressure decrease
6. Density and viscosity reduction due to retention of lighter ends in the oil phase

Without considering all these shifts, compositional simulation tends to estimate ultimate recovery inaccurately. Currently, it is still challenging to conduct any experiments at such small pore size. Many theoretical calculations have quantified such shifts, which can be significant when the pore size reduces to several nanometers.

When pore spaces shrink to the scale of nanometers for shale or ultra-tight reservoirs, capillary pressure, electrostatic, and van der Waals forces take effect, which can cause the phase behaviour of reservoir fluids to deviate from classic thermodynamics. Phase behaviour of unconventional reservoir fluids has received attention in last two decades. Teklu et al. (2014) discussed three pertinent topics: (1) Shift of critical temperature and pressure to lower values as pore space size reduces. (2) The effect of pores at less than 10 nm scale significantly reducing the bubblepoint pressure at low temperatures, while such effect becomes negligible when pore radius is larger than 40 nm. (3) A possible drop in minimum miscibility pressure of 200 psi for pure CO_2 and 500 psi for a CO_2–CH_4 mixture for a pore radius of 4 nm compared to unconfined pores.

Du et al. (2012) noted that the nanometer pore throats in unconventional reservoirs could generate a phase capillary pressure up to 1,000 psi. Therefore, the observed oil viscosity and bubblepoint pressure (P_b) in an unconventional oil reservoir are substantially lower than those reported by a PVT laboratory. Such reductions are further aggravated by the compaction effect and then become variable with pressure depletion. PVT properties for 14 Bakken fluid samples were recalibrated by combining newly developed non-linear fugacity equations. As well, pore throat reduction from pressure depletion further changed PVT properties. Du et al. used the corrected PVT tables in their Bakken reservoir simulation model and successfully explained an inconsistent field gas/oil ratio (GOR) issue, whereby a flat or dipped producing GOR occurs even when the reservoir pressure is below the bulk fluid saturation pressure.

Wang et al. (2013) presented a compositional tight oil simulator that rigorously models suppression of bubblepoint pressure, decrease of liquid density, and reduction of oil viscosity as well as their interactions with pore space compaction, when nano-sized pores start to impact rock and fluid properties. The simulator can capture the pressure-dependent impact of the nanopore structure on rock and fluid properties. Similar to Du et al.'s work, the problem of inconsistent GOR is resolved to improve the history matching process.

Nojabaei et al. (2013, 2014) developed a compositionally extended black-oil model that incorporated capillary pressure with phase equilibrium equations; the resulting nonlinear fugacity equations were used to examine the effect of small pores on saturation pressures and fluid densities. Binary mixtures of methane with heavier hydrocarbons and a real reservoir fluid from the Bakken shale were considered.

Geochemistry – Water Compatibility and Scale Mitigation

Bakken formation brine has significant total dissolved solids (TDS), hardness (mainly calcium and magnesium), and iron and strontium concentrations, not to mention high reservoir temperature. In the US Bakken, TDS is commonly higher than 200,000 ppm, with Ca^{2+} in the range of 10,000–15,000 mg/L, bicarbonate of 350–600 mg/L, and pH of 5.5–6.5 (Szymczak et al., 2014). This requires substantial attention to water chemistry concerns at Bakken, such as the high tendency of scaling problems and incompatibility of injection water with formation water. Research and development in scale inhibitors with high iron and temperature tolerance is critical.

Peng et al. (2015) used a standard static bottle test and dynamic tubing block test to evaluate six scale inhibitors for controlling carbonate scale with high iron concentration in the Bakken Formation brine. The inhibitors included one phosphate ester, three modified phosphonates, and two polymer inhibitors. The modified phosphonates showed good carbonate inhibition and tolerance to high TDS brine with ~200 mg/L iron concentration.

A report on one of the few experiences with Canadian Bakken scaling treatments was published by Wylde et al. (2012), who summarized the scaling observations made over the producing life of Bakken Formation drawn from treating and servicing over 400 wells throughout southern Manitoba and Saskatchewan. The majority (>95%) of the wells experienced $CaCO_3$ scale; occasionally $CaSO_4$ (anhydrite), $CaSO_4 \cdot 0.5H_2O$ (hemihydrate), or $CaSO_4 \cdot 2H_2O$ (gypsum) was observed. Iron sulfide scale was identified in injection wells (and less often in production wells). Seldom were other sulfate scales, such as $BaSO_4$ or $SrSO_4$, observed. The ubiquitous $CaCO_3$ deposition is formed from large pressure drop and temperature decrease. Wylde et al. suggested that it was important to treat the well at the first sign of water breakthrough, or even at a low dose rate prior to water breakthrough. A phosphonate-based blend, with the advantage of high salinity and high temperature tolerance, was extensively applied in Bakken wells. The success of treatment can be judged by injectivity gains, oil production rate increase, and control of deposition in produced-water-handling surface facilities.

Szymczak et al. (2012) developed an environmentally friendly, biodegradable proppant-sized solid scale inhibitor. In contrast to a liquid inhibitor that may get distributed preferentially to water-producing zones, this solid inhibitor is placed into the created fractures and evenly distributed throughout the fractures to allow the inhibitor to desorb into the entire fluid stream from any place in the formation matrix. Out of one operator's 150 producing wells, at least 22 developed severe carbonate scaling issues in the pump and/tubing (Cenegy et al., 2011) within the first two years of production and the first 20,000 bbl of water production. The new solid scale inhibitor has then been applied in the area since 2010. More than 290 North Dakota Bakken wells had been treated at the time of publication with no reported scale-related failures.

Scaling prediction simulation is challenging due to the variability of produced brine composition. In response to the above-mentioned scaling problems experienced by the North Dakota operator (Cenegy et al., 2011), "post-mortem" analysis from all failed wells was conducted to study failure type, date, hydraulic fracturing procedure, pump intake pressure, scaling inhibitor residual, calcium carbonate scaling index, geographic failure concentration, production time to failure, and cumulative water production to failure. The analysis results showed that 82% of scaling issues occurred within the first 20,000 barrels of water produced. Fracturing fluid flowback could be responsible for high alkalinity in the water and in turn represent scaling events. The Bakken operators usually apply high concentrations of liquid inhibitor as an additive to fracturing fluid.

Kalfayan et al. (2013) further discussed the selection of solid scale inhibitor technology, the inhibitor placement process, and the steps taken to further optimize and manage costs of the field-wide Bakken scale inhibition program.

Wong and Moore (2012) reviewed a study of selected wells in the southern Saskatchewan area of the Bakken Formation, highlighting the factors that contribute to severe corrosion and treatment strategies to minimize it. Bakken well corrosion was evaluated by analyzing field parameters such as well dimensions, production data, operating conditions, water analyses, gas compositions, temperatures and pressures. Corrosion was further investigated by performing field compatibility tests and applying routine monitoring methods – such as corrosion coupons, iron and manganese residuals, water analyses, bacteria analyses, failure histories, and copper-ion displacement testing.

Scale potentials were determined using the Tomson-Oddo model, which provides values for the Saturation Index (SI) – a parameter indicating the thermodynamic tendencies for the formation of each scale type and also the mass of precipitate, i.e., the mass of each scale type that is predicted to form. In the Bakken Formation, a small tendency for calcium carbonate (calcite) and strontium sulfate (celestite) was predicted. Field samples obtained from well workover activities over a three-year period were analyzed to monitor changes in the composition of any materials depositing. Over the three years of investigation, significant scaling was identified on a number of wells. Fluids from this formation show a positive potential for calcium carbonate and strontium sulfate formation.

4.1.2 Petrophysical Properties

Proper measurement of the petrophysical properties, e.g., porosity, permeability, and pore throat distribution, is critical for design and implementation of the production processes. That is because tight oil/shale production performance is strongly dependent on interconnected natural and hydraulic fractures in the drainage volume of the horizontal well, i.e., stimulated reservoir volume. When fractures are created or regenerated as a result of in-situ stress and strain change, the distribution and permeabilities of these fractures have determining effects on the tight oil production performance and ultimate recovery. Some petrophysical properties of Bakken formation rocks measured in the literature are listed below:

- Primary porosity and secondary porosity
- Permeability
- Various logs, including porosity type (acoustic, neutron, and density, etc), resistivity type (dual lateral, dual induction, and micro-spherical, etc), dip-meter log, long-spaced sonic log, and natural gamma-ray spectral log
- Drainage and imbibition capillary pressure curves
- Triaxial resistivity
- Microseismic

Zhao and Qing (2014) measured 12 southeast Saskatchewan Bakke rock samples with porosities in the range of 7 to 22% and permeabilities from 0.002 to 0.16 md. They found that the porosity and permeability of Bakken reservoirs are closely related to and/or controlled by lithofacies. Dolomitic rocks in general have higher porosity and permeability than other lithofacies.

Ranking future drilling locations is a critical step in planning the development strategy and optimizing the economics of the play. Pilcher et al. (2011) modified the parameter of stock-tank oil originally in place (STOOIP) that represents the productivity potential by incorporating geological modifiers. These geological modifiers include source maturity, charge access, reservoir facies and properties, geological structures (trap and natural fractures), overpressure, and fluid properties. The potential reservoir deliverability is thus defined to rank acreage, plan the drill schedule, assign rigs within the play, and assess lease acquisition opportunities.

Nandy et al. (2014) used an energy dispersive X-ray fluorescence (ED-XRF) technique to study North Dakota and Montana Bakken upper and lower shale cores. The purpose was to develop chemostratigraphic zonation of the shale members and understand the various geological and paleoceonographic factors that affected the shale deposition. Enrichment of the paleoredox elements indicated that the shale members were deposited under a reducing environment. The high paleoproductivity, periodic upwelling, bottomwater anoxic-euxinic condition and enhanced preservation potential are the reasons for high TOC content in the upper and lower shale members.

Alexandre (2011) conducted a study to characterize the largest Bakken oil field, Elm Coulee field, in the Williston Basin. The field was discovered in 2000 in Richland County, Montana, and produces from the middle member of the Bakken formation with an estimated ultimate recovery of 200–250 million barrels of oil. Understanding the distribution of facies, the types of porosity, and the diagenetic processes that have occurred in the Bakken was found to be the key to directing drilling targets in the Elm Coulee field.

Determining well-deliverability potential by conventional drillstem tests (DSTs) or traditional wireline formation tests (WFTs) in the past has resulted in mixed success in the Bakken. On the other hand, the mini-DST has increased the reliability of pressure-transient tests because the formation interval of interest is produced at a precise constant rate into a chamber between two inflated packers with negligible wellbore-storage effects. Kurtoglu et al. (2013) presented several field tests that were analyzed both by the preceding procedure and by numerical simulation. The analyses of several mini-DST results have provided better understanding of the flow mechanism in the Bakken, both during primary production and in forecasting various improved-recovery and EOR proposals. Kurtoglu et al. (2012) also concluded that the interconnected micro-fractures in the matrix provide a permeable flow path from the matrix to the hydraulic fractures.

Karimi and Kazemi (2015) reported on the use of a centrifuge to generate a complete envelope of drainage and imbibition capillary pressure data for a Middle Bakken core plug. The experiments were very time consuming because of the low core permeability; however, carefully designed centrifuge experiments are valuable for reservoir engineering evaluations and reservoir simulation studies.

In late 2007, seven Bakken oil operators along with Schlumberger formed a consortium to study the effects of various hydraulic fracturing techniques on the oil production (Forrest et al., 2010). Three horizontal wells, each 4,000 feet in length and 1,500 feet apart, were drilled into the Middle

Bakken Member. Schlumberger positioned 16 triaxial geophones, spaced 100 feet apart, in the middle well. Several hundred microseismic events were recorded during the hydraulic fracturing of the other two flanking wells. It was critical to analyze these microseisms to ensure they were located accurately. The US Department of Energy (DOE) and Terrascience's near surface system did not record any microseisms during attenuation through 10,000 feet of sediments overlying the Bakken. MicroSeismic Inc. reported thousands of microseisms with an array of small single-component geophones planted in the soil.

Traditional petrophysical interpretation is limited to the locations of well logs, which are unsuitable for unconventional reservoirs such as Bakken with high complexity and heterogeneities. Klenner et al. (2014) conducted multimineral petrophysical analysis (MMPA) and fracture analysis to characterize and compare thermally immature and mature Bakken oil fields. Core log suites were calibrated to full-diameter core with associated petrographic analysis through scanning electron microscopy (SEM), X-ray diffraction (XRD), X-ray fluorescence (XRF), petrophysical plug properties, and logged core descriptions. A detailed natural fracture analysis was also conducted for macrofractures in full-diameter cores and thin sections for microfractures. Comprehensive structural models were thus designed based on the MMPA results and facies-to-fracture correlations.

