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Geological Survey of Canada
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Saskatchewan Geological Survey
Miscellaneous Report 2016-2

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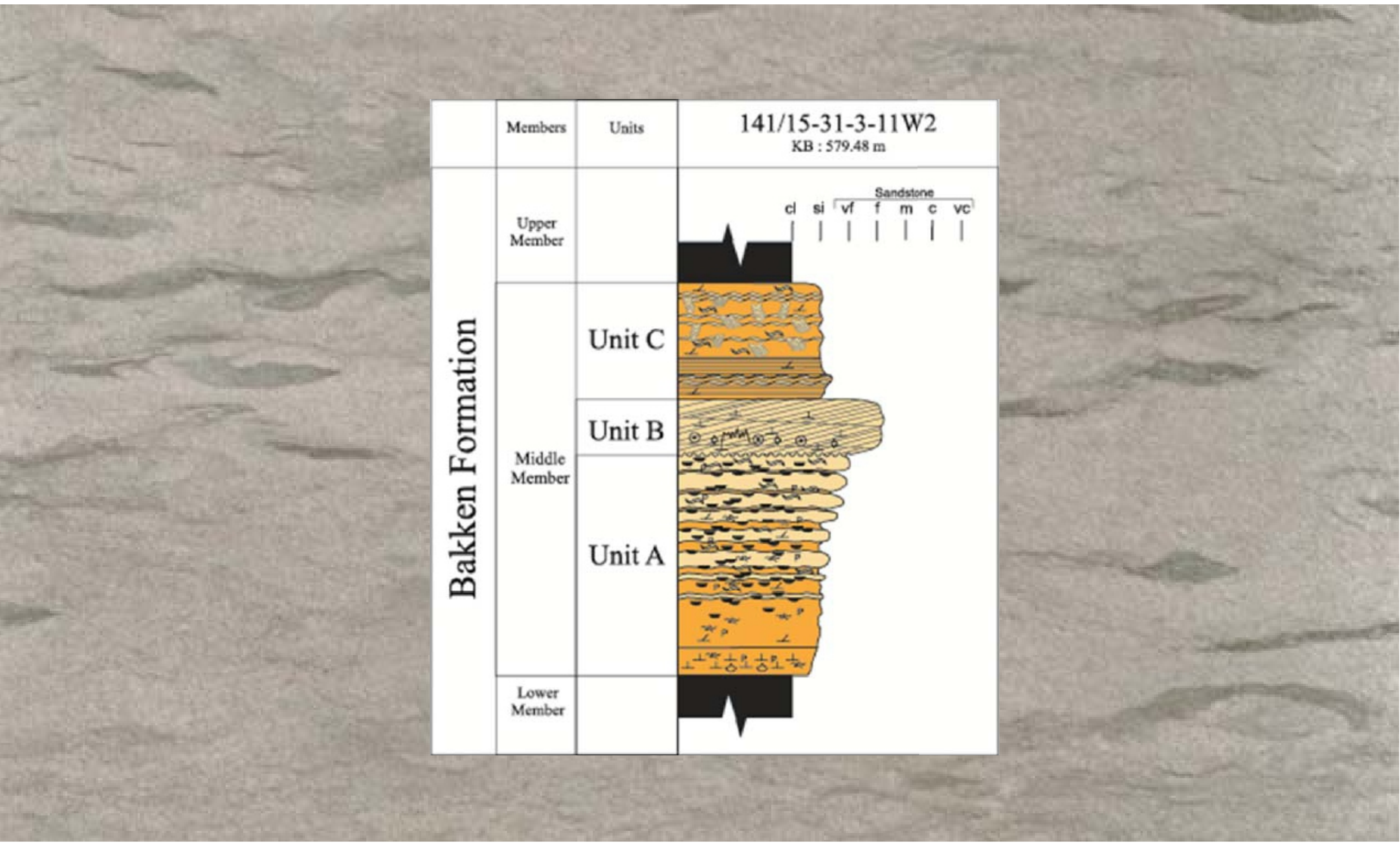


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# *Summary*

This study used an integrated approach that combined well EURs derived from well performance analysis with in-place oil resource calculated from reservoir attribute maps to infer recoverable resource potential in the tight reservoir of Middle Bakken Unit A in southeastern Saskatchewan. A geological risk evaluation was conducted for identifying potential sweet spots of economically producible oil resource in the study area, which resulted in a probability map outlining possible "sweet spots" in the Unit A tight reservoir of the lower Middle Bakken Member. The assessment indicates that the mean recoverable oil and associated gas are 231.3 x $10^6$ $m^3$ (1454.6 x $10^6$ barrels) and 37.77 x $10^9$ $m^3$ (1330.8 BCF), respectively, and the expected in-place endowment of oil is 2.63 x $10^9$ $m^3$ (16.57 x $10^9$ barrels).

## *Introduction*

The economic success in the US Williston Basin has spurred a renewed interest in pursuing development of the Middle Bakken light oil resource in southeastern Saskatchewan (Figure 1). In the past 10 years, light oil and associated gas have been produced from the tight reservoir of the Middle Bakken Member in the Viewfield pool through application of the latest completion technology of multi-stage hydraulic fracturing. The Bakken oil production in southeastern Saskatchewan has substantially increased from approximately 100 cubic metres per day ($m^3$/day) (629 barrels/day) in 2004 to approximately 10 000 $m^3$/day (62 900 barrels/day) in 2014 (Figure 2).

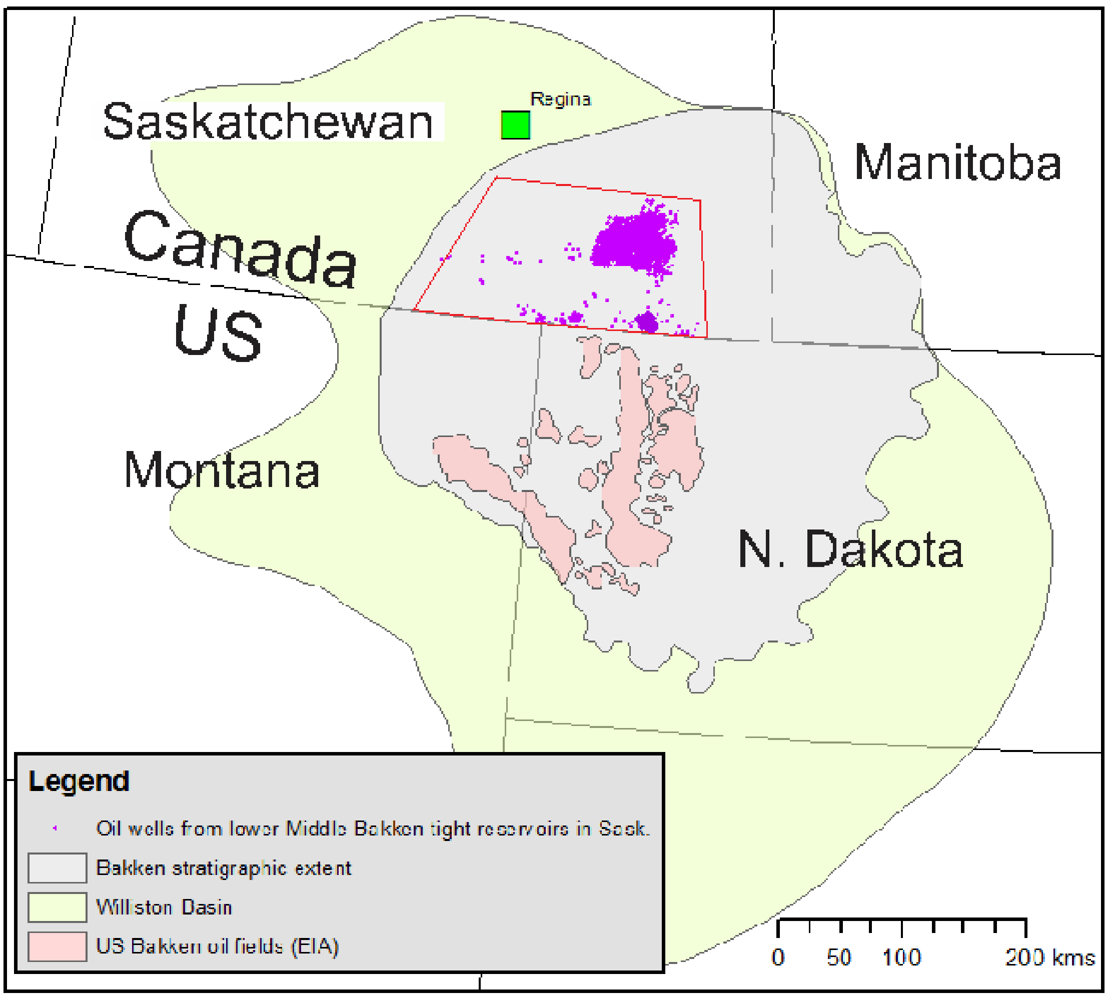


Figure 1. A regional map showing the study area in southeastern Saskatchewan, location of oil wells in tight reservoirs and the major Middle Bakken production hot spots in the Williston Basin. Red polygon represents study area.

