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Front cover photo by F. Ferri. Looking west along the lower part of the Fort Nelson River where it has cut down into resistant sandstone and conglomerate horizons of the Dunvegan Formation. These competent units form the prominent plateaus in the distance. This region is found along the southeastern margin of the Liard Basin.

Page iii photo by F. Ferri. Northeast-verging, folded, calcareous siltstones of the Toad Formation along the southeast bank of the Toad River, southern Liard Basin.

Back cover photo by F. Ferri. Looking south at the confluence of the Fort Nelson (to the east) and Liard rivers in the central Liard Basin. The brown, humic-rich waters of the Fort Nelson River, which drains the peat-, muskeg- and marsh-dominated forests to the east, can be seen mixing with the greener waters of the Liard River, which has had a significant input of fine clays from mountain streams originating in the Northern Rocky Mountains (seen in the distance). The photograph was taken from immediately over the Paramount La Jolie d-057-D/094-O-12 drill pad, a few kilometres northwest of the Apache Patry d-034-K/094-O-05 well site.

FOREWORD

Geoscience Reports is an annual publication that summarizes petroleum-related projects undertaken by staff within the Petroleum Geoscience Section. This public geoscience information provides baseline, regional data that can be used by those undertaking exploration and development within the petroleum sector of the province. These reports not only promote the petroleum resources of the province, but also support responsible development and the formulation of related policy.

The 2014 issue of Geoscience Reports includes a paper describing the use of the Passey log based methodology for deriving organic richness estimations of the Evie, Muskwa and Otter Park units within the Cordova Embayment. This paper was authored by Akindele Balogun, the newest member of the Petroleum Geoscience Section. The information in this paper will form the basis of an upcoming resource assessment of the Cordova Embayment.

Ed Janicki describes the petroleum hydrogeology of the Halfway Formation as part of a regional study examining individual oil pools within the formation. This information should provide explorationists a new approach to understanding one of British Columbia's most prolific oil-producing formations. This paper helps explain oil migration and entrapment in the Halfway, which could lead to new discoveries and might also be useful in examining depleted oil pools as possible water disposal zones.

Ed Janicki also produced an updated description of the North Pine oil pool within the Halfway Formation. This compilation provides some new insights into the pool and opportunities for future development.

Filippo Ferri and Matthew Griffiths describe a region in northeast British Columbia with potential for condensate production from the Muskwa Formation. This paper used available thermal maturity and production data to delineate a zone where shales of the Muskwa Formation are likely in the condensate window. This compilation was part of a work term project through the University of Victoria's Co-operative Education Program.

Elizabeth Johnson presents a pilot air-photo study of historical aerial data examining the change in permafrost coverage within small areas of the Horn River Basin. Although this paper was not available for the print version of Geoscience Reports 2014, readers are encouraged to visit the Petroleum Geoscience Section's website (http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/Geoscience_Pub) for the digital version of this and other papers. This website also has links to the Petroleum Geoscience Publication Index.

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ORGANIC SHALE POTENTIAL OF THE MUSKWA–OTTER PARK INTERVAL WITHIN THE CORDOVA EMBAYMENT AREA OF NORTHEASTERN BRITISH COLUMBIA USING SONIC AND RESISTIVITY LOGS

Akindele Balogun[1]

ABSTRACT

The Δ log R technique is used to identify and estimate the total organic carbon (TOC) content for 16 wells within the Muskwa–Otter Park interval around the Cordova Embayment in northeastern British Columbia. The Δ log R technique for calculating TOC is based on overlaying a correctly scaled porosity log on a resistivity log and interpreting the separation between the log curves. This separation can be transformed directly to TOC if the level of organic metamorphism (LOM), which is an index of organic maturity, is known.

For the wells analyzed, estimated maximum TOC content of the Muskwa–Otter Park shale ranges from 0.0 to 5.1 wt.%. For the individual wells, the average estimated TOC observed within the interval ranges from 0.7 to 1.6 wt.%. The observed range in TOC content is a reflection of interbeds of less abundant organic-lean nonsource-rock intervals (with relatively low TOCs) within the organic-rich source rocks of the Devonian shale formation. A general thickening trend of the interval is observed toward the centre, away from the boundary of the Cordova Embayment in the direction of the British Columbia–Northwest Territories border.

Considering the TOC content, the thickening trend of the Muskwa–Otter Park shale and current gas production from the interval (barring significant changes in the other reservoir properties of the shale unit within the Cordova Embayment), this basinal shale unit is likely prospective in the undeveloped parts of the basin trending northward toward the Northwest Territories. The results of this study are expected to provide a framework for a broader hydrocarbon resource assessment of shale formations within the Cordova Embayment.

Balogun, A. (2014): Organic shale potential of the Muskwa–Otter Park interval within the Cordova Embayment area of northeastern British Columbia using sonic and resistivity logs; *in* Geoscience Reports 2014, *British Columbia Ministry of Natural Gas Development,* pages 1–6.

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Keywords: shale, Muskwa, Otter Park, Cordova Embayment, TOC, Δ log R, sonic, resistivity, LOM

INTRODUCTION

The objective of this study was to use well logs to appraise the amount and distribution of total organic carbon (TOC) within the Muskwa–Otter Park interval of the Cordova Embayment. Data obtained from this study will supplement available TOC data to estimate the volume of hydrocarbon in-place within the Cordova Embayment. This basin has a relatively low level of unconventional shale exploitation activity when compared to the Horn River Basin in northeastern British Columbia, in spite of the fact that the Cordova Embayment hosts the same shale formations that are known to be prolific hydrocarbon reservoirs within the Horn River Basin. These include the Middle to Upper Devonian Muskwa–Otter Park formations and the Middle Devonian Evie-Klua formations.

TOC measurement is a priority in unconventional resource assessment and it is usually the first screen for quantifying organic richness or source-rock quality (Jarvie, 1991). Apart from being the source of hydrocarbons in reservoirs, organic matter in unconventional reservoirs is important because a significant fraction of the total porosity observed in such reservoirs is directly related to the amount of organic matter present within the rock matrix (adsorbed gas), which further necessitates the quantification of TOC.

STUDY AREA

This study will focus specifically on the Cordova Embayment area, British Columbia, Canada (Fig. 1). The Cordova Embayment covers an area of approximately 11 000 km^2 in the extreme northeastern corner of British Columbia, extending into the Northwest Territories (Kuuskraa et al., 2013), and is separated from the Horn River Basin on the west by the Presqu'ile Barrier Reef Complex (i.e., the Slave Point and Keg River reefal carbonates), which, in the Middle Devonian, extended from Alberta through British Columbia and into the Yukon and Northwest Territories.

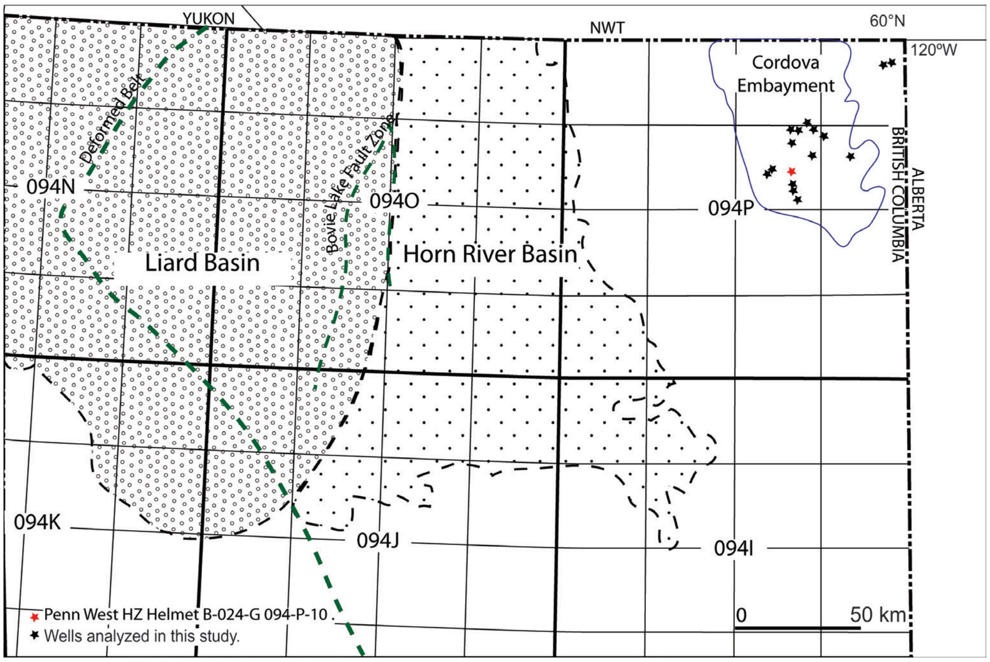

Figure 1. Location of the Cordova Embayment with respect to the Horn River and Liard basins of northeastern British Columbia. Locations of the 16 wells analyzed in this study are shown as stars (outline of the Bovie fault modified from MacLean and Morrow [2004]; outlines of the Liard Basin, Horn River Basin and the Cordova Embayment modified from British Columbia Oil and Gas Commission [2010]).

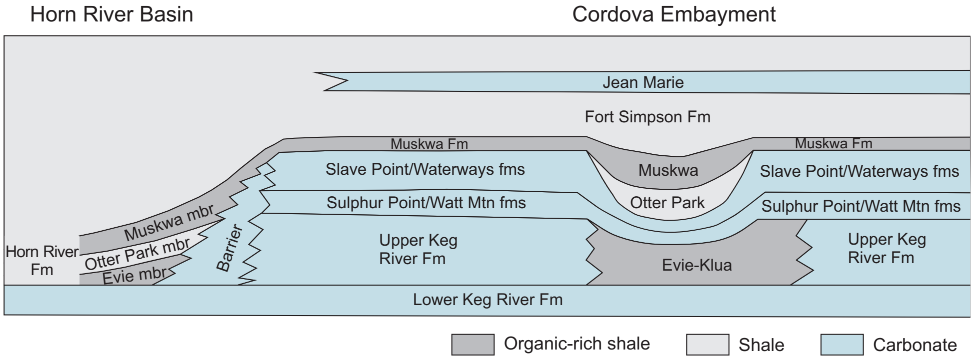

Figure 2. Middle to Late Devonian stratigraphic units within the Cordova Embayment and the adjacent Horn River and Liard basins (from Ferri & Griffiths, 2014).

During the Middle Devonian lowstand periods, shales were preferentially deposited in paleogeographic depressions of the Horn River Basin and the Cordova Embayment; hence, their boundaries are defined by a somewhat abrupt thinning and pinching out of these shale deposits (Fig. 2).

According to production data submitted to the British Columbia Oil and Gas Commission, between November 2007 and December 2013, 21 wells in the Cordova Embayment produced approximately 580.5 × 10^6 m^3 (20.6 BCF; billion cubic feet) cumulative gas from the Muskwa–Otter Park shales, with most of the production on record obtained from block G in NTS map area 094P/10. In May 2010, the Canadian Society of Unconventional Resources estimated the total gas in place for the Cordova Embayment at approximately 5665.6 × 10^{12} m^3 (200 TCF; trillion cubic feet; Dawson, 2010). From the viewpoint of exploiting these shale formations within the Cordova Embayment, the area contains a large number of wells and infrastructure that were used to develop the overlying Jean Marie Formation within the Helmet oil and gas field, which can enhance the cost-effective development of prospective shale formations within the Cordova Embayment.

THE Δ LOG R TECHNIQUE

In this study, the Δ log R technique established by Passey et al. (1990) is used to identify and estimate the amount of TOC contained in the Muskwa–Otter Park interval of the Cordova Embayment. This technique for calculating TOC is based on overlaying a correctly scaled porosity log on a resistivity log and interpreting the separation between the log curves. Passey et al. (1990) found that when correctly scaled transit-time (sonic) and resistivity log curves are overlain, they track (i.e., coincide) in fine-grained, water-wet, non-source rocks (Fig. 3). In organic-rich, fine-grained rocks, however, the curves will show a separation (termed Δ log R). The Δ log R curve separation in immature rocks is primarily a result of the deflection of the sonic log, when the inorganic rock matrix is replaced with low-density and low-velocity solid organic carbon. Upon maturation, the observed Δ log R curve separation is mainly attributed to the generation of hydrocarbons that replace water in the pore space of the rock, resulting in increased resistivity. The Δ log R log separation is used to predict TOC when the level of organic metamorphism (LOM), which is a linear index of organic maturity (Hood et al., 1975; Passey et al., 1990), is known.

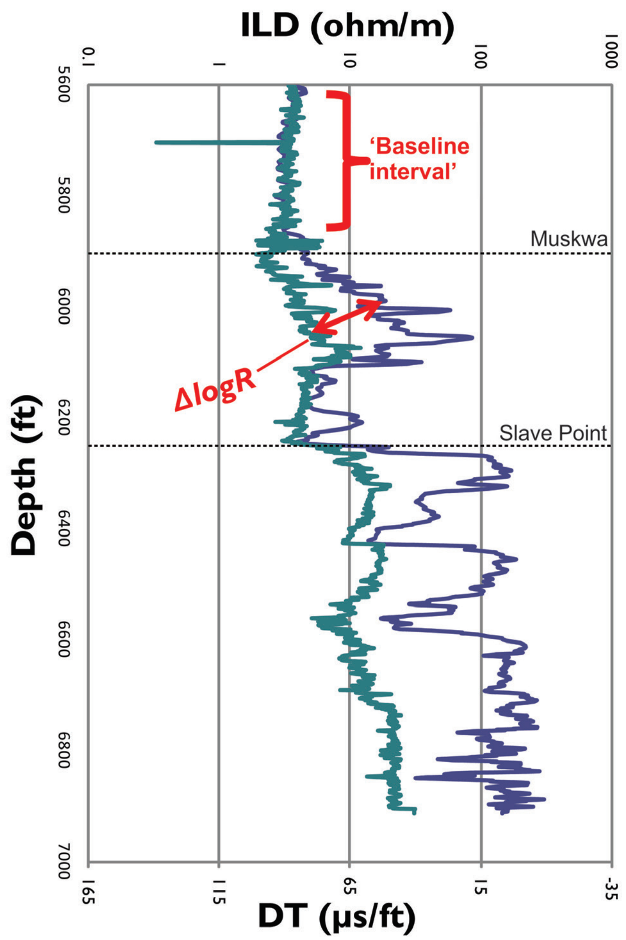

Figure 3. Sonic-resistivity overlay showing Δ log R separation in the Muskwa–Otter Park interval of the Chevron N Helmet C-074-B/094-P-10 well analyzed in this study. The scaling of the sonic (DT) to the resistivity (ILD) curve is 50 μsec/ft, corresponding to one decade of resistivity. The baseline interval is shown in nonsource-rock section of the log.

The following equations by Passey et al. (1990) were used in calculating Δ log R and estimating TOC:

$$\Delta \log R = \log_{10}(R/R_{baseline}) + 0.02 \times (\Delta t - \Delta t_{baseline}) \quad (1)$$

$$TOC = (\Delta \log R) \times 10^{(2.297 - 0.1688 \times LOM)} \quad (2)$$

where Δ log R is the separation of sonic and resistivity curves separation measured in log scale (resistivity cycles), R is the measured resistivity value obtained from the resistivity tool, Δt is the measured transit time values from the sonic log, $R_{baseline}$ is the resistivity corresponding to the measured $\Delta t_{baseline}$ and LOM is the level of organic metamorphism (after Hood et al., 1975).

In addition, structural and isochore maps of the Muskwa–Otter Park interval were made to reveal potential spatial relationships to TOC distribution within the Cordova Embayment and to constrain the spatio-temporal boundary of the reservoir.

RESULTS AND DISCUSSION

The Δ log R technique was used to estimate the amount of TOC for 16 wells with resistivity and sonic log curves, penetrating the Muskwa–Otter Park interval. Locations of analyzed wells are shown in Figure 1. For this analysis, the TOC for the Muskwa–Otter Park interval was estimated by using a LOM value of 11 for all the wells. This LOM value was chosen based on the consideration of available vitrinite reflectance data from Stasiuk and Fowler (2002; see Hood et al. [1975] for a vitrinite reflectance–LOM conversion table) and known hydrocarbon production from the interval. TOC data derived from Rock Eval™ were available for one of the wells analyzed in this study (Penn West HZ Helmet B-024-G 094-P-10) and were correlated with TOC values estimated from the Δ log R technique (calculated using LOM values of 11, 12 and 13) to illustrate how varying the LOM affects the value of the calculated TOC (Fig. 4).

For the Penn West HZ Helmet B-024-G 094-P-10 well, the log-derived TOC values calculated based on an LOM value of 11 are seen to provide the best fit with the TOC values derived from Rock Eval. In reality, the LOM can exhibit significant vertical variation (with depth/time); therefore, using a single LOM value for the Δ log R technique could result in inaccurate TOC values. The TOC derived from the Δ log R technique is very sensitive to the maturity of the shale (LOM) and, if incorrectly estimated, the absolute TOC value will be somewhat in error; however, the vertical variability in TOC will be correctly represented (Passey et al., 1990). Estimates of TOC calculated in this study are somewhat pessimistic because no background TOC value was added to the original TOC val-

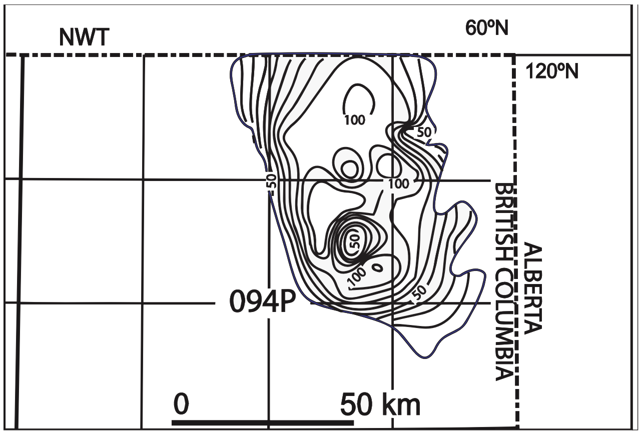

Figure 4. Isochore map of the Muskwa–Otter Park interval within the Cordova Embayment (contour interval = 10 m). A maximum thickness of 130 m for the Muskwa–Otter Park interval is observed around the centre of the Cordova Embayment.