Use of elastic rock properties for characterization of completions is important in tight oil/shale development (Rael et al., 2013). Traditionally, rock elasticity has been determined through geomechanical laboratory measurements on core pieces or plugs and log-derived calculations. Unfortunately, these data sets are rare (i.e., for core) and inconsistent/expensive to collect (i.e., logs) along long laterals. However, cuttings are always available for the entire borehole. They provide a source of compositional and textural rock data that can be quantitatively measured to train standard petrophysical analysis in order to implement rock physics equations (e.g., Young's Modulus, n, l, l-r, and m-r). Using electron beam (e-beam) systems, mineral composition data, together with high resolution textural information (e.g., pore volume, pore fabric, pore size distribution and pore aspect ratio) within cuttings are now directly measureable. This allows for input parameters (e.g., pore aspect ratio) to be directly measured within rocks rather than mathematically derived.

While the effect of stress on matrix permeability and hydraulic fracture conductivity has been studied with more detail, little has been focused on changes in natural fracture permeability from pressure depletion. Cho et al. (2013) presented an experimental study on stress dependence of natural-fracture permeability. They used a slabbed plug held together to simulate the natural fractures, and increased the confining stress from 1,000 psi to 5,000 psi to study stress change. Though the natural fractures have more complex geometry and surface roughness, this experimental method modeled a simplified planar fracture geometry. Pressure-dependent matrix-permeability correlations from literature were used to fit measured results. It was found the natural fractures lose significant permeability under pressure depletion.

Intrinsic anisotropy due to layering, as well as induced anisotropy due to fractures, plays a critical role in fluid flow in organic-rich shales. Mokhtari et al. (2013) characterized the impact of natural and induced fractures on permeability anisotropy utilizing CT-scans at various resolutions and presented the effect of stress on the permeability of such fractured reservoirs. Effective permeability to gas declined exponentially with increasing effective stress on both fractured and unfractured cores. They also investigated the wettability of several shale samples from Eagle Ford, Mancos, Green River, Bakken and Niobrara shale plays. In general, it was found that the contact angle of water increased as total organic content (TOC) increased.

Logging-while-drilling (LWD) measurements have the advantages of determining the reservoir rock properties in real time so that completion decisions can be made rapidly and wells can be steeled with the real-time data. The earliest application in the Bakken formation was in the late 1980s, when a directional gamma measurement-while-drilling (MWD) tool was used to detect variations in the shales. Quinn et al. (2008) showed that LWD image logs can provide solutions for fracture stimulation treatments, detection and understanding of wellbore stability issues, occurrence of natural and drilling-induced fractures, and direction of the type and placement of different packers for multistage fracture treatments.

Forghani-Arani et al. (2013) implemented a technique to suppress surface-wave noise in microseismic data based upon the distinct characteristics that microseismic signals and noise display in the τ-p domain. They applied this noise suppression technique to microseismic data recorded by a star-shaped array, over a Bakken Shale reservoir during a hydraulic fracturing process. They claimed that their technique significantly improved the signal-to-noise ratios of the microseismic events. It was illustrated that the enhancement in signal-to-noise ratio also results in improved imaging of the microseismic hypocenter.

Historically, production type-curves generated from conventional petrophysical analyses of the Bakken formation often showed inconsistent reservoir recovery factors with actual production data as well as knowledge of the reservoir. Simpson et al. (2015) developed a petrophysical model using both deterministic and probabilistic methods to integrate conventional triple-combo logs supplemented with advanced downhole measurements, which included the following:

(1) Triaxial resistivity for thin-bed analysis

(2) Nuclear magnetic resonance for porosity, free fluid and kerogen identification

(3) Dielectric dispersion for water saturation

(4) Geochemical spectroscopy for mineralogy and TOC

(5) Dipole sonic for dynamic rock properties

Results from this integrated petrophysical model provided a basis to refine production type curves and to recalculate stock-tank oil originally in place (STOOIP).

Cui et al. (2013) investigated the controlling effects of anisotropic in-situ stress and permeability on optimizing well and hydraulic fracture placements based on laboratory stress-dependent permeability measurements and field production data of several unconventional formations, such as Montney, Nordegg, Cardium, and Bakken in the Western Canada Sedimentary Basin (WCSB). In-situ horizontal stresses in the WCSB are highly anisotropic, with the maximum horizontal stress (SHmax) approximately in the NE direction. The strong stress anisotropy and pre-existing major NE-striking natural fractures likely result in strong anisotropy of horizontal permeability with the maximum permeability in the NE direction.

Obrien et al. (2011) described how real-time downhole microseismic monitoring, fracture treatment pressure interpretation and subsequent production evaluation were used to better understand the created fracture geometry, completion staging efficiency and fracture stimulation effectiveness in a project with two parallel 4,000-ft middle Bakken horizontal wells 2,000 feet apart with a horizontal well in between.

4.1.3 Geomechanical Properties

Geomechanical properties play a critical role during drilling, hydraulic fracturing, and the pressure depletion process. Drilling activities cause stress alteration around the borehole at a sizeable radius. The quality of the artificial fractures is affected mainly by the geomechanical properties of the formation. The ductile behavior of the formation rocks presents a challenge in hydraulic fracturing, while the brittle sections are the priority concern for fracturing operations. Pressure depletion during production causes changes in pore level pressure and in turn changes in effective stresses on the reservoir rocks. This can cause closure of natural and induced fractures, casing or wellbore failures, and surface subsidence.

In general, lab testing, core analysis, and well log correlations are three major ways to determine geomechanical properties (Zeng and Jiang, 2009), each of which has its advantages and limitations. Lab testing is the most direct and reliable means, though many tests are labour and time intensive. Core analysis is another direct method, but it can only be conducted in cored wells. Well logging is an indirect method that reflects petrophysical and geomechanical properties of the formation and regional geology. Because well logs are usually performed in most wells, it is possible to integrate lab testing, core observation, and well logging using artificial intelligence technology to predict geomechanical properties.

Another important tool for incorporating geomechanics into tight oil exploration and production is a mechanical earth model (MEM). An MEM incorporates all available calibration and validation data, including laboratory core tests, pressure tests, microseismic, mud logs, and daily drilling reports (Ganpule et al., 2015).

The commonly measured/estimated geomechanical properties for the Bakken Formation and other unconventional resources are listed in **Table 1** below.

In 2008–2011, the National Energy Technology Laboratory (NETL) partnered with the University of North Dakota to determine the magnitude and direction of the in-situ stress and geomechanical properties of the Bakken. This knowledge is helpful in the selection of drilling orientation and better design of the hydraulic fracturing process. By integrating field data, core samples, and lab results, the generated database of geomechanical properties can enable operators to design well placements and completion strategies. A series of fundamental and practical research results were generated from this initiative, as detailed in the section below.

In-situ stress field and geomechanical properties change not only along the axis of long horizontal wells but also from location to location in the whole Bakken Formation. Well orientation with respect to the in-situ stresses is one of the determining factors to affect hydraulic fracturing, wellbore stability, and follow-up production. Zeng and Jiang (2009) estimated the in-situ stresses and determined the mechanical properties in the Bakken Formation so as to improve the success rate of horizontal drilling and hydraulic fracturing. The research involved lab testing, field data analysis, and numerical simulation using representative well logs and core samples of the study area.

Havens and Batzle (2010) measured in-situ stress and mechanical properties to improve drilling strategies. The Mohr-Coulomb (MC) failure criterion was implemented and the parameters φ and σ_{ci} were calculated to be 53° and 46 MPa, respectively. The static Young's Modulus was calculated to be 21 gigapascals. They (2011) further measured Biot’s coefficient in two facies from the middle Bakken and applied the Self-Consistent Approach to model continuous static properties throughout the middle Bakken.

Table 1—Geomechanical Properties Studied for Bakken Reservoirs

Property	Details
Maximum horizontal principal stress and its orientation	Determined using an elastic strain recovery and acoustic anisotropy velocity method, and induced tensile fractures in oriented cores
Dynamic elastic properties	Young's modulus, Poisson's ratio, etc., determined from wireline data
Static elastic modulus	Converted from dynamic elastic properties using empirical correlations and calibrated to available core data, or determined from tri-axial test
Rock strength	Laboratory tests, if available, to fit a number of empirical correlations
Vertical stress (overburden)	Integrating bulk density to the depth of interest
Horizontal stress	Determined from poroelastic horizontal strain model, which incorporates pore pressure and static elastic properties to calculate the minimum and maximum horizontal stresses
Pore pressure	Difficult to measure, usually estimated from drilling events (e.g., kicks, influxes, and connection gas), fracture injection tests, and build-up curves.
Fracture gradient	Estimated with laboratory tests
Static Poisson's ratio	Determined from tri-axial test
Dynamic Poisson's ratio	Determined from P- and S- velocity (sonic) and density logs
Biot's coefficient	Describe the ability of the pore pressure to counteract the stresses on the rock, can be calculated using the dry rock stiffness tensor and estimate of the mineral bulk modulus

Wang and Zeng (2011) summarized the screened geomechanical properties of the Bakken Formation in North Dakota's portion of the Williston Basin. They screened completion reports of over 4,000 wells in this area and identified four wells for conducting all-purpose parameter testing and three wells for express geomechanical testing to gain uniaxial compressive strength (UCS). A number of geomechanical properties were quantified, which included UCS, compressive strength, static/dynamic elastic modulus, Biot's coefficient, the shear wave and compressional wave velocity, orientation of maximum horizontal principal stress, and fracture gradient.

Pei et al. (2014) investigated the correlations of the Bakken rock geomechanical properties with the stratigraphic sequence. This correlation provides an approach to predicting the geomechanical properties in different intervals of the formation, and offers support in selecting, designing, and optimizing the hydraulic fracturing operation. Formation intervals which are brittle usually are the priority for a fracturing operation. The authors calculated the brittleness index, investigated its regularity along the depth, and then correlated these properties with the stratigraphic sequence of the formation, seeking to explain the difference between the mechanical properties. Because the facies and stratigraphic features of the formation are identifiable, this correlation helps in predicting the geomechanical properties without time consuming and expensive laboratory testing. The results offer support in selecting, designing, and optimizing the hydraulic fracturing operation.

In a series of studies, Ostadhassan et al. (2011, 2012, 2013) developed a Mechanical Earth Model (MEM) to simulate reservoir geomechanical properties in 1D, 2D or even 3D configurations. The model contains information on rock failure mechanisms, in-situ stresses, stratigraphy, and geologic structure of the reservoir. Built before the drilling, the model could be updated with new information from drilling, fracturing, and production. The elastic parameters and the effective stresses in the three members of the Bakken Formation were generated from a cross-dipole sonic log from a vertical well in North Dakota. The dynamic elastic moduli, i.e., Young's modulus and Poisson's ratio, were converted to static ones through empirical correlations. In-situ stresses and a pore pressure profile were generated under isotropic and anisotropic conditions. The MEM model provided insight to evaluate the potential risks involved with the alteration of in-situ effective stresses around the borehole and the risks associated with the reservoir pressure decline.

To address questions about optimization of hydraulic fracturing and the importance of pre-existing natural fractures as fluid pathways in Bakken reservoirs, Yang et al. (2013) developed a geomechanical model to study multistage fracturing of two parallel horizontal wells in the Bakken Formation. They combined geological, geophysical and geomechanical data to estimate the stress state. They also discovered unusual microseismic events that they believed to result from fluid channeling dominated by pre-existing fractures and faults in the study area.

Jabbari et al. (2011) used a model to analyze the effect of stress change on rock fracture properties in naturally fractured reservoirs (NFRs). In an NFR, fluids are stored inside the pores among grains (primary porosity) and the fractures (secondary porosity). Integrated with geomechanics, porosity and permeability are functions of changes in in-situ effective stress during primary pressure depletion or EOR processes from water/gas injection.

Ganpule et al. (2015) highlighted the importance of characterizing the variability of in-situ stress, as it directly impacts well spacing design. Pore pressure and resulting in-situ stresses vary both vertically and laterally in the Bakken Formation. This variability controls fracture geometry, which in turn affects drainage lengths and well spacing. A stress profile with a normal pore pressure regime results in longer hydraulic fracture lengths so that three wells can be drilled per section. Conversely, wells drilled in an over-pressure regime require more than three per section. Standard treatment without any modifications to account for such variation can lead to over- and under-stimulation of the Bakken reservoirs.

Hawkes and Gorjian (2014) took core samples from the lower, middle and upper members of the Bakken Formation in southeast Saskatchewan from two wells. Both full-diameter samples were submitted to tensile strength and fracture toughness tests, and 24.8-mm plugs were drilled for unconfined compression tests. Permeability and porosity of selected samples, and compressional and shear wave acoustic velocity of all samples, were measured. Results suggested that the upper and lower members of the Bakken Formation tend to have rather different mechanical properties from the middle member. Most importantly, in terms of properties affecting fracture height growth, both the tensile strength and fracture toughness of the shales are consistently lower than the values measured on adjacent strata present in the middle member. These results suggest that out-of-zone height growth would not be mitigated by the shales.