Industry has generated various estimates of the hydrocarbon resource potential of the Middle Bakken Member within their properties. Additional assessments of resource potential of regional extent have been produced by various government agencies. The Energy Information Administration of the United States (EIA, 2013) has estimated the resource potential of the Middle Bakken Member reservoir in the Canadian portion of Williston Basin to be 0.2544 x $10^9$ $m^3$(1.6 x $10^9$ barrels) of technically recoverable oil and 62.3 x $10^9$ $m^3$ (2200 x $10^9$ $ft^3$ (billion cubic feet (BCF)) of recoverable associated gas. Using a volumetric approach, the National Energy Board and Saskatchewan Geological Survey (2015) have recently completed an assessment based on a reservoir volumetric method for the Middle Bakken tight reservoir, resulting in estimates of 223 x $10^6$ $m^3$ (1.4 x $10^9$ barrels) of marketable oil and 81.2 x $10^9$ $m^3$ (2900 BCF) of marketable natural gas.

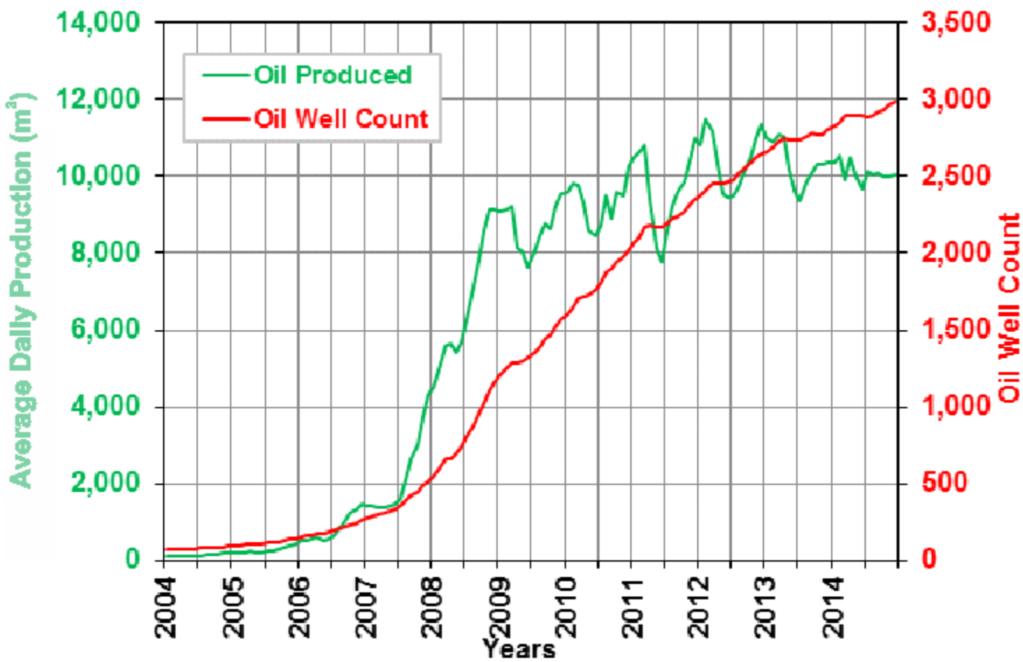


Figure 2. The Bakken average daily oil-production and oil-well-count trends from 2004 to 2014, southeastern Saskatchewan.

Differing significantly from conventional resources, production from tight reservoirs requires a horizontal well coupled with multi-stage hydraulic fracturing. The production performance shows a fast decline rate in the first few years rather than achieving a stable production plateau for a few years before declining as demonstrated by conventional reservoirs. Examining the recoverable resources from a perspective of production performance in tight reservoirs could provide insight for improving our understanding of the recoverability of oil and associated gas. Since 2004, there are more than 3000 stimulated wells in the Middle Bakken tight reservoir producing in southeastern Saskatchewan, allowing a comprehensive examination of the recoverable resources from the reservoir in the region.

This study represents a joint effort by the Geological Survey of Canada and Saskatchewan Geological Survey to address the need for examining the resource potential in the tight reservoir of the lower Middle Bakken Member (Unit A) in southeastern Saskatchewan using an integrated approach that includes the production data analysis. This study assesses the oil and associated gas resource potential in the unconventional tight reservoir of the lower Middle Bakken Member (Unit A) in the identified prospective area of southeastern Saskatchewan. Figure 1 shows the study area with oil wells from tight reservoir of the lower Middle Bakken Member. In this study, we define tight reservoir as clastic reservoir with very low permeability, from which commercial production cannot be achieved without extensive stimulation commonly achieved via horizontal drilling coupled with multi-stage hydraulic fracturing. To year end of 2011, a total of 515 x $10^3$ $m^3$ of oil has been produced from the Bakken-Torquay Play along the Saskatchewan-Manitoba boundary in the Ryerson area, where both the lower Middle Bakken (Unit A) and Lower Bakken Shale are absent (Yang, 2012; Kohlruss, personal communication) (Figure 3). Thus the Ryerson area is excluded in this assessment. In southeastern Saskatchewan, commercial oil production has been achieved from conventional reservoirs of the Middle Bakken Member in the Rocanville, Weyburn, Roncott, and Hummingbird pool areas since 1956 (Yang, 2012) and those pool areas are excluded in this study as well.

## *Geological Background*

The Bakken Formation is divided into three members: Upper and Lower organic-rich black shales (Figure 4), with a middle siltstone to sandstone unit between them. The Upper and Lower Bakken shales contain abundant organic matter and are the major source rocks that expelled more than 100 x $10^9$ barrels of oil from the thermally mature regions located in the US portion of the Williston Basin (Dow, 1974; Meissner, 1978; Dembicki and Pirkle, 1985; Gerhard et al., 1990; Kreis and Costa, 2005). Organic carbon content and shale thickness are greatest near the Bakken depo-centre east of the Nesson Anticline (maximum Bakken shale thickness, 20 m, Dembicki and Pirkle, 1985, their figure 3). The organic matter of Upper and Lower Bakken shale members are type II kerogen, typically found in normal marine clastic source rocks (Kuhn et al. 2010, 2012). Although the Upper and Lower Bakken shales in the Canadian Williston Basin are also organic rich, they are immature to marginally mature (Chen et al., 2009; Flannery and Kraus, 2006), as indicated by a low vitrinite reflectance (Ro < 0.65%; Figure 5).

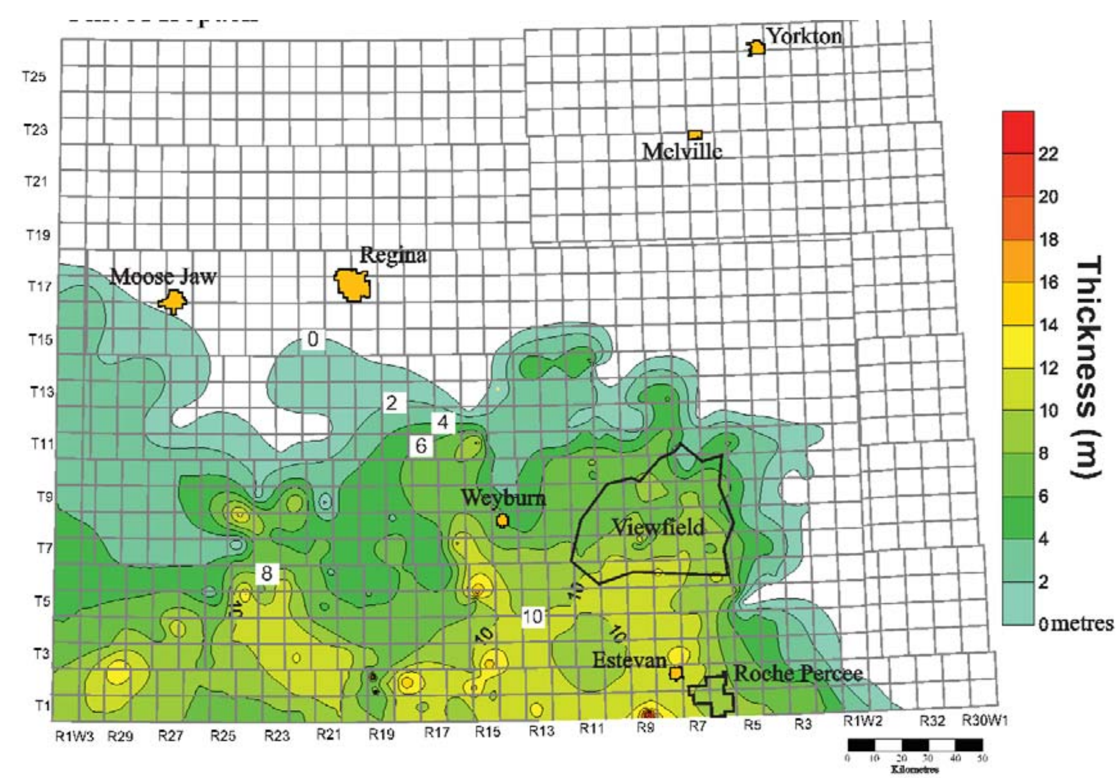


Figure 3. An isopach map showing the spatial variation of the thickness and stratigraphic extent of the Unit A tight reservoir of the Middle Bakken Member in southeastern Saskatchewan.