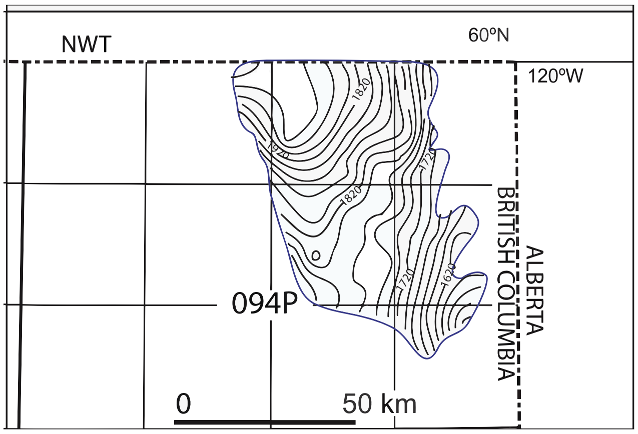

Figure 5. Structural map for the top of Muskwa Formation within the Cordova Embayment (contour interval = 20 m).

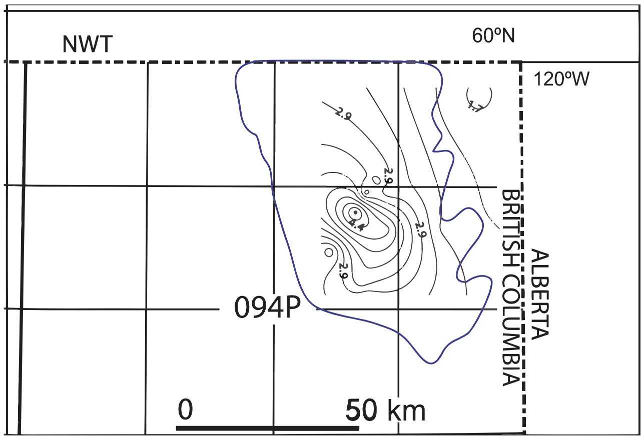

Figure 6. Maximum estimated total organic carbon (TOC) from the analyzed wells, calculated using the Δ log R technique (Passey et al., 1990) for the Muskwa–Otter Park interval (contour interval = 0.3 wt.%). Maximum calculated TOC within the Cordova Embayment is 5.1 wt.%.

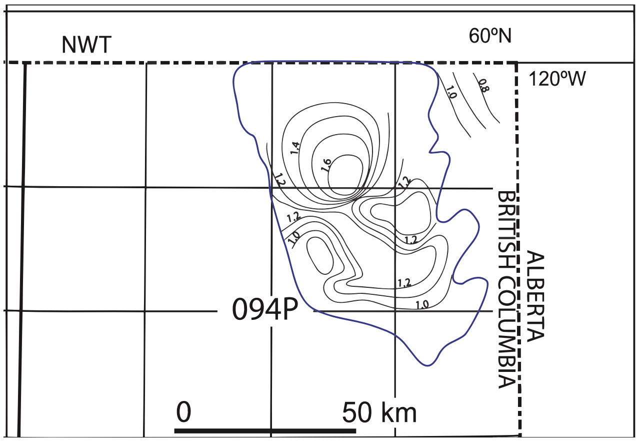

Figure 7. Average estimated total organic carbon (TOC) from the analyzed wells, calculated using the Δ log R technique (Passey et al., 1990) for the Muskwa–Otter Park interval (contour interval = 0.1 wt.%).

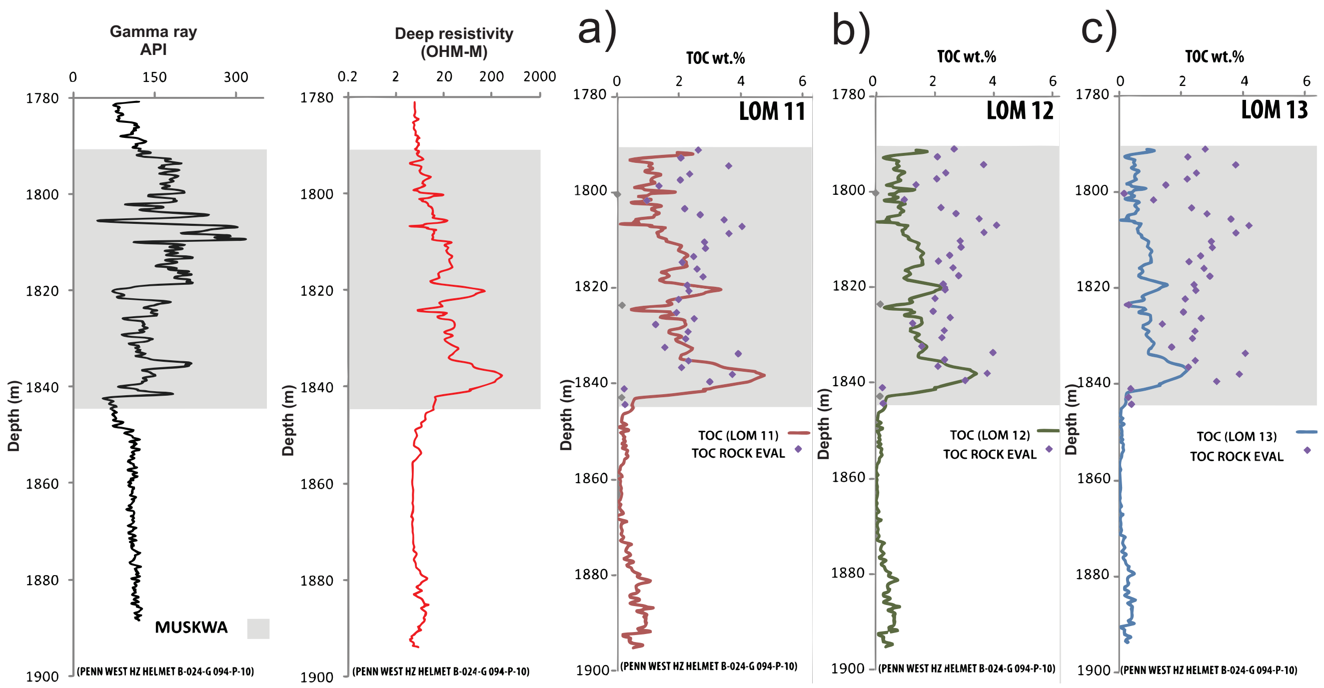

Figure 8. Log-derived total organic carbon (TOC) against TOC derived from Rock Eval™ for varying levels of organic metamorphism (LOM) for the Muskwa Formation: a) TOC calculated with LOM = 11 against TOC from Rock Eval; b) TOC calculated with LOM = 12 against TOC from Rock Eval; c) TOC calculated with LOM = 13 against TOC from Rock Eval TOC calculated based on an LOM value of 11 provides the best fit to the data obtained from Rock Eval. It should be noted that the ∆ log R method (Passey et al., 1990) is very sensitive to the LOM value selected. In reality, LOM variation with depth (time) can lead to a poor correlation between the calculated TOC and the TOC measured from core samples. Gamma-ray and resistivity curves for the interval are displayed for comparison.

TABLE 1: SOURCE-ROCK EVALUATION CRITERIA BASED ON TOC VALUES (MODIFIED FROM MCCARTHY ET AL., 2011).

Source-rock quality	TOC (wt.%)
None	< 0.50
Poor	0.50–1.00
Fair	1.00–2.00
Good	2.00–5.00
Very good	> 5.00

ues computed using equations 1 and 2 above, which is common practice when using the Passey et al. (1990) method for estimating TOC.

For the wells analyzed, estimated maximum TOC content of the Muskwa–Otter Park interval ranges between 0.0 and 5.1 wt.% (for the individual wells, average estimated TOC within the interval ranges between 0.7 and 1.6 wt.%). It should be noted that the observed range in TOC content is a reflection of interbeds of less abundant organic-lean non-source rocks with the more prominent organic-rich source rocks of this Middle to Upper Devonian basinal shale unit.

Only estimated TOC values greater than 0.1 wt.% were used in computing the average TOC for the individual wells. In general, the estimated TOC profile through the Muskwa–Otter Park interval is observed to be higher toward the centre of the Cordova Embayment, in the area where the Muskwa–Otter Park interval is thickest, as observed in Figures 5 and 6. No clear relationship is observed between the isochore and structural maps for the Muskwa–Otter Park interval (Figs. 7, 8). A general thickening trend of the interval is observed toward the centre and away from the boundary of the Cordova Embayment in the direction of the British Columbia–Northwest Territories border, as observed in Figure 7.

CONCLUSION

Based on standard oil and gas industry criteria for rating source rocks (Table 1), the Muskwa–Otter Park shales in the Cordova Embayment mainly rank as fair to good source rocks, with few of the analyzed wells containing intervals with very good source-rock potential (> 5.0 wt.%). Considering the TOC content, the thickening trend of the Muskwa–Otter Park shales and current gas production from the interval (barring significant changes in the other reservoir properties of the shale unit within the Cordova Embayment), this basinal shale unit is likely prospective in the undeveloped parts of the basin trending northward toward the Northwest Territories. Data obtained from this study will form part of a larger resources assessment of shale formations (including the Evie/Klua shale) within the Cordova Embayment, scheduled to be completed by the summer of 2014.

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PETROLEUM HYDROGEOLOGY OF THE HALFWAY FORMATION, NORTHEASTERN BRITISH COLUMBIA

Ed Janicki[1]

ABSTRACT

The petroleum hydrogeology of the Halfway Formation is one component of a detailed examination of British Columbia's existing Halfway Formation oil producers. Petroleum hydrodynamics provides insight on factors important for exploration and development such as formation fluid flow direction, connectivity of reservoirs, trapping mechanisms and oil-gas-water contacts. Pressure, depth and formation water salinity data from more than 500 wells with water-producing drillstem tests (DSTs) were examined. From among those more than 500 DSTs, only just over 200 of the best test results provided DST data to build a pressure-depth plot, salinity map and potentiometric surface map. A pressure-depth plot indicates a pervasive reservoir system, with most data points falling along a common gradient. The reservoir appears to be generally underpressured in relation to a hydrostatic gradient. Updip flow is indicated by the hydrodynamic gradient. Higher salinities generally coincide with the hydrocarbon reservoirs; fresher water occurs along and near the western disturbed belt and near the subcrop edge. A potentiometric surface map shows formation water generally flowing from west to east, except near the subcrop edge, where the direction reverses. Most oil accumulations appear to be within areas of relatively low hydrodynamic potential. Oil appears to be trapped as a result of downdip flow into areas of low potential.

Janicki, E. (2014): Petroleum hydrogeology of the Halfway Formation, northeastern British Columbia; *in* Geoscience Reports 2014, *British Columbia Ministry of Natural Gas Development*, pages 7–24.

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Keywords: Halfway, hydrodynamics, potentiometric, drillstem test, oil, salinity, pressure

INTRODUCTION

This study of the petroleum hydrogeology of the Halfway Formation in British Columbia is intended as partial regional groundwork prior to detailed examinations of individual oil pools. An understanding of the way fluids move through the Halfway Formation might provide explorationists another perspective on British Columbia's most traditional and important oil-producing formation. It might explain in part the how and why of oil migration and entrapment within the Halfway Formation and potentially lead to new discoveries. In addition, this information might be important to the future use of depleted oil pools for water disposal or carbon sequestration.

Most Halfway Formation oil production in British Columbia occurs north of the Peace River (Fig. 1), north and northeast of the town of Fort St. John.

Petroleum hydrogeology (sometimes referred to as petroleum hydrodynamics) is fundamental for understanding how and where hydrocarbons accumulate. It can also be used to show

- whether a single reservoir exists under one pressure regime or a number of reservoirs exist at different pressures;
- flow direction of formation fluids and potential energy (potentiometric surface);
- where permeability barriers might exist, where flow is relatively unhindered or where static nonhydrodynamic conditions prevail;
- gas-oil-water contact elevations; and
- water chemistries where recharge/discharge might be occurring.

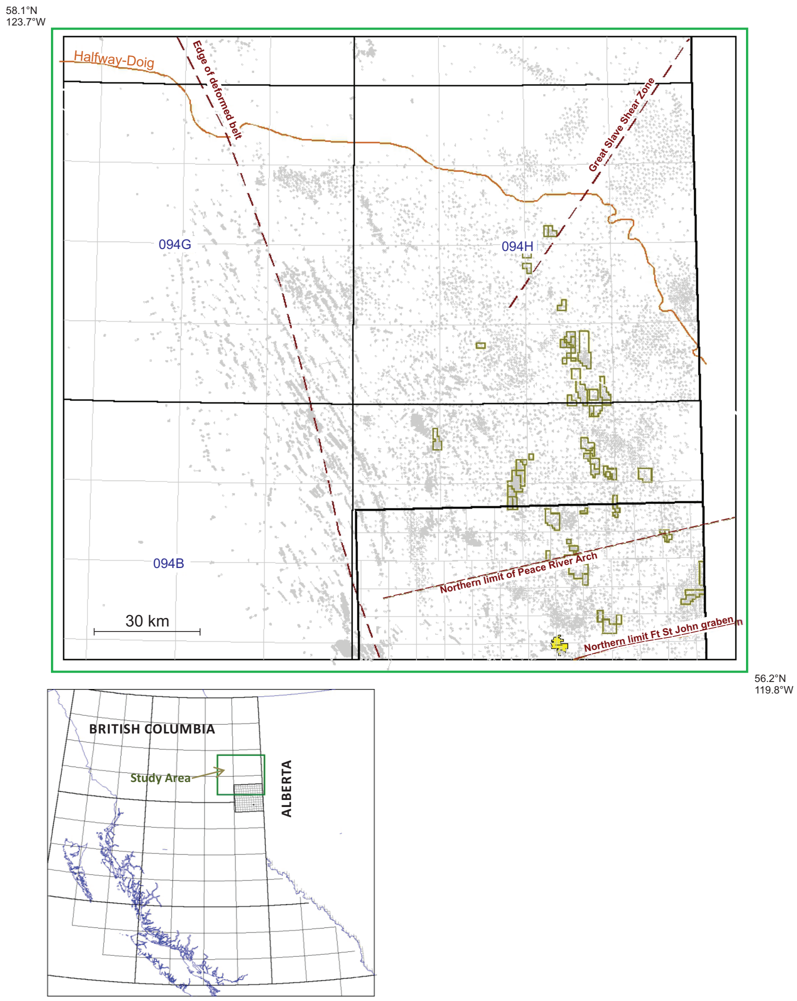


Figure 1. Study area: The Halfway Formation is constrained to the north-northeast by an erosional limit (brown line). To the west it thickens and the structure becomes more complex beyond the edge of the deformed belt. Green polygons represent the main oil-producing pools of the Halfway Formation; grey dots represent all wells within the study area.

With the current increase in drilling for unconventional gas in British Columbia's northeast and the resulting increase in the need for water disposal and water sources, the study of petroleum hydrogeology has found applications beyond its traditional uses. For example, it has been used to evaluate the practice of acid-gas disposal, which has been underway in northwest Alberta since 1990 and northeast British Columbia since 1996 (Buschkuehle and Michael, 2006). For safe disposal of waste fluids, it is important to understand the receiving aquifers to know where fluids might travel, if they will be contained and whether or not they are generally suitable for the purpose. Petroleum hydrogeology is also important for defining the extent and quality of potential water sources for fracking.

The study of petroleum hydrogeology depends on good-quality pressure data, provided mostly by drillstem tests (DSTs), which the Western Canada Sedimentary Basin has in abundance. For studying the behaviour of an aquifer associated with a productive formation, DSTs need to have been run where the formation is wet and therefore uneconomic. In the earlier days of exploration, this was done frequently in the hope that a wet formation might somehow be economic. Determining where oil and gas might contact the aquifer requires the inclusion of DSTs that recovered hydrocarbons. This is not the focus of this paper; the emphasis here is on DSTs with water recovery so that the aquifer can be characterized. Further hydrogeological work including DSTs with substantial hydrocarbon recoveries can be directed in the future to understand accumulations for individual oil pools.

Halfway Formation DSTs and water analysis data provided the basis for the main outcomes of this report, which include

- a potentiometric surface map,
- a pressure-elevation chart, and
- a formation water salinity map.