4.2 Drilling and Completion Technologies

Bakken well activity and oil production has increased dramatically in recent years, largely because of technological advancements in drilling, completion, and hydraulic fracturing. In addition to horizontal drilling, one of the key drivers in the Bakken oil boom is the game-changing multistage hydraulic fracturing technology. The high cost of drilling and completion in the Bakken Formation presents a strong incentive to improve their efficiency. While drilling and casing procedures have become generally standardized in the Bakken Middle Member, there are wide variations in the completion and stimulation practices. Details can vary significantly depending on specific reservoir properties, such as permeability, stress, and natural fractures. A successful drilling and completion strategy needs to consider many aspects, such as geological settings (geohazards, faults, karsts), geochemistry (lithology, hydrocarbon type, or mineralogy changes), geomechanics (tectonic stress, faults); petrophysics (porosity, saturation, permeability, bottomhole pressure), logistics (fluid, proppant equipment, manpower availability), economics (well cost, product price, net present value, return on investment), and environment (resource sustainability, safety, cultural sensitivity).

In the Montana and North Dakota Bakken Formation, horizontal wells typically have 10,000-ft lateral sections in the pay zone and 24- to 36-stage hydraulic fracturing. A number of case studies (Phillips et al., 2007; Lantz et al., 2007; Harkrider et al., 2014) summarized experiences in stimulation and operations in the Bakken Middle Member. Djurisic et al. (2010) summarized challenges encountered during drilling of a Bakken wellbore and outlined approaches to optimize the drilling processes. The authors discussed the use of high-performance drilling motors, reviewed previously used bottomhole assembly (BHA) concepts, and described the benefits of gathering additional real-time downhole drilling data to validate or change best practices.

In southeast Saskatchewan, drilling and completion of a horizontal well can encounter several geological hazards (Alvarez et al., 2013). These include localized thinning of the reservoir, extreme salt collapse, and structural lows related to salt dissolution. The major concern for completion is the fracture growth into the overlying Lodgepole Formation.

In the US Bakken, starting from the first Bakken vertical well in 1953, drilling and completion technologies have evolved over the decades (Baihly et al., 2012; Cox et al., 2008, LeFever, 2005). The first horizontal well in the Bakken was drilled in Billings County in 1987 with a pre-perforated or slotted liner, and was soon followed by other lateral wells. Horizontal wells drilled during this period were completed with a slotted liner and no fracture stimulation. These wells were targeted at the upper organic-rich shale member, and economics were dependent on whether the wells were located in the natural fracture zone (sweet spot). During the mid-1990s, single-stage fracturing with linear gel transporting sand was applied to the Middle Member in Richland County, Montana (Olsen et al., 2009). This completion method was used for the first time in North Dakota, in Sadler field, in 2004. Since the middle of 2000, continuous development of innovative drilling and completion technology have contributed to the boom era in the Bakken in both the US and Canada. One innovation was multilateral wells drilled outwards from one vertical wellbore. The multilateral wells were typically completed with slotted liners and hydraulically fractured.

Since around 2006, significant improvements in completion technology have included uncemented and cased laterals and the mechanical isolation of the fracturing stages using external swell packers. Two types of isolation devices were used: sliding sleeves activated by graduated balls or plug and perf. The fracturing treatments were solely crosslinked or hybrid processes with linear gel or slick water pads followed by crosslinked gel. Several different types and sizes of proppant have been used.

4.2.1 Drilling Technologies

Table 2 summarizes the findings and benefits of several field cases with advanced drilling technologies.

Chrisman et al. (2012) showed how the application of a real-time downhole dynamics tool can help optimize the drilling effort by saving time and increasing the percentage of successful one-run laterals. The dynamics tool’s data consist of optimization information, dynamics information, and wellbore quality with steering information. The tool in the bottomhole assembly (BHA) is placed between the motor and the measurement-while-drilling (MWD) system. Benefits of the real-time information were realized from three aspects: (1) information on weight transfer assists in drilling operation optimization; (2) control stick-slip and lateral vibration to extend the life of drilling bit, MWD, and BHA; (3) information from a source very close to the bit, which was essential for timely decision making while drilling the thin Bakken middle member that requires both inclination and azimuthal control setting. The initial simulation outcome was encouraging, with a 30% reduction of drilling days for wells 1 and 13, and 16 days saved for wells 2 and 3.

Han et al (2013) applied several practical field techniques and technology applications as solutions to help optimize the rate of penetration (ROP), and reduce non-productive rig time and chances of sidetracks.

Lloyd (2010) presented directional drilling advantages and artificial lift benefits using rotary steerable technology (RSS), and advancements in an open hole, multistage fracturing system (OHMS) allowing increased stage density for production optimization. Lloyd describes the combination of drilling optimization with advanced OHMS technology as pushing the envelope for continued improvement in operational and production efficiencies. RSS provides a higher quality lateral before complex OHMS is deployed without any additional borehole conditioning rip.

Because of the significant impact on drilling costs, the correct selection and utilization of drilling equipment including bits, drilling fluids, hydraulics and downhole tools are critical. Ibrahim et al. (2011) adopted a holistic optimization approach that analyzed the entire drilling environment and all BHA components back to surface. A sophisticated simulation software was utilized to test various BHA configurations and resulting components through different formation types and hole sections. The analysis included expert drill bit selection, rock mechanics analysis, drilling shock analysis, drilling fluids, hydraulic optimization, and directional drilling planning.

Variable mechanical properties in the laminated upper and lower Bakken shale structures can increase the likelihood of cement left-in-pipe events (CLIPs), when cement fluids are not completely displaced from the casing during placement. Levy et al. (2014) conduced a three-year study to assess numerous contributing factors, including geomechanics, drilling practice, and slurry design. They determined that in-situ shale stresses have the greatest impact on wellbore stability and CLIP occurrence. Since the upper and lower Bakken Formations are transverse isotropic, rock strength degradation is exhibited when the well is drilled at an oblique angle to the orientation of the bedding plane.

Table 2—Bakken Drilling Field Cases

Field/County	Technology/Best Practice Highlights	Findings and Technology Advantages	Ref
Sanish field, Mountrail County	• Real-time downhole dynamics tool to help optimize drilling activity. • Practical use of the directional information from bending moment and bending tool face close to the bit.	• Save time and increase the successful rate of one-run laterals. • Allow the directional driller to make better real-time decisions whether wellbore correction is needed.	160121
Mountrail County, ND	• Conventional mud motors and MWD/LWD systems together with on-site geological analysis to drill the curve and lateral section. • Electromagnetic (EM) MWD/LWD. • GeoSteering in the lateral section.	• Landing curve: cost effective with adequate results. • EM MWD/LWD: faster data rate than conventional mud-pulse; signal transmission is independent of wellbore hydraulics; allows more lost circulation material (LCM) to be pumped downhole when necessary. • GeoSteering: constantly monitors drilling parameters and cutting samples to avoid undesirable penetration of shale formation.	163957
Burke County, ND	• Rotary steerable system (RSS), “push-the-bit” tool applies force outwards against the wellbore to push the bit in the opposite direction. • Conditioning the borehole with reamer run.	• RSS: simplicity and full rotating capability to effectively clean the wellbore. It is also used to maintain hole verticality above the kick-off point (KOP). • Reamer run: improve borehole trajectory condition by reducing borehole rugosity, spiral boreholes, and propoising effects.	137864
Non-disclosed	• Holistic optimization technique to analyze the entire drilling and all BHA components back to surface. • The results were analyzed as a whole to determine the best drilling solution. • An optimization “roadmap” is generated to include a mainline strategy in addition to several contingency plans.	• Proper drill bit selection and wear pattern emulation to improve drilling efficiency and ROP. • Appropriate liquid and mechanical drillstring lubrications were implemented for effective WOB transfer. • Continuous well monitoring and streamlining of decisions. • 34% reduction in drilling days than projected and established average days.	

4.2.2 Drilling/Fracking Fluid and Proppant Design

Within 10 to 50 meters above the Bakken reservoir there often is a higher permeability water bearing interval in the limestone Lodgepole Formation. Therefore, hydraulic fracturing in the Bakken oil reservoirs in Saskatchewan involves a risk of connection to these overlying water-bearing zones. If hydraulic fractures connect to the higher permeability interval in the Lodgepole, then water production and associated handling costs would greatly increase. To minimize the potential negative impact of partial hydraulic fracture growth out of zone, some strategies, such as reduction of pump rate, slurry volume and fluid viscosity, are implemented.

Hlidek and Rieb (2011) reviewed about 3900 fracturing treatments in more than 460 wells with lateral lengths from 400 m to 1350 m in the Saskatchewan Bakken Viewfield field to study the influence of treatment parameters and completion variables. The detailed variables included proppant type and concentration, fracturing fluid formulation, treatment size, wellbore azimuth, and lateral fracturing density. Two crosslinked polymer fracturing fluids were used for the majority of the treatments. One was a low-pH zirconium crosslinked gel and the other was a high-pH borate crosslinked gel. To address environmental concerns, 40% of the treatments utilized produced water as the base fluid, and required customized chemical formulations. Increased proppant concentration in general appeared to have a more positive effect on water production than on oil production.

To minimize the possibility of penetration of hydraulic fractures to the overlying Lodgepole formation, one strategy that Hassen et al. (2012) applied is to adopt a unique synthetic polymer water based (SPWB) hydraulic fluid with reduced fluid viscosity but still maintaining excellent proppant suspension. Lowering viscosity usually results in fracture placement problems. During laboratory tests, this SPWB system, which is a freshwater based fluid viscosified with a synthetic polymer, presented good sand suspension characteristics. Viscosity loss due to shear and high temperature were also examined. The first field treatment with SPWB was conducted in December 2010. Up to the summer of 2012, 88 wells in the northern portion of the Viewfield field were selected for this investigation. At a low pump rate, the SPWB fracture fluid was very effective in minimizing water production from out of the Bakken pay zone. Six-month accumulative production after the fracturing stimulation showed that the SPWB-treated wells, with much lower water/oil ratio, on average recovered 21% more oil than non-treated ones.

Kakadjian et al. (2013) reported a newly developed fracturing fluid system that utilizes 100% untreated produced brine. In addition, the back end costs are significantly reduced by transporting produced and/or flowback water to locations for re-use rather than to distant disposal well(s). Laboratory evaluation of the fluid in untreated produced water from the Bakken included a hydration test, viscoelastic property, proppant settling test, size distribution of the broken crosslinked gel system, and conductivity. The first two-well field trial test consisted of a total of 52 fracturing stages using 100% untreated produced Bakken brine. Eight weeks of production showed that the new fracturing system had higher production than offset wells completed with a borate-crosslinked guar hybrid system in fresh water.

Luo (2014) found that some widely used ceramic proppants are vulnerable in weakly acidic conditions (i.e., pH=4), and that increasing the temperature accelerates proppant degradation. The broken proppant released a significant amount of fines that either deposited in fractures to reduce the fracture conductivity or were produced to the surface, creating extra wastewater treatment costs. Since Bakken wells can produce CO_2 and H_2S and some scale inhibitors can lower the fluid pH to 3–4, extreme care should be taken when using the ceramic proppant in such acidic conditions.

Schmidt et al. (2014) presented an investigation that was conducted to ascertain the potential effect of the mixed proppant sizes relative to fracture conductivity. It is common in hybrid completion designs to mix various sizes of proppant based on stimulation design assumptions and criteria. It is expected that a high concentration of the least conductive proppant is likely to dominate the overall fracture conductivity, but to what degree and to what extent was the question.

The guar-based fracturing fluids leave insoluble residues in the proppant pack, which impede the oil flow through the proppant. Fry and Paterniti (2014) introduced a residue-free hydraulic fracturing fluid as an alternative to guar-based systems to increase the resultant fracture conductivity. Up to the date that the paper was published, more than 40 wells had been completed in either the Bakken or Three Forks Formations of North Dakota using the res-free fracturing fluid. The Bakken wells treated with res-free fracturing fluid could outproduce their offset wells and use 12% less proppant and 24% less water per foot of lateral during hydraulic fracturing treatments.

Proppant Selection

Various types of proppants have been applied in the Bakken fields. Proppant conductivity plays an important role in the well production performance. Ceramic proppant exhibited the highest conductivity, followed by resin-coated sand and silica sand. As well, ceramic proppant is comparatively unreactive and exhibits greater strength than the other two proppants (Kurz et al., 2012). Hu et al. (2014) reviewed different proppant types and amounts used in stimulation designs in the Bakken since 2011. A total of 72 wells in four Bakken fields were selected for the study. The production and economic analysis indicated that in high-producing fields, a combination of a high percentage and large amounts of ceramic proppants has been proven to yield higher production and EUR (estimated ultimate recovery).

Penny et al. (2012) presented laboratory and field studies to compare various sizes and types of proppants and the influence of surfactants used in oil-bearing formations including commonly used demulsifiers and a multiphase complex nano fluid system.

An investigation of the performance of a group of Bakken wells in Montana and North Dakota was conducted for the purpose of assessing the relative benefit of premium ceramic proppants compared to 20/40 white sand, other ceramic proppants and a mixture of proppants (Crafton, 2014).

Liang et al. (2015) reviewed diagenesis/geochemical reaction of proppants and formation face under heat and pressure and provided selection criteria for unconventional resources. High conductivity and durability are desired in fracturing work. These properties are determined by proppant strength, sphericity, size distribution, etc.