The Middle Bakken Member reservoir has been subdivided into a lowermost Unit A, a middle Unit B and an uppermost Unit C (Figure 4). Unit A conformably overlies the Lower Bakken Member shale (Kohlruss and Nickel, 2009, 2013). This unit is mainly a massive grey to greenish grey argillaceous dolomitic siltstone to silty dolostone and is characterized by abundant bioturbation. The unit coarsens gradually upward to become a silty sandstone at its top, where the majority of hydrocarbon production is likely from. Unit B sharply overlies Unit A and consists of a fine-grained calcite-cemented sandstone ranging from massively bedded at the base, to high-angle planar cross-bedded, to laminated at the top. Unit C is recognized by its laminated argillaceous dolomitic siltstone to very fine-grained sandstone. Bioturbation and soft sediment deformation is abundant within Unit C and can readily be identified in core.

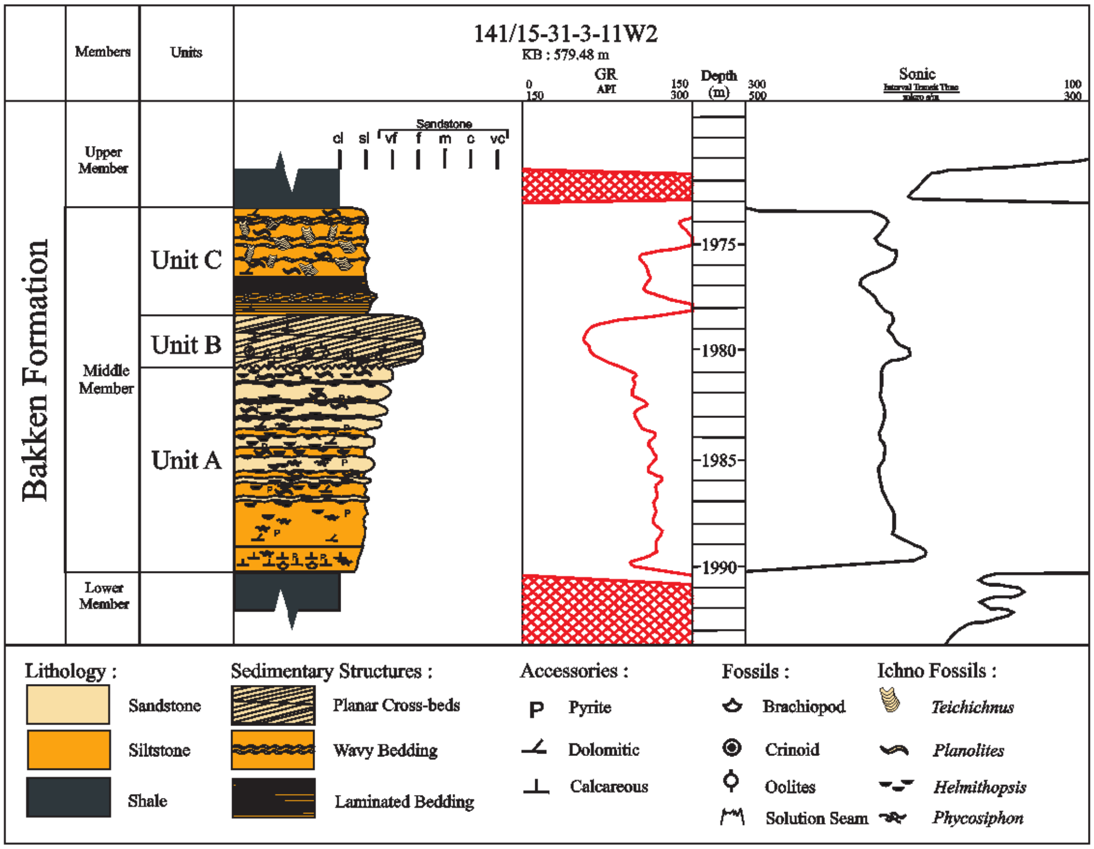


Figure 4. Type litholog (well 141/15-31-003-11W2, Lic# 81D003) of the Bakken Formation and the stratigraphic units of the Middle Bakken Member in southeastern Saskatchewan (modified from Kohlruss and Nickel, 2013). Unit A is the main reservoir and producing unit in the Viewfield pool. Unit B is absent or very thin in the Viewfield pool and, where present, can be produced conventionally.

Conventional oil fields produce primarily from Unit B sandstones of the Middle Bakken. The conventional oil accumulations of Unit B are primarily found in discrete structural traps, such as those in the Hummingbird and Rocanville fields, and they are sealed by the Upper Bakken shale. The renewed oil developments in the Canadian Middle Bakken Member in southeastern Saskatchewan are focused on the “sweet spots” of the tight reservoir in Unit A of the Viewfield oil pool and near areas bordering the US, where essential elements for forming conventional accumulation, such as structure and regional seal, are less obvious. It is likely that up-dipping stratigraphic entrapment plays an important role for the oil accumulation in the Viewfield area

(Kohlruss and Nickel, 2012). Thus, lithological variation may generate similar small accumulations south of the Viewfield pool.

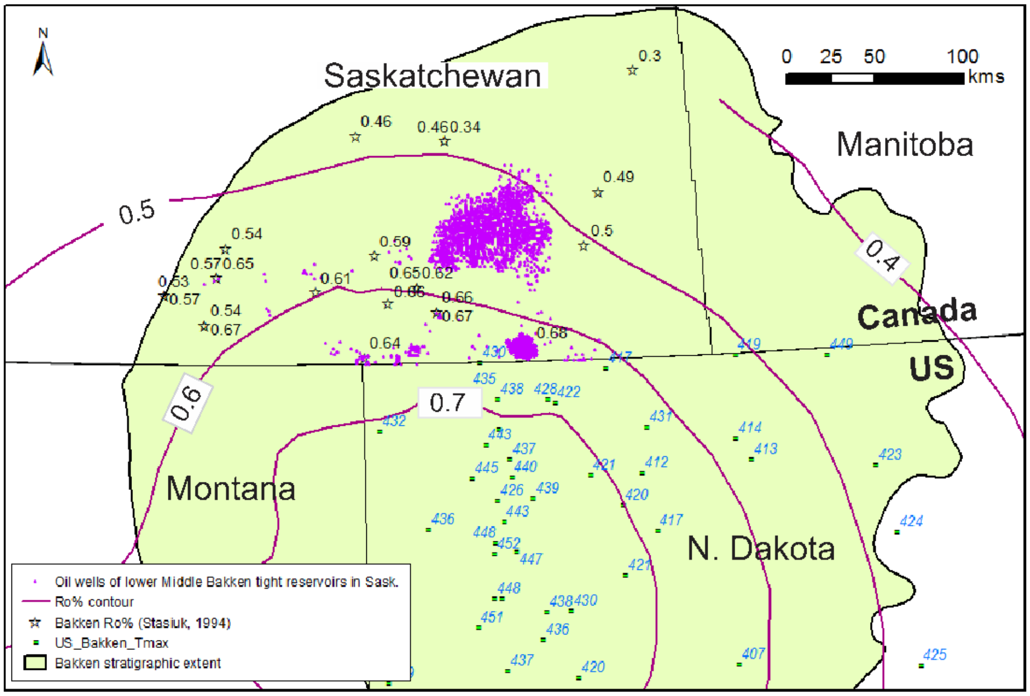

Figure 5. A thermal maturity map of the Bakken shale indicated by vitrinite reflectance in Williston Basin (modified from Chen et al., 2009). See text for more explanations.

Organic geochemical analyses of crude oil samples from the Middle Bakken Member of the Viewfield area in southeastern Saskatchewan indicate that the hydrocarbon accumulations are genetically related to the Bakken shales (e.g. a high abundance of arylisoprenoids, a pristane-over-phytane ratio greater than one and a dibenzothion-over-phenanthrene ratio less than one) but are thermally more mature than the local Upper and Lower Bakken Member shales. The light oils in Unit A of the Middle Bakken in the Viewfield pool are therefore believed to have migrated primarily from the thermally mature Bakken shales found in the United States' portion of the Williston Basin.