Geology

The Middle Triassic Halfway Formation (Fig. 2) was deposited as shallow marine parasequences (beds bounded by flooding surfaces) along the western margin of the North American craton in barrier island, shoreface and tidal inlet channel environments (National Energy Board, 2006). The Doig Formation

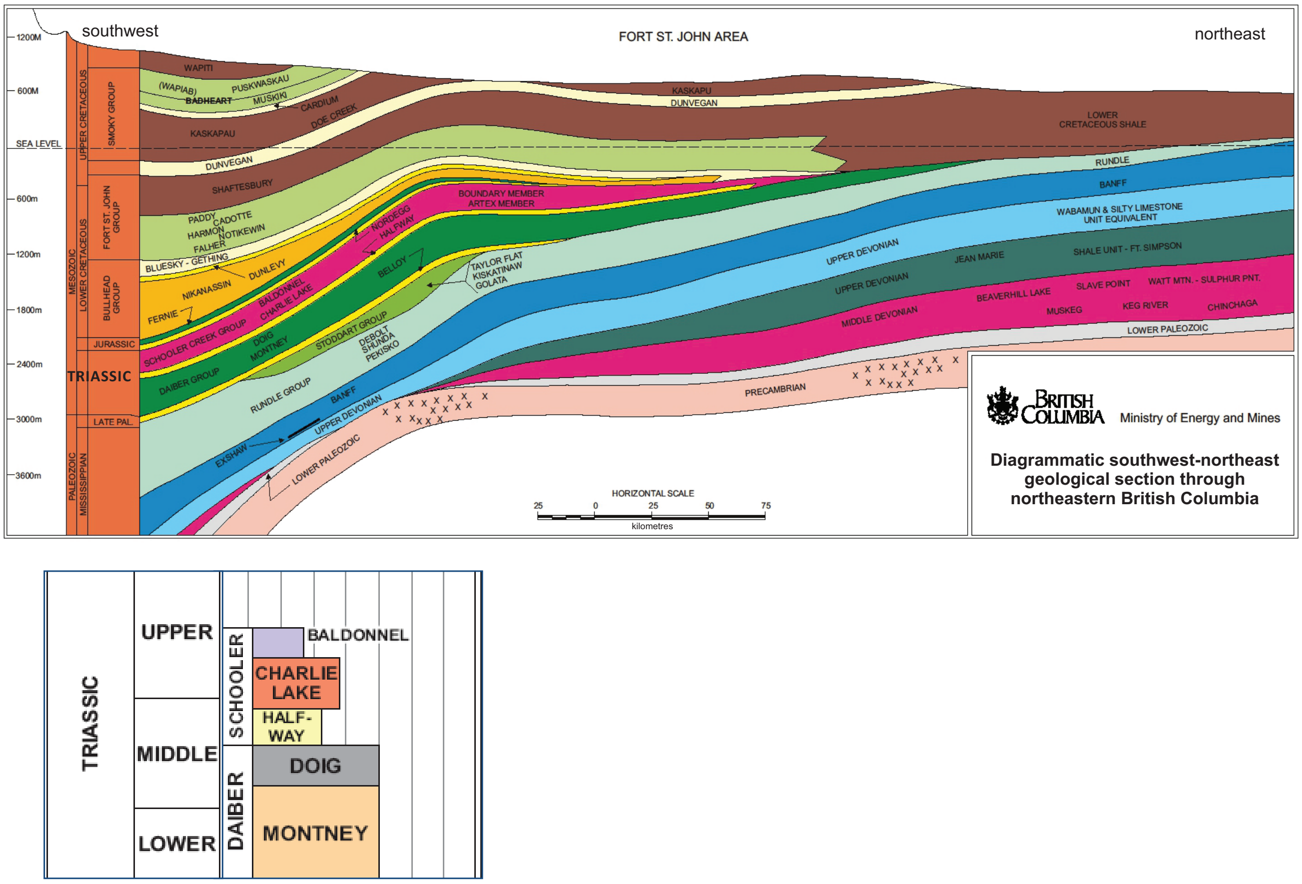


Figure 2. Schematic cross-section and Triassic stratigraphic chart for northeastern British Columbia. The Halfway Formation is shown as a thin yellow layer from the Middle Triassic, tapering off to the northeast. An unconformity follows Jurassic deposition and this limits the Jurassic–Triassic section to the northeast.

underlies the Halfway Formation and is difficult to differentiate lithologically in places. In the western part of the study area, the Halfway is more massively bedded and the contact with the Doig Formation is conformable, suggesting a continuum of deposition; to the east, over the Peace River Arch (Fig. 1) it might be unconformable in places (Hunt and Ratcliffe, 1959; O'Connell, 1994). For the purpose of this study, the two formations will be considered as one because they are assumed to be in communication. An extensive permeability barrier does not appear to exist between them (Fig. 3), although the degree of communication can vary from place to place.

Halfway Formation sandstones are primarily quartz arenites and sub-litharenites with local bioclastic (shell debris) sandstones and coquinas. Grain size varies from very fine to fine. Much of the sand is aeolian, having been blown in from the North American craton, where desert-like conditions prevailed during the Triassic. The best reservoir facies occur updip where the Halfway Formation is relatively thin and where channel-fill cuts into barrier islands. Downdip, where the Halfway Formation is more continuous, reservoir quality is generally less favourable, although localized secondary processes have acted to enhance porosity in places.

In the eastern part of the study area, the Halfway Formation is preserved discontinuously as barrier islands or shoreface sands cut by tidal channels. As a result, hydrocarbon trapping is largely stratigraphic due to rapid changes in facies. To the west-southwest, the Halfway Formation transitions to more continuous shelf sandstones. The eastern-northeastern pre-Jurassic–pre-Cretaceous erosional limit cuts down into the Triassic section, with deeper erosion occurring to the north, so that more of the Triassic is preserved in

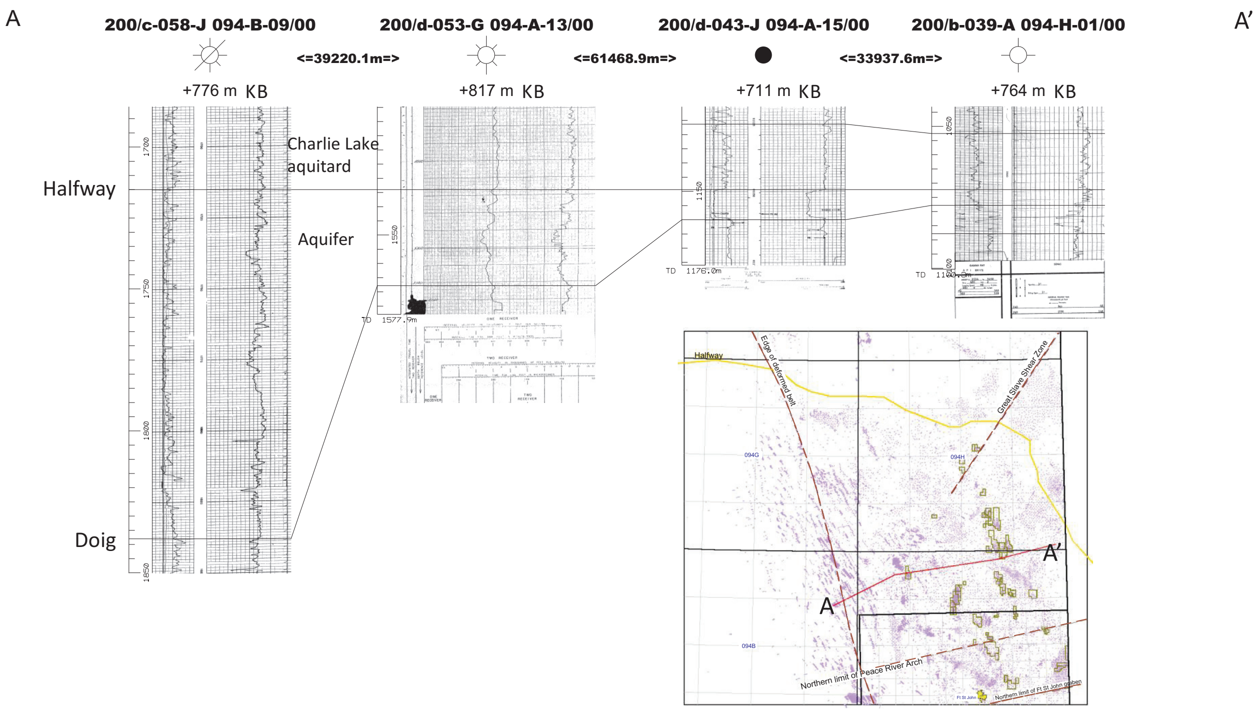


Figure 3. Stratigraphic cross-section A–A': The datum is the top of the Halfway Formation. This cross-section passes through the heart of Halfway Formation oil production. The Halfway Formation thickens considerably and is massively bedded to the west. It thins to the northeast and is bounded by relatively distinct flooding surfaces. The underlying Doig Formation cannot always be readily distinguished from the Halfway Formation. On this cross-section the picks are fairly clear. The Doig Formation tends to be finer grained than the Halfway Formation. The Halfway-Doig section, which contains porous sandstones and siltstones, is considered an aquifer unit, whereas the overlying Charlie Lake Formation, which is predominantly shaly/silty, is considered an aquitard.

the south and only the lowermost Montney Formation remains at the northeastern edge (Gibson and Edwards, 1990).

Doig Formation sandstones are generally finer grained than sandstones from the Halfway Formation because deposition results from a rapid transgression over an eroded surface. They are well-sorted, very fine to fine-grained sub-litharenites to quartz arenites, deposited along shelf margins as lowstand shoreface sands or transgressive barrier sands (National Energy Board, 2006).

The Triassic section, which includes the Halfway and Doig formations, dips more or less uniformly to the southwest (Fig. 2) until it encounters the edge of the deformed belt, where the structure abruptly becomes more complex. At the southeast corner of the study area (Fig. 1), the picture is complicated by reactivation of deep-seated faulting over the Fort St. John graben during the mid- to late Triassic (Barclay et al., 1990; Caplan and Moslow, 1997; Norgard, 1997). The Fort St. John graben was initiated during the Paleozoic and eventually filled in by Carboniferous–Permian sediment. During the Middle Triassic, deep-seated faulting was reactivated by a series of north-south– and east-west–trending normal faults forming horsts and grabens. Reservoir rock was preserved in grabens and eroded on horsts. These are small displacement faults and do not appear to propagate through the Triassic, so their effect on structural elevation appears muted at the interval used to contour the Halfway Formation's structural elevation in Figure 4. Faulting at a deeper level, however, might have produced enough relief to influence facies development and porosity distribution in the central part of the study area. The Peace River Arch, which passes through the southern part of the study area, is another deep-seated structural feature that likely influenced sedimentation.

Petroleum production

Hydrocarbons were first discovered in the Halfway

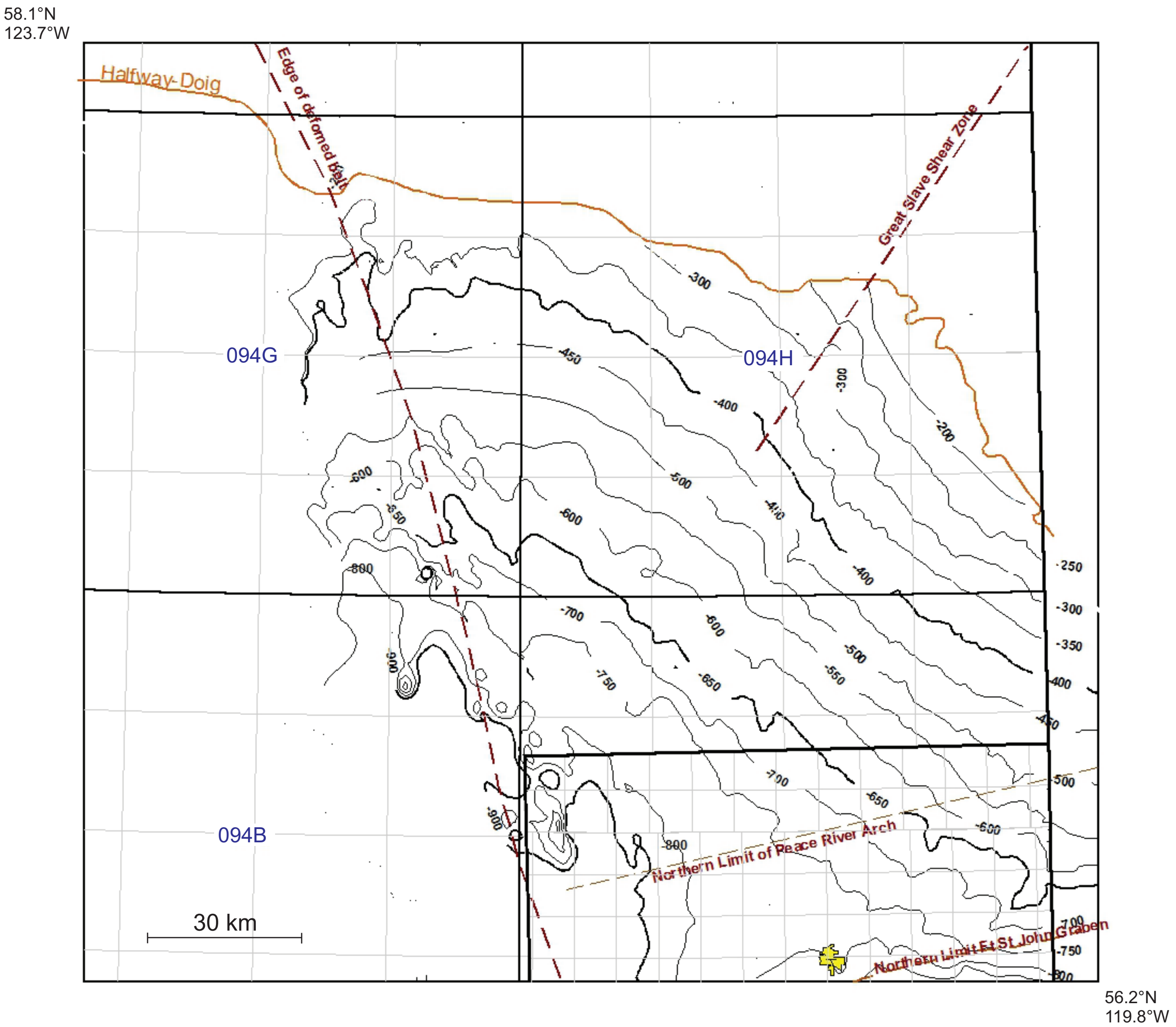


Figure 4. Structural elevation top of the Halfway Formation (contour interval 50 m): The Halfway Formation dips more or less uniformly to the southwest until the deformed belt, where the structure becomes more complex. The influence of deep-seated faulting might be evident by deviations from the general trend near the Fort St. John graben in the southeast.

Formation in the late 1950s. This followed the success of British Columbia's first oil production from the Boundary Lake member (Charlie Lake Formation) in 1956 (Janicki, 2008a, b). Since then, approximately 2000 wells have produced oil and/or gas from the Halfway or Doig formations.

Most Halfway Formation oil is produced from pools located within the east-central portion of the study area (Fig. 4). These pools appear to align along strike in two or three subparallel northwest trends. Gas production follows the same trends but also forms long linear trends further west along the edge of the disturbed belt and in irregularly shaped groupings of various orientations. Some hydrocarbon accumulations can result from structural position and some might be influenced more by porosity distribution (Janicki, 2008a, b); however, as is discussed later, hydrodynamics might have been a determining factor in where some of the oil pooled.

During the past few decades, the Halfway Formation has been used extensively for water disposal because it offers many depleted reservoirs and available boreholes and is generally receptive to large quantities of disposal waters, at least for the short term. Faults originating at greater depths do not appear to propagate through the formation (Norgard, 1997; Buschkuehle and Michael, 2006), which would provide migration pathways.

Study methods

Hundreds of wells in the region have Halfway or Doig formation DSTs, so there is an abundance of pressure and salinity data from which to draw maps. A major task is culling the data so only the most reliable are used. Because this study is primarily concerned with the behaviour of the Halfway-Doig aquifer system, the focus here is on DSTs that recovered water. Consequently, DSTs that recovered significant amounts of oil or gas were not used. If the water recovery was large, a small hydrocarbon recovery was acceptable. More than 500 DSTs were examined; of those, more than 200 were used to supply data for a pressure-elevation chart and potentiometric surface map. These data are summarized in Appendix A.

The DSTs were selected on the basis of three criteria: a significant water recovery indicating good permeability; rapid buildup and stabilization of pressures on shut-in intervals; and the pressure recorder being within the interval tested. In each case, the DST pressure-versus-time chart was examined to ensure the test was mechanically successful and to qualitatively evaluate permeability. In cases where the DST demonstrated very good permeability by a substantial water recovery and rapid stabilization of shut-ins, it was included despite having an outside recorder. Where initial and final shut-in pressures differed, the higher of the two was used, assuming they did not differ significantly; if they did, the DST was not used. Extrapolations to original reservoir pressure, as provided by a data vendor (geoSCOUT®) or the service company, were used when available. Horner plots to achieve the most accurate original reservoir pressure possible were not created for tests lacking pressure extrapolations; however, because only DSTs with pressure readings near or at stabilization were used, they could be expected to be within a few percent of an extrapolated value. For the purpose of potentiometric mapping, a small deviation from total precision should not impair the general result significantly because of the broad contour interval used.

A discussion of how DST charts are interpreted can often be found in the wellfile report supplied by the service company. A very thorough discussion of the use of DST data and petroleum hydrogeology in general is provided in Dahlberg (1995).