4.2.3 Completion Technologies

The number of fracture stages and the spacing of these stages in horizontal wells are prevalent issues during multistage fracturing. Zander et al. (2010) provided insight into the advantages of various stage numbers and optimum stage spacing by analyzing up to 15 months of production results from horizontal wells targeting the Bakken in Stanley field, North Dakota. A positive-set, mechanical packer was used together with a hydraulic and ball-activated fracturing port. It provided superior results with fewer mechanical risks. Higher oil production and lower water cut than with other completion practices were seen. Stage number and length analysis showed that average production from 12- and 14-stage OHMS completions outperformed the 9-stage wells; and shorter stage spacing outperformed the longer interval.

One simulation study conducted by Saputelli et al. (2014) also demonstrated that increasing the number of fractures will not always improve the short-term economics. There is an optimum value for the fracture number, which is determined by critical assumptions of permeability and natural-fracture distribution.

Chong et al. (2010) reviewed the evolution and development of completion practices of the major USA shale reservoirs in the last two decades and presented a road map for effective completion practices for shale stimulation. The completion road map uses the history of 16,000 shale frac stages in the Barnett, Woodford, Haynesville, Antrim, and Marcellus shales. The authors listed factors that cause the shale operator to change the drilling and completion strategy:

- Geological (geohazard, faults, karst)
- Geochemical (lithology, hydrocarbon type, or mineralogy changes)
- Geomechanical (stress-field changes caused by tectonic stress, faults, production)
- Petrophysical (porosity, saturation, permeability, bottomhole pressure)
- Logistics (fluid, proppant, equipment, manpower availability)
- Economics (well cost, product price, net present value, return on investment)
- Environmental (state, Bureau of Land Management, resource sustainability, safety, cultural sensitivity)

Chong et al. state that because of the different geologic setting, lithology, and production mechanism for each shale play, it is useful to develop specific strategies for discovery, development, and decline phases. The shale well completion design should include three key factors, namely fracability, producibility, and sustainability. The former two are usually determined early to justify the continuation of the project, and the third factor evolves as economic and environmental factors change. In particular, historical drilling and completion data related with production data should be constantly reviewed to help make step changes or adjustments to ongoing projects.

McCormick and Wilcox (2013) discussed the rig data, torque and drag models, and the post-job friction factors, which are an overall indication of the hole condition, for six wells. Through the creation of a database of friction factors for completions operations that consider completion type, fluids used, use of centralizers, lithology and work string data, past experience has shown that even offset wells in the Bakken can have significantly varying amounts of drag.

Slickwater Fracturing

Slickwater fracturing is a technique developed in recent years that injects a specially designed water and sand proppant solution into a horizontal well under high pressure to enable the flow of trapped oil through the fracture channels created. Lightstream is one of the first operators to test and deploy this technology in the Cardium Formation, Canada. It typically results in 25% lower completion costs with better production flow rates and reserve recognition.

According to Pearson et al. (2013), an operator employed a completion design that included: (1) an open-hole “uncemented” linear section; (2) annular zonal isolation created by swell packers; (3) “plug and perf” technology to individually open successive zones for stimulation; (4)

slickwater fracturing treatment at high rate; and (5) high-quality ceramic proppant. Production from 58 wells in which this completion and stimulation design was conducted showed that the use of this approach resulted in well performance that was 25 to 45% superior to any other Bakken completion technique. The high-rate, low-viscosity slickwater likely created multiple fracture initiation points and stimulated a more complex set of natural fractures. On the other hand, due to the high complexity of natural fractures in the Bakken, a large amount of proppant may settle in the fractures due to poor transportation. Application of small-mesh and stronger ceramic proppant helps transport proppants into the deeper fractures and provide more strength for the required long-term fracture conductivity.

The fracking stage for Bakken wells steadily increased from an average three stages in early 2007 to 30 stages in recent years. It is not uncommon to see 40 or more stages now. Baihly et al. (2012) analyzed the stage count versus the production impact of horizontal Bakken wells to determine the economic stage count in the play. Six well groups based on fields across North Dakota were determined. Well drilling and completion summary as well as production type curves were discussed. Among over 20 conclusions the authors made, it was found that the highest stage numbers are not always the most economic. With a few exceptions, the optimum economic stage range varies from 18 to 37 stages. Nevertheless, as the drilling and completion cost and commodity price change, the economic optimum stage number will also change.

Helis Oil and Gas Company, LLC, formed a multidisciplinary team in 2008 to evaluate its completion approach in the South Antelope field in Bakken (West et al., 2013). After evaluating the pre-2009 results, the team recommended 10 changes in the areas of landing targets, lateral length, formation contact, pump-down operation, fracturing mechanisms diagnosis, proppant selection, flush procedure, pressure management and proppant schedule, treatment fluid design, and flowback and flowrate control. After systematic changes to these engineering techniques, 30 wells drilled in 2010–2012 resulted in ~1,500 barrels of oil per day (bopd), with a maximum of 2,500 bopd and EUR of ~1,200 million barrels of oil equivalent.

McNeil et al. (2011) presented the successful execution of a multi-interval fracture-stimulation treatment for a long-lateral horizontal completion in the Bakken shale using a state-of-the-art hybrid coiled-tubing (CT) system together with low-rate hydrajet-assisted fracturing (HJAF) technology. When the middle Bakken member is targeted for hydraulic fracturing, different in-situ stresses within the Bakken members can contribute to fracture growth into the overlying Lodgepole Formation or underlying Three Forks Formation, which is detrimental to oil production from the middle member. Two effective methods to control fracture height growth are reducing the hydraulic fluid viscosity and reducing the injection rate. Nevertheless, reducing fluid viscosity has a negative effect on transport of the proppant. According to McNeil et al., HJAF uses dynamic diversion to prevent flow into the previous frac interval. It has the major advantage of a low-rate fracture treatment to control fracture initiation and propagation, thereby limiting unwanted fracture growth out of the middle member.

Miller et al. (2008) identified an uncemented liner and a compartmental completion technique as having the highest degree of success when completing transverse-oriented hydraulic fractures. These compartments can be tailored to cover specific areas of the borehole so the treatment is placed near the best shows. The frac compartments are created with the use of swellable external casing packers and ball-actuated stimulation sleeves. Bakken wells from both Montana and North Dakota were selected to compare 3-month cumulative production with the maximum monthly production. The analysis results showed that the best-producing group can be characterized as follows: (1) lateral length: 4,000 to 7,000 ft; (2) completion type: compartmental or pre-perforated liner; (3) stimulation fluid: cross-linked; (4) stimulation fluid volume: >150 gallons per foot of lateral length; (5) proppant type: 20/40 or small natural sand or man-made proppant; (6) proppant mass: > 300 lb/foot of lateral length; (7) average proppant concentration: >2.5 ppg. On the other hand, the lower producing group had these characteristics: (1) lateral length: >7,000 ft; (2) mechanical diversion: none; (3) stimulation fluid: mostly slickwater and a few crosslinked; (4) stimulation fluid volume: <60 gallons per foot of lateral length; (5) proppant type: mostly natural sand; (6) proppant mass: <100 lb/foot of lateral length.

Vincent (2011a) explained the challenges of accommodating multiphase flow in transverse fractures and summarized theoretical, laboratory, and field results demonstrating the best practices. Despite the tremendous advantage of reservoir contact by transverse fracture in horizontal wells, transverse fractures can be limited by (1) inadequate fracture height and/or hydraulic continuity; and (2) flow convergence due to limited connection between a transverse fracture and wellbore. The author compared different fracturing practices in the USA and Canadian Bakken. In much of North Dakota and Montana, the productive Middle Bakken and underlying Three Forks are separated by a thin layer of Lower Bakken shale, which has vertical permeability up to 4000 times lower than the horizontal permeability for the middle Bakken. The lower Bakken shale was a natural barrier to a conductive fracture from the Three Forks Formation into the overlying Middle Bakken. In contrast, in the Saskatchewan Bakken, fractures tend to grow into the immediately overlying Lodgepole Formation, which results in excessive brine production. Interestingly, refracking activities in this area have frequently shown reduced watercut and occasionally total water rate reduction and oil production increase (Vincent, 2010).

Wright et al. (2014) presented a completion approach developed in 2010 for Central Basin Bakken wells. Plug & perf technology was applied with slickwater fluids and ceramics proppant in an uncemented liner. Production from more than 100 wells showed that this approach is superior to conventional ball-sleeve, gel and sand completions. The authors ascribed this to (1) creation of a more complex fracture geometry through the distributed plug & perf initiation points and creation of widespread complexity through high-rate, large-volume, low-viscosity frac jobs; and (2) placement of higher conductivity, smaller-size, and stronger ceramic proppant to open fracture network more effectively.

Effective wellbore compartmentalization by open hole packers is critical to successful fracturing operations. Rivenbark et al. (2011) discussed a dual-element, hydraulic-set, mechanical (DHM) packer used in open hole, multistage (OHMS) systems to generate the annular compartmentalization necessary for effective multistage stimulation and production. The packer can provide reliable open hole isolation with various benefits compared to swellable, inflatable and other mechanical packers. It has been applied in different field environments including high pressure high temperature (HPHT), multilaterals, proppant fracturing and acid stimulation with on- and offshore cases. The authors summarized the key factors when choosing suitable packers for hydraulic fracturing in OHMS completions: (1) minimum tool/element length and outer diameter to reduce torque and drag for ease of system installation; (2) effective zonal isolation throughout stimulation and the life of the well; (3) resistance to the “shock cooling” effect caused by cooler fracturing fluids coming into contact with the rubber elements of the packer; (4) withstanding differential pressure up to 10,000 psi without resorting to excessively long (e.g., 30 ft) elements; and (5) no need to pump special “activation” fluid to initiate pack-off of the elements.

Houston et al. (2010) analyzed production results for two completion methods employed in the Bakken today: cemented production liners with "plug and perf” diversion, and open hole, multistage system (OHMS) completions. Though both methods introduce fractures along the entire length of the horizontal wellbore, their operations have significant differences. The first method requires that a production liner be deployed and cemented in the horizontal lateral. Several follow-up service lines included pumping composite bridge plugs and perforating guns, setting plugs and firing guns, displacing ball to provide mechanical diversion, stimulating and flushing the wellbore to prepare for the next pumping plug and gun. Multiple interventions increase the possibility of operational and safety related issues. By contrast, the OHMS is compartmentalized into the desired number of stages by running open hole packers to provide annular diversion while leaving the lateral uncemented. Diversion inside the liner can be plug and perf, ball-on-seat, or a combination of these two. Field cases quoted by the authors show that OHMS outperformed cemented liners with plug-and-per diversion from mechanical and production perspectives.

Alvarez et al. (2013) summarized one southeast Saskatchewan operator’s practice of applying a ball drop system and open hole packers, leaving the balls and ball seats in the wellbore, and milling them out afterwards. The reservoir pressure is relatively low in the area, so that balls are not typically recovered during the post fracturing treatment phase. If the production shows sharp decline compared to offset wells, a milling out operation is then required, which increases the overall capital cost of the wellbore construction. The operator’s completion group proposed to deliver a full internal diameter (ID) wellbore to avoid milling out the seats and to potentially improve the well production. After different completion methods were tested, the comparisons are as follows: (1) The ball drop without milling out was the cheapest during initial completion; however, it was unsuitable for future intervention. (2) It is more economical to mill out the seats immediately after stimulation than later in the life of the well. (3) The hybrid system, i.e., coiled tubing actuated frac sleeves and open hole packers for fracturing isolation, is the most cost effective method to achieve a full wellbore ID. (5) The retrievable seat system is most similar to ball drop system in terms of operations, while removal of the seats took longer than expected. (6) Different completion methods did not seem to affect production.

Wellhoefer et al. (2014) evaluated and compared three currently applied completion methods, plug-and-perf, single-entry fracturing sleeve system (SE FSS), and multi-entry fracturing sleeve system (ME FSS). The authors concluded that the ME FSS can increase production efficiency when appropriately compartmentalized and stimulated, whereas the specific completion system type is not as important as the zone spacing and hydraulic fracturing. They noted that a data set with a larger number of completion data, along with other advanced technology such as fracturing mapping and fiber optic monitoring, could enhance the findings from the study.

Campbell et al. (2011) reported a new method to create multiple fractures in a barefoot completion with a sand fracture treatment that has been successfully deployed in Canada. This new method, utilizing an inflatable packer straddle system, has allowed all potential pay intervals to be effectively stimulated, as compared with traditional methods. This new approach of stimulating the open hole, without having permanent packers and frac sleeves or a cemented liner, has resulted in reduced completion costs and improved production results.

Table 3 summarizes the advantages and disadvantages of the various completion methods used in the Bakken Formation, outlined above. **Table 4** summarizes the conditions and results of several relevant field cases.

