

Hydrocarbon Potential of Bakken and Torquay Formations, Southeastern Saskatchewan

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Abstract

Upper Devonian to Lower Mississippian Bakken Formation shales in the Williston Basin are rich source rocks that are believed to have generated and expelled at least 16 billion m³ (100 billion barrels) of light oil (~40° API), but only a small fraction of this Bakken-sourced oil has been identified in, or produced from, Williston Basin reservoirs. Over the past few years, multi-lateral horizontal well completions and large sand-fracture completions in low-permeability reservoirs have resulted in significant new Bakken production in the Williston Basin. Careful examination of cores, geophysical logs and production data indicates a high potential for further development through horizontal completions in low-permeability by-passed pay that typically shows low resistivity and in undiscovered reservoir sandstones of the Middle Member of the Bakken Formation in southeastern Saskatchewan.

In recent years, dolostones and dolarenites of the Upper Devonian Torquay Formation, underlying the Bakken Formation, have, for the first time, also proven to be productive along their subcrop edge in an area straddling the Saskatchewan-Manitoba border where, large land positions have been taken in pursuit of 40° API oil from the Torquay Formation at depths of less than 1100m.

Keywords: Bakken Formation, Torquay Formation, Late Devonian, Early Mississippian, southeastern Saskatchewan, Williston Basin, source rock, resistivity, by-passed pay, sandstones, dolostones.

1. Introduction

Upper Devonian to Lower Mississippian Bakken Formation shales in the Williston Basin are inferred to have generated and expelled at least 16 billion m³ of oil (100 billion barrels), but only a small fraction of this Bakken-sourced oil has been identified in, or produced from, Williston Basin reservoirs. Recently, horizontal drilling and large sand-fracture completions have resulted in significant Bakken production in Richland County, Montana. Careful examination of cores, geophysical logs and production data indicates a high potential for similar horizontal completions, by-passed pay and undiscovered oil in siltstones and sandstones of the Middle Member of the Bakken Formation and in weathered and brecciated dolostones of the Torquay Formation in southeastern Saskatchewan.

In Saskatchewan and Manitoba, production from the Bakken Formation has been restricted to the siltstone to sandstone Middle Member (Martiniuk, 1988; LeFever *et al.* 1991). In North Dakota, however, additional production was obtained from overlying and underlying Bakken shale members during the late 1980s to early 1990s. Some horizontal wells drilled

entirely within the Upper Member shale resulted in significant but highly variable production. Drilling problems, *e.g.*, well-bore collapse in naturally fractured shales, and the need to locate and intersect open-fracture systems appear to be the most important challenges for this play.

Recently, horizontal drilling has again become a favoured method for exploitation of the Bakken Formation but only within the conventional sandstone, siltstone, and limestone reservoir rocks of the Middle Member. This play began in 2001 in Richland County in eastern Montana within the Middle Member of the Bakken Formation. Here, it is common practice to drill one or two laterals that are subsequently subjected to sand/fractured completions with as much as 450,000 kg (1,000,000 lbs) of sand. The economic success of this play over the past few years has spurred a renewed interest in land acquisition and exploration of the Bakken eastward into McKenzie County and northward into Divide County, North Dakota, and the Estevan area of southeastern Saskatchewan. Bison Resources Ltd. announced, in the March 30th 2005 issue of Nickle's Daily Oil Bulletin, its intention to

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develop the Bakken Formation in the Viewfield area, Saskatchewan, using multi-lateral completions.

In recent years, dolostones and dolarenites of the Upper Devonian Torquay Formation, underlying the Bakken Formation, have, for the first time, also proven to be productive in Saskatchewan in a region along the Saskatchewan-Manitoba boundary.

2. General Stratigraphy

The Bakken Formation is present over a large portion of southeastern Saskatchewan and ranges in thickness from zero to 30 m (Figure 1), but is locally over 70 m thick when associated with salt collapse structures. It is subdivided into three members characterized by a middle siltstone to sandstone unit sandwiched between black organic-rich shales. In southeastern Saskatchewan, the Late Devonian to Early Mississippian Bakken Formation is conformably overlain by grey, fossiliferous limestones of the Souris Valley (Lodgepole) Formation of Mississippian (Kinderhookian) age (Smith and Bustin, 2000). The Bakken Formation conformably overlies greenish grey shales of the Big Valley Formation in much of southeastern Saskatchewan. Where Bakken overlaps the Big Valley, it unconformably overlies interbedded weathered dolostones, dolarenites, dolomitic mudstones and minor anhydrites of the Upper Devonian Torquay Formation (Christopher, 1961).

3. Detailed Stratigraphy

a) Lower Member, Bakken Formation

In southeastern Saskatchewan, the Lower Member of the Bakken Formation ranges in thickness from zero in the northern and southeastern portions of the map area to a maximum of 18 m in the south (Figure 2). Locally, anomalously thick (up to 26 m) Lower Bakken shale is found in areas of known salt dissolution (*e.g.*, 15-5-1-8W2). The rock is characteristically dark grey to dark brownish-black to black, fissile, non-calcareous, and organic-rich shale. It can be hard or soft, and commonly has a “wax-like” feel to the touch suggesting that it is rich in organics. Pyrite nodules, disseminated pyrite and pyritic lenses are common in some cores. Fractures are generally parallel to bedding planes giving the shale a “poker chip” appearance but can also be conchoidal and blocky. In some areas, high-angle slickensided fractures are observed suggesting local tectonism. Sometimes these fractures appear to be open while others are lined with minerals like pyrite, calcite and anhydrite.

Fossils found in Saskatchewan cores include conodonts, chonetid brachiopods, algal plant spores and woody plant fragments (Fuller, 1956; Christopher, 1961; Karma, 1991).

As previously mentioned, the Bakken laps over the Big Valley Formation in southeastern Saskatchewan and lies unconformably upon the Torquay Formation (Figure 3). Christopher (1961) cites the presence of deep, infilled fissures within the top of the Lower Bakken shale as evidence for widespread desiccation, and therefore of a major hiatus, prior to deposition of overlying sediments that now make up the Middle Member of the Bakken Formation.

b) Middle Member, Bakken Formation

In southeastern Saskatchewan, the Middle Member of the Bakken Formation ranges in thickness from zero in the north to a regional maximum of 25 m in the south (Figure 4). Like the Lower Member of the Bakken Formation, the Middle Member is anomalously thick (up to 44 m) in areas of known salt dissolution (*e.g.*, 15-5-1-8W2). The Middle Member isopach map shows obvious thickening towards a depositional centre in northwest North Dakota and northeastern Montana. Christopher (1961) referred to the thickened area in the western portion of the map as part of the Elbow Sub-Basin, a region in which he attributed thickening of the Middle Member to contemporaneous dissolution of salt in the Prairie Formation.

The area of relatively thin Middle Member centred around Township 18, Range 23W2, was named the Regina-Melville Platform (Christopher, 1961). Another area of anomalously thin Middle Member is present in the extreme southeastern corner of the map area, and will be discussed later with regard to the Torquay Formation oil play.

Another noteworthy feature of the Middle Member isopach map is the thickened zone that extends from the Rocanville Pool southwestward to the Torquay embayment. This northeast-southwest trend is coincident with a similar trend described by Christopher (1961) called the Rocanville-Torquay trend, about which he suggested: “...this trend consists of a band of northeasterly aligned furrows into which the study beds are downwarped”. He noted that salt sinks in the Rocanville, Wapella and Kisbey pools, and oil shows and oil production in both Bakken and older rocks were aligned along this trend. Examination of cores and geophysical logs in the present study suggests that sandstones developed along this trend are potential migration conduits for Bakken-sourced oil into the Rocanville region.

For discussion purposes, the authors have subdivided the Middle Member of the Bakken into the following informal units (bottom to top): A, A1, B, and C (Figure 5). Cross section A-A' shows the regional correlation of the Bakken Formation and its subunits from its depocentre northeast to the Rocanville Pool.

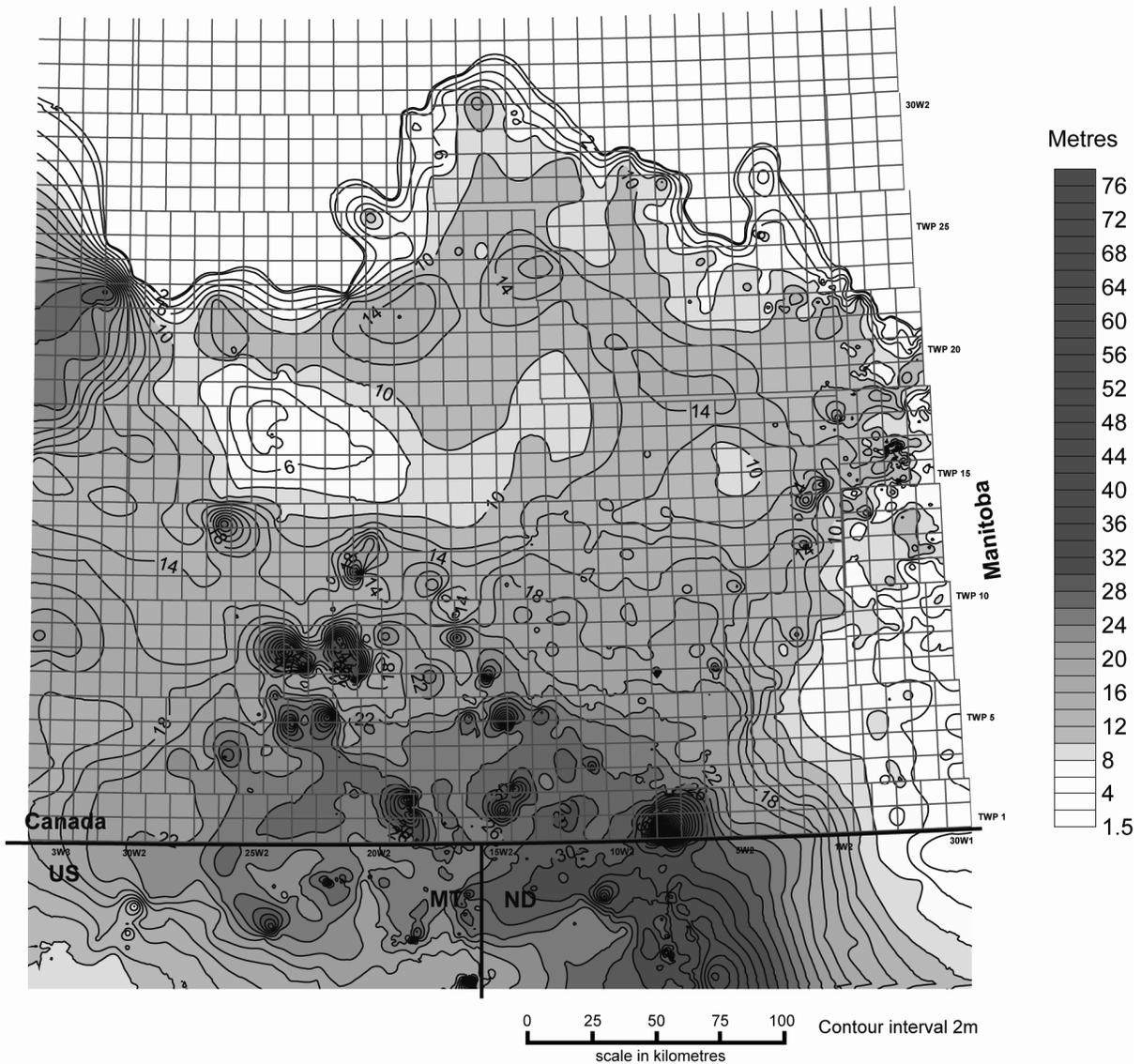


Figure 1 - Computer-generated isopach map of the Bakken Formation.