## *Methods*

The methods used in this study for assessing oil and gas resource potential consist of the following four stages (Figure 6):

1) Volumetric oil in-place estimation (Figure 6, left stream marked blue),
2) Production performance analysis and estimated ultimate recovery (EUR) calculation (Figure 6 right stream marked green),
3) Risk analysis and recoverable factor estimation (Figure 6, central stream marked purple), and
4) Recoverable resource calculation and resource aggregation (Figure 6, last box marked yellow).

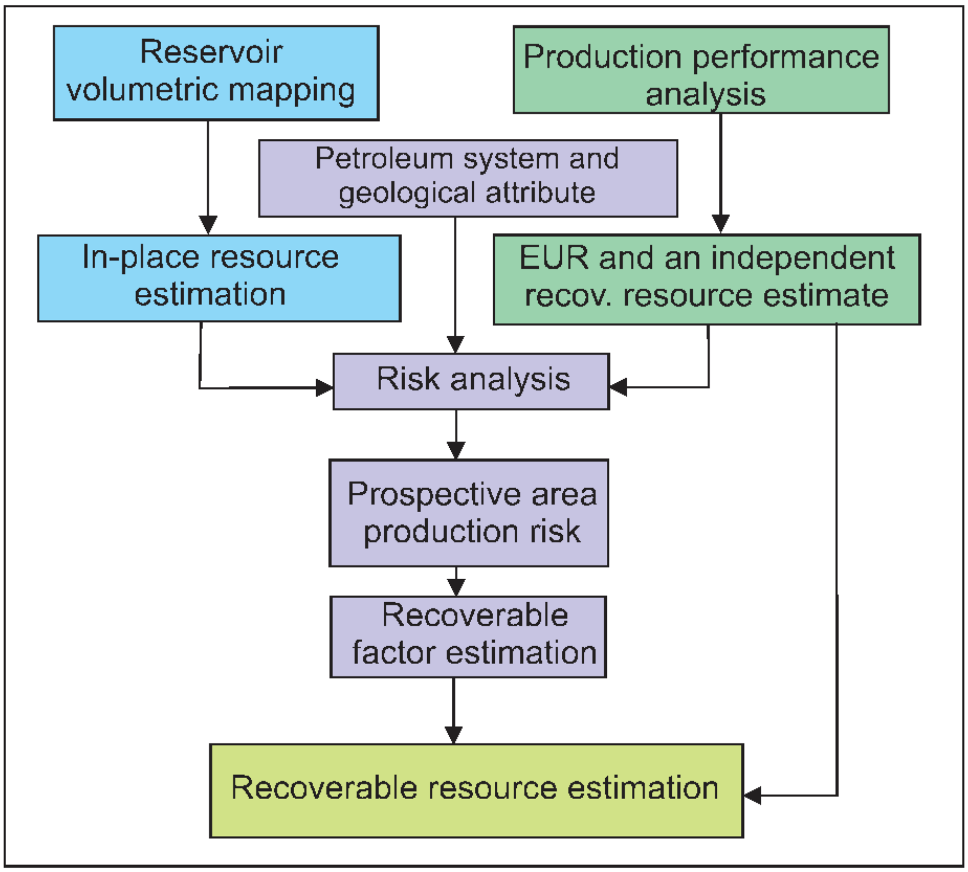


Figure 6. A flow chart showing the procedure and major steps of resource assessment of the Middle Bakken Unit A tight reservoir in southeastern Saskatchewan.

## *1) Volumetric calculation*

To capture the spatial variability of the resource potential in the target reservoir, the study area is divided into $N$ equal-sized cells with location index of $n$. The total hydrocarbon pore volume ($V_{oil}$) in the reservoir can be estimated from the following volumetric equation:

$$V_{oil} = \sum_{n=1}^{N} A(n)T(n)\,\emptyset(n)S_O(n) \qquad (1)$$

where $A(n)$ is the cell size ($m^2$), $T(n)$ is the reservoir thickness (m), Ø (n) is reservoir porosity (decimal fraction) and $S_O(n)$ is oil saturation (decimal fraction). Because there is no free gas at reservoir conditions in the study area, the hydrocarbon pore volume is actually the oil pore volume.

The following equation is applied to convert the hydrocarbon pore volumes at reservoir conditions to oil volume under standard surface conditions.

$$Oil_{in-place} = V_{oil} / FVF \tag{2}$$

where $FVF$ is the oil formation volume factor.

The recoverable resource, $Oil_{recov}$ in the study area is the in-place resource multiplied by a recovery factor.

$$Oil_{recov} = Oil_{in-place} R_f \tag{3}$$

where $R_f$ is the recovery factor estimated from production data or by analogue.

The recoverable associated gas ($Gas_{recov}^{solution}$) is calculated from the relationship:

$$Gas_{recov}^{solution} = Oil_{recov} GOR \tag{4}$$

where $GOR$ is the gas-to-oil ratio, a parameter estimated from production data.

All reservoir volumetric parameters were derived from publically available well log interpretations and laboratory tests.

## 2) *Production performance analysis and estimated ultimate recovery calculation*

The single-well estimated ultimate recovery (EUR) is derived directly from historical production data by fitting a decline model to the well (Lee, 2012). Two established decline models, Arps and Valko, have been used to calculate EUR for each well on production in the study area. The Arps model provides a well-known production forecasting model for various conventional reservoirs and has been applied to estimate well EUR for decades (Arps, 1945; Lee and Sidle, 2010). The Arps method has the following form (Arps, 1945):

$$q = q_i \frac{1}{(1 + bD_i t)^{(1/b)}} \tag{5}$$

where $q$ is production rate, $t$ is time, $q_i$ is initial production rate, and $b$ and $D_i$ are model parameters.

Application of the Arps model, by assuming a hyperbolic decline rate, may not be appropriate to extremely low permeability unconventional reservoirs (Ilk et al., 2008; Lee, 2010). Valko and Lee (2010) proposed a stretched exponential model (also called Valko model) to estimate well EUR for different purposes, including unconventional shale gas, tight reservoirs and unconventional resource assessment (Valko and Lee, 2010; Lee, 2012; Chen and Osadetz, 2013). The model has the following form:

$$q = q_i \exp\left[-\left(\frac{t}{\tau}\right)^n\right] \tag{6}$$

where $q$ is production rate, $t$ is time, $q_i$ is initial production rate, and $n$ and $\tau$ are model parameters.

This study utilizes the Valko model for EUR calculation, and estimates from the Arps model were used as a reference. In general, the Arps model appears to generate a slightly greater well EUR than that obtained using the Valko model (Lee, 2012). The EURs derived from projecting the available historical production records form a statistical sample that presumably represents the ultimate recoverable resource potential variations per drainage area in Unit A of the Middle Bakken Member.

### *3) Risk analysis and probability mapping*

Productivity from unconventional reservoirs may vary significantly depending on the in-place resource abundance, fracturability of the reservoir and many other unknown factors. Commercial production is commonly obtained in "sweet spots", where the resource abundance and reservoir quality are optimal. Although Unit A extends across southeastern Saskatchewan as indicated by well data, it may not contain economically producible oil resource elsewhere beyond the known "sweet spots" at the Viewfield pool and other areas. Identifying prospective areas with meaningful oil production potential and evaluating the risk for the occurrence of a producible resource are necessary steps in the resource assessment.

The method used for risk evaluation is a quantitative approach based on geological similarities between the established commercially producing area at the Viewfield pool (the analogue area) and the undrilled (the target) areas. Chen and Osadetz (2006) developed a method employing multivariable analysis and Bayesian statistics to conduct geological risk analysis for a conventional petroleum play in western Sverdrup Basin in Arctic Canadian. These methods are employed in this study to formulate a classification of "sweet spot" versus "non–sweet spot" for the production wells, based on selected geological attributes such as reservoir permeability, oil saturated pore volume, thickness of the overlying Upper Bakken Member shale, structural components and others. These geological attributes are extracted from i) exploration and production wells that tested Unit A for oil in the Viewfield and target areas, and ii) regional geological maps. The resulting classification can discriminate the better performing wells in "sweet spots" from the poor performers in "non–sweet spots", and the geological risk is measured by probability representing the uncertainty. This criterion for classification was then applied to undrilled target areas to project the probability that these areas could produce oil above a cut-off rate if indeed production wells had been drilled. A probability map of commercial oil productivity is subsequently generated. Readers are referred to Chen and Osadetz (2006, 2013), Xie et al., (2011) and Zou et al. (2012) for the mathematical detail and application examples of the methods.

### *4) Recoverable resource calculation and resource aggregation*

Combining the obtained probability map of commercial oil productivity from step 2 and the in-place resource map generates a risked in-place resource map. An estimate of oil recoverable factor is achieved by comparing the risked in-place resource and well EUR derived from production performance analysis at each well location. In other words, the ratio of single-well EUR to the risked in-place oil resource at a well location within its drainage area defined by its stimulated reservoir volume (SRV) gives an estimate of recovery factor. The recovery factors derived in such a way form a population representing the variation of the recoverability of the in-place resource.