Table 3—Summary of Common Completion Methods in Bakken Formation			
Method	Advantage	Disadvantage	Ref
Cemented liner	• Allows control of wellbore stability, direct control of fracture initiation, and greater well serviceability. • Cemented liner and hydrajet perforations placing the fracture treatment with coil tubing.	• A primary concern with conventional liner methods is being assured of where the fracture is being placed. • Impossible to determine that there was adequate annular isolation to ensure where any of the planned fracture treatments were placed. • Potential for formation damage during completion. • Potential isolation of natural fractures that would otherwise contribute to conductivity in the open hole.	Houston et al (2010); Campbell et al (2011); Hlidek et al (2011)
Open hole, multi-stage system (OHMS) completions	• All fracturing treatments can be conducted in a single, continuous pumping operation. Drilling rig or wireline/CT services are not needed, relatively quick and inexpensive. • Less fracturing fluid is used because bridge plugs are not pumped down the tubing; this removes the need to clean out all proppant to avoid a plug getting stuck before it reaches the desired setting depth. • Has good potential for improved recovery from refracturing techniques.	• Single-stage fracturing in the open hole provides little control over fracture initiation and propagation. • Other methods of open hole completions include the insertion of liners and ball-actuated sliding sleeve systems for multistage fracturing.	Houston et al. (2010);
Ball drop (ball-on-seat) systems and open hole packers	One operator's approach was to complete wells using ball drop systems and open hole packers, leaving the balls and ball seats in the wellbore and milling them out later based on well-by-well analysis. Production performance dictates the decision of when to mill out the ball seats.	• Long laterals drilled with conventional bent assemblies need to run time-consuming reamer to remove tortuosity and hole rugosity. • This does not allow further workover operations or refrac opportunities without removing the restrictions. • Other drawbacks include additional cost, loss of production during the operation, longer operation	Alvarez et al. (2013); Lloyd et al. (2010)

		time and excessive fluid losses.	
Plug-and-perf	• Uses wireline intervention to set composite fracturing plugs for stage isolation and to perforate individual stages. • Creates distinctly distributed initiation points along each stage's section in the lateral. • Perforation with high injection rate helps distribution of fluid and proppant along the lateral.	• Premature setting of bridge plugs requires additional remedial services. • Each stage needs to be flushed with a minimum of two stages volumes to clear the wellbore of residual proppant and displace the next plug and gun. • Multiple intervention increases the chances of operational and safety issues. • Typically 20% more expensive than ball-on-seat system.	Wellhoefer et al. (2014); Lloyd et al. (2010); Houston et al. (2010)
Single entry fracturing sleeve systems (SE FSS)	• Ball activated fracturing sleeves are installed with the completion liner stream and offer a single entry point per stage. • Remove the need for wireline intervention, thereby increasing completion efficiency.		Wellhoefer et al. (2014)
Multi-entry fracturing sleeve systems (ME FSS) completions	• Also ball activated, but a single ball opens multiple fracturing sleeves. • Do not require wireline intervention, and allow for multiple entry points per stage to be simultaneously stimulated.		Wellhoefer et al. (2014)
Barefoot completion	• Utilizing an inflatable packer straddle system, has allowed all potential pay intervals to be effectively stimulated, as compared with traditional methods. This new approach of stimulating the open hole, without having permanent packers and frac sleeves or a cemented liner has resulted in reduced completion costs and improved production results.		Campbell et al. (2011); Ross (2012)

Table 4—Bakken Formation Completion Field Cases			
Field	Technology Highlights	Findings/Advantages	Ref
Stanley Field, ND	A positive-set, mechanical packer was used together with hydraulic and ball-activated fracturing port. It provided superior results with fewer mechanical risks.	• Production improvement and reduced water production. • Average production from 12- and 14-stage OHMS completions outperformed the 9-stage wells. • Shorter stage spacing outperformed the longer interval.	Zander et al, 2010
South Antelope Field	A multi-disciplinary team evaluated completion results before 2009 and recommended 10 changes.	As the result of changes of engineering techniques, 30 wells drilled in 2010-2012 were among the best wells in the Williston Basin.	West et al. (2013)
58 wells by an operator	• Open-hole "uncemented" linear section. • Annular zonal isolation created by swell packers. • "Plug and perf" • Slickwater fracturing treatment at high rate. • High-quality ceramic proppant.	• Production from 58 wells showed 25% superior results after 90 days, and over 45% better after 365 days, than other completion techniques.	Pearson et al. (2013)
One undisclosed well	• Hybrid coil-tubing (CT) system • Hydrajet-assisted fracturing (HJAF) technology	• HJAF proved to be able to avoid penetration into the Lodgepole formation, and minimize the water production. • Combining CT and jointed pipe saved considerable amount of time reaching the target depth	McNeil et al. (2011)
22 central-basin Bakken wells	• Plug and perf • Slickwater fluids. • Ceramics proppant. • Uncemented liner.	• More complex fracture geometry distributed plug & perf initiation point and high-rate large-volume low-viscosity slickwater fluid. • Higher conductivity, smaller-size, and stronger ceramic proppant to open fracture network more effectively.	Wrigth et al. (2014)
• HP deep Rocky Mountain, AB • HP geothermal well, Cooper Basin, Australia • Multi-laterals, Bakken, SK • Extended reach wells, Bakken, ND	Dual element, hydraulic-set, mechanical (DHM) packer.	• Reduced torque and drag. • Two independent sealing points via dual elements. • No need to formulate specific downhole fluids or wait for them to swell. • No thermal contraction. • Rubber element does not reduce its durometer rating when setting.	Rivenbark and Dickenson (2011)

• Acid stimulation, Wabamun carbonate, AB • Screen completion, offshore Brazil			
• Viewfield, SK	Hybrid system, i.e., coiled tubing actuated frac sleeves and open hole packers for fracturing isolation	• More economical compared to ball drop with milling out. • Lower treating volumes compared to the ball drop system. • Ability to quickly recover in the event of a screen out. • Accurately places the proppant at the intended depth and provides post stimulation using bottomhole recorder. • Redundancy with the jetting tool in the case of a sleeve shift failure.	Alvarez et al. (2013)
• 241 Middle Bakken wells, ND	With ME FSS, the fracturing sleeves and isolation packers are installed with the completion liner and provide multiple entry points to the formation. The ball activated multiple fracturing sleeves isolate the target fracturing sleeve from previous fracturing stages and divert fluid flow out the exit ports in the multiple sleeves in that stage.	• Increases production efficiency when appropriately compartmentalized and stimulated.	Wellhoefer et al. (2014)

4.3 Production Optimization and Stimulation Technologies

Due to the tight nature of Bakken reservoirs, the drainage area is largely defined by the size and shape of the hydraulic fractures. As a consequence, tight oil wells usually have steep decline curves with production rate drops up to 70% in the first year. The more common strategies to arrest this decline is drilling new wells, optimizing production, and restimulating existing wells. At the current low oil price environment, technologies that revitalize old wells are gaining increasing popularity because of the economic benefit.

4.3.1 Production Optimization

Mullen (2010) stated that there are two important questions to be addressed. First, is this an optimal practice for well placement? Second, is there a “sweet spot” layer in which the horizontal well should be placed to increase production? In one Bakken well, an azimuthally-focused resistivity (AFR) tool and an azimuthal deep-reading resistivity (ADR) tool were run as a final wiper trip to investigate the location of natural fracture swarms and the variations of rock properties along the 10,000-ft lateral. The goal of this exercise was to test the concept of improving production by using a “smart” horizontal completion technique, spacing the swellable packers, and locating fracture stages based on horizontal reservoir data.

Vincent (2011) explained the challenges of accommodating multiphase flow in transverse fractures and summarized theoretical, laboratory, and field results demonstrating the best practices. The author reviewed evidence indicating that fractures fail to sustain hydraulic continuity through many laminations, and suggested techniques that can improve the ability to drain multiple stacked pay intervals with horizontal wells. Updated production results from the Bakken and Eagle Ford should be of benefit to any operator stimulating horizontal wells that produce significant oil, water, or condensate volumes.

Large scale data-mining projects performed on Middle Bakken oil reservoirs have been used to identify key variables that drive production results (LaFollette, 2013). Such variables include reservoir quality proxies, along with well architecture, completion, stimulation, and sometimes production practice parameters. The work has evolved from single-variable statistics using spreadsheets and cross plots to map-based Geographic Information System (GIS) analysis combined with multivariate statistical modeling using multiple linear regression and boosted-tree models. A key conclusion is that variation in reservoir quality is one of the main drivers in both tight oil and gas shale. Beyond that, operational practices matter, from well completion to stimulation treatment parameters.

Besler et al. (2007) summarized the lessons learned during the stimulation and operation of horizontal laterals completed in the Middle Bakken Formation of North Dakota and Montana. They compared the production histories of these wells to offset wells completed with other techniques to evaluate best industry practices. The effects of lateral length, wellbore azimuth and stimulation design on well production and overall well economics were discussed.

4.3.2 Refracking Technologies

Refracking is the filling in of fractures within previously fracked shale and tight rock formations, then fracking the same well over again, thereby enabling the recovery of more oil from previously fracked shale/tight rock formations. The technique itself originated in the 1950s. The drastic production decline rate and low ultimate recovery of tight/shale oil wells poses unprecedented need for restimulation technologies such as refracking. At a fraction of the cost of drilling an initial well, the technology has the potential to significantly slow down the production decline rate and increase estimated ultimate recovery. At today's low oil price, the cost benefit and production increase from refracking makes it a very appealing opportunity. Jacobs (2014) commented that refracking may become Act Two for the North American "shale revolution".

Refracking has only been applied to Bakken Formation in recent years and remains in low activity overall. Currently, it only accounts for less than 1% of the overall hydraulic fracturing market today, according to Christopher Robart, managing director at IHS Energy. The first key challenge for refracking is to identify the right candidates. While the refracking operation itself is not so different from the original fracturing, not all wells are inherently good candidates for the technology. Determination of suitable candidates involves not only the wells themselves, but also the surrounding environment. Some industry analysts had concerns that the refracking only accelerates the production rate without increasing the ultimate recovery over the life of the well. As well, fractures between wells interfere with each other so as to produce oil from neighboring wells' drainage area. In worst cases, failed fracking can damage the economics of both the treated well and offset wells. Robin Mann, global leader of the resource evaluation and advisory group in Deloitte LLP's Houston office, commented that "there's always a risk you're going to damage the reservoir or create interference between wells."

Another challenge is that the refracking performance as judged by production increase is more unpredictable than with newly fractured wells, which makes operators more hesitant to adopt this technology. To reduce risks for customers, services companies are relying on production risk-based business models. For instance, Schlumberger conducts reservoir characterization and then selects an ideal portfolio of wells for refracking.

Vincent (2011b) compiled and analyzed a comprehensive database of published field cases to identify the mechanisms responsible for production improvement following refracking. He reviewed restimulation attempts in six Canadian reservoirs and then present a more detailed review of restimulation of horizontal wells in the Bakken Formation. In addition to a summary of published results, the author discussed a significant amount of previously unpublished data regarding refracking treatments of horizontal laterals completed in the Middle Bakken.

Vincent commented that "while wells receiving a poor initial stimulation are often good candidates, the vast majority of field studies indicate that the most profitable candidates for re-stimulation were excellent wells, not poor wells….We have demonstrated that we can take the best well in most fields and make it better. Even wells fractured one year ago can typically be improved pumping re-stimulation treatments of significantly lower quality and expense compared to the initial job."

Murtangh et al. (2015) cited that in a study conducted by Bloomberg Intelligence, about 80 North Dakota Bakken wells drilled in 2008 or 2009 that were refracked years later showed a clear regain on production. The wells on average produced more than 30 percent more oil in the month after the refrack than the original completion.

Radioactive tracer logs can identify significant intervals, particularly in the heel section of laterals that were not fractured during the initial completion (Wiley et al., 2004; Lantz et al., 2007). In late 2003, one operating company decided to implement a refracking treatment on a well that showed a long unpropped interval from a tracer log. The first refracking treatment on this well gave encouraging results, since the peak post-refracking production rate was higher than that after the original completion stimulation. As of the paper was published, the overall increase was over 1,300,000 stock tank barrels (STB) or 30% in the estimated ultimate recovery (EUR) for the wells in the study.

During depletion of a hydraulically fractured reservoir, local stress fields around the fractures change due to fluid flow and rock deformation. This stress field change may greatly affect the fracture development in a subsequent refracking process. Han et al. (2015) used a coupled geomechanical and reservoir fluid flow model to study the stress tensor change. In both the planar fracture case and the fracture network case, the simulation showed the minimum in-situ stresses surrounding the fractures turn 30 to 90 degrees to their original directions, when stress anisotropy is limited. The subsequent refracking treatment will likely create fractures generally perpendicular to the initial fractures. When it is challenging for refracking to tap into the undepleted zone, mechanical or chemical diverters are then recommended to control the fracture growth direction.

Indras and Blankenship (2015) assessed the economic performance of refracking in Bakken, Barnett, and Haynesville. A sensitivity analysis showed that refracked wells in the Bakken can generate higher net present value (NPV) than drilling a new well. Whereas new Bakken wells have a profit-to-investment ratio (P/I) of over 1.0, refracking existing Bakken wells can have P/I three times larger because of lower capital investment.