Unit A

Unit A unconformably overlies the Lower Bakken shale (Christopher, 1961). It is a massive, medium grey to dark greenish grey, calcareous, argillaceous, pyritiferous, fossiliferous siltstone. Calcite brachiopod shells are common. Unit A records the initial transgression of the Middle Member sea with deposition of silt and clay in a quiet-water environment that favoured preservation of abundant brachiopods. This unit shows little to no oil-reservoir potential in all cores observed in this study.

Unit A1

Unit A1 is in gradational contact with the underlying unit A. The lithological differences between A and A1 are often subtle. The present authors have attempted to break A1 out from unit A in an effort to draw attention to the fact that unit A can coarsen up into slightly coarser sandstones near the top of the sequence that become reservoir-quality rocks in areas like the Hummingbird, Viewfield and, possibly, Rocanville pools.

In southern portions of the study area, unit A1 is generally a light greenish grey to dark greenish grey argillaceous siltstone to silty, argillaceous, very fine-grained quartzose sandstone. Sedimentary structures

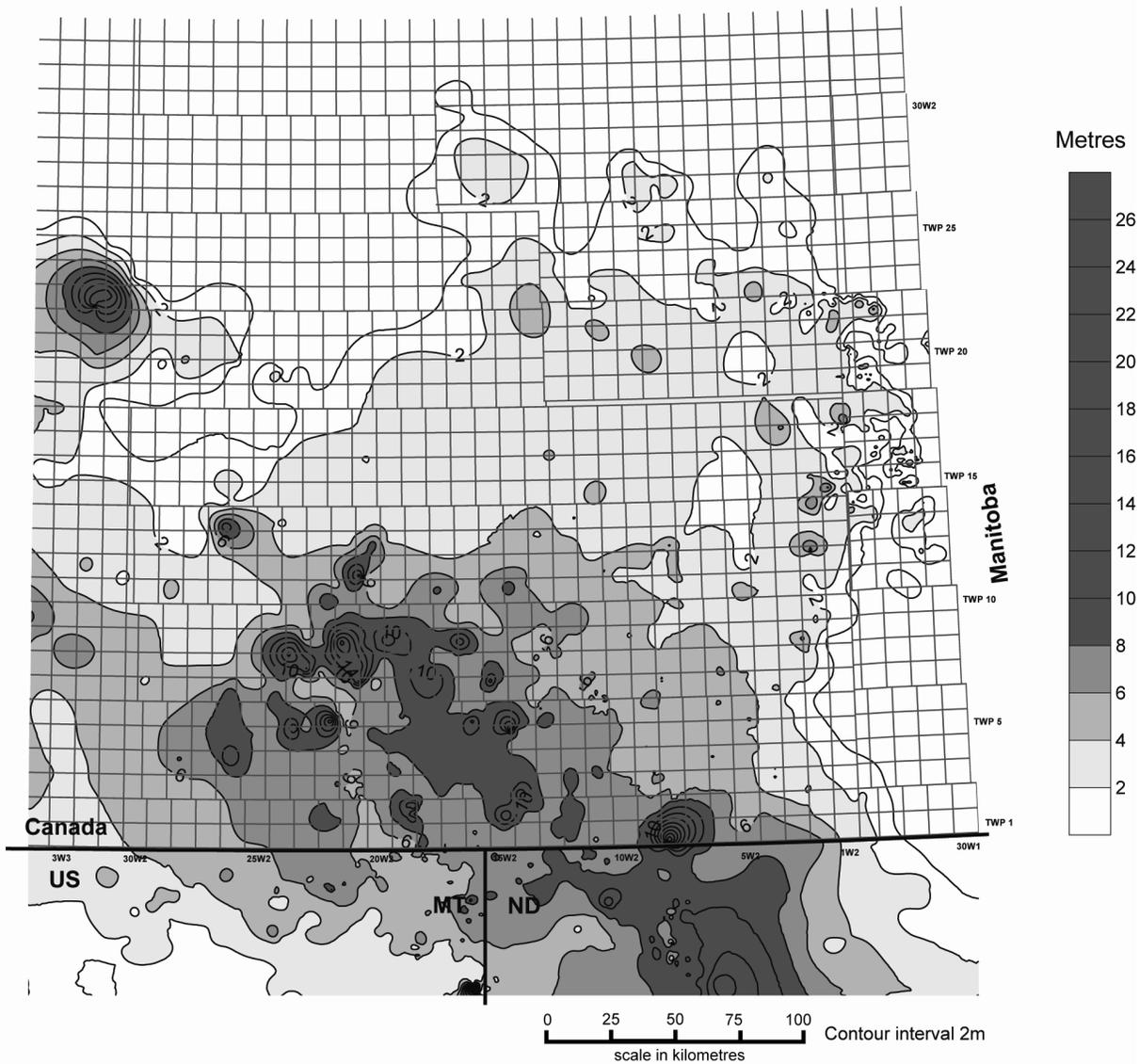


Figure 2 - Computer-generated isopach map of the Lower Member of the Bakken Formation.

are diverse, but the unit is generally characterized by a sequence of moderately to highly bioturbated, wispy laminated siltstones interbedded with very silty and argillaceous very fine-grained sandstones. In some localities, the sandstones are less argillaceous and sedimentary structures such as flaser bedding, current ripples and low-angle laminations suggest deposition in higher energy environments that may be found in a shallow-shelf or near-shore setting that was tidally influenced. Reservoir quality in these sandstones can be very good and light brown oil-stained, flaser-bedded sandstones are observed near the top of unit A1 in the 14-1-2-19W2 well in the Hummingbird South Pool (Figure 6). The best Bakken producer in the area (3-26-2-19W2) has yielded over 71,000 m³ oil in its first 17 years of production. A one-metre thick, very porous interval is noted at the top of unit A1 (pick based upon

geophysical-log signatures; a core was not taken in this well, so details of the lithology and sedimentary structures are speculative).

Regionally, unit A1 appears to become increasingly less argillaceous to the north and east toward the Viewfield and Rocanville areas (Figure 7). This is interpreted to represent deposition in slightly more littoral and higher energy depositional settings than are indicated in unit A1 to the south and west. The correlation in cross-section A-A' suggests that some of the lowermost productive sandstones in the Rocanville Pool might be unit A1 facies equivalents although this correlation is uncertain (Figure 7).

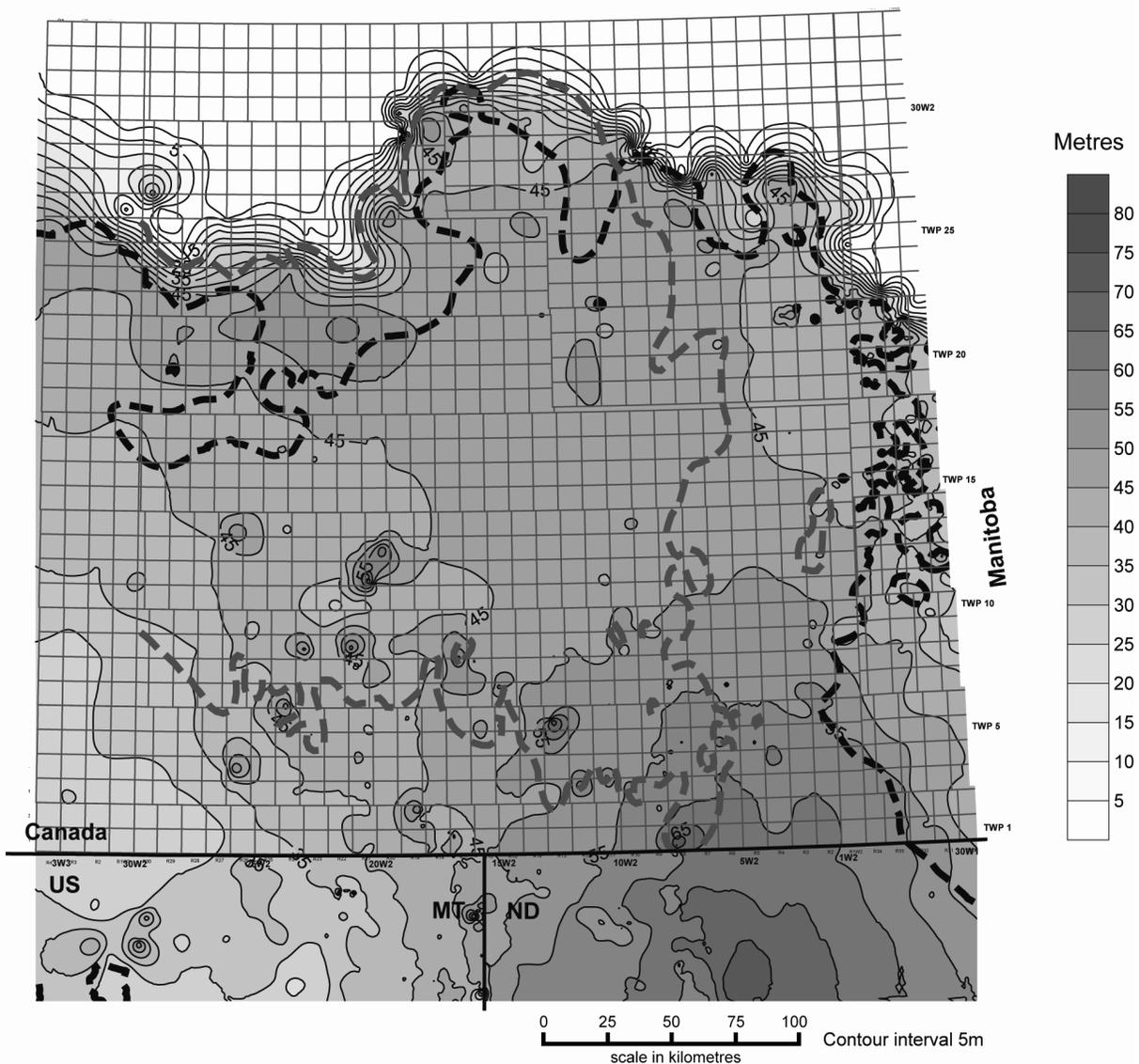


Figure 3 - Computer-generated isopach map of the Torquay Formation, also showing Lower Bakken zero edge (black dashed line) and Big Valley zero edge (grey dashed line).