RESULTS AND DISCUSSION

Potentiometric surface

Figure 5 shows the potentiometric surface, also known as the hydraulic head, of the Halfway-Doig formations. It represents the height to which a column of water would rise in a wellbore open to the Halfway Formation. It is often considered as the potential energy (not to be confused with hydrocarbon production potential) of the aquifer at that point. Each data point is calculated using the formula

Potentiometric surface = static reservoir pressure / static pressure gradient + elevation

where static reservoir pressure is taken either from a stabilized or an extrapolated shut-in pressure on a DST; the static pressure gradient is the change in pressure over depth of a column of formation water, as determined by the salinity of water samples; and elevation is the height in relation to sea level of the pressure recorder. Because salinity is highly variable, even within a formation at one location, many authors, including Dahlberg (1995), recommend the use of a common static freshwater gradient of 9.7 kPa/m. This is what was done for this study. Although this approach yields different absolute values along the potentiometric surface, in practice the differences are averaged over a region and broad contour intervals (typically 100 m) are not significantly affected.

Potentiometric surface maps can reveal much about an aquifer. Formation water will move from high to low potential energy. Widely spaced contours suggest little change in permeability and low flow rates, whereas closely spaced contours indicate rapid changes or possibly a permeability barrier. Under near-static conditions, structural closure is needed for hydrocarbons to accumulate. Without structural closure

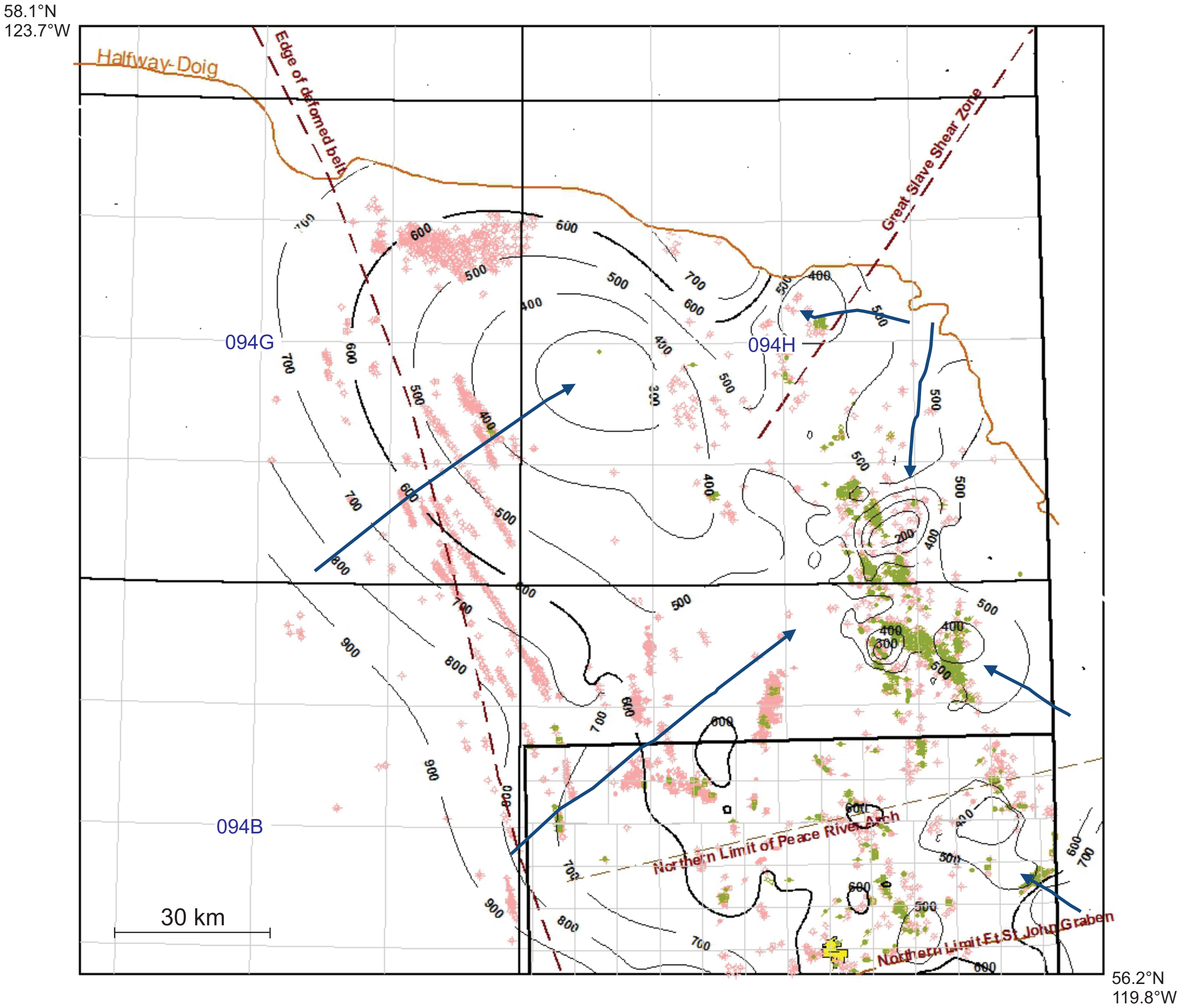


Figure 5. The potentiometric surface (contour interval 100 m) is the height to which formation fluid would rise in a wellbore. Flow is generally from west to east except for apparent reversals from the edge of the Halfway Formation into the centre. Widely spaced contours in the central region indicate small potential differences and little tendency for flow, except for some centres of low potential highlighted by closely spaced concentric contours. Many oil producers (green dots) appear to be clustered near those potentiometric lows. Gas producers (pink dots) tend to be in areas of higher potential. A common water gradient of 9.7 kPa/m was assumed. Inferred flow directions are indicated by blue arrows.

or facies change, trapping can occur hydrodynamically because of different densities (buoyancy) for oil, gas and water. It also depends on whether flow is updip or downdip. Downdip is favourable for oil; updip might allow gas to be trapped under certain conditions. Knowledge of the hydrodynamic situation can explain why in some cases trapping of hydrocarbons can occur in suboptimal structural situations. Under flowing conditions, gas, oil and water will settle into traps suitable for their density. This is why oil, gas and water are separated in both vertical and lateral space (Dahlberg, 1995).

Formation fluid flow in the map area is generally from west to east, except for some apparent reversal occurring from the Halfway Formation edge back into the central area occupied by the oil pools. This confirms generally with established theories (e.g., Toth, 1963) that say aquifer flow conforms largely to topography: water moves from high land to lower land. This seems to hold true here, at least in a general sense, because the ground elevations rise abruptly near the edge of the deformed belt (Fig. 6). Relatively high

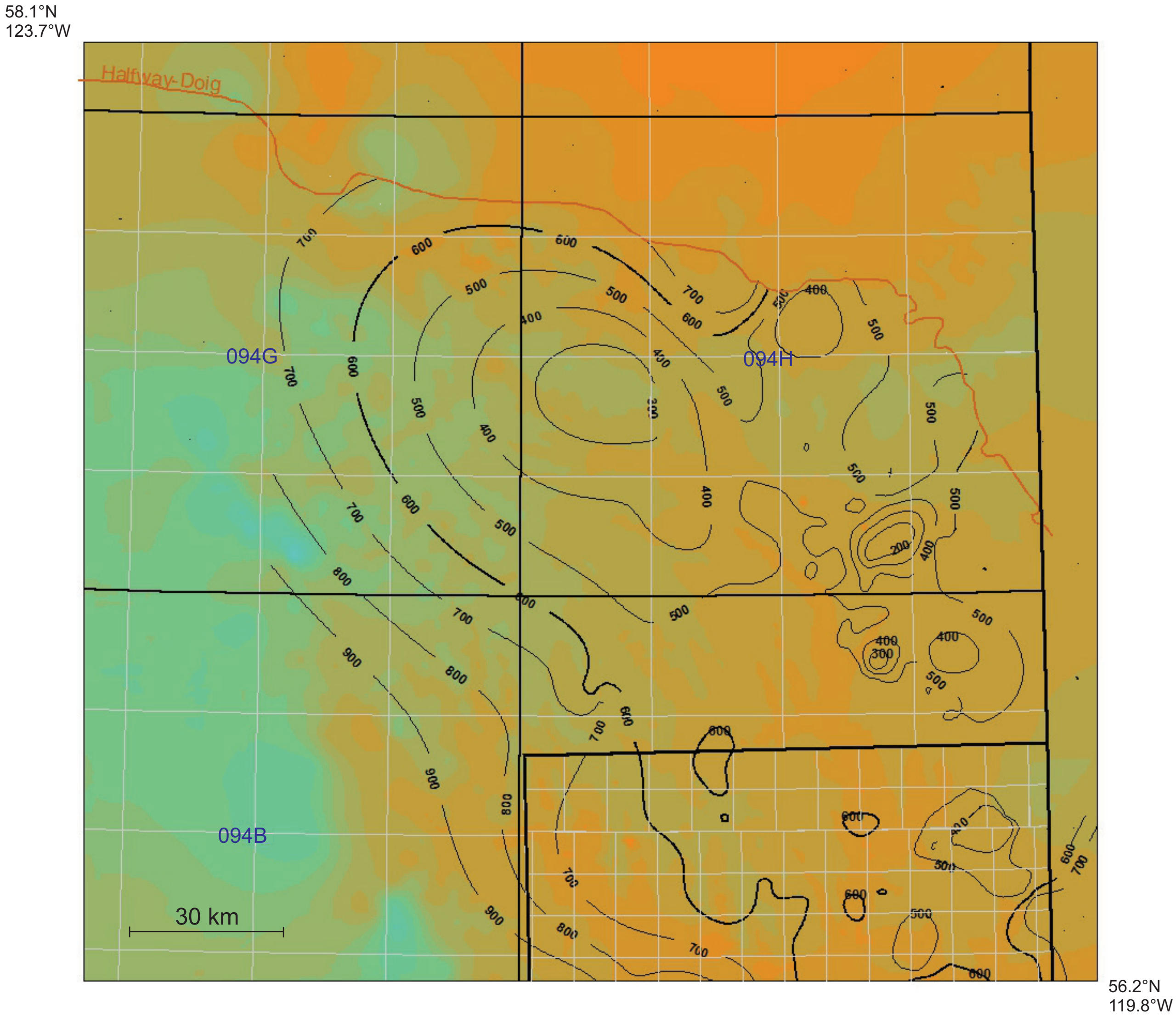


Figure 6. Topography and potentiometric surface: The shading represents topography, based on ground elevations surveyed at more than 18 000 well sites. Green areas are highlands; browns are lowlands. Land rises to the west, flattens in the central region and rises again somewhat to the northwest and northeast. Topography generally conforms to hydrodynamic flow, which goes from the highlands to the west into a central low, and also to some extent from the vicinity of the Halfway-Doig section edge westward back into the centre.

topography also exists east of the Halfway Formation edge and this would be consistent with a change in flow direction. Most Halfway Formation oil pools fall within a region of relatively level and low topography, which also generally conforms to the areas of low potential energy. As a general principle, hydrocarbons will come to rest in an area of low potential energy (Hubbert, 1953).

As well as high potential over the topographically higher land to the west, an area of high potential is present along the northwestern part of the Halfway Formation edge, where it is intersected by the deformed belt. This might be due to some infiltration of the overlying Cretaceous aquifer, which is under relatively higher pressure than the Triassic aquifer (Buschkuehle and Michael, 2006). Where overlying Jurassic aquitards are thin, the Cretaceous might come into contact along the edge. Over most of the study area, the intervening Charlie Lake Formation provides a barrier between aquifers. Another pocket of apparent high potential is present in the southeast corner. There is no ready explanation for that, except perhaps that it falls within an area of known faulting east of Fort St. John, and that environment might introduce other pressure regimes. Topography also rises up slightly in the southeast. Figure 7 illustrates schematically how the Halfway-Doig aquifer comes up against the pre-Cretaceous unconformity and unconformably underlies possible Cretaceous aquifer rock. The Fernie Group, which acts as an effective barrier (aquitard) between aquifers, does not extend to the edge of the Triassic. Overlying aquitards of the Fernie Formation present to the west are absent, approaching the Halfway Formation edge. To the west, the Halfway Formation might be overlain by several hundred metres of Triassic or Jurassic rock; near the eastern edge of the Formation, the Triassic section might be less than 100 m thick. As a result, recharge or infiltration could be occurring in proximity to the Halfway Formation edge where aquitards are thin or absent; it might also be occurring near the edge of the disturbed belt, where structural dislocation might have brought different aquifers into contact with each other or possibly in contact with the surface.

Pressure depth

Figure 8 shows pressure plotted against elevation. Most points plot along a common gradient of approximately 11.5 kPa/m, which means that for every metre of depth the pressure increases by 11.5 kPa due to the weight of overlying water. The freshwater gradient is approximately 9.7 kPa/m and water of the salinity normally expected for the Halfway Formation would be approximately 11.0 kPa/m. The gradient is somewhat higher (lower slope) than would normally be expected for water with salinities and densities typically found in the Halfway Formation. The gradient for a pressure-depth plot by Kirste et al. (1997) shows close agreement.

Dahlberg (1995) demonstrates that a less than hydrostatic slope is an indication of updip flow in the aquifer. Hitchon et al. (1990) explain that a less than hydrostatic slope, which is seen in Figure 8, indicates a vertical (upward) component to flow. The combined forces of gravity flow and buoyancy effects on waters of varying density create a deviation from normal hydrostatic. An alternative explanation—or perhaps an adjunct—is the possibility of a leaking aquifer. This would produce a gradient different from one caused only by the density of water. Some leakage seems likely, particularly near the edges of the Halfway Formation, where overlying aquitards thin.

Despite the strong linear trend displayed in Figure 8, a number of points plot away from the gradient, either on the relatively underpressured (left) or overpressured (right) side. Figure 9 shows where these wells are located. As might be expected, those on the underpressured side fall within areas of low potential energy and those on the high-pressured side are mostly located along the high-potential rim near the deformed belt and the erosional edge, which might be indicative of recharge from the overlying Cretaceous aquifer.

If a normal saltwater gradient (11.0 kPa/m) is drawn from an elevation typical for the Peace River region (approximately 800 m above sea level) and is projected to depth, it plots to the right (higher pressure) side of the Halfway Formation gradient. This indicates that the Halfway Formation is at a lower pressure than would result from a static column of typical formation water. One possible explanation for this observation is that a pressure equilibrium was reached before the end of the Triassic, when the Halfway Formation and other Triassic horizons became well lithified and isolated from overlying influences. Pressures remained constant despite the erosional episodes that followed. Afterward, during the Cretaceous, more sediment was deposited than was previously eroded. As a result, the pressure observed today is a result of the preserving effects of early compaction and lithification, which would explain the lower than normal values expected for the thickness of overburden.

The reader might question the validity of much of these pressure data because the oil fields have been producing for decades from many wells and pressures must have been artificially lowered; however, a close examination of this dataset affirms its validity. Most DSTs used for this study recovered abundant water and for that reason did not produce any great quantities of formation fluids that would have altered formation pressures. This is also true for nearby offsets. In addition, the well density around most of the data points is actually not as high as might be suggested by the

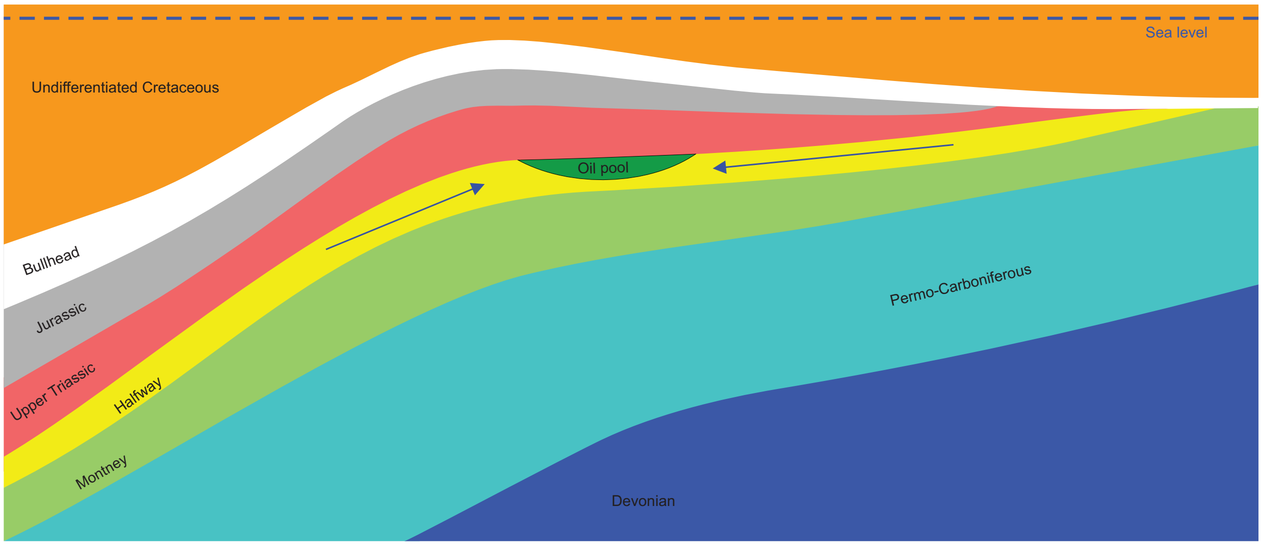


Figure 7. This schematic cross-section illustrates how the Halfway Formation comes up against the Bullhead aquifer to the east. Fresh recharge might take place along the edge. Hydrodynamic flow is mostly updip from west to east, except for a small reversal from the edge. The arrows show inferred direction of formation fluid flow and suggest a possible mechanism for oil entrapment approximately where flow is slowed in an area of lower potential.