Schlumberger (2015) recently touted its BroadBand Sequence fracturing service. The technology sequentially isolates fractures at the wellbore to ensure every cluster in each zone is fractured and fully stimulated, resulting in more contact. By temporarily locking and unlocking clusters, the composite fluids are diverted to higher stress regions for increased fracture stimulation within each stage. One Bakken case study was conducted on a 901-ft (275-m) openhole interval in completion with casing that had not reached the planned depth. The BroadBand Sequence fracturing service was applied to temporarily isolate previously initiated fractures and induce stimulation of the entire interval of interest. The results showed that the service increased the fracture initiation pressure consistently, with a total gain of 1,376 psi, and that the treated well had a higher initial production rate and flowed at a higher pressure than its direct offset wells.

Halliburton (2015) describes its AccessFrac℠ stimulation service as incorporating one or more of these several components: (1) A unique new chemical diverter system; (2) proppant coating technology; (3) polymer alloy proppant; and (4) special fluid and treatment design, and pumping schedule. Its AccessFrac RF, where "RF" stands for refrac, service is designed for refracturing treatments that seal off existing perforations in order to stimulate bypassed and new intervals. The process employs Halliburton's biodegradable diverting technology and pressure sink mitigation techniques to ensure effective stimulation of the entire length of the lateral. The company claims that the diverting technology enables users to block off the existing perforations and stimulate the new perforations. Over time and temperature those diverters will biodegrade and allow the existing perforations to flow again.

In a refracking operation, it is important to protect previously stimulated perforations and add new fracking to untreated perforations or bypassed zones. Mechanical diverters have been applied for decades to deploy perforation ball sealers, degradable balls, rock salt, and dissolvable flakes, and incorporate downhole equipment. For a side-tracked well that is drilled after the initial completion and is open hole, a slotted liner can be used for stage placement. Annular isolation may be challenging, as packers may not be able to achieve a proper seal and withstand differential pressure during the treatment. Fragachan et al. (2015) introduced chemical packers that could provide temporary isolation between zones and allowed down-hole sliding-sleeve isolation tools to be retrieved for maximum contact to the rock surface. Degradable mechanical diverters, on the other hand, have the same effect as traditional diverters, while they can temporarily plug off perforations for restimulation treatments as opposed to squeezing the perforations and sealing them off.

Oruganti et al. (2015) used a proprietary algorithm to first identify from public sources refracked Bakken wells, then they applied the modified hyperbolic Arps decline equations to derive a production decline curve and estimate incremental recovery. Finally, they conducted economic analysis to show incremental net present value (NPV) from refracking. A majority of the identified potentially refractured wells had positive incremental NPV based on the EUR increase of 69%, on average, for 22 identified Bakken wells. The average initial production (IP) ratio was 0.92. The economic analysis concluded that the incremental NPV ranged from $-1.5 MM to $10.5 MM, where 19 out 22 wells exhibited positive incremental NPV.

4.4 Enhanced Oil Recovery Technologies

Due to the extremely low permeability and poor connectivity of Bakken reservoirs, the tight oil production rate can drop to 10% of its peak value after the first year. Under this circumstance, pressure maintenance is needed to keep the reservoir producing. Waterflooding is the most widely used improved oil recovery (IOR) technique, which follows primary production, in depleted conventional reservoirs. Water injection in the Bakken began in North Dakota in 1958. As of 2009, there were 67 active waterflooding projects (Stilwell, 2009).

Crescent Point Energy is the pioneer in conducting waterflooding pilot tests in the Canadian Bakken: they have done eight tests to evaluate the production and injection response, various completion techniques, lateral length, well spacing, and the design (i.e., the number of producer and injector wells) of each pilot. In early 2015, Crescent Point completed the unitization of its first waterflood in its Stoughton unit, and continued to move forward with the unitization of three more units in the Viewfield field. Based on production history, the company estimates that waterflooding has reduced decline rates by up to 10 percent in swept areas, compared to areas under primary production only.

The efficiency of waterflooding depends on spontaneous imbibition of water into the oil-bearing matrix in fractured reservoirs. However, Bakken reservoirs are characterized intermediate- to oil-wet wettability, which significantly limits the performance of waterflooding. As a result, methods that can alter rock wettability are being sought, and that is why enhanced waterflooding was developed. On the other hand, gas is also used to displace reservoir oil because gas can enter into small pore spaces due to its lower molecular size and viscosity. As a result, oil producers choose the most economic method after comparing the costs and gains of waterflooding, surfactant flooding and gas flooding.

4.4.1 (Enhanced) Waterflooding

The Bakken is characterized by having a light crude oil trapped in the matrix due to an oil-wet condition, as well as by natural and induced fractures. The combination of these features suggests that a surfactant technology can be employed to recover more oil. There have been extensive laboratory studies on using surfactant solutions for EOR. The common investigations include surfactant phase behavior, oil–brine interfacial measurement, stability test at high temperature and high salinity, adsorption test, contact angle measurement, spontaneous imbibition test using an Amott cell, and laboratory core displacement test.

Shuler et al. (2011) found a custom surfactant agent that, when mixed with hydraulic fracturing fluids or other aqueous-based treatment fluids, can improve spontaneous imbibition to enhance migration of the fluids into the fracture system. Among a series of papers regarding surfactant screening and mechanism investigation, Wang et al. (2011) reported their work aimed at identifying a formulation that promotes imbibition while minimizing clay swelling and formation damage. The results indicated that an ethoxylate nonionic surfactant performed best among all the 17 candidates tested in terms of stability at high temperature and high salinity, and imbibition effects. As well, for a given surfactant, the surfactant concentration, brine salinity, and divalent cation concentration can be optimized to reach maximum recovery. In 2012, Wang et al. tested four surfactants—dimethyl amine oxide, ethoxylated alcohol, internal–olefin sulfonate, and anionic linear a-olefin sulfonate—that all showed positive results in terms of wettability alteration and enhanced spontaneous imbibition. In another paper, Wang et al. (2014) reported that selected surfactants recovered 57% of OOIP through spontaneous imbibition in cores from the Middle Bakken Member, at optimal salinity. However, the same group published another paper in 2013 that stated that no optimal salinities were observed in some of the tests, suggesting wettability alteration was a more dominant mechanism than IFT reduction in these tests. This conclusion was further confirmed by further research (Nguyen, 2014), in which cationic, anionic, and non-ionic surfactants were tested, and recovery factors did not correlate with IFTs. Samiha et al. (2014) found a surfactant, Stim aid A., which is compatible with Bakken oil and brine. Their tests showed that 0.2 wt% of Stim aid A. surfactant can be used in the preflood fluid prior to waterflooding in order to increase the recovery factor.

With the application of a high-speed centrifuge, researchers were able to obtain relative permeability curves as well as capillary pressure curves using Bakken fluids and rocks under the reservoir temperature. Karimi and Kazemi (2015) measured capillary pressure curves in a middle Bakken core with a high-speed centrifuge. The results were discouraging: the forced imbibition cycle is very steep, and mobile oil saturation is very narrow. Water flooding is thus unlikely to succeed, and surfactants are needed to alter relative permeability and capillary pressure curves.

Although extensive laboratory studies have been conducted, including searching for the best formula for surfactants, and investigating surfactant–rock reactions, water chemistry and compatibility, there is still a long way to go before taking these results from the lab to the field. At present, there is no chemical EOR field project being operated to recover the deep Bakken oil in the central area of the Bakken formation in Williston Basin.

4.4.2 Gas Flooding

Although chemical methods (or typically surfactant flooding) have the above-mentioned advantages, it is believed imbibition efficiency is uneconomically slow if fractures are not fully developed (Mattax and Kyte, 1962). Another obvious drawback of enhanced waterflooding is loss of injectivity, due to the extreme low permeability of Bakken reservoirs. Moreover, the high temperature of Bakken reservoirs (65–100°C on the Canadian side and above 100°C on the US side) and high salinity significantly lower the stability of surfactants.

To further improve the development of the Bakken oil reservoirs, gas flooding has been proposed as an EOR technology. Gas flooding typically refers to CO_2, natural gas or nitrogen injection, and the injection scheme can be direct gas injection, water-alternating-gas (WAG) injection, gas huff-n-puff, or water-gas co-injection. It is applied as either a miscible or an immiscible process. Miscible gas flooding aims at creating a miscible condition in which the interfacial tension between the injection gas and the reservoir oil is completely eliminated; whereas the main mechanism for immiscible gas flooding is normally pressure maintenance. Hoffman (2012) demonstrated that injecting gas (both immiscibly and especially miscibly) could appreciably increase oil recovery in very low permeability reservoirs.

Compared with a traditional waterflooding process, gas flooding has its own advantages. Injected gas is much less viscous than water, so the injectivity is significantly improved. Moreover, gas flooding provides multiple mechanisms to recover oil, rather than just pressure maintenance. For example, oil swelling, viscosity reduction, and miscibility are all believed to affect the recovery results. Hawthorne et al. (2013) conducted a recovery test using CO_2 for a low permeability middle Bakken sample, an ultra-low permeability upper and lower Bakken member sample, as well as a conventional reservoir sample. The result indicated that the mechanism for CO_2 recovery of oil in a tight reservoir is different from that for recovering oil from conventional reservoirs.

However, gas flooding is still at laboratory tests, pilot tests, and simulation stages. The major reasons limiting the application of gas flooding are gas source availability, uncertainties in reservoir connectivity, and the current low oil price**.**

For a gas flooding project to be successful, an accurate equation-of-state (EOS) model for oil–gas mixtures needs to be acquired first. Pu and Hoffman (2014) built an EOS model for compositional simulation based on PVT tests from Bakken reservoir fluids and to investigate different factors which might influence recovery for CO_2 injection. Teklu et al. (2014) modified conventional vapor/liquid equilibrium (VLE) calculations to account for the capillary pressure and the critical-pressure and -temperature shifts in nanopores.

From the EOS model, the performance of gas can be roughly estimated by looking at changes in viscosity and formation volume factor after gas addition. The next step is to determine minimum miscibility pressure (MMP) between the live oil and injected gas by either model prediction or experimental measurement. Minimum miscibility pressure is the most important parameter in the design of a miscible gas flooding process (Jarrell et al., 2002). The rising bubble apparatus (RBA) test determines the multi-contact MMP (Srivastava and Huang, 1998). Compared to the slim tube test, RBA is significantly faster and simpler but conducted without porous media. The MMP obtained from RBA testing tends to be higher than that from slim tubes tests. Therefore, an RBA test is often performed to find a rough range of MMP, which is then further narrowed down with slim tube tests.

The final step before pilot testing and field implementation is to build a sophisticated geological model, especially for naturally fractured, tight reservoirs, and conduct an economic analysis. Kurtoglu et al. (2013) presented an overview of the geologic characterization of a Bakken reservoir, the Bailey oil field in Dunn County, North Dakota, as a first step to determine its potential for a pilot CO_2 EOR test. Shoaib and Hoffman (2009) analyzed the impact of CO_2 flooding in the Elm Coulee field, of which a section was selected for reservoir modeling. Xu (2013) separated simulation models with multiple transverse hydraulic fractures wells, and longitudinal hydraulic fracture wells have been built based on a section of the Elm Coulee field. Moreover, the injection scheme needed to be carefully designed. Cheng et al. (2014) used an EOS-based compositional reservoir simulator, UT-COMP, to simulate both primary recovery and CO_2 huff-n-puff recovery in a shale matrix typical of the Bakken formation, with the aim of investigating the effect of reservoir heterogeneity on hydrocarbon recovery. Yu and Sepehrnoori (2014) investigated effects of fracture properties such as fracture half-length, fracture conductivity, and number of fractures, and operating parameters such as CO_2 injection rate, injection time, soaking time, number of cycle of CO_2 huff-n-puff and CO_2 diffusivity through a simulation approach.

4.5 Numerical Simulation

The industry has been utilizing numerical simulation techniques more and more in every aspect of exploration and production. For new fields, field engineers can use simulation tools to identify the well spacing, completion type, or possible artificial lift if needed. For ongoing operations, simulation techniques can be used to determine whether hydraulic fracturing, skin factor removal, or pressure maintenance is needed. IDC Energy Insights, an information technology (IT) advisory firm, predicted that the world's top 25 oil and gas firms will use modeling and simulation tools to optimize field development programs by the end of 2017; and that the investment on connectivity-related technologies will increase by 30 percent between 2014 and 2016 (The Bakken Magazine, 2015). Moreover, for exploration in tight reservoirs such as Bakken, IDC predicts that higher simulation skills will be required for reservoir engineering.