In the Viewfield area, most of the light oil (40° API) appears to be reservoired in uppermost unit A1 sandstones as there appears to be only a thin (~1 to 3 m thick) interval of unit B sandstone overlying unit A1 here. These sandstone reservoirs are typically silty, argillaceous and very fine grained (Figure 8). Porosities generally range from 10 to 15% while permeabilities are rarely greater than 1 to 2 millidarcies. Resistivity values are characteristically low (*i.e.*, usually <4 ohms).

Unit B

Unit B disconformably overlies unit A1. In most cores the contact is sharp and erosive and is interpreted to

represent a low-stand in deposition at the end of unit A1 time. Unit B is typically made up of light to medium grey, dolomite- and calcite-cemented, very fine- to fine-grained, clear quartz sandstone to oolitic calcarenite. Sedimentary structures are diverse. The lower portion of this unit is commonly massive but in places shows cross bedding with dips measuring up to 15°. The upper portion of this unit is generally overlain by thinly laminated, silty and argillaceous, very fine-grained sandstones that grade up into interbedded and bioturbated, argillaceous siltstones and silty, very fine-grained sandstones of unit C.

Reservoir quality in unit B is highly variable. In the Rocanville Pool, sandstones in some wells exhibit excellent reservoir characteristics. Locally, sandstones

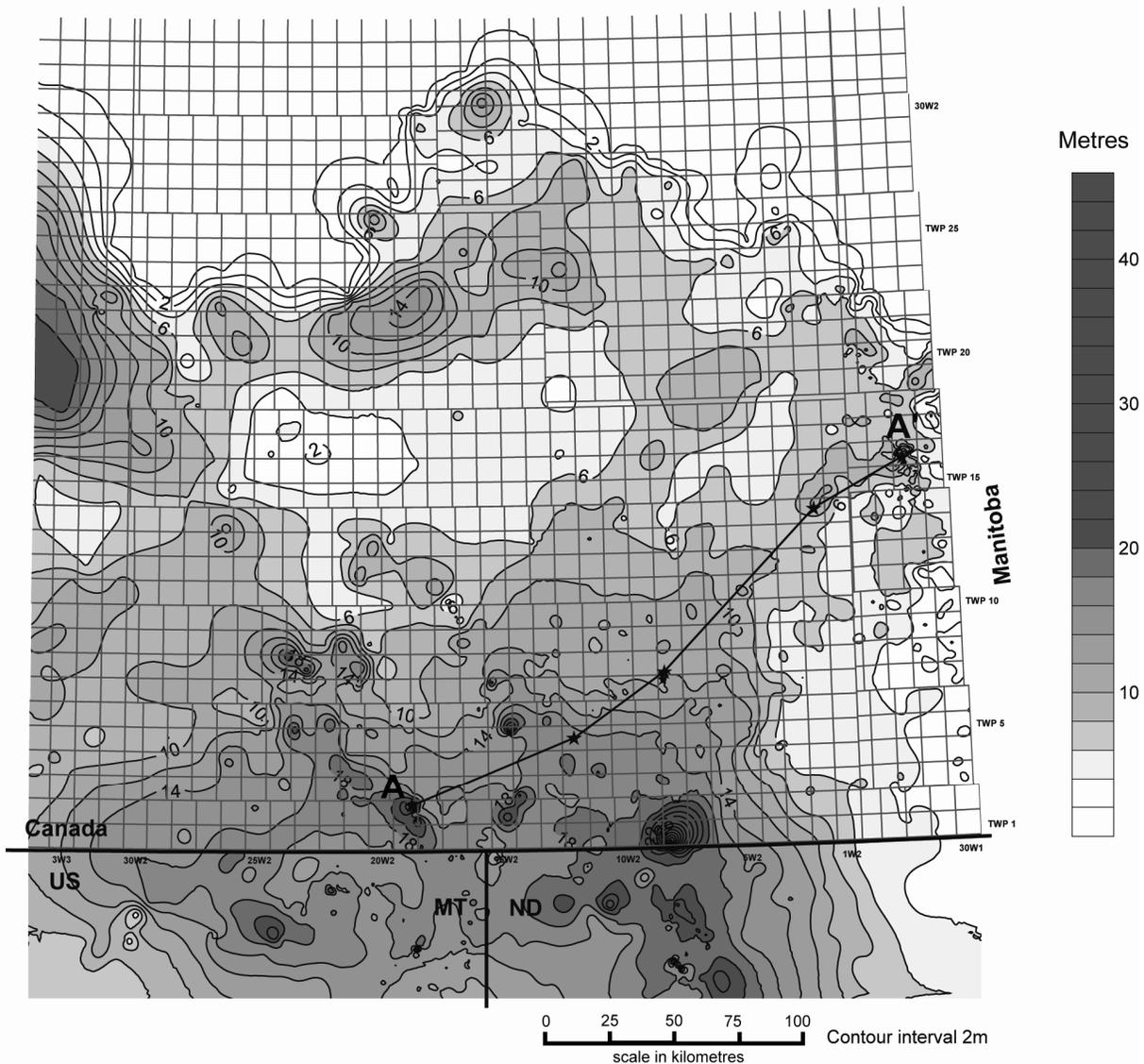


Figure 4 - Computer-generated isopach map of the Middle Member of the Bakken Formation.

coarsen to fine and medium grain size and dolomite- and calcite-cements are less prevalent. Porosities are commonly between 15 and 25%, and permeabilities range from 10s to 100s of millidarcies (Figure 9). The Transwest Rocanville 8-5-16-31W1 well has produced more than 95,000 m³ (599,000 bls) oil from a vertical well over 44 years and an additional 58,000 m³ (366,000 bls) from a horizontal well at the same location between 1993 and the end of 2004.

Historically, exploration companies have targeted “clean” (*i.e.*, relatively free of argillaceous content) unit B sandstones with relatively high geophysical-log resistivities as their primary reservoir in southern areas proximal to the U.S. border. However, perforated intervals of high resistivity are commonly dolomite- and calcite-cemented sandstone with moderate to poor

reservoir characteristics. Careful examination of numerous cores in this study has shown that, where present, the “dirtier” (*i.e.*, more silty and argillaceous) sandstone immediately overlying the calcite-cemented lower portion of unit B often shows a faint oil stain that produces a strong milk-white cut but gives a very low resistivity on geophysical logs (*i.e.*, 1.5 to 3 ohms).

When completing the calcite-cemented portion of the unit B reservoir, companies have regularly fractured and sometimes acidized the interval in an effort to enhance production but have often ignored the immediately overlying, non-calcite-cemented “dirty” sandstone. A good example of this occurs in the 15-31-3-11W2 well where the calcite-cemented portion of unit B was perforated and produced over 7,300 m³ (45,800 bls) of oil. Non-cemented rock immediately

overlying this interval was not perforated (Figure 10). Resistivity values over this upper interval are only a few ohms but a faint oil stain and strong milk-white cuts were observed.

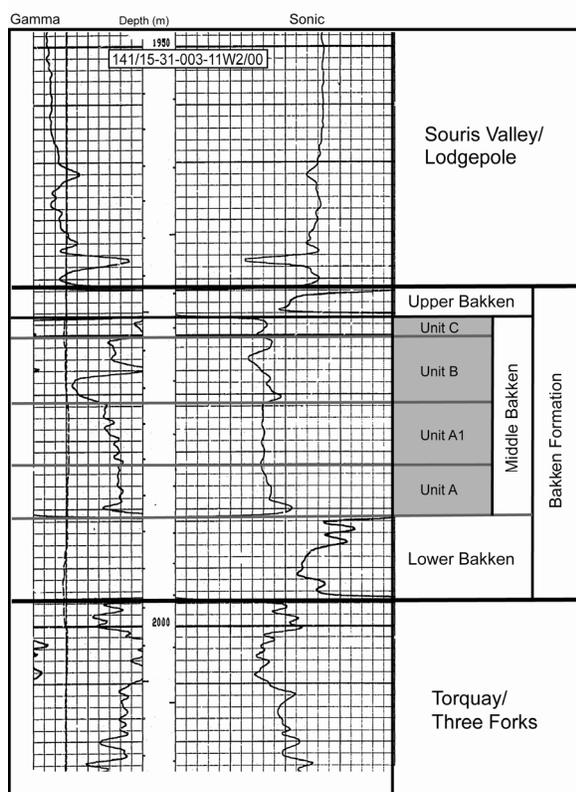


Figure 5 - Sonic log showing informal Middle Bakken subdivisions used in this paper.

Unit C

The basal metre or so of unit C is characterized by a widespread marker bed (Figure 11) made up of interbedded siltstones and sandstones distinguished by bioturbated beds of light grey to tan (*i.e.*, cleaner), silty, very fine-grained sandstones and argillaceous siltstones. Contacts are gradational with both the underlying unit B and the overlying massive to wispy laminated, medium grey to light grey calcareous and argillaceous siltstones of unit C. From log correlation, it appears that the marker bed may have undergone a facies change into laminated and/or massive sandstones in the Rocanville area, and may be effective reservoir rock in some wells (Figure 7).

c) Upper Member, Bakken Formation

Shales of the Upper Bakken range in thickness from zero in the north to a maximum of 8.6 m in the south (Figure 12). The Upper Member conformably overlies the Middle Member (Christopher, 1961). It is lithologically similar to the Lower Member shale (Christopher, 1961; Webster, 1982; Hayes, 1984; Smith and Bustin, 2000). Christopher (1961) reported

that conodonts and chonetid brachiopods were more abundant in the Upper Member shale than in the Lower Member shale.



Figure 6 - A) Flaser bedding near the top of unit A1 (*i.e.* approximately 2264.0-2265.0m) in the Northrock et al Hummingbird 14-1-2-19 well at 14-1-2-19W2; note light brown oil staining in clean sandstone within ripples. B) Close-up of light brown, oil-stained flaser-bedded sandstone (wetted surface).

A striking exception to the dark colours typical of Bakken shales is noted in a core from the 14-16-18-30W1 well where the Upper Member shows variegated colours ranging from reddish brown to purple (Figure 13). This colouration is attributed to relatively thin overlying Souris Valley Beds that resulted in the exposure of the shales to meteoric waters percolating down from the overlying Mississippian erosional surface. Vertical fractures are interpreted to be the result of local collapse tectonics due to karstification of the underlying Duperow Formation (Halabura *et al.*, 2002).

d) Torquay Formation

The Torquay Formation is unconformably overlain by the Big Valley and Bakken formations in southeastern Saskatchewan (Figure 3), where it ranges in thickness from zero in the north to a maximum of 76 m in the south (*e.g.*, 15-5-1-8W2).