Treating the volumetric variables obtained in step 1 at each cell as a spatial random variable, the geographically referenced variables were contoured using a kriging algorithm to express their spatial variations. The mean and variance of the oil volume at each cell mapped using the kriging algorithm represent the most likely resource estimate and the uncertainty at that location. The subsurface oil pore volume estimation was calculated at each cell based on these kriging algorithm maps. A Monte Carlo simulation is then applied to aggregate the resource estimates at each cell to produce a resource potential estimate for the entire study area. The probabilistic distribution of the total resource estimate from the aggregation represents the uncertainty of the resource estimation. The Monte Carlo method is a type of computational algorithm that relies on repeated random sampling to compute results for problems that have no exact answers. Charpentier and Klett (2008) and Crovelli (1993) provided application examples for using Monte Carlo methods in petroleum resource assessment.

## *Assessment*

The prospective area of the Middle Bakken Unit A tight oil reservoir in southeastern Saskatchewan is defined by the stratigraphic extent of Unit A and its existing production trend. The Unit A tight reservoir is treated as a continuous play, with varying resource density and reservoir characteristics. Although oil accumulations in Unit A could be continuous across the entire southeastern Saskatchewan, the dynamic sweet spot of high commercial productivity may not be always coincident with a static sweet spot where high in-place resource abundance is indicated by volumetric calculation. Oil and gas development is likely to be limited to the dynamic sweet spots where commercial production can be achieved. Outlining the prospective area objectively forms the basis for the resource assessment.

## *Data and data analysis*

Three types of data are used in this assessment: 1) basic geological information and maps, such as spatial extent of the Middle Bakken Member, structural maps at different stratigraphic levels and their derivatives, and source rock thermal maturity data; 2) reservoir volumetric data, such as porosity, water saturation and isopach map of the Middle Bakken Unit A interpreted from well logs or from laboratory core analysis, formation volume factor, and gas-to-oil ratio (GOR) from production data; and 3) historical production records of monthly oil and gas production rates, compiled and prepared from industrial reports submitted to the Saskatchewan Ministry of the Economy.

The spatial variation of the thickness and stratigraphic extent of the Unit A tight reservoir in the study area is depicted in Figure 3. The statistical characteristics of the major volumetric variables, such as porosity, water saturation, reservoir thickness and hydrocarbon pore volume are presented graphically in Figure 7 and numerically in Table 1.

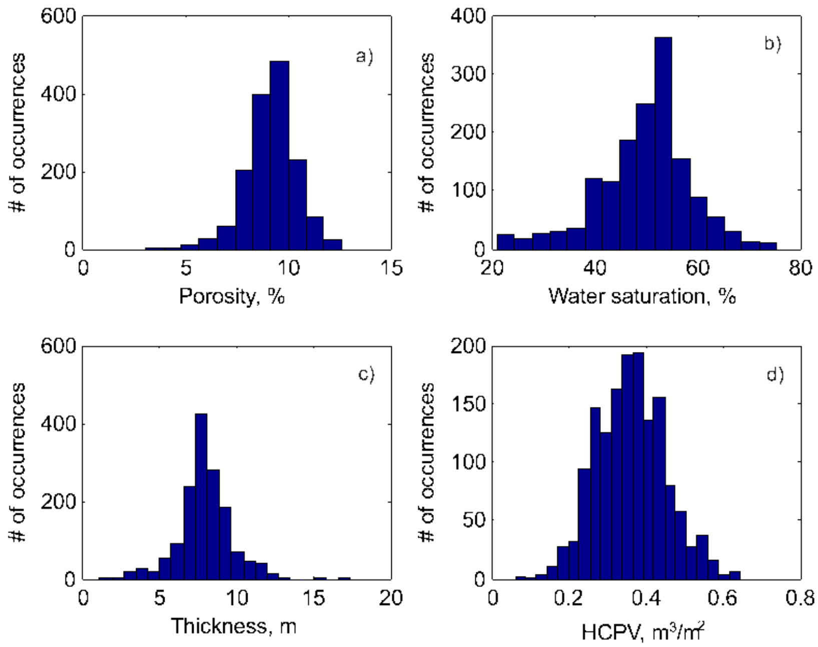


Figure 7. Statistical characteristics of the major volumetric variables for Unit A tight reservoir of the Middle Bakken in southeastern Saskatchewan: a) porosity; b) water saturation; c) reservoir thickness; and d) hydrocarbon pore volume (HCPV). The sample values of these volumetric variables are regenerated from krigged maps of the corresponding variables. See Table 1 for the statistical features of these and other volumetric variables used for resource calculations.

Table 1. Statistics for volumetric variables for Unit A tight reservoir of the Middle Bakken in southeastern Saskatchewan, derived from data analyses and estimated from laboratory tests.

| Variables | Mean | Variance |
|---|---|---|
| Porosity, % | 9.21 | 1.48 |
| Water saturation, % | 49.79 | 82.11 |
| Reservoir thickness, m | 7.95 | 2.72 |
| Estimated Ultimate Recovery (EUR), $m^3$ | 12,719 | 9.58E+07 |
| Oil recovery, % | 8.69 | 0.0031 |
| Formation Volume Factor (FVF) (a single value) | 1.25 | NA |
| Gas to oil ratio (GOR) m/m | 121.5 | 6765 |

Up to December 2014, a total of 3200 horizontal Bakken oil wells have been drilled in southeastern Saskatchewan. Among them, 2222 wells with longer than 12-month production records from the Unit A tight oil reservoir of the Middle Bakken Member are available for well performance analysis. Most of these horizontal wells were drilled in the Viewfield pool area after 2005, with most horizontal legs ranging from 600 to 2000 metres (mostly 1500 metres) (Figure 8). The majority of wells have less than 5 years of production history (46 months of mean production). For a specific reservoir condition, production rate is affected by the size of stimulated reservoir volume (SRV), which is related to the length of horizontal interval, well spacing and number of hydraulic fracturing stages of a production well. The Arps and Valko models were used to fit the production decline trends and extended to a maximum of 30 years of production to determine EURs for each production well across the study area. Well EUR calculations have been performed only on those wells with more than one year of production history. Figure 9 shows a single well example of the production data and model fits. The production in this well exhibits a rapid drop in production at the end of the first year and the rate of decline in first year can be more than 60% as shown in other wells. The decline rate in the following year slows down and gradually approaches a relatively stable production rate in subsequent years. Figure 10 illustrates the distribution of the EURs and it shows a large variation in the oil productivity from the Unit A reservoir.

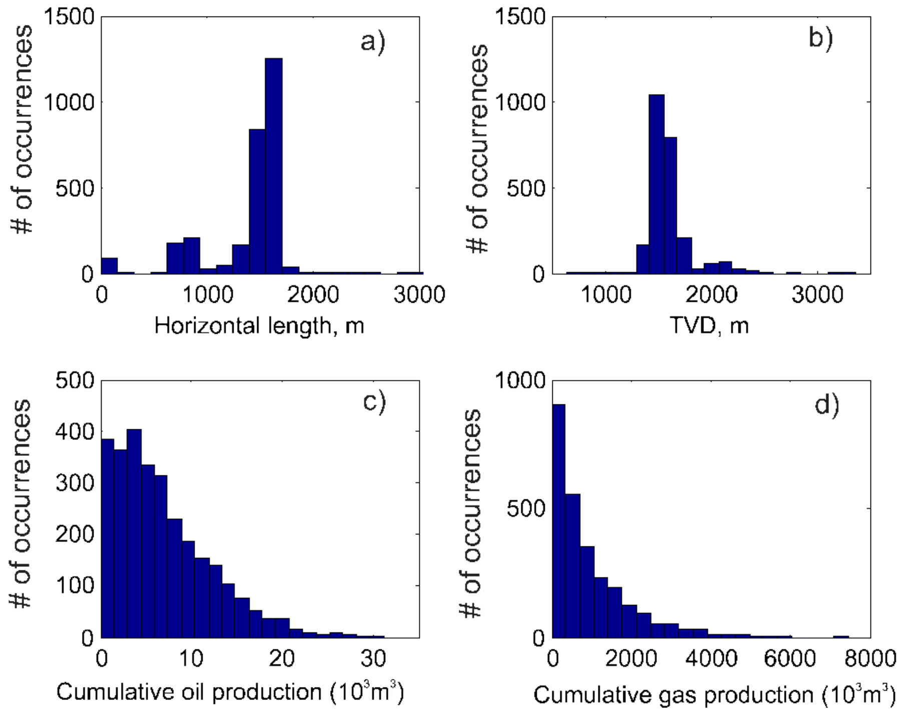


Figure 8. Statistics of the Bakken oil wells from the Viewfield pool in southeastern Saskatchewan: a) horizontal well length; b) total vertical depth (TVD); c) cumulative oil production; and d) cumulative gas production.