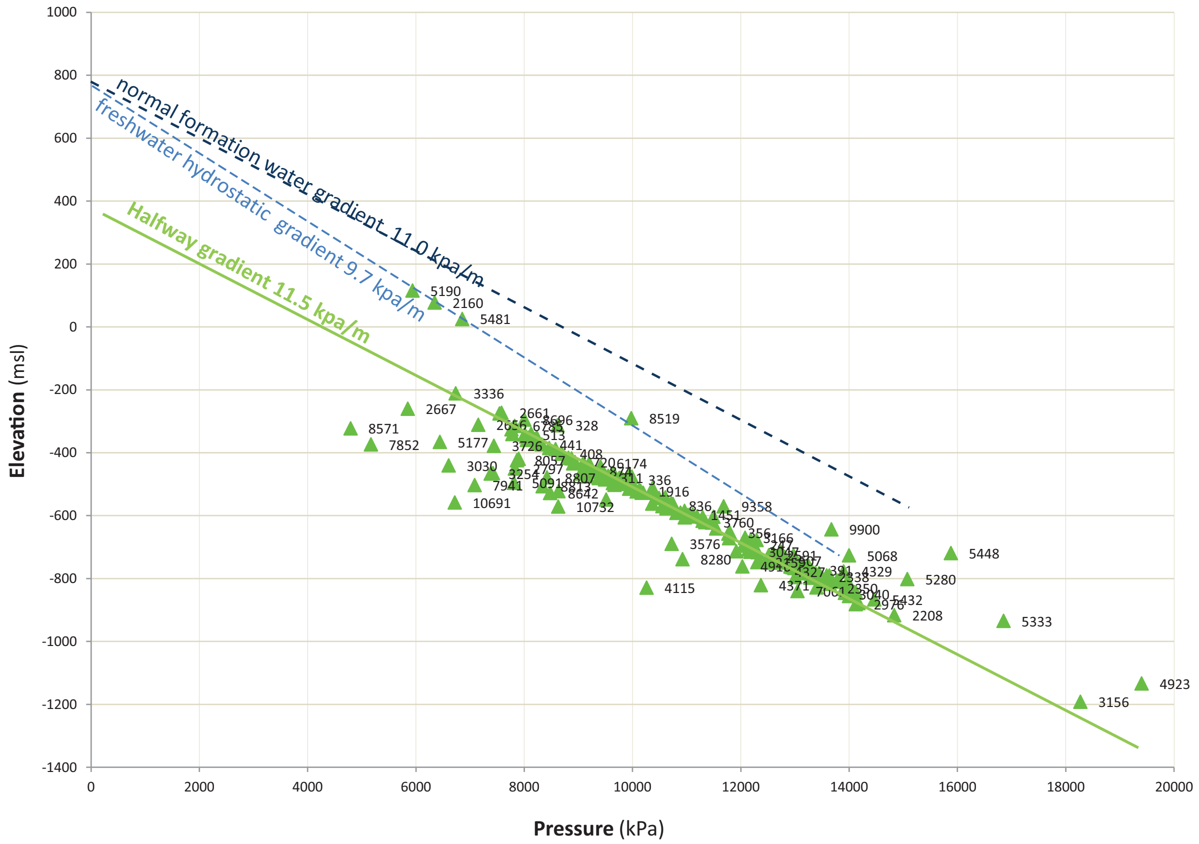
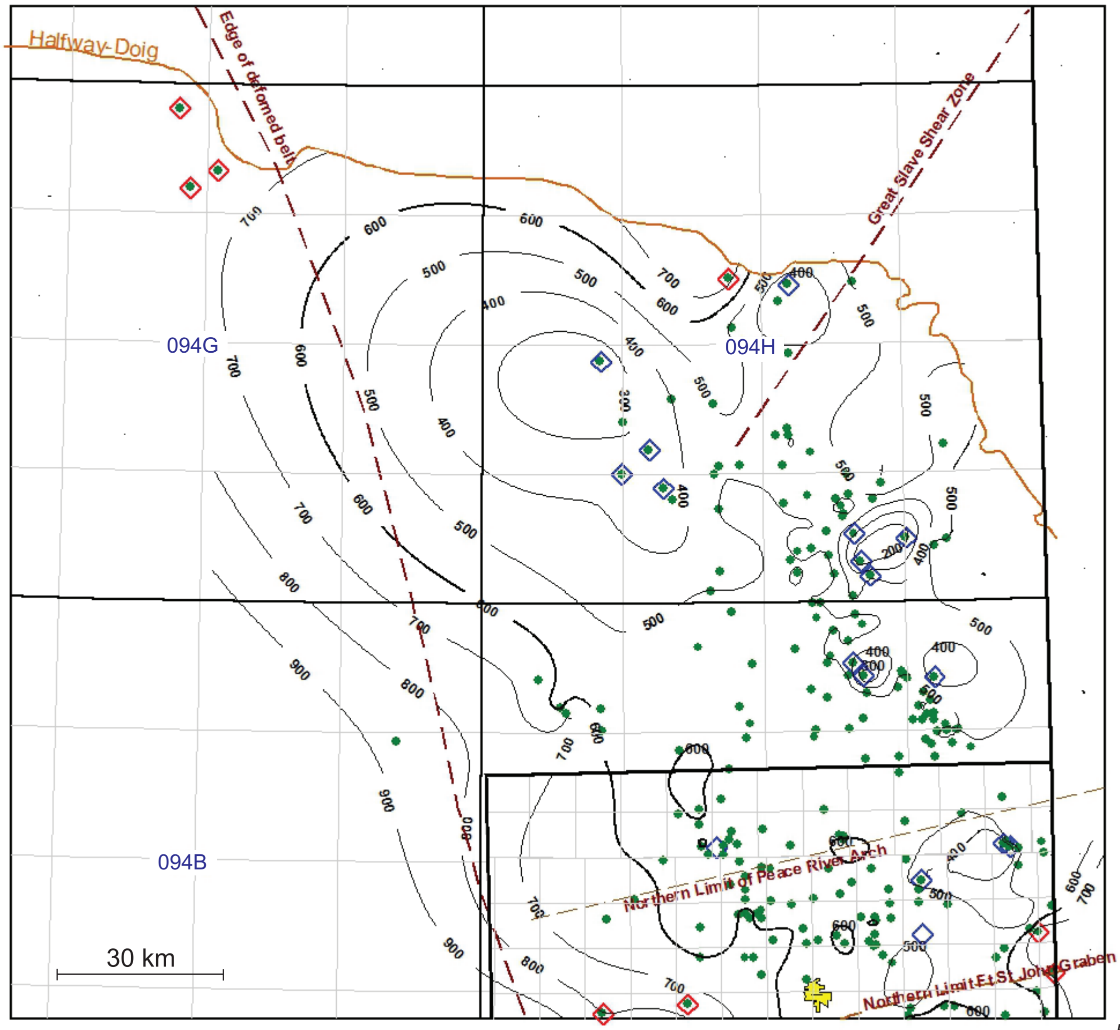


Figure 8. Pressure versus elevation (kPa vs. m elevation): Most data fall along a gradient of approximately 11.5 kPa/m. A freshwater gradient is 9.7 kPa/m and a normal saltwater gradient for the Halfway Formation (120 000 mg/L) is approximately 11.0 kPa/m. These water gradients are plotted assuming zero pressure at surface, which occurs at an elevation of approximately 800 m. The Halfway Formation pressure regime is lower than the water gradients. Locations on the higher pressure side (right) tend to be in areas of higher potential (see Fig. 5) and those on the lower pressure side (left) of the gradient tend to be in areas of low potential. Data points are labelled with well authority (WA) numbers. Due to space limitations not all points are labelled.

58.1°N
123.7°W



56.2°N
119.8°W

Figure 9. High and low pressures: The green dots represent data points used in this study. Blue diamonds highlight wells on the low pressure (left) side of the Halfway Formation gradient of Figure 8. They tend to fall within low-potential areas. Red diamonds indicate wells on the high-pressure (right) side of the gradient. They are generally in areas of higher potential. These wells with pressures on either side of the normal pressure-depth gradient may be within separate pressure regimes.

mapping; offsetting wells are generally more than 1 km away and likely outside the radius of influence.

Salinity

Figure 10 plots salinity (in mg/L) analyses from DSTs or production test water samples. Not all available water tests were used; standard culling procedures as outlined by Johnson (1991) were used to select values representative of the actual formation waters. The values displayed are generally from substantial water recoveries taken from the bottom of the water column (fresh and filtrate waters tend to be near the top). They have pH values in the range of 6–8 and an ionic composition consistent with formation waters for the area. 'Stiff' diagrams (Fig. 11) available in the wellfiles provide a qualitative check on the validity of a sample; a valid water sample should have an ionic composition that provides a characteristic shape. If a sample does not meet the aforementioned criteria, it is culled from the compilation of salinity data. In practice, more samples are culled than accepted.

Most salinities fall in the range of 90 000–150 000 mg/L, but vary widely over short distances.

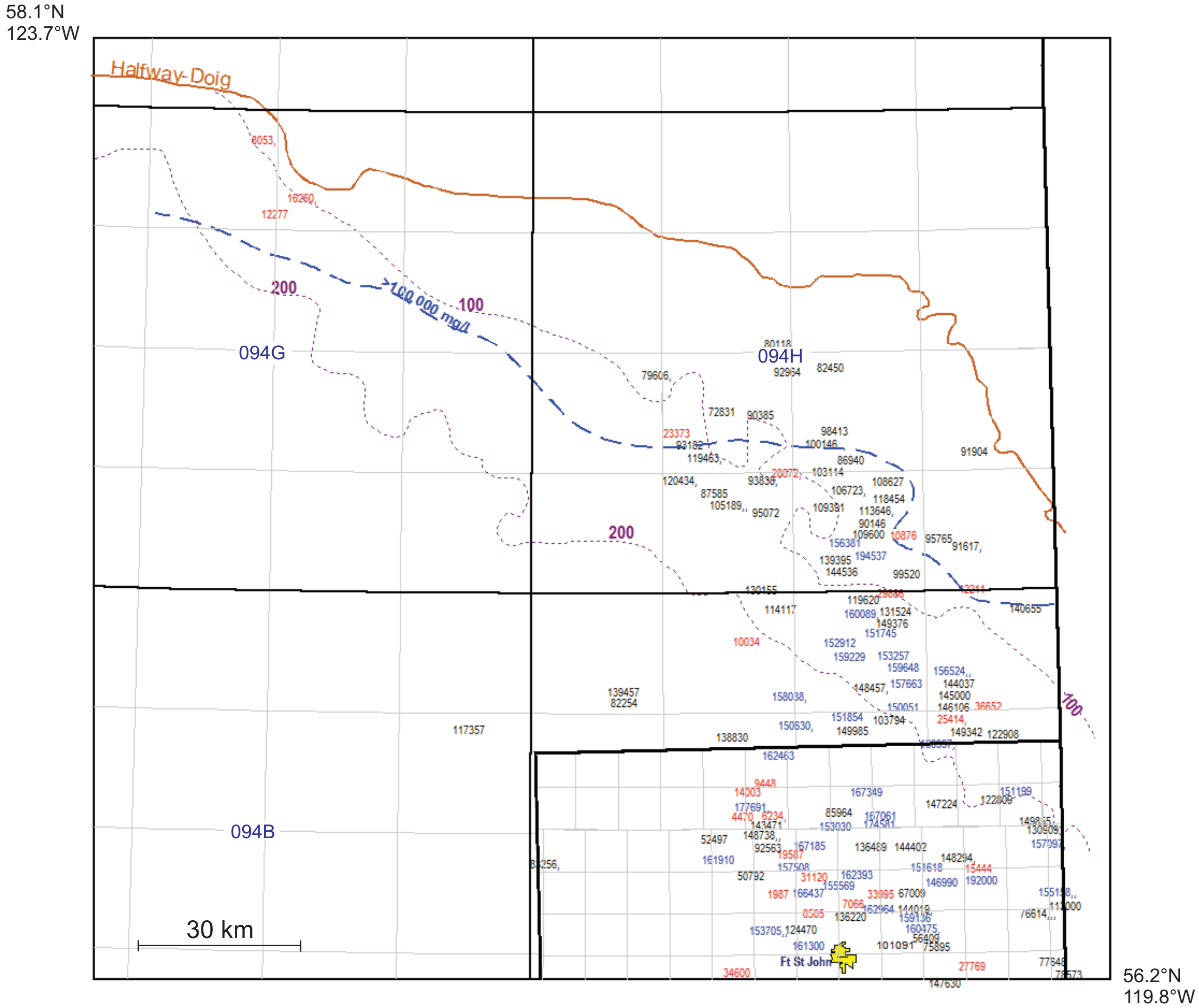


Figure 10. Halfway Formation water salinity map (mg/L): Red values represent water samples lower than 50 000 mg/L; the records suggest they are valid. Not all values are placed exactly adjacent to their well. Some valid salinities are not shown due to lack of space (refer to Appendix A for a complete list). Salinity is generally lower near the Halfway Formation edge. North of the blue dashed line, salinities are lower than 100 000 mg/L. Salinities greater than 150 000 mg/L occupy the central part of the study area and are shown in blue. The magenta dashed contours indicate the isopach (in metres) between the sub-Cretaceous unconformity and the Halfway Formation.

The practice of water sampling is historically far from standard. Over the decades, service companies and individual samplers have used different methods, so results can be difficult to compare. As well, each DST yields results particular to the formation at that location. Little precision can be attached to the results and care must be taken when making comparisons from well to well.

Nevertheless, if suspect analyses are culled so that only the most trustworthy analyses are used, salinities can be plotted and a few tentative observations can be made. For example, over the central part of the study area higher salinities of more than 150 000 mg/L tend to coincide, more or less, with Halfway Formation oil production. This might be evidence for a concentrating effect in the central region where flow slows. A number of anomalously low salinity values—verified as valid bottom-hole samples and representative stiff diagrams—seem to follow a northwest trend near the town of Fort St. John. Perhaps this could be related to some structural activity, parallel to the deformed belt, locally introducing fresher waters to the Halfway Formation. There are several apparently valid, but anomalous, low salinities at the northwest corner of

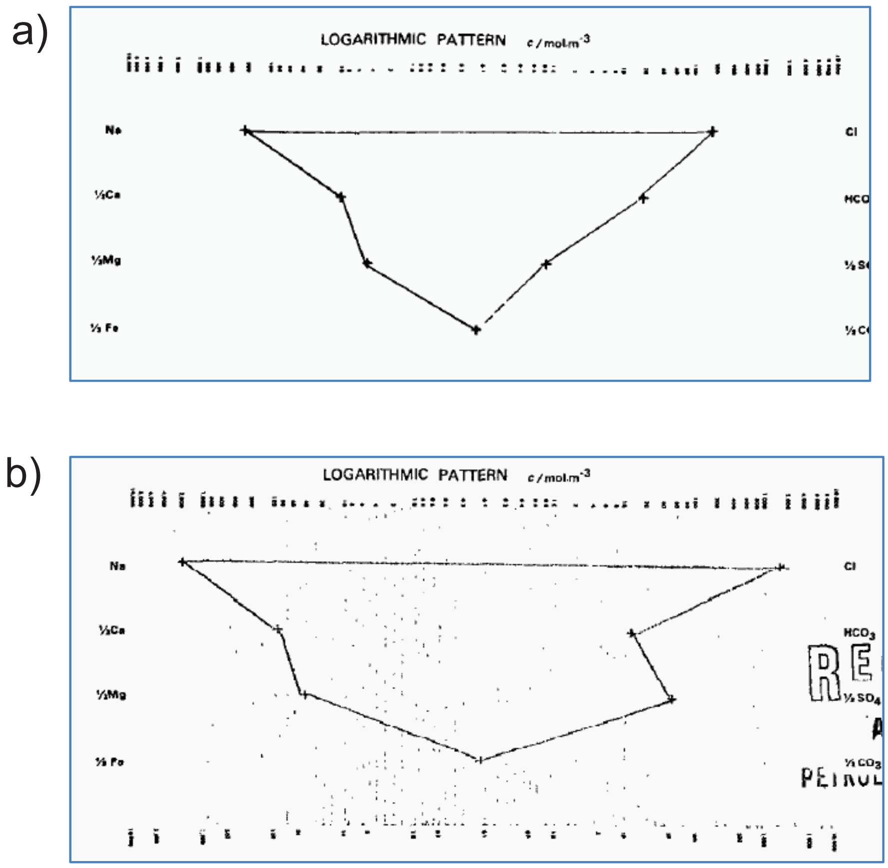


Figure 11. Stiff diagrams: a) Stiff diagram from location c-55-A-94-G-14, WA 5190, DST 1. This Halfway Formation sample was taken from the bottom. The stiff diagram shows readings similar to a typical Upper Cretaceous formation water. It is located near the Halfway Formation limit and west of the edge of the deformed belt. Salinity is 12 277 mg/L. b) Stiff diagram for location d-53-D-94-H-6, WA 5091, showing a typical shape for Halfway Formation water samples in the area. Salinity is 119 463 mg/L.

the map area, with characteristics similar to Upper Cretaceous waters. This would suggest recharge from Upper Cretaceous aquifers where Jurassic aquitards thin near the Halfway Formation edge. Alternatively, it could be due to structural dislocation along the edge of the deformed belt. Salinities are somewhat lower near the Halfway Formation edge, which could be a result of near-contact with the Cretaceous. Dashed lines in Figure 10 show an approximate isopach for the interval between the sub-Cretaceous unconformity and the top of the Halfway Formation. A clear connection between salinity and isopach is not evident, except that the line for salinity less than 100 000 mg/L and the 100 m isopach are subparallel. Also, the isopach is clearly very thin near the Halfway-Doig section edge in NTS 094G, where three low salinities are found.