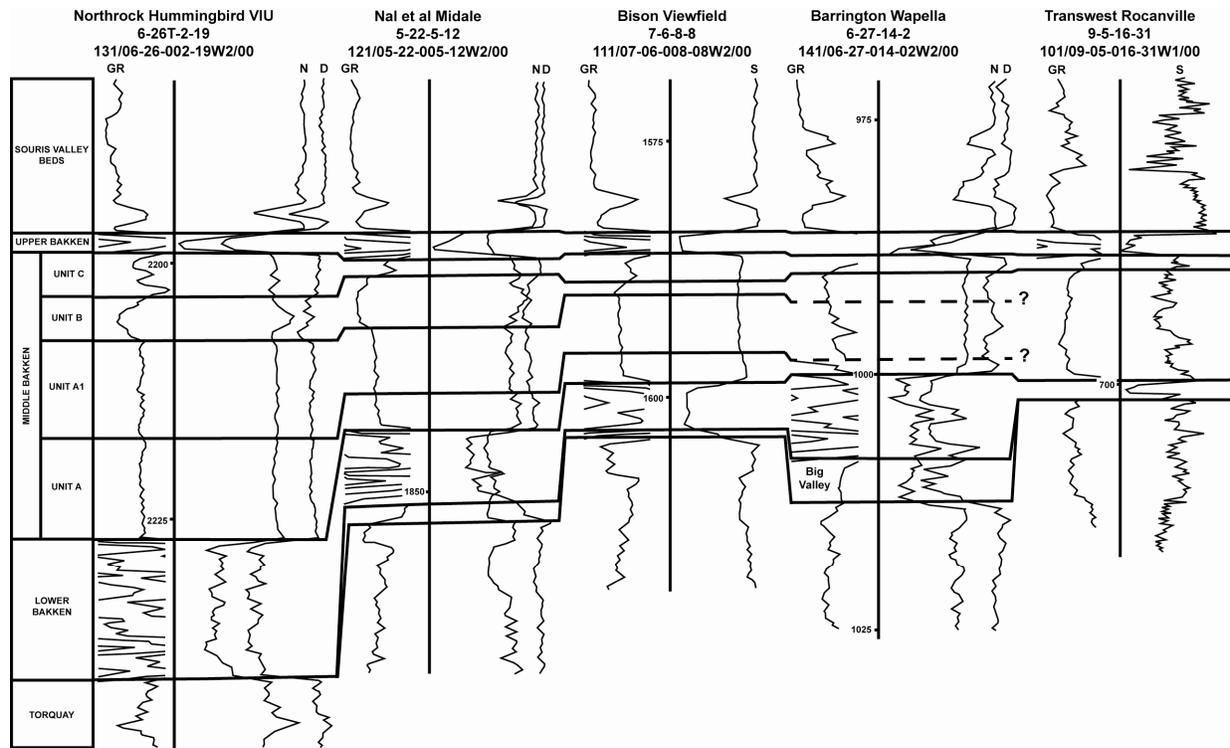


Figure 7 - Southwest-northeast cross-section A-A' (see Figure 4 for cross-section location).

It is a sequence of interbedded dolostone, dolarenite, dolomitic mudstones and siltstones, and lesser amounts of anhydrite. Dolostone colours range from light to medium grey to tan and medium reddish brown for the dolostones. Mudstone and siltstone colours range from medium greenish grey to bright green to dark reddish brown, and those of anhydrite from a dark brownish grey to white (Christopher, 1961). Christopher reported abundant evidence for intraformational weathering with well developed soil horizons and widespread brecciation. He interpreted brecciation of bedding in dolostones to be the result of leaching and collapse early in the weathering process, and the relative lack of anhydrite in the eastern portion of southeastern Saskatchewan to be indicative of greater weathering in this area. Christopher also noted a progressive truncation of the upper units of the Torquay Formation in the region east of the zero limit of the Lower Bakken into Manitoba. The present authors recognize thinning of the Torquay Formation in this area and interpret it to be in part depositional and in part erosional in origin. This area is interpreted to have been a region of uplift prior to Bakken deposition. Thinning and onlap of the Bakken are recognized in the eastern portion of cross section A-A' (Figure 7) and are inferred by the pronounced Bakken thinning in an area paralleling the Saskatchewan–Manitoba border (Figure 1). Christopher (2003) also noted a belt of uplift along the Saskatchewan–Manitoba boundary and named it the Moosomin–Hudson Bay structural belt, which he viewed as the western limit of a broad structural feature in Manitoba, the Birdtail–Waskada Axis (McCabe, 1959).

We also recognize a greater degree of weathering in the southeastern portion of the study area along the Saskatchewan–Manitoba border. Uplift appears to have played a role in the regional accumulation of oil within subcropping beds of unit 4 (as defined by Christopher, 1961) of the Torquay Formation. Here, the reservoir characteristics of dolostones of unit 4 appear to have been favourably enhanced by subaerial exposure at their subcrop especially when compared with the petrophysical properties of non-subcropping, equivalent unit 4 dolostones to the west. Improved primary reservoir development here may also be due to a shallower and higher energy depositional setting. For example, well developed ripple-bedded dolarenite is common in Torquay Formation cores from the Rocanville Pool area (e.g., 8-5-16-31W1). Another critical element to this accumulation is the onlapping relationship of the overlying Middle Member of the Bakken Formation. In areas where the Lower Bakken shale is absent and the Middle Bakken is porous and permeable, it is possible that underlying dolostones of the Torquay Formation were charged with light Bakken-sourced oil that migrated from a hydrocarbon-generation 'kitchen' to the south and west (Figure 14). The upper seal for this accumulation appears to be tight siltstones of unit C and the Upper Bakken shale that overlie unit 4 at its subcrop. The lower seal appears to be underlying well developed, oxidized, reddish brown siltstones and mudstones of unit 3 of Christopher (1961). Over the past several years, large tracts of land have been taken in Townships 7 to 10 and Ranges 30 to 32W1 in pursuit of the unit 4 subcrop play in southeastern Saskatchewan at depths of less than 1100 m.

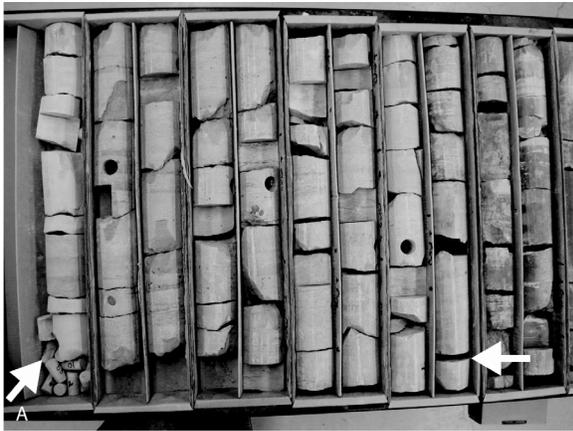


Figure 8 - A) Silty, argillaceous, very fine-grained quartz sandstone reservoir rock of units A1 and B between arrows (i.e. 1589.0-1594.4m) in the 7-6-8-8W2 well; note that oil staining is a pale light brown and almost invisible to the naked eye. B) Close-up of unit A1 reservoir rock; note the presence of large pyrite nodules and pyrite-rich interlamination.

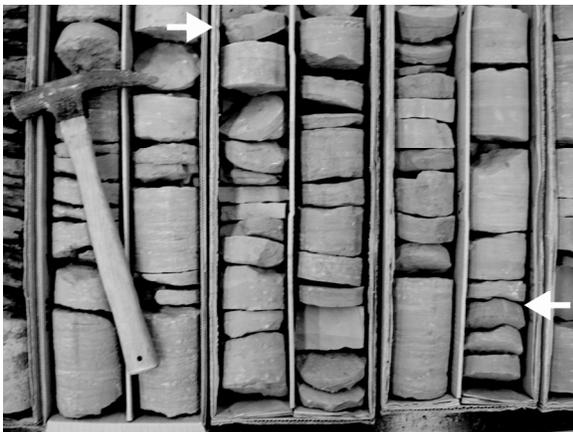


Figure 9 - Oil staining in a fine- to medium-grained sandstone of the Middle Member of the Bakken Formation at Rocanville Pool in 8-5-16-31W1. Light brown oil staining is most prevalent between approximately 692.5-695.0m (i.e. interval between arrows).

The Torquay Formation in the inferred area of uplift exhibits reservoir-quality brecciated dolostones that show moderate to good porosity on sonic, density and neutron logs. The first two Torquay producers in Saskatchewan came from 8-35-6-30W1 and 12-36-6-30W1. These wells were vertical completions and each produced approximately 3,180 m³ (20,000 bls) of oil in the three years up to the end of 2004. Here, the Middle Member sandstone is generally less than 3 m thick. We consider that the heterogeneous distribution of these brecciated dolostones lends itself to exploration and development using horizontal completions. It should be noted that reservoir-quality dolostones giving streaming milk-white oil cuts under fluorescence have been observed in Torquay Formation cores from 1-30W1 to 22-1W2.

4. Low Resistivity Pay

Worthington (2000) discusses factors controlling low-resistivity pay zones citing numerous examples from around the world. He indicates that the low-resistivity pay problem is focused upon the inability to accurately evaluate water saturations from a resistivity log in certain circumstances. He suggests that this problem is most common in reservoirs displaying one or more of the following characteristics: laminated sandstones and shales, fresh waters, conductive minerals, fine-grained sandstones and microporosity. Careful examination of core in this study suggests that Middle Member reservoirs often show many of these characteristics. The Middle Member sandstone is commonly silty, argillaceous, very fine grained and interlaminated, and locally contains an abundance of the conductive mineral pyrite (commonly >5%). For these reasons, considerable care must be taken in evaluating the prospectivity of a Middle Member reservoir from geophysical logs. Low-resistivity readings (i.e., <5 ohms) are often observed in the producing intervals of the Middle Bakken, which are made up of rocks like those described above. For example, a core from an oil-producing Middle Member sandstone in the 7-6-8-8W2 well of the Viewfield Pool shows a very silty, argillaceous, weakly interlaminated to massive, very fine-grained quartz sandstone with abundant pyrite over the perforated interval (Figure 8). Over most of this interval, a faint, light brown oil stain is present, yet resistivity values range from only 3.4 to a maximum of 4.7 ohms. Daily oil production reported from this vertical well is 3.03 m³ (19.1 bls) in its first 8 months. Another well at 2-6-8-8W2 reported a daily average production of 3.62 m³ (22.75 bls/d) from an interval showing <4 ohms resistivity. This well has a cumulative fluid production of 965 m³ (6,075 bls) oil and 824 m³ (5,184 bls) water in its first nine months of production.