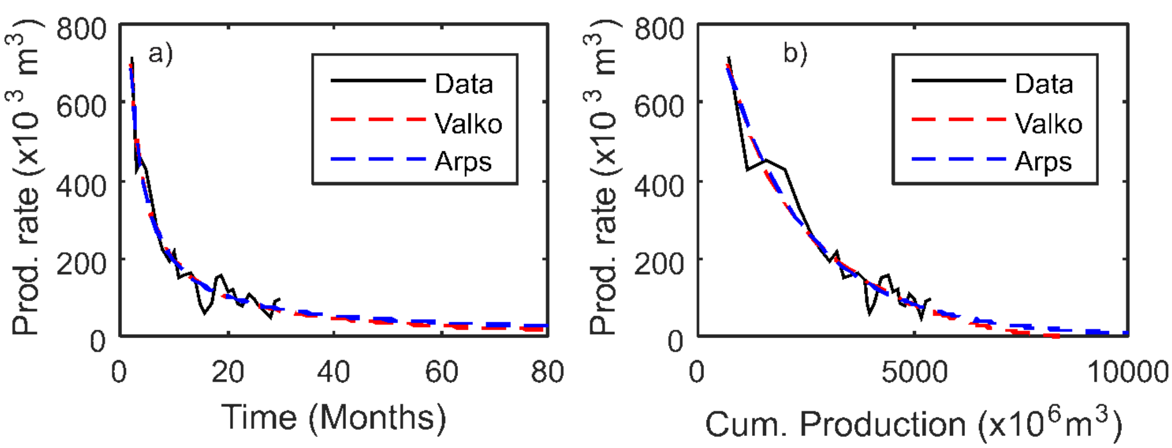


Figure 9. Production performance (black) and modelled production (red: Valko, green: Arps) decline curves of a typical oil well (191/12-13-007-06W2) from the Middle Bakken Unit A tight reservoir in southeastern Saskatchewan. a) Monthly production rate vs production time (month), data and fitted models; and b) cumulative production vs. monthly production rate, data and fitted models. The curve match for both models fit well with $r^2 = 0.9361$ and $r^2 = 0.9407$ for Valko and Arps models, respectively.

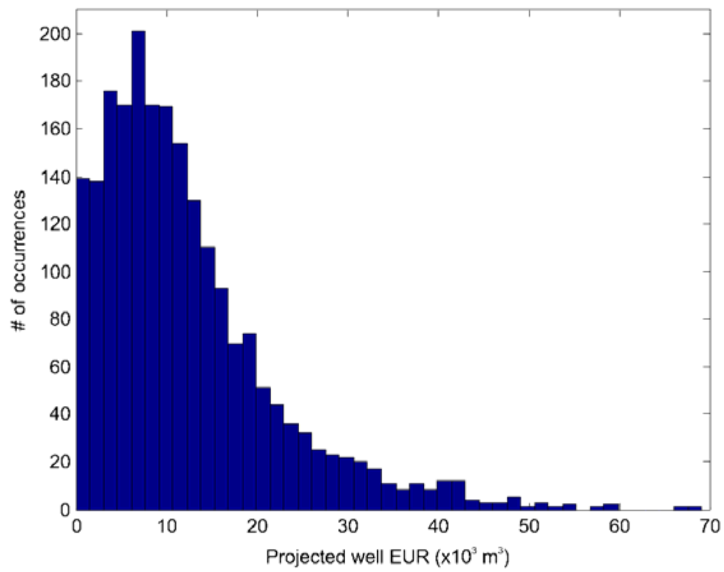

Figure 10. Histogram of well URs for recent horizontal wells with multi-stage hydraulic fracturing from the Middle Bakken Unit A tight reservoir, southeastern Saskatchewan. The EURs are estimated from historical production records with production trend projected to 30 years.

The EURs are directly derived from well performance, but the spatial coverage is limited as production wells are limited to a few certain "sweet spots" in the Viewfield pool and US border areas, as well as other isolated and scattered small areas to the south and west of the Viewfield pool. While the volumetric approach does provide the in-place resource estimate with better spatial coverage, it has great uncertainty with respect to recovery because productivity may not be directly proportional to the in-place resource abundance. In fact, oil recovery in the Unit A tight reservoir depends not only on the reservoir quality and in-place resource abundance, but also on other petroleum system elements in this region, as evidenced by the lack of strong spatial correlations between in-place hydrocarbon volume and well EUR. Data analysis suggests that lateral lithological variation and top seal could be critical factors affecting oil accumulations and preservation in Unit A. Validating the areas of meaningful oil production potential and evaluating the uncertainty in the occurrence of producible resources in untested area can improve the reliability of the resource assessment.

In the risk evaluation, wells with EURs were used as a training set to establish a quantitative relationship between oil productivity and various geological characteristics, from which potential productivity of a well at any untested location within the study area can be inferred by geological similarity using a quantitative model (Chen and Osadetz, 2006). Wells tested for oil in the Unit A tight reservoir were divided into two groups. Production wells with EUR ≥ 3000 $m^3$ of oil are regarded as economic wells in “sweet spot” areas and wells with EUR <3000 $m^3$ are non-economic wells on “non–sweet spot” areas. Although no rigorous economic analysis has been performed in this study, the selection of the economic threshold of EUR ≥3,000$m^3$ of oil was based on a) an optimistic crude oil price, b) additional solution gas resource (average GOR of 100 $m^3$/oil $m^3$), and c) most importantly, technology advances that will boost the future ultimate recovery.

Figure 11 shows the geographic distribution of “sweet spot” vs “non–sweet spot” wells in the study area. Many “non–sweet spot” oil wells occur around the periphery of the Viewfield pool and are scattered to the south and west of the Viewfield pool. Comparison of geological attributes in these “sweet spot” vs “non–sweet spot” wells found that the reservoir permeability, structural residue, formation water salinity, surface elevation, Upper Bakken shale thickness and reservoir volumetric attributes show more obvious differences than other attributes, and these attributes were thus used as “diagnostic variables” for differentiating between the two groups of wells.

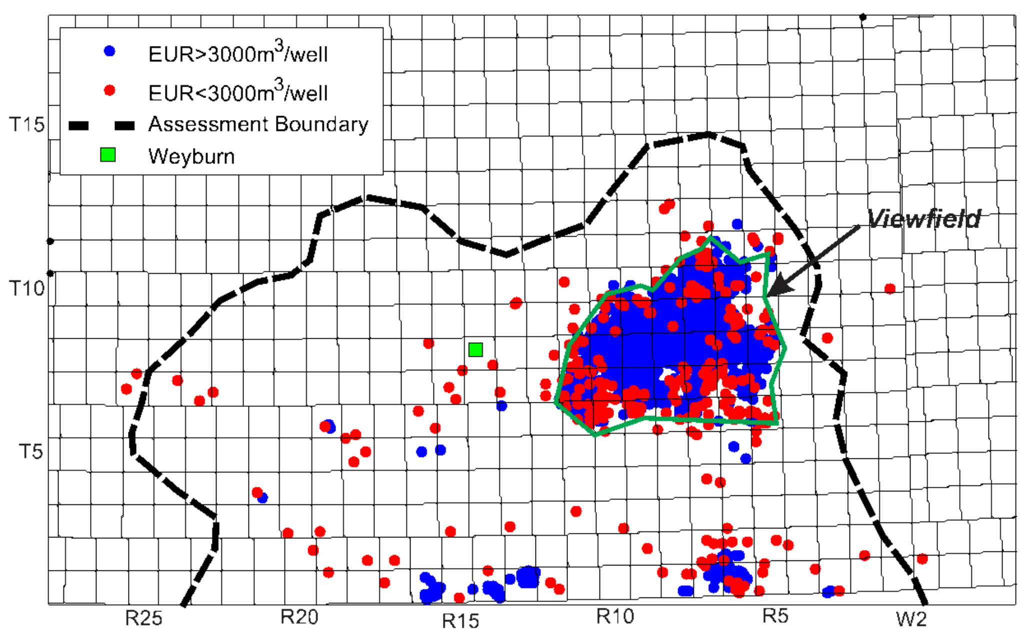


Figure 11. Aerial distribution of “sweet spot” vs “non–sweet spot” production wells of the Middle Bakken Unit A tight reservoir in the study area based on EURs. Blue dots: well with EUR >3000 $m^3$/well; red dots: well EUR <3000 $m^3$/well. Green polygon indicates the outline of the Viewfield pool.