SUMMARY AND CONCLUSIONS

Data from more than 200 DSTs were used to construct a pressure-elevation chart and potentiometric surface map for the Halfway Formation in northeastern British Columbia. Pressures for most wells fall along a common gradient. The gradient, or slope, is higher than normal hydrostatic, which is an indication that the flow of formation fluids is updip. Pressures located outside the common gradient generally fall along the edges of the study area near the erosional edge, the disturbed belt or in areas of lowest potential energy. The potentiometric surface map shows that formation fluid flow is generally to the northeast into a central low-potential area where most of the oil pools are located. Some reversal of flow direction appears to occur from the Halfway Formation edge westward into the centre. The coincidence of low potential with oil production seems to suggest that hydrodynamics is an important factor in the location of oil accumulations. Relatively high formation water salinities tend to occur in areas of low potential. Gas has accumulated largely in areas of higher potential. Lower salinities near the Halfway Formation edge might be due to infiltration of fresher water from the overlying Cretaceous aquifer.

When abundant DST data are available, as is the case for this study of the Halfway Formation in northeastern British Columbia, petroleum hydrogeology can be a valuable adjunct to other forms of geological examination such as stratigraphy, sedimentology and structure. It deals with the fundamental object of economic interest: the movement and resting place of hydrocarbons and other fluids within the target formation. It can provide clues about what would happen to fluids or gases under pressure (such as produced waters) and it can be used to point to new areas for exploration not necessarily revealed by seismic surveys or other methods of geological mapping.

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APPENDIX A

DATA USED TO DRAW THE POTENTIOMETRIC SURFACE AND SALINITY MAPS; WELLS ARE ARRANGED IN ORDER OF WELL AUTHORITY (WA) NUMBER.

WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m	WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m
311	a-31-k-94-a-15	Beatton	152 319	495	2828	d-98-g-94-h-2	Milligan	90 146	471
328	a-77-i-94-h-2	Hunter	103 642	575	2976	10-18-83-16w6	Two Rivers	147 630	575
336	b-23-d-94-a-16	Doig River	124 960	541	2999	6-22-86-20w6	W. Stoddart	19 587	572
408	d-39-k-94-h-2	W. Beatton	132 189	494	3009	10-8-87-20w6	W. Stoddart	4339	592
441	d-48-k-94-h-2	W. Beatton	107 083	485	3010	11-12-84-19w6	Ft St. John	18 986	578
513	d-40-j-94-h-2	Beatton	114 331	483	3030	a-67-i-94-h-5	Spangler	79 606	241
699	d-87-d-94-h-7	Beatton River	100 628	480	3040	11-27-84-21w6	Goose	44 987	602
720	b-70-b-94-h-2	Weasel	128 357	491	3047	11-35-85-17w6	Pluto	152 241	541
721	c-39-i-94-h-2	Alder	107 087	462	3055	7-31-86-16w6	Siphon	11 949	557
874	d-61-d-94-h-2	Donis	144 536	495	3068	11-2-87-14w6	Boundary	130 002	531
987	d-17-a-94-h-6	Pickell	28 872	485	3083	10-32-87-21w6	Teal	7007	593
1012	d-64-d-94-a-16	Buckthorn	137 846	512	3092	b-7-j-94-h-2	Beatton	89 300	488
1190	11-10-86-20w6	Stoddart	157 508	580	3141	b-48-f-94-h-1	Drake	37 500	503
1224	c-13-h-94-a-15	Peejay	80 000	554	3156	b-46-b-94-a-13	Inga	82 254	692
1300	d-11-e-94-h-2	Pure Donis	128 792	492	3159	c-99-g-94-a-14	Umbach	10 034	551
1401	a-27-f-94-h-2	Pure Donis	156 381	493	3166	6-9-86-16w6	Gopher	6364	575
1447	b-3-e-94-h-7	Eucalyptus	98 413	480	3197	7-30-86-19w6	Stoddart	2000	527
1451	10-9-87-14w6	N. Boundary	149 855	549	3218	11-27-84-17w6	Cecil	140 000	579
1599	d-2-f-94-h-2	Donis	194 537	493	3254	c-20-e-94-h-6	Martin	17 300	294
1763	d-33-i-94-a-10	Rigel	160 997	531	3278	d-39-a-94-h-11	Mercury	80 118	479
1859	d-68-k-94-a-9	Melanie	162 059	531	3336	a-69-c-94-h-8	Velma	91 904	483
1873	d-27-g-94-a-15	Wolf	89 178	511	3388	6-13-86-18w6	Oak	37 500	579
1880	d-15-d-94-h-7	Beatton	103 114	496	3399	6-13-84-20w6	Wilder	161 300	610
1911	d-97-k-94-a-15	Falcon	78 657	500	3564	6-17-86-20w6	Stoddart	9688	590
1915	d-73-c-94-a-15	Beavertail	148 457	542	3576	10-16-86-16w6	Siphon	119 000	416
1916	d-82-b-94-a-15	Wolf	157 663	525	3726	c-60-a-94-h-2	Weasel	82 100	390
1924	d-7-j-94-a-15	Grouse	84 168	503	3738	d-53-f-94-a-15	Raccoon	154 537	526
1951	6-6-86-18w6	Stoddart	162 393	579	3760	6-29-87-16w6	Rigel	147 224	549
1959	11-34-85-19w6	Stoddart	155 569	582	3770	11-15-85-21w6	Red	38 159	554
2032	b-26-d-94-a-16	Fox	146 106	527	3928	6-10-85-18w6	W. Eagle	162 964	603
2093	d-22-h-94-a-15	Peejay	127 000	466	3931	c-94-j-94-h-3	Pickell	96 000	491
2130	b-64-g-94-h-6	Bercli	90 385	505	3967	6-2-85-18w6	Eagle	27 578	607
2159	10-25-86-20w6	Stoddart	166 885	521	3972	d-13-j-94-h-3	S. Wargen	95 075	507
2160	c-97-d-94-g-15	Prophet	16 260	732	4005	6-11-86-17w6	Pluto	151 618	552
2208	16-21-85-23w6	Coplin	4905	613	4008	7-21-87-20w6	W. Stoddart	4500	567
2235	d-33-d-94-a-16	Currant	75 000	526	4091	c-97-c-94-a-15	Beavertail	151 621	518
2350	6-28-85-20w6	Mallard	7990	599	4128	16-6-85-19w6	Mallard	8505	611
2417	d-53-k-94-a-9	Osborn	122 908	513	4285	b-6-a-94-a-13	Fireweed	81 052	570
2507	10-5-85-17w6	Cecil	4408	573	4323	d-97-i-94-h-6	Redeye	92 964	498
2523	6-1-85-19w6	Badger	136 220	588	4327	7-33-86-20w6	W. Stoddart	92 563	546
2571	6-28-86-18w6	Montney	136 489	544	4329	b-24-f-94-a-13	Inga	145 390	656
2584	7-11-87-21w6	W. Stoddart	4470	603	4383	16-6-85-18w6	Eagle	7068	586
2591	11-8-88-20w6	Silverberry	9948	565	4408	11-33-85-16w6	Gopher	146 990	553
2656	d-73-l-94-h-7	Lapp	82 450	426	4426	6-27-85-20w6	Stoddart	2929	616
2661	b-44-g-94-h-10	Gutah	64 300	508	4429	11-33-88-20w6	Buick	148 000	590
2667	d-33-e-94-h-10	Lapp	65 313	343	4459	d-31-h-94-a-14	Maple	153 714	532

WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m	WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m
2741	b-6-c-94-a-15	Rigel	151 854	525	4466	7-27-86-14w6	Boundary	157 097	560
2780	6-16-87-20w6	W. Stoddart	6234	570	4511	16-22-85-20w6	W. Stoddart	1987	612
2797	a-23-e-94-a-16	Peejay	16 569	357	4639	d-97-k-94-a-9	Currant	51 642	529
4730	10-35-86-22w6	N. Red	52 497	588	6981	6-32-84-14w6	Boundary	2209	575
4901	8-26-85-20w6	Stoddart	6132	591	7061	9-19-83-16w6	Two Rivers	37 849	505
4916	10-23-84-17w6	Flatrock	101 091	479	7107	10-18-83-13w6	Clayhurst	20 000	611
4921	d-55-k-94-11	Buick	138 830	599	7200	d-86-i-94-a-11	Buick	150 630	550
4923	c-74-k-94-b-9	Cameron	117 357	867	7412	11-21-85-17w6	N Pine	67 009	588
4962	6-2-88-21w6	Spirea	14 003	612	7419	c-58-b-94-a-13	Inga	139 457	598
4977	d-80-i-94-a-14	Prespatou	114 117	552	7686	d-58-a-94-a-14	Buick	11 000	582
5008	14-25-85-20w6	Stoddart	4209	588	7735	16-3-86-18w6	Oak	119 000	575
5028	6-11-87-19w6	Montney	153 030	577	7754	a-7-b-94-a-15	Rigel	103 794	545
5043	11-26-84-20w6	Tea	124 470	615	7762	c-75-l-94-a-9	Currant	147 055	521
5091	d-53-d-94-h-6	Wargen	120 365	309	7852	b-93-b-94-h-2	Weasel	104 900	159
5110	c-94-k-94-a-15	Kestrell	119 620	498	7941	d-23-g-94-a-15	Peejay	159 658	228
5136	d-13-a-94-h-6	Pickell	80 400	499	7995	c-96-k-94-a=9	Currant	32 471	470
5159	6-8-87-13w6	Boundary	109 600	525	8057	b-15-b-94-h-2	Weasel	29 886	387
5177	d-55-g-94-h-2	Milligan	9860	298	8403	b-9-c-94-a-16	Currant	25 414	494
5190	c-55-a-94-g-14	Prophet	12 277	728	8519	a-60-h-94-h-11	Mars	9031	738
5270	d-35-d-94-a-16	Buick	150 792	516	8571	c-50-e-94-h-1	Woodrush	96 765	171
5280	10-29-83-21w6	Monias	36 883	753	8642	c-36-k-94-h-3	Birley	20 000	346
5318	6-22-88-15w6	Cardinal	135 320	524	8663	a-72-f-94-a-15	Osprey	149 888	495
5333	6-21-83-23w6	Fox	20 458	803	8696	d-22-e-94-h-1	Drake	91 617	531
5370	c-25-b-94-h-3	Prespatou	130 155	507	8712	c-99-k-94-a-9	Currant	19 300	486
5392	d-86-d-94-a-16	Peejay	144 037	529	8807	c-55-g-94-a-15	Peejay	153 257	390
5409	6-9-85-17w6	Cecil	144 019	570	8813	d-69-k-94-h-3	Birley	87 585	354
5432	7-6-86-22w6	Bluejay	128 289	625	8891	1-4-88-18w6	Rigel	167 349	543
5448	6-24-87-19w6	Squirrel	85 964	918	8899	4-28-86-17w6	Oak	144 402	556
5481	a-49-i-94-g-14	Bunch	8053	732	9111	13-33-84-17w6	Flatrock	95 000	575
5491	6-9-88-14w6	N. Boundary	29 087	557	9164	2-6-86-19w6	Stoddart	31 120	580
5496	d-25-l-94-h-2	W. Beatton	109 391	497	9358	3-13-87-18w6	Muskrat	22 736	634
5518	d-47-c-94-h-7	Elm	86 940	484	9391	14-12-87-18w6	Oak	163 491	553
5720	d-93-a-94-a-15	Lynx	155 126	527	9421	11-13-87-18w6	Muskrat	174 581	578
5771	6-17-83-14w6	Alces	8338	584	9457	b-32-j-94-a-10	Rigel	18 000	545
5814	d-23-b-94-a-15	Beavertail	150 051	523	9515	10-36-83-14w6	Boundary	6000	598
5868	14-24-85-20w6	W Stoddart	141 705	586	9598	16-14-87-18w6	Muskrat	167 061	547
6134	7-21-85-17w6	Bison	119 000	605	9668	d-91-i-94-h-4	Nig	120 434	368
6174	d-43-j-94-a-15	Osprey	149 376	526	9829	d-54-h-94-a-14	Buick	12 700	540
6253	d-93-d-94-h-2	Big Arrow	139 395	511	9900	A8-12-85-14w6	Boundary	113 000	766
6303	d-65-j-94-a-15	Osprey	131 524	511	10 087	14-24-83-16w6	Two rivers	4385	631
6359	A6-26-87-21w6	W. Stoddart	177 691	591	10 227	d-77-d-94-h-6	Wargen	93 182	300
6364	8-33-87-15W6	Alberta Lagarde	122 809	545	10 352	d-64-l-94-a-9	Currant	140 000	515
6501	a-92-e-94-a-15	Bluebird	152 912	538	10 377	16-30-88-16w6	Rigel	123 000	519
6616	d-87-k-94-a-10	Rigel	149 985	548	10 691	6-9-87-14w6	N. Boundary	98 000	134
6647	a-63-f-94-h-2	W Milligan	109 600	488	10 732	13-3-87-14w6	N Boundary	142 000	318
6690	a-66-k-94-a-15	Dede	160 089	526	11 187	12-27-84-20w6	Bear Flat	153 705	615
6716	15-19-85-17w6	N Pine	33 995	590	11 526	c-57-d-94-a-16	Currant	145 000	495
6739	7-1-87-21w6	W Stoddart	148 738	573	12 029	a-29-d-94-a-16	Rigel	150 000	524
6785	b-96-j-94-h-2	North Beatton	108 627	492	12 670	c-46-j-94-h-2	Beatton	118 454	475
6811	d-83-d-94-h-7	Elder	87 506	498	16 670	b-76-f-94-h-6	Martin	72 831	395
6921	10-23-85-17w6	W Flatrock	16 979	516	19 065	5-31-85-15w6	Paradise	192 000	545

FORT ST. JOHN OIL FIELD: NORTH PINE A POOL

Ed Janicki[1]

ABSTRACT

The North Pine A pool in the Fort St. John oil field is one of the oldest oil discoveries in British Columbia. Like most early oil discoveries in BC, exploration was facilitated by proximity to the Alaska Highway, which was built in the 1940s to improve access to Alaska during World War II. The discovery well at 3-14-83-18W6 was drilled by Pacific Petroleum Ltd. in 1952 and was initially completed in the Baldonnel Formation, although their original drilling licence indicates they expected production to be from the Permo-Pennsylvanian.

Oil production started in 1956 and remained steady until approximately 1992, with two or more wells always producing. A steady decline began circa 2000. Water cut has averaged approximately 12% over the life of the pool; this percentage has not increased greatly over time. The estimated original oil in place is 4 231 500 barrels, of which 2 080 960 barrels have been produced as of October 2012. This represents a very efficient recovery rate of 50%, assisted by gas expansion in a permeable reservoir.

Some level of communication for the North Pine exists over the entire pool but a partial permeability barrier appears to impede communication between north and south. The North Pine is thin and discontinuous, so trapping appears to be primarily stratigraphic. Seismic shows it is truncated to the north by a fault, so structure appears to constrain the pool in that direction. The North Pine was deposited as a winnowed, narrow and linear shoreface sand trending north-northeast. Production has declined along with a decline in pool-wide pressures. A secondary recovery scheme could be effective because good permeability in the North Pine should permit good receptivity of water or gas injected to increase pressure.

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Keywords: North Pine, pool, oil, permit, water-cut, Triassic, pressure survey

DEVELOPMENT HISTORY

The North Pine A pool in the Fort St. John Oil Field is one of the oldest oil discoveries in British Columbia (Table 1). Like most early oil discoveries in the province, exploration was facilitated by proximity to the Alaska Highway (Fig. 1), which was built in the 1940s to improve access to Alaska during World War II.

Oil and gas rights for this pool were first issued as permit 22 by the Government of British Columbia to the Peace River Natural Gas Company in 1949. Reconnaissance geological mapping was done during the summers of 1949–1950 (Falconer, 1951) to fulfill the requirements of this permit. In the course of their mapping, the Peace River Natural Gas Company identified what they believed was a promising structure. Further encouragement was provided by oil shows in the Lower Cretaceous and Upper Triassic sections from previous drilling in the area. Seismic surveys were not used because the technology was still in a rudimentary state at that time.

Discovery well 3-14-83-18W6 was drilled by Pacific Petroleum Ltd.[1] (Pacific) in 1952 and was initially completed in the Baldonnel Formation (formerly known as Triassic A in the 1950s), although

[1] The relationship of Pacific Petroleum Ltd. with the original permit holder, Peace River Natural Gas Company, is uncertain.