5. Bakken Formation Production History

Production and shows are widespread throughout the Bakken Formation in southeastern Saskatchewan (see Figure 9 in Kreis *et al.*, 2005).

The first Bakken discovery in southeastern Saskatchewan was in 1956 from the Middle Member sandstone in the Barnwell Roncott 09-34-005-25W2 well in the Roncott Pool. This well produced 33,907 m³ (212,936 bls) of oil between 1956 and 1990. The second Bakken oil discovery in southeastern Saskatchewan was in 1957 from the Middle Member sandstone in the Riddle TW Rocanville 16-32-015-31W1 well in the Rocanville Pool. This well produced 1,555 m³ (9,765 bls) of oil between 1957 and 1966.

Table 1 shows the specific gravity of Bakken oils and the API equivalent values for some of the pools in southeastern Saskatchewan. Note that the Welwyn and Welwyn South pools and, to a lesser degree, the Rocanville Pool, have a slightly lower gravity oil. The variations in oil gravity are not understood but biodegradation is a possible cause. The molecular composition of Bakken oils does not, however, exhibit much internal variation (Pasadakis *et al.*, 2004) nor standard indicators of biodegradation (Osadetz *et al.*, 1992; Obermayer *et al.*, 2000).

| Pool | Specific Gravity (g/cm ³) | °API |
|-------------------|---------------------------------------|------|
| Ceylon | 0.825 | 40.0 |
| Hummingbird | 0.825 | 40.0 |
| Hummingbird South | 0.825 | 40.0 |
| Rocanville | 0.843 | 36.3 |
| Roncott | 0.823 | 40.4 |
| Welwyn | 0.888 | 27.8 |
| Welwyn South | 0.841 | 36.7 |

Table 1 - Specific Gravity for selected Bakken pools in southeastern Saskatchewan.

Other pools and areas of miscellaneous Bakken production have been discovered since the Roncott and Rocanville pools. To December, 2004, the total oil production from the Middle Member in southeastern Saskatchewan was 1,278,750 m³ (8,030,550 bls) from 159 wells of which 11 were horizontal. Some 123,379 m³ (774,820 bls) oil ahead been produced from the Roncott Pool and 774,034 m³ (4,860,940 bls) from the Rocanville Pool. Hummingbird Pool production was 183,194 m³ (1,150,458 bls) oil. Together, these three pools accounted for more than 85% of the total Bakken production in southeastern Saskatchewan. The two most productive wells were Transwest Rocanville 08-05-016-31W1 with 95,318 m³ (599,000 bls) and Northrock Hummingbird 03-26-002-19W2 with 71,393 m³ (448,350 bls). In 1992, a horizontal well was also drilled at 191/08-05-016-31W1 and produced an additional 58,323 m³ (366,200 bls) of oil. It was the fourth most productive Bakken well in southeastern Saskatchewan. The third most prolific Bakken producer was the Transwest Rocanville 10-5-016-31W1 well drilled in 1960, which yielded 68,828 m³

(432,240 bls) and was still producing. Together, these four wells were responsible for 23% of the total Bakken Formation production in southeastern Saskatchewan.

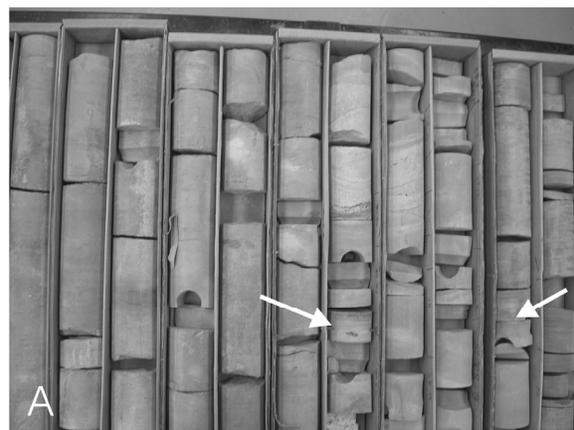


Figure 10 - A) Contact between units A1 and B in well 15-31-3-11W2 at approximately 1980.4m (arrow on left); the interval between the arrow at the contact and the arrow on the right (approximately 1978.4-1980.3m) comprises interbeds of oolitic limestone and extensively calcite-cemented, very fine-grained sandstone; the overlying unit is a silty, argillaceous, laminated noncemented sandstone. B) close-up view of the overlying wispy-laminated sandstone.

In recent years, exploration activity for Bakken Formation production in southeastern Saskatchewan has focused upon two regions, the first defined by Twps 6 to 8, Rges 6 to 11W2, and the second by Twps 1 and 2, Rges 9 and 10W2. Over the 14-month period from October 2003 to December 2004, the number of producing wells in the Bakken rose from 8 to 28, increasing the monthly production from 232 m³ (1,457 bls) to 3,252 m³ (20,423 bls). This upswing in Bakken drilling and production is readily visible on the line graph in Figure 15.



Figure 11 - Bioturbated and interbedded sandstone and siltstone of a widespread marker unit at the base of unit C (centred around approximately 1942.0m) in the 15-10-6-19W2 well in the Ceylon Pool.

6. Bakken Formation Source-Rock And Hydrocarbon Potential

a) Source-Rock Potential

Although the depositional environment has been much debated (see LeFever *et al.*, 1991 for a review), the presence of normal-marine planktonic faunas and an impoverished benthic fauna as well as stratigraphic and sedimentological evidence suggest that the Bakken shales were deposited in poorly oxygenated, marine-shelf environments. The abundance of organic carbon characteristic of these shales has commonly led to the interpretation that their depositional environment included a layered water column and strongly anoxic bottom conditions. While there is significant sedimentological indication of a layered water column, the presence of strongly anoxic bottom water layers is not suggested by the composition of resulting oils and source-rock solvent extracts (Osadetz *et al.*, 1992), although some samples examined by Leenheer (1984) provide evidence that a persistent anoxic bottom layer may have been present in Alberta.

Some important, early source-rock studies were performed in the U.S. part of the Williston Basin. Williams (1974) observed the compositional similarity between three major oil types and solvent extracts from stratigraphically close-lying, potential source rocks.

From this observation, he identified the likely sources for each oil type. Most subsequent studies elaborated on the oil-source associations suggested by Williams (1974) and Dow (1974), with a strong focus on the Bakken Formation, primarily because of the importance attributed to it by both Williams and Dow (Dembicki and Pirkle, 1985; Price *et al.*, 1984; Leenheer, 1984; Webster, 1984; Schmoker and Hester, 1983; Meissner, 1978). Price *et al.* (1984) studied the Bakken Formation throughout the U.S. portion of the Williston Basin. They distinguished two different facies but could not chemically discriminate between the two shale members. The two facies follow distance from the formation's edge and reflected kerogen and source petroleum generation potential variations controlled by the paleogeographic setting. Leenheer (1984) characterized Williston Basin Bakken and Alberta Basin Exshaw solvent extracts, while Thode (1981) studied sulphur isotope compositions of Bakken extracts and concluded that only the lower shale was an effective source for oils (*cf.* Williams, 1974).

In Canada, the petroleum potential and thermal maturity of Bakken Formation lithologies have been extensively studied (Osadetz *et al.*, 1992, 1994; Caplan and Bustin, 1996; Stasiuk and Fowler, 2004). The connection between source-rock potential and lithology was found to be strong, such that shales with colours other than black and brown which were sampled were generally found to have little or no TOC and thus little or no potential to generate hydrocarbons. Current sample depth roughly reflects distance from paleoshoreline during deposition, and Christopher (1961) clearly indicated changes in facies and shale colour reflect depositional setting. Potential sources are generally restricted to black shale lithologies. Green, red and maroon lithologies in northern and eastern areas do not have significant hydrocarbon potential (HC), neither do carbonaceous partings that occur within the coarser Middle Member. Comparison with the work of Christopher (1961) indicates lithological distributions and colour variations generally coincide with source-rock richness.

Black Upper and Lower Member shales are the richest, most widespread source rocks. Thirty-one Canadian samples from the Lower Member shale have an average total organic carbon (TOC) value of 11.77% and average total petroleum potential of 61.4 kg/t. Twenty-nine Canadian samples from the Upper Member shale have average TOC of 17.63% and average TPP of 93.72 kg/t. Both members exhibit a strong linear relationship between TPP and TOC. For the Lower Member shale, $TTP = 5.87 \times (TOC) - 7.66$, whereas for the Upper Member shale $TTP = 5.63 \times (TOC) - 5.69$. The 30 richest samples from both shales have an average TOC of 18.71% and a TPP of $6.15 \times (TOC) + 1.68$. Considering the great volume of Bakken Formation shales, their total petroleum potential is remarkable and consistent with other estimates (Dembicki and Pirkle, 1985; Price *et al.*, 1984; Leenheer, 1984; Webster, 1984; Schmoker and Hester, 1983; Meissner, 1978).