Due to widespread natural fractures, a dual-porosity model is often employed for simulation of tight oil and shale gas reservoirs. In dual-porosity systems, different porosities and permeabilities are assigned to the matrix and natural fractures, and the oil in the reservoir is produced by flowing to fractures first. Understanding the contributions of the matrix and fractures to daily oil production is the key to identifying reservoir drivers affecting the well productivity over its lifetime. Nevertheless, introduction of secondary (hydraulic) fractures makes the fluid flow physics more complicated. Due to the larger upfront cost in drilling and completion, as well as sharper production decline, exploration in the Bakken requires more sophisticated sensitivity and economic analyses, which rely on accurate simulation techniques. Chu et al. (2012) characterized several phenomena in unconventional oil reservoirs, including confined PVT properties of the reservoir fluid, the pressure- and stress-dependent permeability, and intervening multiple porous media created by multi-stage fracturing.

4.5.1 Reservoir Modeling

Reservoir modeling plays a more and more important role in today's oil and gas industry. The most significant advantage of reservoir modeling is that it gives operators a better understanding of the reservoirs they are producing from, in a numerical way. It also allows them to predict the performance of different scenarios without a big capital cost.

A model can be built using minimal data, but a sophisticated and realistic reservoir model requires input data from every aspect from exploration to production. As a result, reservoir modeling requires a systematic and comprehensive approach, which involves input from geologists, drilling and completion engineers, production engineers, and laboratory technologists. A reservoir model can always be improved, but in a real situation, this will depend on the extent to which the heterogeneity of the reservoir needs to be accounted for, how much data is available, and, most importantly, the time and budget for the project. The common inputs and outputs from reservoir modeling can be itemized as follows:

- Inputs:
  - ✓ Rate-transient analysis (estimates of permeability, fracture length and conductivity)
  - ✓ Petrophysics (uncertainty of permeability and saturation)
  - ✓ Routine and advanced core analysis (end points from mercury injection, Corey coefficients to define the relative permeability function, elastic properties)
  - ✓ Advanced logs, such as magnetic resonance, triple combo, 3D sonic, and triaxial resistivity logs (estimates of porosity, saturation, density)

- Outputs
  - ✓ Horizontal and vertical stress profile
  - ✓ Drainage pattern
  - ✓ Production profile

In 2008, the National Energy Technology Laboratory (NETL) initiated a project with the University of North Dakota's Energy and Environmental Research Center (EERC) to analyze key factors that affect production performance. Those factors can be reservoir rock and fluid properties, well completion methods, well placements, etc. Three activities were taken on. The first was to utilize a risk-based data management system (RBDMS) and other databases to analyze factors affecting Bakken well productivity and oil recovery. The second activity involved analyzing seismic data together with geo-mechanical properties of payzone and cap rock samples. This was to understand how the macroscale stress and strain forces in central North Dakota affect microscopic geo-mechanical properties of reservoir and cap rocks. The third activity was to interpret the source of fractures in the Bakken.

One common approach is to simulate the geological and operational condition of a reservoir, either hypothetically or practically, using commercialized or open-sourced software. Specifically for Bakken or other similar naturally fractured reservoirs, a dual porosity model, which can represent a fracture network, is commonly used. It considers fluid flow from matrix to fracture and within fracture networks. Different relative permeability curves are allocated separately to the matrix and fracture**.** Fabian (2012) constructed a numerical simulation model using typical fluid and rock properties for Bakken and Three Forks under a dual-porosity frame. Multistage hydraulic fracture properties were coupled with the flow models, and the performances of water and gas flooding were presented. Yu and Sepehrnoori (2014) investigated effects of fracture properties such as fracture half-length, fracture conductivity, number of fractures, and operation parameters such as CO_2 injection rate, injection time, soaking time, number of cycle of CO_2 huff-n-puff, and CO_2 diffusivity through a simulation approach. Chen et al. (2014) used an equation-of-state (EOS) based compositional reservoir simulator, UT-COMP, to simulate both primary recovery and CO_2 huff-n-puff process in the Bakken formation. They then fitted the recovery factors by a two-parameter exponential formula. Jin et al. (2013) generated a correlation between well and fracture spacing and recovery factor for both ideal and non-ideal reservoirs, where stress-sensitive reservoir permeability or overpressure exists. Kurtoglu et al. (2013) compared results from single-porosity and dual-porosity models and decline curve analysis for an abnormally high-pressure, unconventional shale reservoir. Brent et al. (1992) determined the porosity of Bakken shale to be 2 to 3%, with 0.2% being micro-fractures, and the fracture to matrix permeability ratio to be 100 to 1. They used a simulation approach by history matching drawdown, buildup, and interference data from horizontal wells in the Buckhorn field, McKenzie County, North Dakota. Stitchler et al. (2013) used both production modeling and wellbore modeling to determine the influence of key parameters (fracture length, connectivity, number of fractures) to productivity. They also illustrated how infill drilling can alter drainage patterns.

Ibrahim et al. (2011) used wellbore simulation software to optimize a directional well drilling plan, including drill bit selection, rock mechanics analysis, shock studies, drilling fluids and hydraulic optimization. Robert et al. (2012) developed a predictive data-driven model from a detailed evaluation of over 50 horizontal Bakken completions, and used the model to facilitate optimization of hydraulically fractured wells. Lolon et al. (2009) pointed out that infill drilling had significant potential in increasing oil recovery, a conclusion they drew from results of a fracture modeling and multi-well simulation study. Izadi et al. (2013) incorporated multivariate analysis with Geographic Information Systems (GIS) pattern recognition. Tao (2013) used simulation to investigate the effects of well pattern on changes in fracture conductivity in a simulation approach. Yu and Sepehrnoori (2014) simulated the performance for wells with three different proppant types (i.e., sand only, sand/ceramic, and ceramic only), with or without stress dependent fracture conductivity. Chen and Wang (2012) investigated the best hydraulic fracturing scenario for Bakken formation and the effects of fracture geometries on oil recovery. Sookprasong et al. (2013) analyzed the sensitivity of well performance to planning, drilling, completion, and stimulation treatment parameters in two fields in the Williston Basin of North Dakota.

Some researchers developed their own simulator or coupled their own post-processing module with an existing reservoir simulation package. For example, Fai-Yengo et al. (2014) developed a field-scale matrix/fracture model to investigate hydrocarbon transportation between fractures and matrix during a CO_2 injection process. The result indicated that gas diffusion is the dominant mechanism in the ultra-tight formation with high capillary pressure. King and Wray (2014) used multivariable software to identify high sensitivity completion and reservoir parameters for a

Bakken field in North Dakota, which are lateral length, proppant volumes, stage lengths, and water cut. Luo et al. (2011) introduced static and dynamic uncertainty parameters in a geological model. They constructed proxy equations and generated Monte-Carlo simulations for full-field development and optimization. Dechongkit and Prasad (2011) calculated deterministic and probabilistic recovery factors for the Antelope, Sanish, and Parshall fields, separately, in the Bakken formation using material balance equations. Masoud et al. (2014) identified three different pore systems with distinctive storage/transport characteristics in a shale reservoir: inorganic medium, kerogen, and fractures. Their simulation results showed that gas recovery in a shale reservoir is more efficient because of the diffusion mechanism of gas. Through an investigation of phase behavior change of a fluid in porous media, Alharthy et al. (2013) showed that a favourable phase envelope shift in gas-condensate and bubblepoint systems is an important reason to economically produce hydrocarbon from tight oil reservoirs.

With the rapid increase of computing power these days, artificial intelligence (AI) technologies have been widely employed in reservoir modeling. Unlike traditional physical models, the new data driven models with AI techniques do not require the understanding of flow mechanism in the reservoir, which is a huge advantage for tight reservoirs with many uncertainties. Zargari and Mohaghegh (2010) built a top-down intelligent reservoir model, combining conventional reservoir engineering methods, data mining and artificial intelligence to identify reservoir sweet spots and infill locations. As well, the accuracy of the model could be enhanced as more detailed data became available. Mohaghegh et al. (2011) developed a model to predict recovery using production history, well log and hydraulic fracturing data. Valentine et al. (2014) compared analysis of a large dataset to the original Arps decline curve to find the best timing for infill drilling and remedial activity, as well as surface facility planning. Roth and Roth (2013) employed a method called self-organizing map to describe stratigraphical features in the Bakken and Three Forks formations. The method successfully identified sweet spots in the reservoir and highlighted regions of no production, high water cut, marginal production and outstanding production. Keith (2012) developed an expert system incorporating spatial-temporal database, fuzzy logic, genetic algorithms, and sensitivity analysis. The system can be used for a shale gas reservoir to reduce risk and decrease cost.

4.5.2 Geological/Geomechanical Modeling

Geological modeling is a computerized representation of a reservoir based on observed geophysical and geological properties. In order to generate a geological model, the boundary of the area of interest needs to be defined first; next, a three-dimensional mesh is applied with the consideration of required accuracy and computational power; then, geophysical properties (i.e., rock type, porosity, permeability, saturation) are assigned to each grid representing the heterogeneity of the reservoir (using geostatistical methods); and finally, partial differential equations governing the physical processes in the subsurface, such as seismic wave propagation or fluid flow in porous media, can be solved.

The National Energy Technology Laboratory (NETL) funded a project by the Colorado Energy Research Institute at the Colorado School of Mines to assess the hydrocarbon potential of the Bakken shale and develop an integrated geologic model. The integrated reservoir study (YEAR) included subsurface mapping of depositional and fracture systems using seismic data, core and well logs, sequence stratigraphic analysis, and reservoir characterization (Beat the Bakken). The University of Calgary established a Tight Oil Consortium program with industry sponsors, which aims to characterize reservoir parameters that distinguish the high-performing wells in Bakken, develop methods to accurately assess the potential of tight reservoirs, and conduct initial assessments for frontier oil resources.

Many researchers have worked on establishing geological models of fields in the Bakken, but most are from the U.S. side. Liu et al., (2014) generated a detailed geological field model focusing on the Middle and Lower Members of the Bakken Formation in the North Dakota areas of Murphy Creek and Grenora. The model was developed based on field characterization, well log interpretation, and laboratory core analysis by scanning electron microscopy, ultraviolet fluorescence, and standard optical microscopy techniques. Dechongkit and Prasad (2011) used a material balance equation (MBE) approach to determine the deterministic and probabilistic recovery factors for the Antelope, Sanish, and Parshall fields in the Bakken. Dong et al. (2013) used a numerical reservoir simulator to evaluate the performance of CO_2 injection for a sector of the Sanish field in the Bakken. Shehbaz and Hoffman (2009) selected one sector in the Elm Coulee field for reservoir modeling in order to analyze the impact of CO_2 flooding. The important parameters and results for these field case simulations are highlighted in **Table X.**

Table 5—Summary of Bakken Field-scale Numerical Simulations

	SPE-168979	SPE-149471	SPE-168827	SPE-123176
Location	Bailey Field	Antelope Sanish Parshall	Sanish	Elm Coulee
Size of model	6800 ft * 1800 ft		2 mile * 2 mile	2 mile * 2 mile
Thickness	40 ft		30 ft	24 ft
No. of wells	2		3	6
Fracture dimension	300 ft in length, 2ft wide		600 ft half length,	
Production methods	CO2 injection	Primary + solution gas drive	Primary,	Primary

			Water injection CO2 injection	CO2 injection
Perm			0.04 md	0.01–0.04 md
Porosity			6%	7.5%
Recovery factor	43% to 58% more oil recovered than cases without CO2	Antelope 9.2% Sanish 14.9% Parshall 16.0%	Up to 30% if new horizontal wells are drilled 5.42% for primary, 6.36 for water flood	6.02% for primary, 8.52% to 20.99% for CO_2 injection

Besides geological modeling, there is another stream of models that aim to investigate the geomechanics of the reservoir during drilling, completion and production. Geomechanical modeling is extremely important for tight, naturally fractured reservoirs, because fracture closure and propagation are closely related to the stress in the reservoir; as well, the permeability change under compaction significantly affects production.

Roundtree et al. (2009) developed a near-wellbore model using a finite element method, and applied it to wells with different completion methods. The results indicated that fracture-initiation behavior was closely related to maximum and minimum reservoir stress directions. Manchanda et al. (2012) adopted a three dimensional geomechanical model to investigate the stress shadow effect in the Bakken, Barnet, and Eagle Ford shales. Fakcharoenphol et al. (2013) used a coupled flow/geomechanics model to calculate changes of stress under increased reservoir pressure and decreased temperature caused by waterflooding.

4.5.3 Production/Decline Analysis

It is quite complicated to estimate recovery factors for the Bakken formation, due to its widespread uncertainties and heterogeneities. Several years of production, a detailed well activity record, and high quality, reliable production data are required. Only after comparing mass balance, decline curve analysis with sophisticated geological model including parameter heterogeneity and fracture variation, can a reliable possible recovery factor be estimated.

Normally oil and gas wells reach their maximum production shortly after drilling and completion; then the production rates decline slightly to lower and stable values. Decline curve analysis is a means to predict future production for an oil/gas well based on past production history. It is a traditional and quick way to identify potential problems during production and predict well performance and total production during the well's lifecycle. The analysis depends on the decline curve, which is the amount of oil and gas produced per unit of time for several consecutive periods. Although reservoir simulation techniques have been widely applied, decline curve analysis is still popular due to its simplicity, and is most often used for reserve estimations by both the operators and commercial reserve estimators.