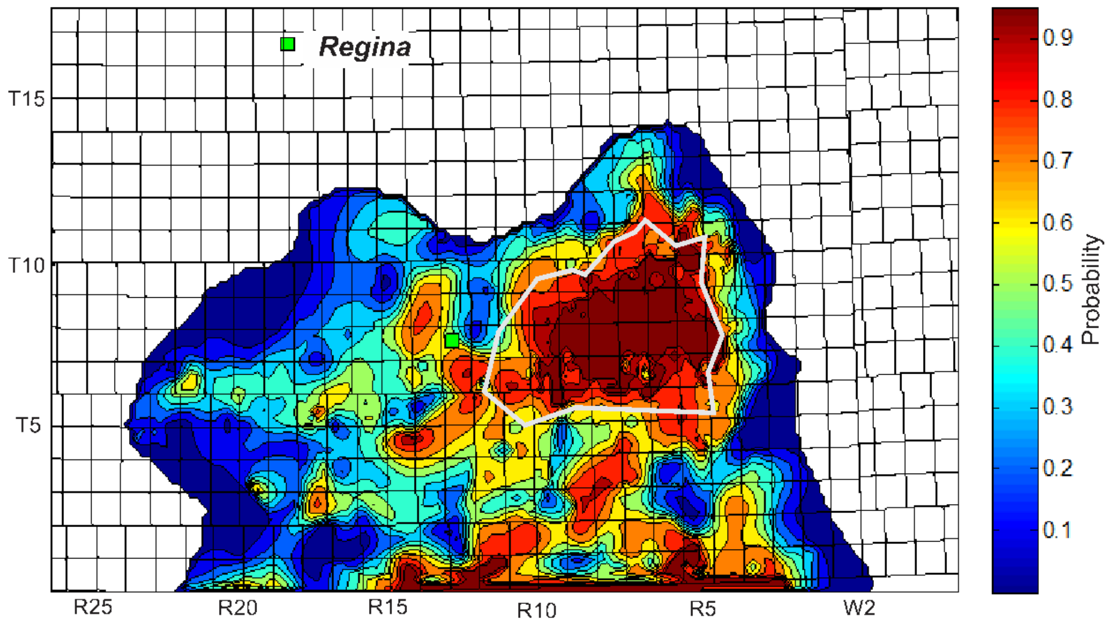


Figure 12. A map of the probability of economic oil occurrences in the Middle Bakken Unit A tight reservoir, southeastern Saskatchewan. Economic oil occurrence is referred to as the accumulation in a well's drainage area from which ultimate oil production can be greater than 3000 $m^3$. This map is produced from a Bayesian statistical approach using geological and reservoir diagnostic variables that are believed to be the elements controlling oil accumulation in Unit A. The white polygon indicates the outline of the production area of the Viewfield Field.

## *Results*

Based on the results of the well classification of "sweet spots" versus "non-sweet spots" for the production wells, a quantitative relationship between EURs and selected geological attributes (the "diagnostic variables") was established. An extrapolation of the relationship was applied to areas within the study area without productive wells. The inferred occurrence of producible oil has been mapped throughout the study area, and is presented in Figure 12 as "probability of recoverable resource occurrence". Figure 12 shows the probability of occurrence of commercial producible oil based on the geological similarity to the current producing wells using multivariable analysis and a Bayesian statistical approach. The higher the probability, the more likely commercial producible oil occurs. This probability map is then used to adjust the initial hydrocarbon in-place estimate from volumetric calculations to derive a risked resource density map (Figure 13). The risked oil in-place resource density map indicates the spatial variation of the expected oil resource in the study area. As indicated by the probability and risked in-place resource maps (Figures 12 and 13), the majority of areas of high productive oil accumulation ("sweet spots") are concentrated in the Viewfield pool area, with a few other smaller potential "sweet spots" scattered across the study area. The mean of the estimated initial oil in-place is 2.63 x $10^9$ $m^3$ (16.57 x $10^9$ barrels) (Table 2). It should be noted that the areas with high in-place resource abundance derived from volumetric parameters are not necessarily coincident with the sweet spots of high productivity indicated spatially by well performance. Thus, the initial in-place resource potential on Figure 13 may not be directly proportional to economically recoverable resource.

The histogram in Figure 14a shows the distribution of estimated oil recovery factors that is derived from the ratio of EUR to risked oil in-place. This is used along with the volumetric estimates to calculate the recoverable oil resource. The estimated recovery factor displays a two-mode distribution, which may indicate that there is a mixture of two different reservoir qualities in Unit A. A small portion of the wells show higher recovery factor around a median of 14%, whereas the majority of the production wells exhibit a lower recovery factor typical of tight reservoirs with a median at 6%.

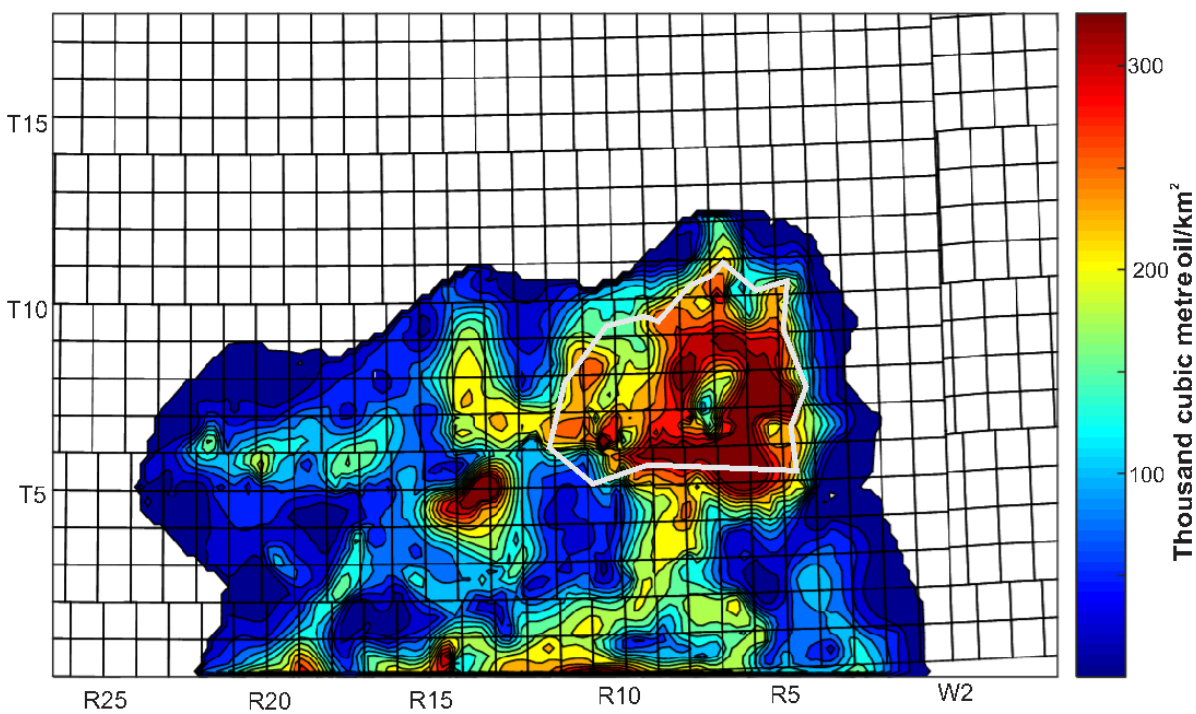


Figure 13. A risked resource density map of oil in-place. This is the production of un-risked initial oil in-place along with the probability map of oil occurrence in Unit A. The map's contour interval is in thousand cubic metre of oil (in-place) per square kilometre drainage area, showing the spatial variation of the abundance of oil resource. The white polygon indicates the outline of the Viewfield pool's production.

Table 2. Distribution of in-place oil and gas resource estimations shown as different percentiles of probability and means of Unit A tight reservoir of the Middle Bakken in southeastern Saskatchewan. A wide range of distribution suggests large uncertainty in the resource estimates.

| Probability | 95% | 90% | 75% | 50% | 25% | 10% | 5% | Mean |
|---|---|---|---|---|---|---|---|---|
| Oil in-place, x$10^9$ $m^3$ | 1.11 | 1.37 | 1.88 | 2.54 | 3.28 | 3.98 | 4.48 | 2.63 |
| Oil in-place, x$10^9$ barrels | 6.99 | 8.65 | 11.84 | 15.95 | 20.66 | 25.06 | 28.18 | 16.57 |

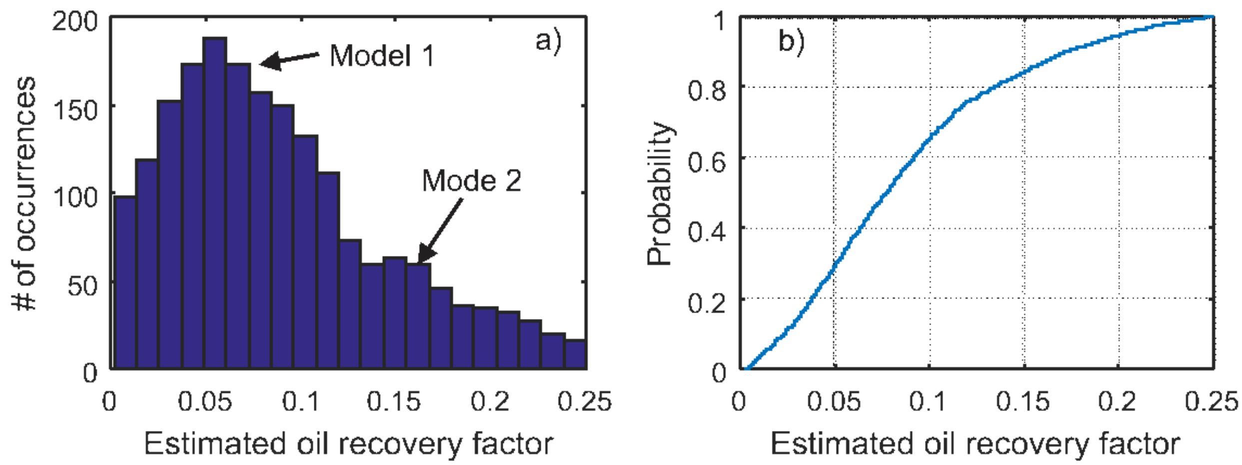


Figure 14. Histogram (a) and cumulative probability plot (b) of estimated recovery factor for the Middle Bakken Unit A tight reservoir, southeastern Saskatchewan.