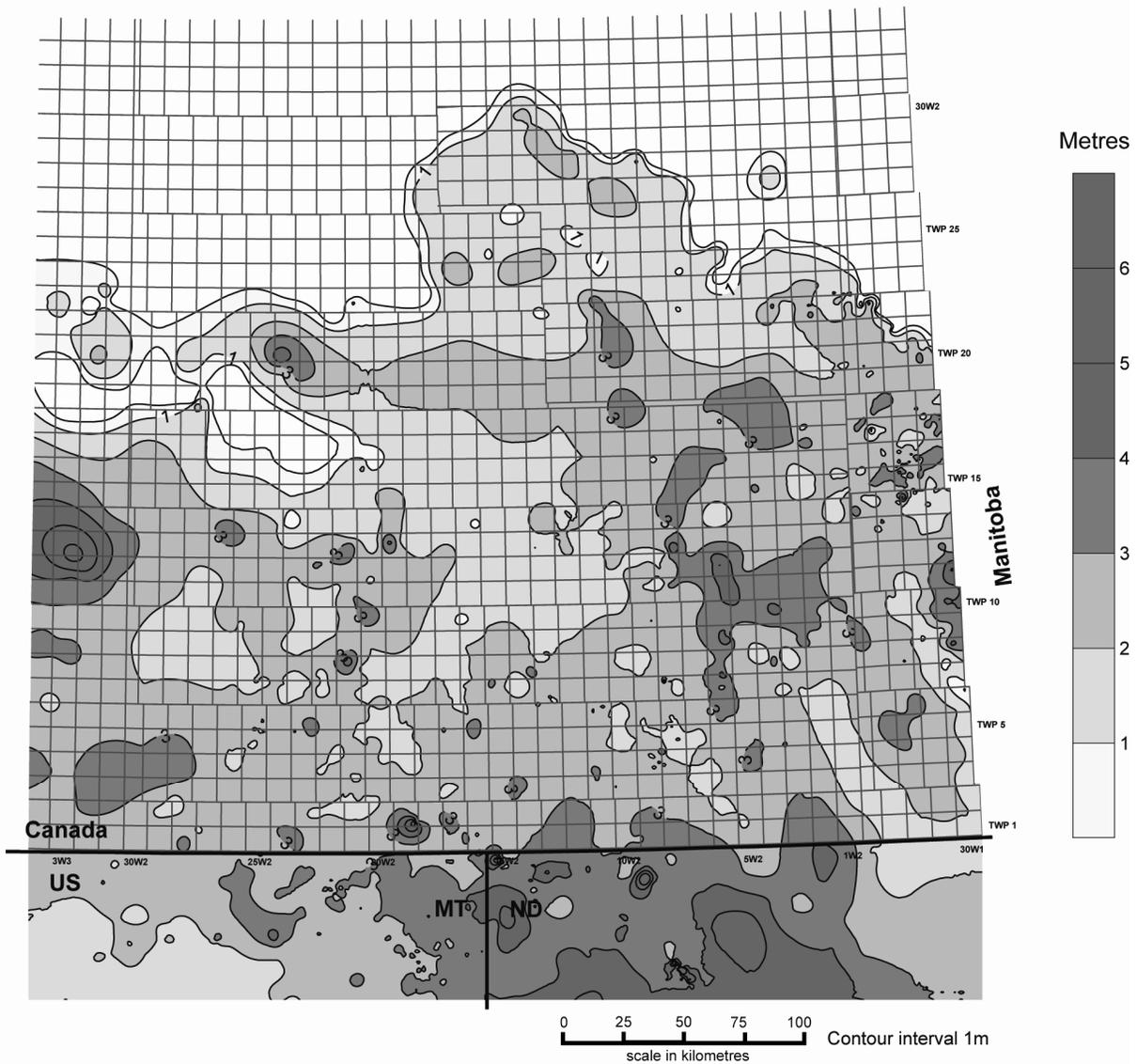


Figure 12 - Computer-generated isopach map of the Upper Member of the Bakken Formation.

Rich sources appear to be restricted to present depths greater than 1600 m and are characterized by hydrocarbon indices (HIs) > 400. They apparently accumulated in deeper water where diagenetic oxidation of the source rock kerogen was not effective. Lower Member samples cluster such that TOC values greater than 8.97% and $(S1+S2)/TOC > 500$ occur at present depths below 1700 m (where S1 is effectively the adsorbed petroleum content and S2 is effectively the remaining petroleum generation potential of the kerogen). Four samples from 1000 to 1100 m depth show a considerable TOC range (3.50 to 10.65%), intermediate HIs, and $(S1+S2)/TOC$ between 300 and 500. Nine other samples from diverse depths and also having a considerable TOC range (0.47 to 21.60%) show HI and $(S1+S2)/TOC$ values less than 300.

Similar variations were observed in the U.S. Williston Basin (Price *et al.*, 1984; Webster, 1984).

In the Canadian Williston Basin, percentage carbon (PC) values are approximately 50%, a characteristic of Type II organic matter (OM). In the U.S. Williston Basin, some samples have PC values up to 72% and HIs substantially greater than H_{IO} (H_{IO} is the Hydrogen Index, or ratio of the initial petroleum generation potential per weight per cent TOC) determined from Canadian samples (Price *et al.*, 1984; Webster, 1984). This indicates organic matter compositional variation attributed to adding Type I OM to the predominant Type II OM. Type I material is probably *Tasmanales* alginates, a common palynomorph in the Bakken (Christopher, 1961).

Finally there are some Type III HIs with PC values significantly less than half the TOC. Petrographic observations confirm a complex kerogen composition (Stasiuk *et al.*, 1990). Much organic material is a degraded, amorphous, non-fluorescing Type III bituminite. Non-degraded materials are predominantly planktonic marine alginite with subordinate acritarchs, terrestrial sporinite and minor amounts of vitrinitic and inertinitic material (Stasiuk *et al.*, 1990). The Lower Member in particular contains abundant *Tasmanites*-rich alginite. Stasiuk *et al.* (1990) suggested bituminite resulted from either diagenetic microbial degradation or depositional oxidation.



Figure 13 - Variably coloured, oxidized Upper and Middle Bakken members overlain by tan to whitish limestones of the Souris Valley between approximately 490.5-499.0m in a well at 14-16-18-30W1.

Within the Canadian Williston Basin, Lower Member shale samples with more than 8.97% TOC occurring at depths greater than 1700 m have $H_{I0} = 594 \pm 79$, typical of a rich Type II organic matter source. Upper Member shales, including many very rich samples with TOC > 20%, have reduced HIs and $(S1+S2)/TOC$ suggesting that organic matter type varies with facies and diagenesis. However, rich Canadian Upper Member shale samples from depths greater than 1750 m with more than 13.25% TOC exhibit consistently high HIs and suggest a $H_{I0} = 544 \pm 102$. Combined, the restricted rich Type II source samples in both Upper and Lower Member shales have $H_{I0} = 615 \pm 60$. Not all Bakken sources are as rich as the geographically restricted subset used above to characterize H_{I0} . Approximately half the Canadian samples have HIs less than 550 due to depositional facies and diagenetic variations (Osadetz and Snowdon, 1995).

Estimates of Bakken Formation hydrocarbon generation from a thermally mature area centred in North Dakota have ranged between 16 billion m^3 (98 billion barrels) to more than 32 billion m^3 (200 billion barrels) (Webster, 1982, 1984; Schmoker and Hester, 1983).

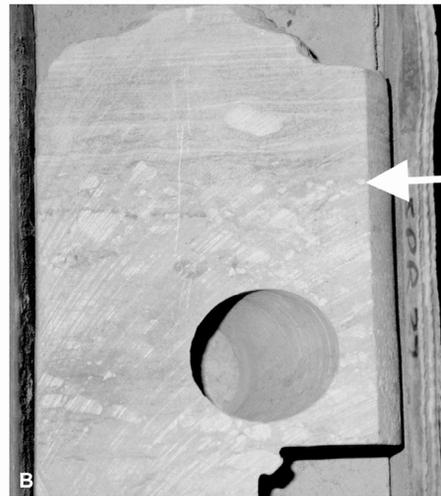
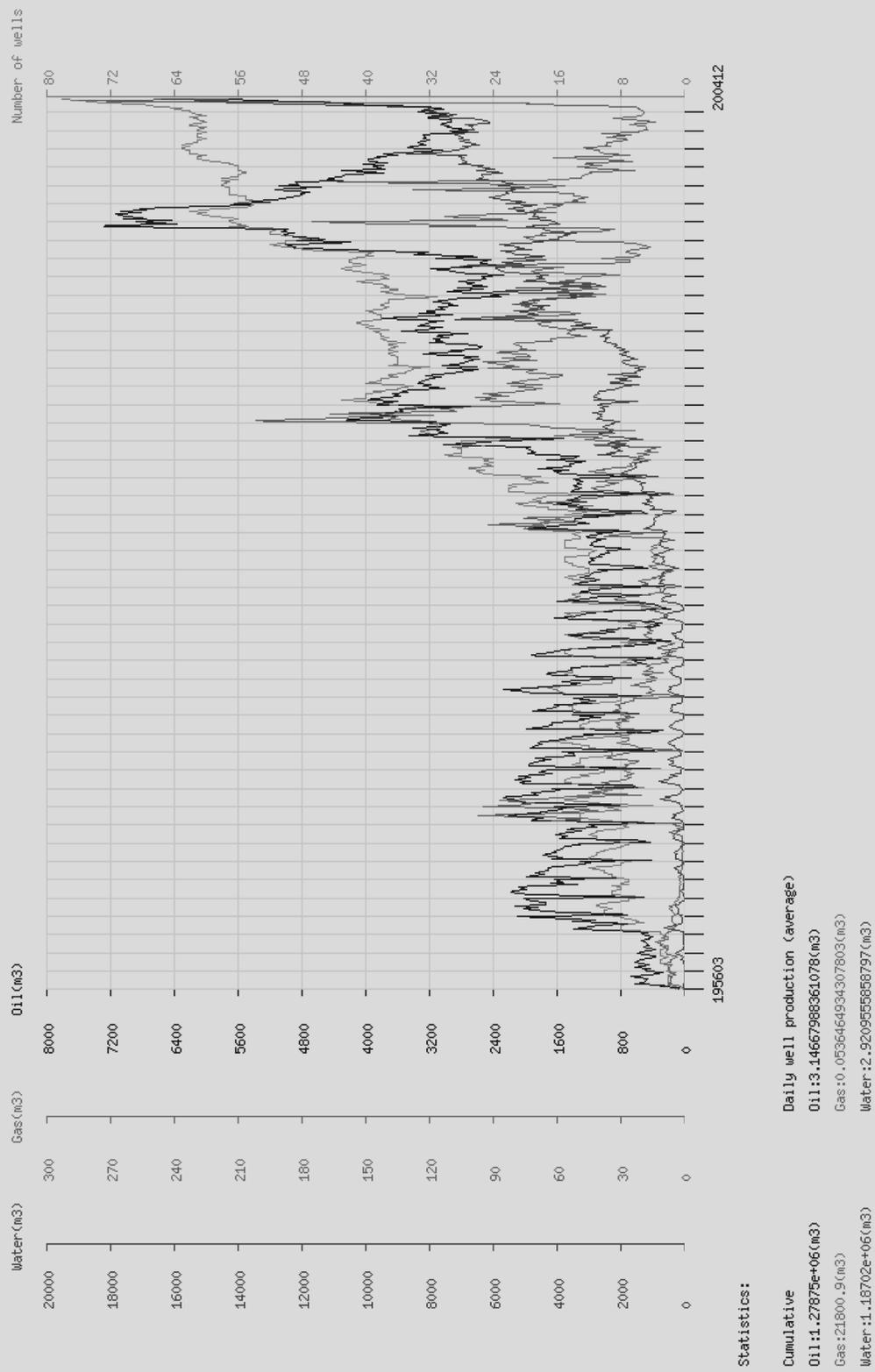


Figure 14 - A) Unconformity (shown by arrow) between laminated sandstone of the Middle Bakken and dolomitic mudstones of the underlying Torquay Formation at approximately 1079.1m in 8-35-6-30W1. B) Detailed view of the contact shown in A.

b) Source-Rock Thermal Maturity

Webster (1984) identified a single oil window beginning at 2740 m (9,000 ft) and an intense HC generation zone at 3048 m (10,000 ft). He associated these critical thermal maturities with approximately 0.53% and 0.69% VR (Webster, 1984; his Figure 26). Price *et al.* (1984) preferred pyrolytic indicators to solvent-extract maturity criteria and identified two oil windows, based primarily on RockEval/TOC results, at approximately 2300 m and 3050 m current depth. Solvent-extract HC% values first enter main stage oil generation (45 to 55 %HC) at approximately 2300 m depth, in the United States, at the same depth that Rock-Eval PI and Tmax data indicate the main stage of hydrocarbon generation and thermal maturity. Yet, most samples remain marginally mature (25 to 45 %HC), even at these or greater depths, suggesting a deeper oil window consistent with a lower effective heat flow region oil window that was described in, and which is exclusively restricted to, the United States (Price *et al.*, 1984).