The type of curves which are often employed by field engineers include exponential decline, harmonic decline and hyperbolic decline. Other than those, many researchers have developed different production decline models for tight oil reservoirs. Childers and Callard (2015) developed a finite conductivity model using publicly available production data in the Bakken shale, in McKenzie and Williams Counties, North Dakota, to match the reciprocal rate versus cumulative production profile. Tan (2011) mentioned three types of Bakken well production trends, each of which had its own meaning. The Type I production trend represents a solution gas drive reservoir when reservoir pressure drops below the bubblepoint; this type of production is produced from a large fracture system. The Type II trend represents single phase flow of oil mainly from the matrix; while the Type III production trend has a scattering of production data from wells with different type of trends, which is difficult to analyze. Finally, OOIP, fracture half length, and matrix drainage area can be calculated using analytical solutions for a dual porosity slab model. Clark (2009) estimated the ultimate recovery for Bakken shale in Mountrail County, ND, as 7% using decline curve analysis, and compared the results with calculation from a material balance, and recovery factors used by companies working in the same area. King and Wray (2014), after analyzing the sensitive parameters in completion design, did an economic analysis using the cost of the respective completion design and expected performance. Luo et al. (2010) conducted decline analysis for multi-stage fractured horizontal wells (MFHW) applying log-log reciprocal rate derivative plots to identify and analyze flow regimes of MFHW wells producing under constant bottomhole pressure. Sipeki and Hower (2013) conducted type curve analysis to horizontal wells in Williams County, North Dakota. The wells showed strong hyperbolic behavior with steep initial decline, which is consistent with simulation models.

Although there have been many successful cases in using decline curve analysis to calculate original oil in place and recovery factor in Bakken reservoirs, one question still remains to be addressed: whether all the production is from the Bakken formation, or part of the oil is from another successful producing zone referred to as the Three Forks, which is directly beneath the lower Bakken shale. Another drawback of using the decline curve analysis method is found in the limitation of the decline curve itself (Clark, 2009). A well is expected to have reached boundary dominated flow before a decline curve can be used, while transition time, which is related to permeability, is extremely long for unconventional reservoirs.

Kurtoglu et al. (2012) conducted several short and long pressure transient tests in vertical and horizontal wells, to determine critical formation properties in the middle Bakken and Three Forks formations. They then presented an analytical solution to identify bilinear and linear flow regimes using numerical inverse Laplace transform as well as closed-form approximate solutions. In an earlier paper, these same authors (2011) reported their use of log-log type-curve diagnostic plots and Fetkovich log-log normalized plots to identify the flow regimes and varying decline rate from long-term producing wells in Elm Coulee field. Siddiqui et al. (2012) used rate-time plot and rater-normalized pressure versus material balance time plots to identify micro-fractures and pressure interference between fractured wells in a tight reservoir. Malekzadeh (1992) conducted multiple well interference tests, providing information about reservoir characteristics such as areal average transmissibility, storativity, and degree of communication between horizontal wells in Bakken formation. Ezulike, and Dehghanpour (2013) developed type-curves for DPM (dual porosity model), QFM (quadrilinear flow model, which allows simultaneous matrix-micro fracture, matrix-hydraulic fracture flow), STPM (linear sequential triple-porosity model, in which fluid flows from matrix to micro-fracture first then to hydraulic fracture), and used them on two wells in the Bakken and Cardium formations.

4.5.4 Economic Analysis

Long-term economic viability and profit maximization are always the goals for every hydrocarbon production company. Especially for tight oil producers, these goals are much harder to realize. Horizontal or multi-lateral well drilling costs more than conventional vertical well drilling; hydraulic fracturing is an extra expense. During production, the sharp production decline adds huge uncertainties in the cash flow. If infill well drilling or enhanced oil recovery is required, the return and cost associated with it need to be analyzed. Last but not least, in this vulnerable market, oil price is one of the most significant factors to affect producers' decision making.

There are various economic models in the market, and novel algorithms are emerging. Schuenemeyer et al. (2014) assumed a distribution for drilling cost in the future, and employed distributions of potential productive area, average well drainage area, area of sweet spots specified by the US Geological Survey, then obtained a resource cost curve for the Elm Coulee-Billings Nose and Three Forks assessment units. Hamm and Struyk (2011) generated an economic model to compare profitability of several tight oil plays. They mentioned that, due to the significant difference in royalty structure among the various areas, the Saskatchewan Bakken play was able to generate higher income per dollar of capital cost in the first 18 months, albeit at a lower production rate. Saputelli et al. (2014) built a fracture model and conducted economic analysis. Their numerical simulation results indicated that as the number of fractures increased, oil recovery increased between 8 to 15%, while net present value (NPV) increased 8 to 24%. Wright et al. (2014) conducted multi-variant analysis to a new "plug & perf" technology with slickwater fluids and ceramics proppant, and then provided economic evaluation for design parameters. Wilson and Durlofsky (2012) converted a complicated geological model to a reduced-physics surrogate model first, then used the surrogate model to optimize the well locations, lengths, and number of fracture stages. In two examples, the net present values are more than double those of the base case.

4.6 Produced Water Recycling

In recent years, US Bakken producers have started to seek more economically and environmentally sustainable practices, of which recycling of produced formation water is gaining increasing attention. Fresh water supply has become a concern, as the fluid volume requirement in fracturing treatment has increased significantly. Rather than looking for fresh water sources and meanwhile disposing of produced and flowback water, partial or full reuse of produced Bakken brine for well stimulation can reduce the environmental footprint, preserve more fresh water sources, and save the cost of a central gathering system and water transportation.

Schmidt et al. (2015) reported a field case study of using 100% produced brine from the Bakken Formation to stimulate a two-well pad over a two-year period in Williams County, North Dakota. Challenges in this practice include the following:

- While the produced water supply is generally equal to the water needed in hydraulic fracturing operations, the frac tank and open receptacle for storing produced water can be costly.
- When demand for fracking water increases, accommodation and transportation of produced water can be a concern.
- Guar based zirconate can be crosslinked using the produced water at suitable water quality. The produced water can present variable water chemistry, such as pH and sulfate concentration, and total suspended solids (TSS). Real-time water quality monitoring is needed to process the water and adjust the zirconate fluid usage.
- In the project, the produced water reuse was still more expensive than fresh water stimulation.

Another similar field case study (McMahon et al., 2015) was reported to use 7 million gallons of produced Bakken water (of which 2.2 million gallons were crosslinked) throughout the slickwater and crosslinked components of about sixty hydraulic fracturing stages. The use of produced water has two distinctive benefits:

- Completion costs are reduced as fresh water sourcing and produced water disposal costs are saved.
- Logistics costs are greatly reduced.

The industry's commonly used guar crosslinked by boron at high pH significantly loses its effectiveness when the water's total dissolved solids (TDS) content is higher than 4–8%. Most water treatments are costly and capital-intensive, and often generate waste streams. Use of a salinity-resistant guar derivative was reported, but its cost is about twice that of guar itself. McMahon et al. developed an inexpensive polysaccharide gelling agent, pH adjuster, and a proprietary metal crosslinker. The treating pressure observed in the field indicated that the fluid assisted in near wellbore proppant transportation, while it was highly tolerant of water quality fluctuations during a stage.

Griffin et al. (2014) provide insight into the effectiveness of produced water stimulation including slickwater designs in the Bakken petroleum system. The technical challenge is mainly from the sensitivity of friction reducers used in slickwater to produced water chemistry, which tends to vary with production location and time. The authors used a fraction flow loop to study friction reduction of different fluids under various conditions. Variables included type and concentration of commercial friction reducers, ratio of fresh water to produced water, and temperature. The laboratory and field tests showed that several commercially available friction reducers can effectively reduce pipe friction using the high-salinity Bakken produced brine.

Realizing that high cation concentration in Bakken produced water can reduce the efficiency of friction reducer to below 30%, Zhou et al. (2014) developed a water-based friction reducer to address the challenges of high-TDS produced water. It was tested in produced water types from Bakken, Marcellus, Eagle Ford, Permian Basin and other shale plays at different temperatures and found to be highly effective. In a produced water sample with TDS of over 300,000 ppm and total hardness as $CaCO_3$ of over 90,000 ppm serving as representative water, the new polymer hydrated within 10 seconds and gave a friction reduction profile similar to that of current inverse-emulsion friction reducers in fresh water.

4.7 Bakken Oil Processing and Transportation

Despite big differences in production scale, the Canadian and US Bakken have similar challenges with the shortage of pipeline infrastructure to transport Bakken crude oils to market. Currently, rail is an important means of transportation. With the operation cost itself more expensive than the pipeline transportation, several recent train derailment tragedies related to the shipping of highly flammable Bakken crude oil have posed severe railroad safety concerns.

The Government of Canada announced a Bakken Pipeline Project (the Project) would transport crude oil from a new pump station near Steelman, Saskatchewan, to the existing Enbridge Pipeline Inc. (EPI) Cromer Terminal near Cromer, Manitoba. The Project would involve the construction of a 123.4km long crude oil pipeline and associated facilities. The proposed pipeline corridor would be alongside and contiguous to an existing Enbridge Westspur pipeline right-of-way (RoW) and utility corridors for approximately 77.3 km of its entire length. The remaining 46.1 km would require new non-contiguous RoW. The associated facilities would include the construction of a new pump station near the existing Enbridge Westspur Steelman Terminal and a new pig receiver at the existing EPI Cromer Terminal. The Project would require the crossing of several watercourses, drainages, and water bodies including wetlands.

The Energy Information Administration (2006) stated that, in addition to other technical factors, pipeline transportation capacity issues could hinder further development of the Bakken Formation. As production in Montana and North Dakota increases, the existing transportation system is becoming a bottleneck.

4.8 Produced Gas Utilization

Due to the lack of pipeline transportation infrastructure, much of the natural gas produced along with the Bakken oil has to be flared. There are several factors affecting capture and utilization of produced gas, including government regulations and the reluctance of landowners to tolerate further requests for easements on their land (Northlands NewsCenter, no year). In order to support Bakken oil producers with flaring solution technology, the Energy & Environmental Research Center (EERC) provides a database containing vendor-supplied technical and economic information about gas utilization technologies. In 2011, the Saskatchewan Ministry of Economy developed Directives S-10 and S-20 for regulating gas conservation and flaring requirements. This drives development of cost-effective technologies in the Bakken to cut down on gas flaring and promote utilization.

Rapid oil development has exposed producers to the inadequacies of the regional gas processing and transportation infrastructure in the Bakken (Seto, 2015). To meet these gas-flaring reduction goals in the short term, a number of companies have turned to well site compressed natural gas (CNG) technology. Now the flaring restrictions imposed by the North Dakota Industrial Commission (NDIC) have motivated development of mobile technology to address flaring concerns and to monetize associated gas,

Wallace (2014) discussed the technical feasibility of replacing diesel with Bakken produced gas for powering drilling and hydraulic fracturing operations. The analysis of average energy generated from the volume and composition of the produced gas showed that it is sufficient for supplying the energy required for powering the drilling rig and frac spreads. After reviewing the produced gas separation technologies and power sources, including turbines, dual-fuel, and dedicated spark ignited engines, which can use natural gas, Wallace recommended the best use of produced gas.

Hoffman et al. (2014) evaluated the recovery potential along with the costs of reinjecting gas to determine the economic value of this process. A dual-porosity, compositional flow simulator was used to model the gas injection process into a well surrounded by producers and to determine the amount of incremental oil and gas produced. This process has a two-fold advantage with very positive economics. Oil production rates can be significantly increased, and significant volumes of produced gas can be recycled.

5. Acronyms

AI:	artificial intelligence
BLM:	Bureau of Land Management
BHA:	bottomhole assembly
BHP:	bottomhole pressure
BOPD:	barrel of oil per day
BOE:	barrel of oil equivalent
CLIP:	cement left in pipe
CT:	coiled-tubing
DHM:	dual element, hydraulic-set, mechanical
DST:	drillstem test
EOS:	equation-of-state
EUR:	estimated ultimate recovery
GIS:	geographic information systems
GOR:	gas/oil ratio
HPHT:	high pressure high temperature
HJAF:	hydrajet-assisted fracturing
IOR:	improved oil recovery
KOP:	kick-off point
LCM:	loss circulation materials
LWD:	logging-while-drilling
ME FSS:	multi-entry fracturing sleeve system
MEM:	Mechanical Earth Model
NFR:	naturally fractured reservoirs
MMP:	minimum miscibility pressure
MWD:	measurement-while-drilling
NPV:	net present value
OHMS:	open-hole, multi-stage fracturing system
OOIP:	original oil in place
ROI:	return on investment
ROP:	rate of penetration
RSS:	rotary steerable system

SE FSS:	single-entry fracturing sleeve system
SPWB:	synthetic polymer water based
SRV:	stimulated reservoir volume
STB:	stock tank barrels
TDS:	total dissolved solids
TOC:	total organic content
WAG:	water-alternating-gas
WCSB:	Western Canada Sedimentary Basin
WOB:	weight on bit
WOR:	water/oil ratio

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