A Monte Carlo simulation method is used to aggregate the recoverable resources at each cell of the study area to form a total resource endowment estimate for oil and associated gas, and to reveal the uncertainty associated with data interpolation and inferences. Figure 15 shows the histograms and cumulative distribution of the aggregated total initial recoverable oil and associated gas resources in Unit A and associated uncertainty ranges. Table 3 shows the variance in the probability of recoverable oil and gasoil. The mean value of total recoverable oil is 231.3 x $10^6$ $m^3$ (1454.6 x $10^6$ barrels) and the mean recoverable gas resource is 37.77 x $10^9$ $m^3$ (1333.8 billion cubic feet (BCF)) (Table 3). From Figures 15a to d and Table 3, we can see that there are large uncertainties in the resource estimates. For example, the estimated recoverable oil can vary from 56.4 x $10^6$ $m^3$ (0.354.5 x $10^6$ barrels) at a probability of 95% (P95) to 527.7 x $10^6$ $m^3$ (3318.9 x $10^6$ barrels) at a probability of 5% (P05), a magnitude of difference of almost 9 times. One important source of the uncertainties is the data coverage, as producing wells are concentrated in the Viewfield pool and only a few wells testing Unit A exist in areas beyond the Viewfield pool. Another reason may be related to the nature of oil accumulation in Unit A. The lack of distinctive features for identifying sweet spots prevents the statistical method from reducing the uncertainty more effectively.

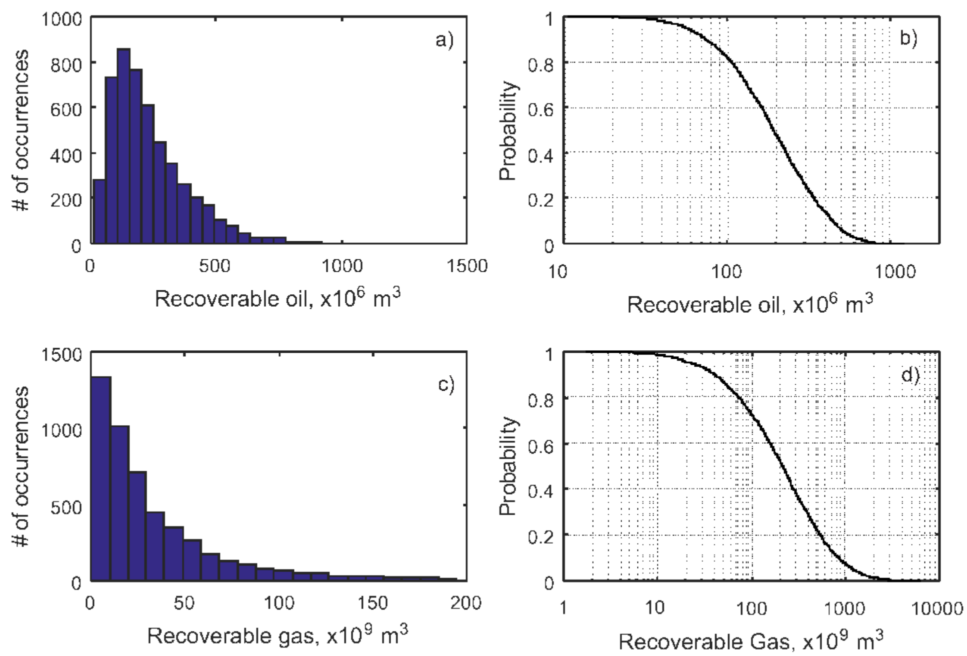


Figure 15. Histograms and cumulative distribution curves of estimated recoverable oil and associated gas endowment in the the Middle Bakken Unit A tight reservoir in southeastern Saskatchewan, from Monte Carlo simulation. a) Histogram of original recoverable oil, in billion barrels (Bbbls); b) cumulative distribution of original recoverable oil; c) histogram of recoverable associated gas in trillion cubic feet (TCF); and d) cumulative distribution of recoverable associated gas. Also see Table 3 for more percentiles.

The assessment results can be validated using production-derived EURs and available geological data. The current Viewfield pool covers an area near 2,500 km$^2$. For a fixed well density of 4 wells/section, it will require 3,860 wells to produce the recoverable oil resource. The cumulative oil production as of December 2014 from the Viewfield pool is 22.3 x 10$^6$ m$^3$ (0.14 x 10$^9$ barrels). With an average EUR of 87114 barrels/well, determined from modeling 2111 production wells in the Viewfield pool, the current production wells and additional infill drilling could produce 0.34 x 10$^9$ barrels of oil (54.1 x 10$^6$ m$^3$), which is very close to P95 of 0.3545 x 10$^9$ barrels (56.4 x 10$^6$ m$^3$) (Table 3). The risk evaluation suggests there is a 50% chance that the areal extent for an occurrence of recoverable oil resource could reach around 8200 km$^2$ in this study area. This gives an estimated total recoverable oil resource of 1.09 x 10$^9$ barrels (173.3 x 10$^6$ m$^3$), close to the median (P50) in Table 3 of 1.213 x 10$^9$ barrels (192.9 x 10$^6$ m$^3$). With 10%

probability, the areal extent of recoverable resource could be up to 17970 $km^2$. If we apply the same assumptions of well density and average EUR to the calculation, the recoverable oil resource could reach 2.4 x $10^9$ barrels (381.6 x $10^6$ $m^3$), which is close to the estimated P10 value of 2.792 x $10^9$ barrels (443.9 x $10^6$ $m^3$) in Table 3.

Table 3. Distributions of recoverable oil resource estimations shown as different percentiles and means of statistical distributions of Unit A tight reservoir of the Middle Bakken in southeastern Saskatchewan.

| Probability | 95% | 90% | 75% | 50% | 25% | 10% | 5% | Mean |
|---|---|---|---|---|---|---|---|---|
| Recoverable Oil, $10^6$ $m^3$ | 56.4 | 74.6 | 119.8 | 192.9 | 307.2 | 443.9 | 527.7 | 231.3 |
| Recoverable Gas, $10^9$ $m^3$ | 2.4 | 4.2 | 9.5 | 22.0 | 46.7 | 86.2 | 123.4 | 37.8 |
| Recoverable Oil, $10^6$ barrels | 354.5 | 469.3 | 753.4 | 1213.3 | 1932.3 | 2792.0 | 3318.9 | 1454.6 |
| Recoverable Gas, $10^9$ $ft^3$ (BCF) | 85.5 | 146.6 | 334.4 | 776.9 | 1647.4 | 3044.2 | 4356.1 | 1333.8 |

## *Comparison with other assessments*

In the *World Shale Oil and Gas Assessment* by EIA (2013), 3.59 x $10^9$ $m^3$ (22.6 x $10^9$ barrels) of risked oil in-place and 0.45 x $10^{12}$ $m^3$ (16 trillion cubic feet (TCF)) of in-place associated gas were estimated for the Middle Bakken Member of the Canadian Williston Basin. The risked technically recoverable oil is 0.25 x $10^9$ $m^3$ (1.6 x $10^9$ barrels) and gas is 62.3 x $10^9$ $m^3$ (2.2 TCF). In their report, the prospective area was estimated to be 14,000 $km^2$ (8700 $mi^2$) and the average resource density was 0.68 x $10^6$ $m^3$/section (4.3 x $10^6$ barrels /section). Compared to the EIA (2013) assessment, this study produced a more conservative estimate of the recoverable oil and associated gas resource endowments. However, a direct comparison may not be appropriate for two reasons. First, the economic assumptions for these two assessments are different: the EIA (2013) provides technically recoverable oil and gas resources while this study used a threshold of 3000 $m^3$/well (18,870 barrel/well) as an economic cut-off and no well with productivity less than 3000 $m^3$/well was considered. Secondly, the EIA (2013) assessment includes all the oil resources in the Middle Bakken Member as well as prospective areas in Manitoba, whereas this study assesses resource endowments in Unit A of the Middle Bakken in Saskatchewan only.

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