Production from 193001 to 200412 inside the area defined by 70-30W2 and 1-30W1 and for the interval between BAKKEN M. SAND to



Statistics:

Daily well production (average)

Oil: 3.14667988361078 (m3)

Gas: 0.05366464934307803 (m3)

Water: 2.920955588797 (m3)

Cumulative

Oil: 1.27875e+06 (m3)

Gas: 21800.9 (m3)

Water: 1.18702e+06 (m3)

Hours: 9763137

Figure 15 - Line graph of monthly Bakken oil production in southeastern Saskatchewan.

The variations in the position of the oil window were attributed to lateral heat-flow variations, controlled by an inferred, aborted, Late Cretaceous–Paleocene rift (Price *et al.*, 1984). The enhanced maturity zone generally coincides with the Nesson Anticline. It extends into Canada (Majorowicz *et al.*, 1988; Osadetz *et al.*, 1989, 1990) where elevated heat flows occur due to compositional differences in Precambrian basement, rather than due to tectonic activity (Morel-a-l'Hussier *et al.*, 1990).

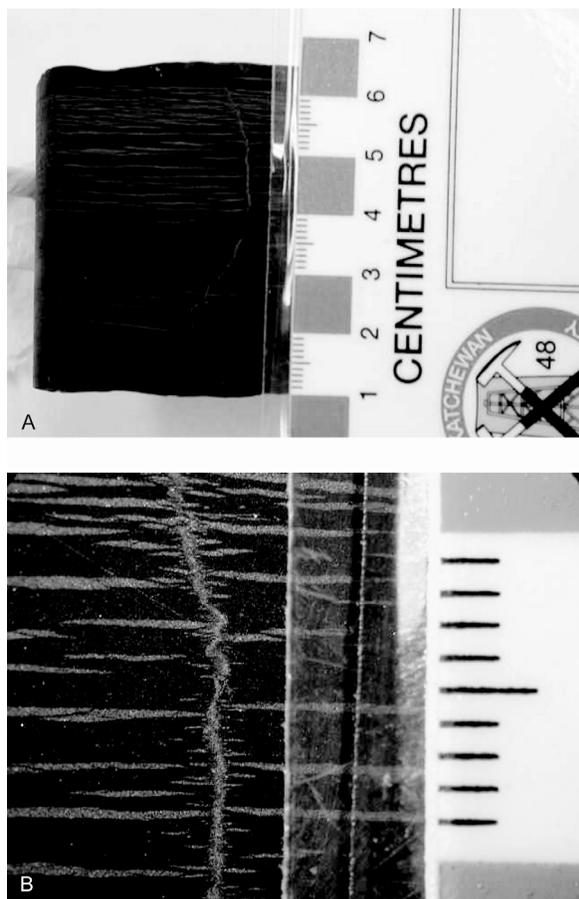


Figure 16 - A) Network of calcite-filled horizontal fractures cross-cut by a vertical calcite-lined fracture which starts and terminates within a 5 cm thick interval (well 12-27-1-6W2, between approximately 2081.0 and 2082.0m. B) Magnified view of a portion of this 5 cm thick interval.

Previously examined and reported Bakken Formation sources are not generally thermally mature in Canada (Osadetz *et al.*, 1992; Osadetz and Snowdon, 1995; Stasiuk and Fowler, 2004). Immature Bakken samples can be identified using Tmax, PI and %HC. The deepest Canadian samples have the highest HIs in both shale members, suggesting that significant hydrocarbon generation has not begun. Canadian Bakken Formation maturity indicators are consistent with U.S. studies where Price *et al.* (1984) defined an oil window between approximately 2330 and 2440 m (7650 to 8000 ft) in enhanced maturity regions, while the oil window was reached at approximately 3050 m (10,000 ft) in "normal" geothermal gradient areas. The

depth of Bakken Formation oil windows in enhanced maturity regions compares closely with inferred patterns of thermal maturity in other Williston Basin source rock formations (Osadetz *et al.*, 1992; Burrus *et al.*, 1996a, b; Osadetz *et al.*, 1994). A more recent geochemical and petrographic study (Stasiuk and Fowler, 2004) confirms the conclusions of previous studies. Still, there are some observations that suggest the area of thermal maturity, or localized thermal maturity anomalies, may extend into southeastern Saskatchewan, although it is not typical of the region. For example, some cores (Figure 16) like that from the Lower Member shale in the Clarion et al Pinto 12-27-1-6 well exhibit horizontal filled fractures that are consistent with an overpressure inferred to accompany hydrocarbon generation. The extent and distribution of the oil window in Canada remains to be confirmed by geochemical or petrographic methods.

7. Formation Resistivity And Petroleum Saturations

An anomalous increase in resistivity associated with either migrated or generated oil within source rocks has been reported in the literature (Goff, 1983; Meyer and Nederlof, 1984; Smagala *et al.*, 1984). Schmoker and Hester (1990) describe a process in which the onset of oil generation in organic-rich, low-porosity shales causes the displacement of conductive pore waters by non-conductive hydrocarbons. As this process continues, oil saturation within the source-rock itself is increased and the formation resistivity as measured by well-log response is increased. Physical rock characteristics like water salinity, mineralogy, porosity, tortuosity and the salinity of water within the pore volume all contribute to the resistivity of the source-rock shale but do not appear to mask the increase in resistivity due to oil generation (Schmoker and Hester, 1990). Their core research concluded that a resistivity value of greater than 35 ohms coincides with the onset of observable oil generation in Bakken shale. However, similar effects are observed if oil has migrated into the formation.

Murray (1968) suggested that areas of anomalously high resistivity in Bakken shales of the Williston Basin were indicative of hydrocarbon saturated-pore space. Meissner (1978) described the relationship between shale resistivity and hydrocarbon generation and used resistivity values from Bakken shales to map areas of thermal maturity in the U.S portion of the Williston Basin. Meissner also pointed out that areas of low pore-fluid pressures correlated with areas of low resistivity in Bakken shales and areas of overpressured Bakken were correlated with areas of anomalously high resistivity.

Burrus *et al.* (1996a, b) demonstrated a linkage among Bakken shale petrophysical parameters, Rock-Eval/TOC parameters and overpressures in the Bakken Formation as described by Meissner (1978). Within the region of thermally mature Bakken Formation in the United States, they showed the overpressure in the Antelope Field resulted from hydrocarbon generation

in Bakken Formation source rocks. Further, they showed that most of the hydrocarbon in the Bakken shale members was expelled from the rock volume where it was generated and that the intrinsic shale porosity and permeability of the Bakken shales were consistent with shale porosities of approximately 3%, which were simultaneously consistent with the residual hydrocarbons stored in mature Bakken source rocks, and the mechanical properties required for the persistence of an overpressure in the Antelope Field since Paleogene time (see Burrus *et al.*, 1996b, their Figures 6 and 10). Their models also indicated that the high pressures associated with hydrocarbon generation in Bakken source rocks did not reach the hydraulic fracturing threshold of the lithology in the absence of an additional tectonic stress (see Burrus *et al.*, 1996b, their Figure 7). The combination of thermal maturity patterns and shale porosity and permeability, with observed formation pressures has important implications for hydrocarbon exploration strategies.

The present study mapped resistivity values for Upper and Lower Bakken shales in southeastern Saskatchewan (Figures 17 and 18). Only deep-reading laterologs were used and no borehole or environmental corrections were applied to the resistivity data. As with the resistivity mapping by Schmoker and Hester (1990), the area of anomalously high resistivity (*i.e.*, >35 ohm-m) in the Upper Member shale oversteps that of the Lower Member shale. Schmoker and Hester concluded that a higher level of thermal maturation is required for oil generation in the Lower Member than in the Upper Member, but the same patterns are just as likely to result from petroleum migration and staining.

Given that Bakken petroleum source rocks are characteristically immature in Canada, as previously discussed, it is noteworthy that the areas of highest resistivities for Upper and Lower Bakken shales are located immediately north and west of the Nesson Anticline, which is the feature associated with the region of enhanced hydrocarbon generation in the United States and which is also spatially located within the Trans Hudson Orogen (Kreis and Kent, 2000). This area has been documented to be a region of anomalously high heat flow related to basement tectonics (Majorowicz *et al.*, 1986; Majorowicz *et al.*, 1988) and enhanced hydrocarbon generation (Osadetz and Snowdon, 1995). A NE-SW striking trend of extremely high resistivities (*e.g.*, 8-13-1-10W2 at 25,000 ohm-m, 15-25-2-10W2 at 16,000 ohm-m, and 3-8-1-11W2 at 16,000 ohm-m) is recognized for the Upper Member shale (Figure 17). This trend is parallel to, if not coincident with, a northeasterly projection of the Brockton-Froid-Fromberg Fault Zone, a possible migration fairway (Gerhard *et al.*, 1987, Figure 4). Also, the salt-free area known as the Hummingbird Trough, where tectonic stress concentrations might be expected, is coincident with a region of anomalous resistivity values in both Upper and Lower Bakken shales. Recognition of these structural and resistivity trends has obvious implications for hydrocarbon exploration in this area, especially as all of the petroleum appears to have undergone a secondary

migration to its place of entrapment, based on the observed patterns of thermal maturity.

Pitman *et al.* (2001) reported enhanced reservoir characteristics in Bakken Formation through horizontal fracturing in sandstones and siltstones of the Middle Member in deeper (*i.e.*, >3,000 m), thermally mature areas of the Williston Basin. He interpreted that these fractures were caused by superlithostatic pressures that formed in response to increased fluid volumes in the source rocks during hydrocarbon generation. Horizontal fractures have also been observed in this study within the Lower Bakken shale (Figure 18) in a core from the 12-27-1-6W2 well at a depth of approximately 2,100 m (Figure 16), where they might represent a similar overpressure. This well falls within the area of anomalously high resistivity (Figures 17 and 18) where Bakken shales are inferred in advance of geochemical or petrographic evidence to be anomalously thermally mature in places. In the future, we hope to confirm this interpretation by applying petrographic and geochemical techniques following the work of Pitman *et al.* (2001).

8. Discussion

The Bakken Formation shale members are rich, but characteristically thermally immature petroleum source rocks in deeper parts of the Canadian Williston Basin

Areas of anomalously high resistivities in Bakken shales in southeastern Saskatchewan suggest either that the Lower and Upper Member shales are anomalously thermally mature, or that they outline a migration fairway for oils generated elsewhere. In these areas, rare fracturing is interpreted to be related to hydrocarbon generation, where the effective stress appears to have exceeded the overburden load. Elsewhere, it is more likely that fractures are related to combinations of basement tectonics and basin processes, most notably evaporite dissolution and differential compaction. This fracturing may provide a mechanism for porosity and permeability improvement in both the Bakken Formation shale members and the adjacent Middle Member sandstone and siltstone reservoirs.