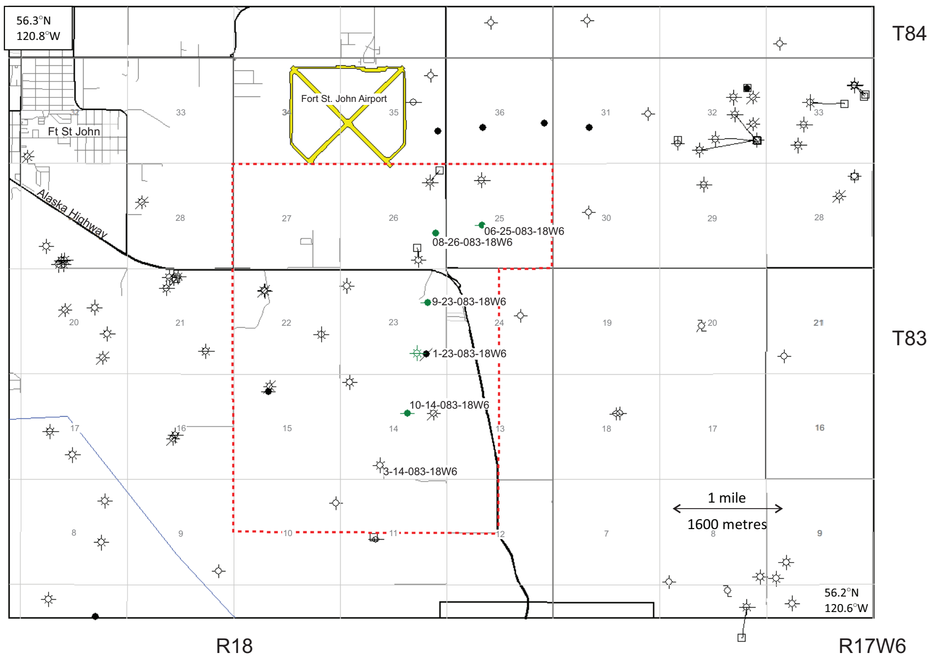

Figure 1. Fort St. John Oil Field North Pine A pool: The North Pine A pool is outlined in a dashed red line. North Pine A oil pool wells are shown by green symbols.

their original drilling licence indicates that they expected production to be from Permo-Pennsylvanian strata (now known as the Belloy Formation). The Baldonnel Formation was subsequently squeezed off and the hole was recompleted as a North Pine (formerly known as Triassic C) oil well in 1956, which produced between 1956 and 1991. Other wells followed soon after, with some of those later wells also being completed unsuccessfully in the Baldonnel Formation. Pacific was likely aware of oil shows and porosity in drillcore and cuttings from lower members of the Triassic section such as the North Pine because such wells were not abandoned despite poor results from the Baldonnel Formation or the lack of shows from the Permo-Pennsylvanian strata.

It is not entirely clear from early geological reports (e.g., Falconer, 1951[2]) why Pacific was astute enough to drill along a constrained northeasterly trend. In those early reports of the 1950s, Pacific and other operators had difficulties getting good seismic data in terrain dissected by deep river valleys, and the technology was very basic then. Airborne scintillometer, magnetometer and electrical methods (along with surface mapping) formed the basis for their understanding of structure and possible hydrocarbon traps. Based on previous drilling experience, they knew that there was sandstone with good hydrocarbon potential several hundred feet below the top of the Triassic section, but they did not hint at knowledge of facies or trends. Early slim holes were used successfully as a quasi-substitute for seismic surveys in the hopes of identifying large drillable structures. From those holes, they were able to obtain some stratigraphic knowledge, but only to depths of approximately 1200 ft. (approximately 365.8 m). Their surface mapping would not reveal anything about the thin-bedded Charlie Lake Formation lying several thousand feet deeper.

In 1978, Pacific was acquired by the newly formed national oil company, Petro-Canada Inc., which took over operation of the original wells in sections 14 and 23. After several other transfers of interest, the oil and gas rights for the Charlie Lake Formation eventually came to be held by Penn-West Petroleum Inc. (Penn-West). The lands on which wells were later drilled in the northern part of the pool have had a complex ownership history, but they are now operated by Penn-West as well.

PRODUCTION

Oil production began in 1956 and remained steady

[2] Reports submitted by operators as work requirements to hold permits are available for the public to view at the office of the British Columbia Ministry of Natural Gas Development, 1810 Blanshard St., Victoria, British Columbia. Most were done in the early years of exploration, so they are mainly of historical interest; however, many contain information that could be of use to current operators. Titles and contact information for making an appointment are given in the PNG Contact Information Guide, found at: http://www.empr.gov.bc.ca/TITLES/OGTITLES/OTHERPUBLICATIONS/Pages/default.aspx

TABLE 1. RESERVOIR PARAMETERS FOR THE NORTH PINE A POOL IN THE FORT ST. JOHN OIL FIELD

FORT ST. JOHN OIL FIELD

North Pine A pool

Pool Parameters

Field code: 3600 **Pool code:** 4580A
Formation: Charlie Lake, North Pine member
Discovery well original name: Pacific Fort St. John No. 9 3-14-83-18W6 **WA#:** 00034
Current operator: Penn-West Petroleum Ltd.
Rig release: July 11, 1952
Other oil and gas shows: North Pine gas, Halfway gas, Baldonnel gas
Number of wells (as of October 2012): Oil: 6 Gas: 2 Active: 2

Reservoir Data

Area of pool: 892 acres, 361 ha
Average depth of producing zone: 4350 ft., 1326 m
Lithology of reservoir rock: sandstone
Trap type: structural/stratigraphic
Estimated maximum reservoir thickness: 3.5 m
Drive mechanism: gas cap expansion
Average porosity: 13%
Average net pay: 1.5 m
Average permeability: 83 mD
Average water saturation (%): 25
Oil formation volume factor (%): 127
Gravity: 41° API
Original pressure: 1919 psi, 13 231 kPa

Reserves

Estimated original oil in place: 4 231 500 barrels, 672 734 m^3 (volumetric)
Recovery factor (%): 50
Estimated recoverable oil: 2 115 750 barrels, 336 367 m^3
Cumulative oil production: 2 080 960 barrels
Remaining recoverable oil: 34 790 barrels
Remaining original oil in place (%): 51
Cumulative water production: 171 050 barrels

until approximately 1992, with two or more wells always producing. A steady decline began circa 2000 (Fig. 2). In the past ten years, only one or two wells have been under production at any given time; the decline in production can be attributed both to general depletion and the number of producers. In the early days of pool development, individual wells could produce approximately 70 barrels/day. Recent production levels have been approximately 6 barrels/day.

Water production does not appear to have been a major problem because water cut has averaged approximately 12% over the life of the pool; this percentage has not increased greatly over time. No water disposal wells or injectors are used for this pool. Produced water is taken by truck to a disposal well operated by Newalta Corporation at location 15-5-83-17W6.

A plot of pressure survey readings (Fig. 3) for individual wells taken at different times shows a cluster along a slope of an approximate 3000 kPa pressure drop every 10 years. Pressure trend lines are subparallel for the older wells in the south end of the pool, whereas wells in the northern part of the pool exhibit a generally steeper drop in pressure over time. Some level of communication for the entire pool is suggested by the clustering of values, but a partial permeability barrier apparently impedes communication between north and south.

GEOLOGY

At the time of early development of this pool, the Triassic section was poorly understood because the area was relatively remote and few wells penetrated to that depth. As the area developed and mapping of stratigraphic equivalents in the disturbed belt provided a more 3D perspective, the Triassic section could be subdivided into formations and members. This was not easy—and is still open to debate—because the entire Triassic section is represented by a complex series of sandstones, dolomites and evaporates characterized by swift vertical and lateral changes in lithofacies. Units often have little lateral continuity; for that reason, lithofacies are difficult to correlate over distance. The lack of data also makes time correlations difficult. Even the most widely accepted time marker within the Charlie Lake Formation, the Coplin unconformity, cannot be picked within each well in the Fort St. John area. The old log suites that exist for some of the wells, consisting of micrologs and elogs, are not ideal for correlations of rapidly changing facies of thin beds. Lithostratigraphic correlations have been done for the Charlie Lake Formation largely on the basis of the gamma ray curve (e.g., McAdam, 1979). Elogs or micrologs provide only a limited ability to make lithostratigraphic correlations among thin-bedded members of the Charlie Lake Formation.

The North Pine member of the Charlie Formation

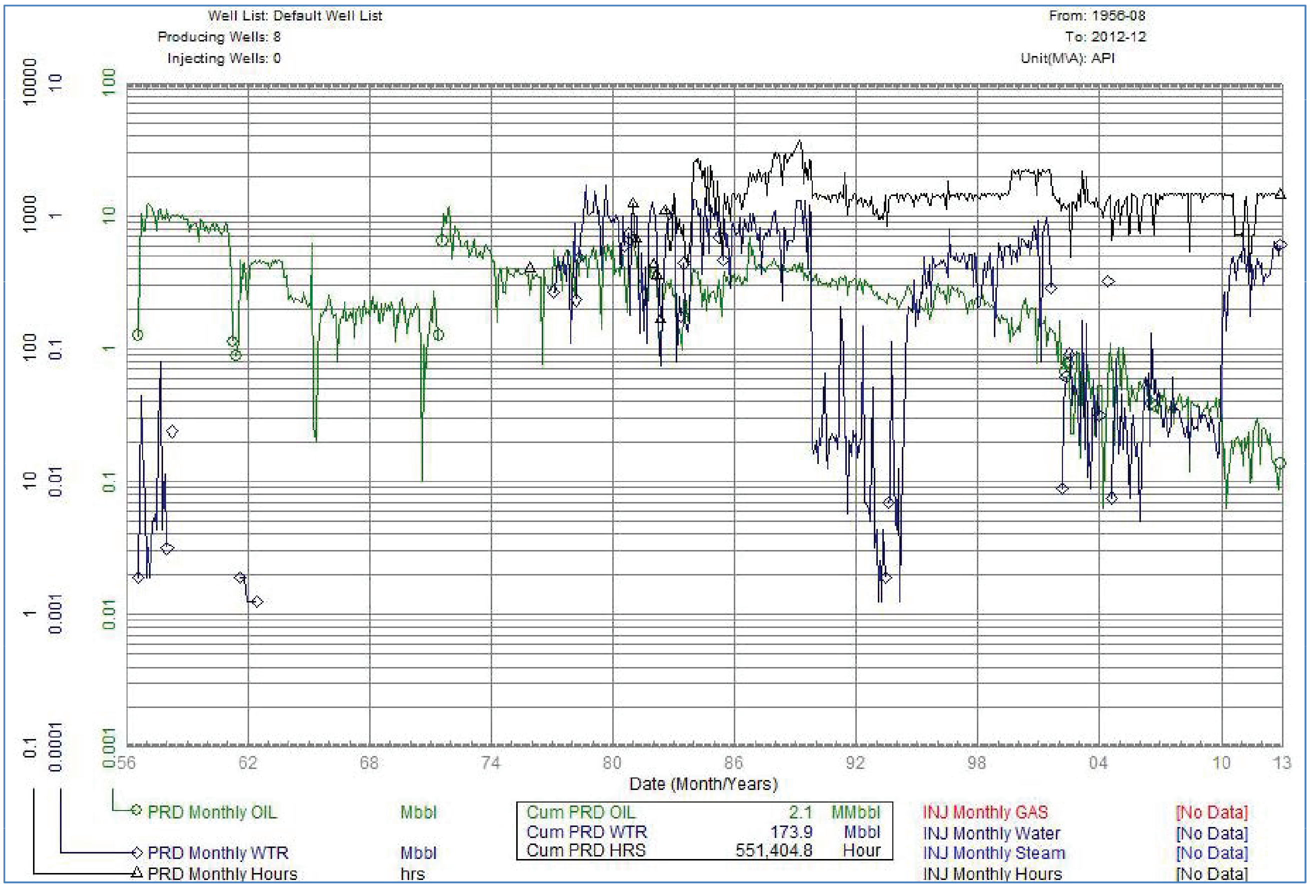

Figure 2. North Pine A oil production: This chart shows oil (green line) and water (blue line) production over the life of the pool. Oil production started in 1956, held steady until approximately 1992 and began to drop sharply in approximately 2000. The black line for hours on production indicates that two or more wells were on production most of the time (approximately 750 h/month). Data records are incomplete for water and hours production between 1958 and 1976. Upward and downward jumps in water production are largely attributable to incomplete records for some wells. The big dip in produced water between 1989 and 1995 is due to incomplete reporting for one well of the wells on production.

is thin and discontinuous, so trapping appears to be primarily stratigraphic. Seismic surveys indicate that it is truncated to the north by a fault, which appears to structurally constrain the pool in that direction. The North Pine member was deposited as a winnowed, narrow and linear shoreface sand trending north-northeast. It can be correlated along its length (Fig. 4) but becomes silty or shaly to the east or west.

The North Pine member is generally described in core and samples as a light grey or white, fine- to medium-grained, friable to well-consolidated sandstone. Porosity is variable, ranging from poor to good. Oil staining or shows are sporadic, visible in a few locations and absent in others. Appendix A provides descriptions and pictures of drill cuttings taken across the North Pine member.

Water cut is comparatively low and oil-water contacts are not evident in any wells. Overlying and underlying beds are shaly and would be neutral with respect to effects on pressure. Consequently, the highly efficient recovery factor of 50% must be largely attributable to gas cap expansion; however, without fresh input of water, a steep drop in pressure is inevitable without active intervention.

A gas-oil contact can be picked at –706 m (below mean sea level) at location 8-26-83-18W6 (Fig. 5), but it cannot be seen at the same elevation in the other pool wells. In the other wells, this elevation occurs either above or below the North Pine member. At location 6-25-83-18W6, a gas-oil contact can be seen at a depth of –713.5 m (1387 m measured depth). Gas-fluid contacts are not apparent on the elogs or

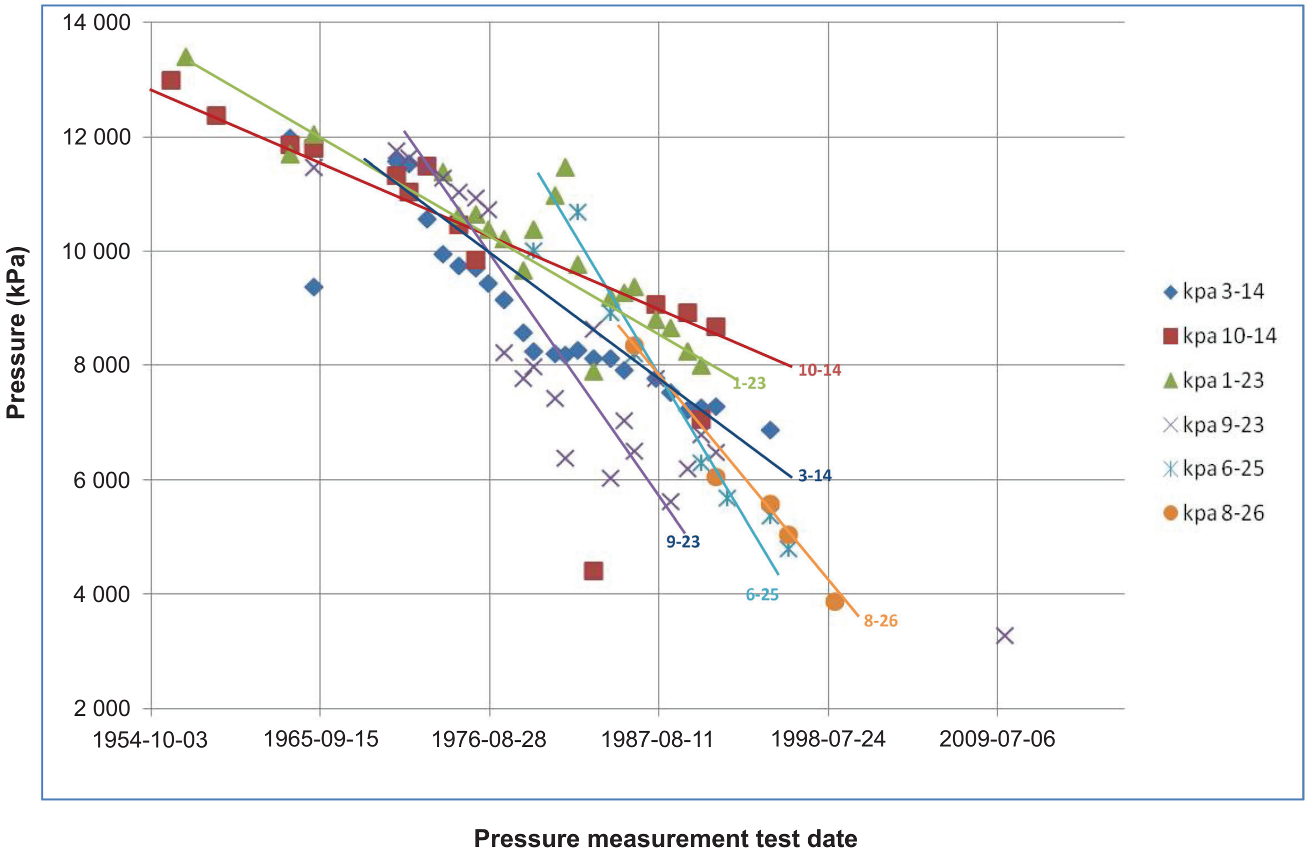

Figure 3. North Pine A pressure survey readings: The graph suggests two possible pressure regimes: northern wells (8-26, 6-25 and 9-23) show steeper drops in pressure over time than the southern wells. Pressure has dropped overall at an approximate rate of 3000 kpa every ten years. The first four wells to be drilled (3-14, 10-14, 1-23 and 9-23) indicated reservoir communication by following similar pressure drop-slope slopes for approximately the first ten years of production. The divergence between north and south slopes becomes more apparent in the early 1980s. Not many readings have been taken in the last 15 years, so little can be said about recent pressure trends. Anomalous outliers can be partly explained by unusually long or short shut-in times. Anomalous readings can also be the result of inconsistent measurement techniques.

micrologs run for the wells drilled prior to 1960. Imperfect communication among the producing wells, as demonstrated above, likely precludes the likelihood of common fluid contacts in a reservoir consisting of a thin heterogeneous sandstone occupying a narrow corridor and stretched over a long distance. Fluid contacts might at one time have been at the same elevation and then shifted with tectonic movement. On the other hand, localized contact elevations could have developed at the time of hydrocarbon emplacement as a result of imperfect communication along a long narrow and thin sandstone body.