Most of the oil production in southeastern Saskatchewan is located north, northwest and northeast of the basin-centred area of Bakken maturity. Oil appears to have migrated into these areas from the mature basin through Middle Member sandstones and siltstones. The widespread occurrence of oil shows and production in the Bakken Formation suggests that reservoir quality sandstones exist under much of southeastern Saskatchewan. The presence of relatively thick Middle Member sandstones northeastward from the Midale Pool (Twp 6-7, Rge 11W2) through the Viewfield Pool (Twp 8, Rge. 8W2) to the Rocanville Pool (Twp 15-16, Rge 31W1) suggests an exploration fairway along this trend.

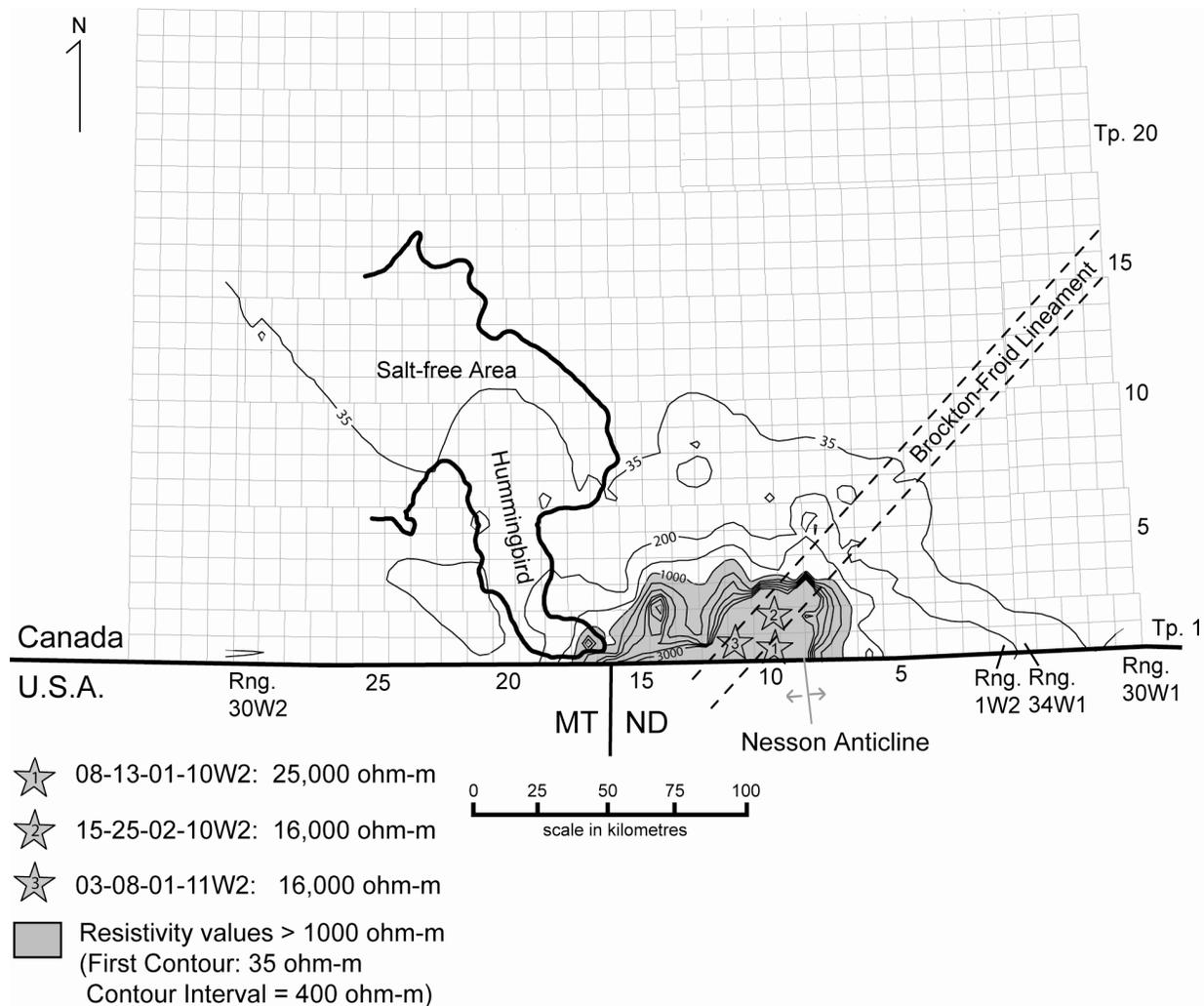


Figure 17 - Isopach map showing resistivity values (ohm-m) for the Upper Member of the Bakken Formation; note anomalously high resistivity in grey-shaded area.

Regional correlations and core examinations indicate that unit A1 is generally non-reservoir rock in the southern extremities of southeastern Saskatchewan but that it undergoes a facies change to the north in the Viewfield area where it becomes a silty, very fine-grained sandstone, and to the northeast in the Rocanville area where it can be a very productive fine- to medium-grained sandstone. Also, in the Hummingbird Pool (Twp 2, Rge 19W2) and surrounding area, it becomes a flaser-bedded, very fine-grained sandstone with good reservoir characteristics. Unit B is thickest in southern portions of southeastern Saskatchewan.

Core and geophysical log evaluations from the present study suggest that the potential for by-passed pay in units A1 and B of the Middle Member sandstone is considerable in southeastern Saskatchewan and is also likely in other parts of the Williston Basin.

A large regional oil play in Torquay dolostones and, to a lesser degree, in thin (<3 m) Middle Member Bakken

Formation sandstones exists along the Saskatchewan–Manitoba interprovincial boundary. The heterogeneous nature of the brecciated dolostone reservoir rocks of the Torquay Formation here lends itself to exploration and development through horizontal well completions.

9. Conclusions

- Bakken Formation shales are rich oil-prone source-rocks, which are characteristically mature in the U.S. portion of the basin, especially in a region of elevated heat flow and enhanced thermal maturity.
- Evidence for some maturation anomalies extends into Canada, but the extent of these anomalies remains to be confirmed both geochemically and petrographically.

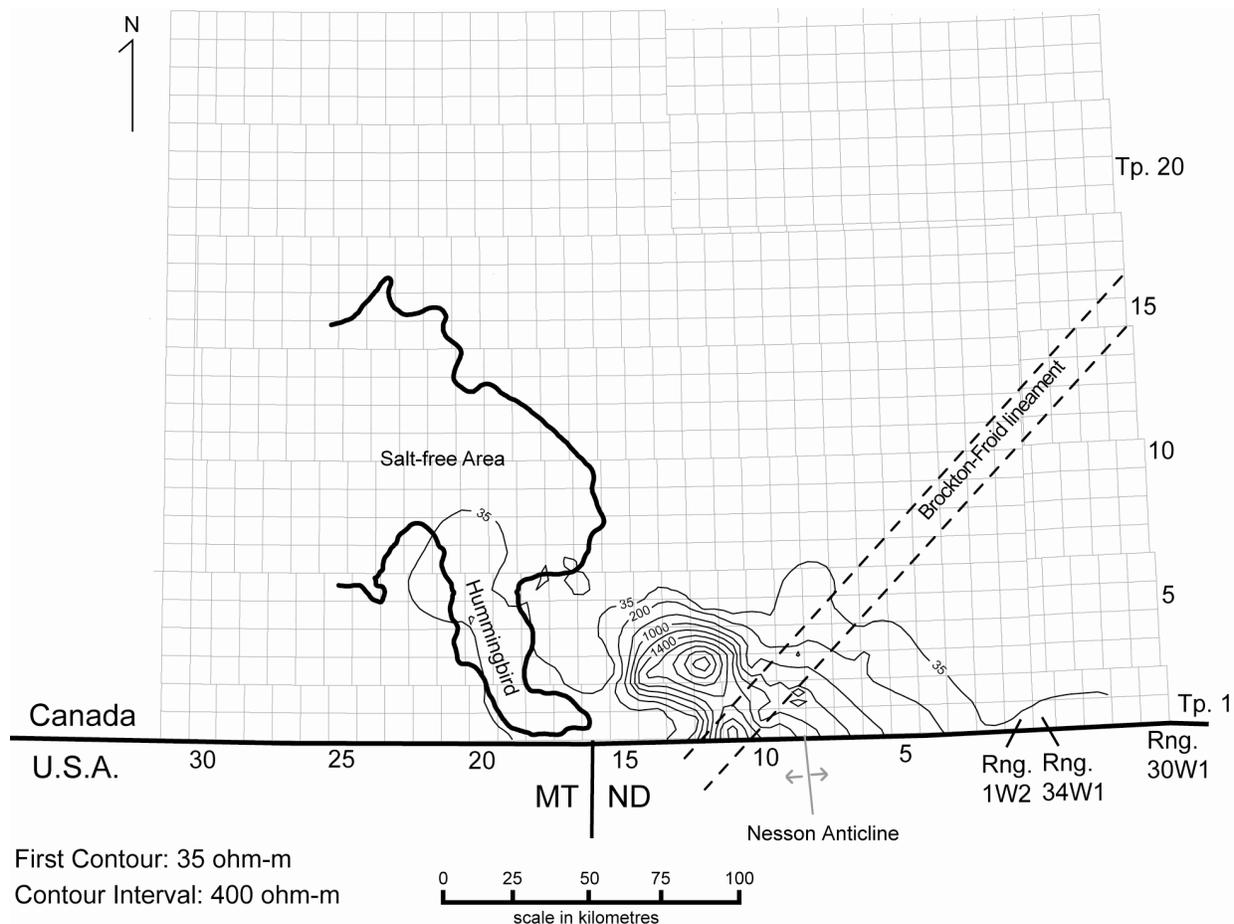


Figure 18 - Isopach map showing resistivity values (ohm-m) for the Lower Member of the Bakken Formation; note anomalously high resistivity in grey-shaded area

- High resistivities in the Canadian Bakken Formation are attributed to oil saturation that is observed to be associated with basement structures, compactional features and regions of Middle Devonian salt dissolution, all of which probably control fractures that act as the primary migration pathways for Bakken sourced oils into possible plays in the Bakken and Torquay formations.
- Depositional controls on the Middle Member Bakken Formation and on the Torquay Formation are augmented by diagenesis and tectonics, the latter largely controlled by basement tectonics, compaction and salt dissolution, which result in conventional petroleum pools that are best exploited by horizontal wells.
- A large untested or poorly evaluated rock volume remains in the Bakken and Torquay formations of southeastern Saskatchewan, within which there may be significant potential for undiscovered oil.

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