The structure of the North Pine member shows a gentle east-southeast dip (Fig. 6). As discussed previously, a water contact is not obvious in any of the pool wells and water cut has been comparatively low, so water likely does not act as a lateral constraint. Instead, hydrocarbon distribution is probably determined by the quality of the sandstone

Twenty drillstem tests (DSTs) were run at discovery well 3-14, including one over the North Pine sandstone. The sample description contains a mention of light oil staining; as a result, although it is also described as having poor to fair porosity, it was tested. Gas (1000 mcf/d) and oil (810 ft., or 246.9 m) were recovered. The test chart (Fig. 7) is difficult to read but does indicate liquid inflow during the flow period (only one flow) but a slow buildup during shut-in, suggesting fair permeability. Shut-in and flow periods were probably too short to give a proper representation. Figure 8 shows a DST chart for location 8-26-83-18W6, where a DST demonstrated very good to excellent permeability in the North Pine member. Here the shut-in and flow periods were long enough to provide a more realistic

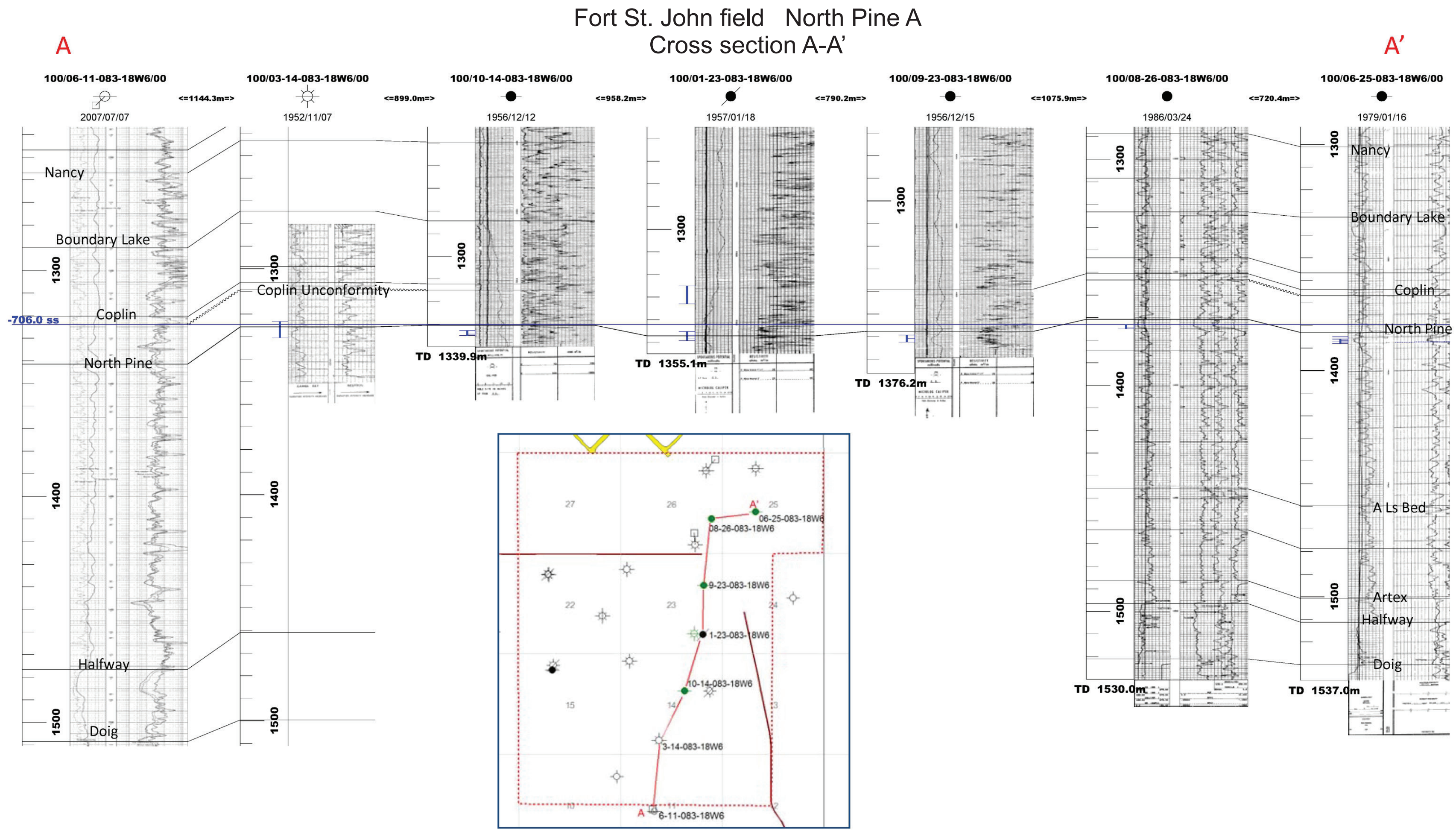

Figure 4. Structural cross-section A–A' North Pine A pool: Structural cross-section with datum (blue line) at –706 m mean sea level (msl), which is the original gas-oil contact at 8-26. Other wells cannot share this exact gas-oil elevation because the North Pine member is below this elevation at the other wells. A gas-oil contact is present at –714 m msl at 6-25. The North Pine member can be correlated along the length of the pool as shown in this cross-section, but it is absent or poorly developed laterally.

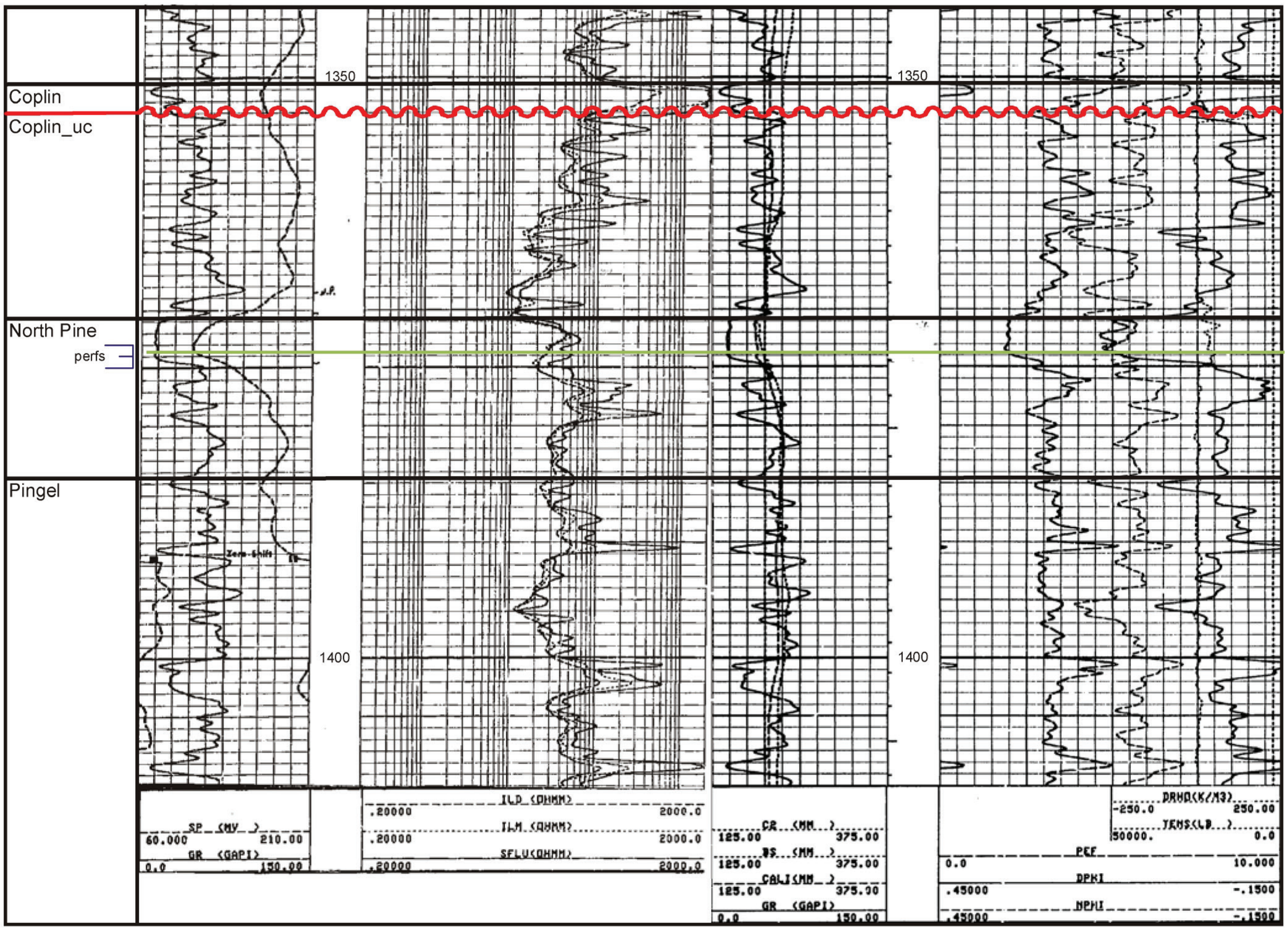

Figure 5. Location 8-26-83-18W6 induction and neutron-density logs: Neutron-density crossover in the North Pine indicates gas. This gas component has been important for the efficient 50% recovery rate of the pool. A gas-oil contact is at 1373 m measured depth (–706 m mean sea level).

picture of the North Pine member’s flowing potential.

A kink in net pay contours (Fig. 9) adds some evidence that the pool could consist of two or more separate segments. The extent of oil pay is well defined to the north but more open-ended to the south. A fault might limit its southward extent (Fig. 6); however, pay could continue along trend south of the pool boundary as suggested by contouring.

OPPORTUNITIES FOR FURTHER DEVELOPMENT

A very efficient recovery rate of 50%, derived from gas expansion in a permeable reservoir, suggests that much of the original oil in place must have already been recovered. Production has declined along with pool-wide pressures. Some efficiency might be restored if pressures could be increased through a secondary recovery scheme. Good permeability in the North Pine member should permit good receptivity of water or gas injected to increase pressure, which would result in significant production gains.

The precision and resolution of modern 3D seismic surveys might be applied to extending the limits of the reservoir in an east-west direction and to the south. Some of the thicker accumulations of the North Pine sandstone might be within the resolution of new seismic technology. Although the pool extent is limited by faulting to the north, the exact placement of that boundary might leave room for another producer, or possibly an injector.

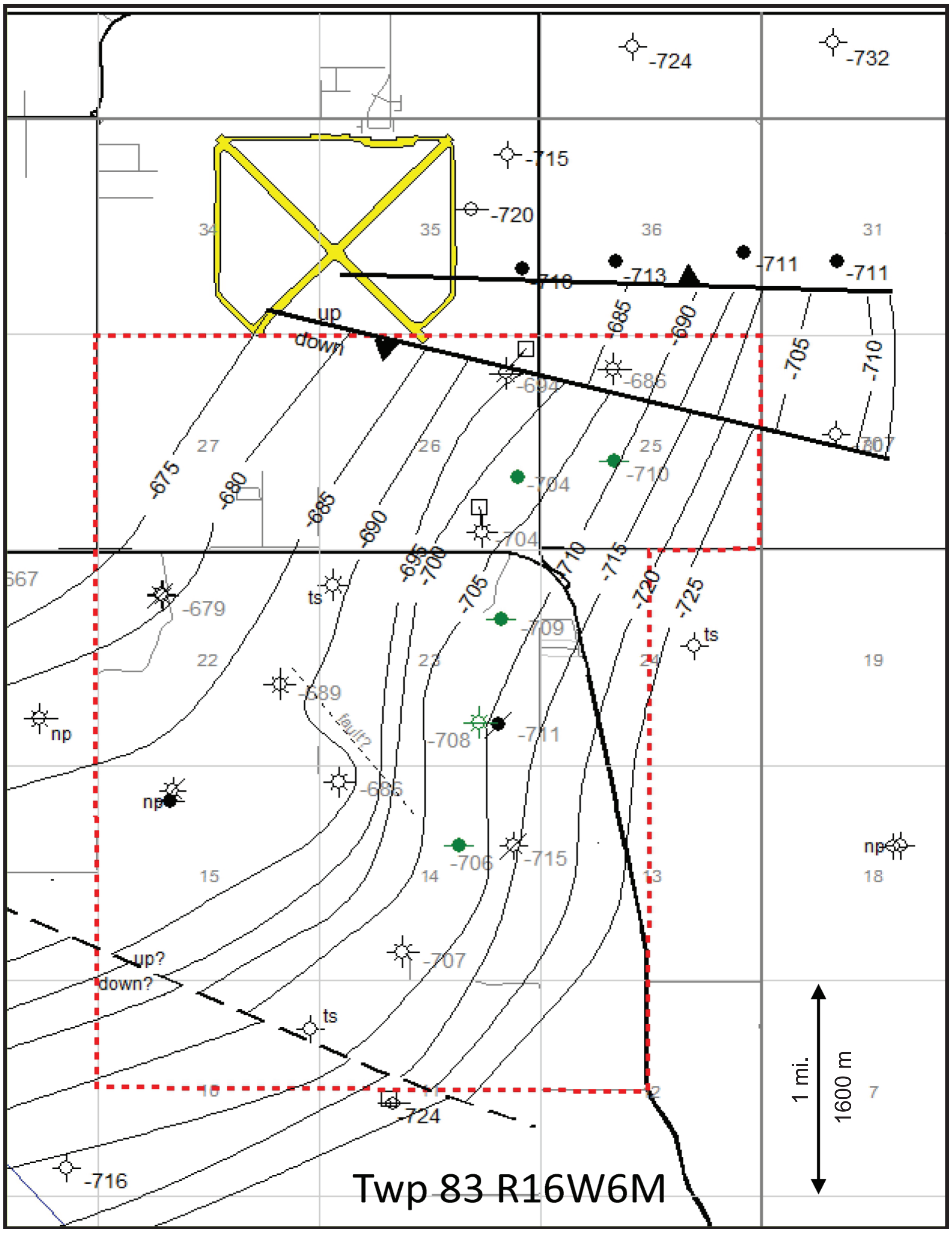

Figure 6. Structure of the North Pine member (5 m contour interval): Pool wells are indicated with green symbols and the pool is outlined in a dashed red line. The dip is to the south-southeast. Seismic evidence backs the presence of the fault limiting the pool to the north. The fault drawn at the south end of the pool is conjecturally based upon the apparent sudden drop in structural elevation near the south end of the pool. A possible small fault oriented northwest-southeast could explain the plateauing and bunching of contours in the south-central region; np = not present; ts = too shallow.

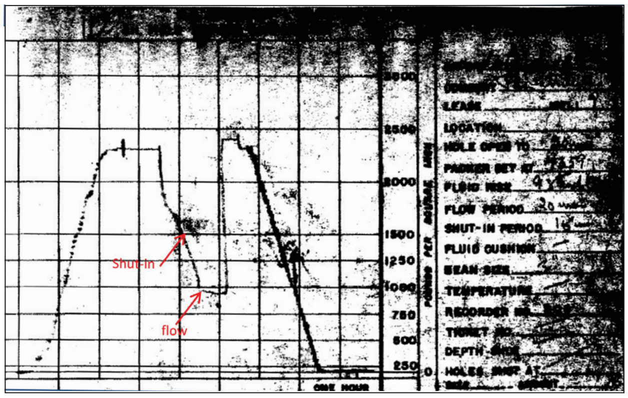

Figure 7. DST #12 (4358—4375 ft.) at location 3-14-83-18W6 (run 1952/07/04). Upward slope on flow indicates fluid. Shut-in slope indicates fair permeability. Shut-in (15 min) was not long enough for pressure to stabilize, so the test is not conclusive. Apparently only one flow period was run. Gassy oil (810 ft.) and gas (1000 Mcf/d) were recovered.

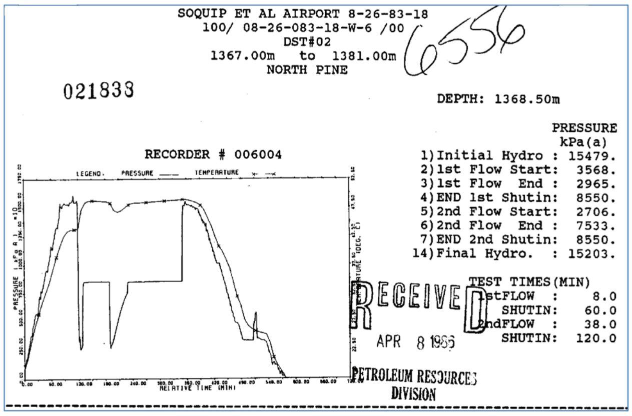

Figure 8. DST #2 at location 8-26-83-18W6. Very good to excellent permeability is displayed by almost immediate stabilization upon shut-ins. Oil (200 m) and water (100 m) were recovered.

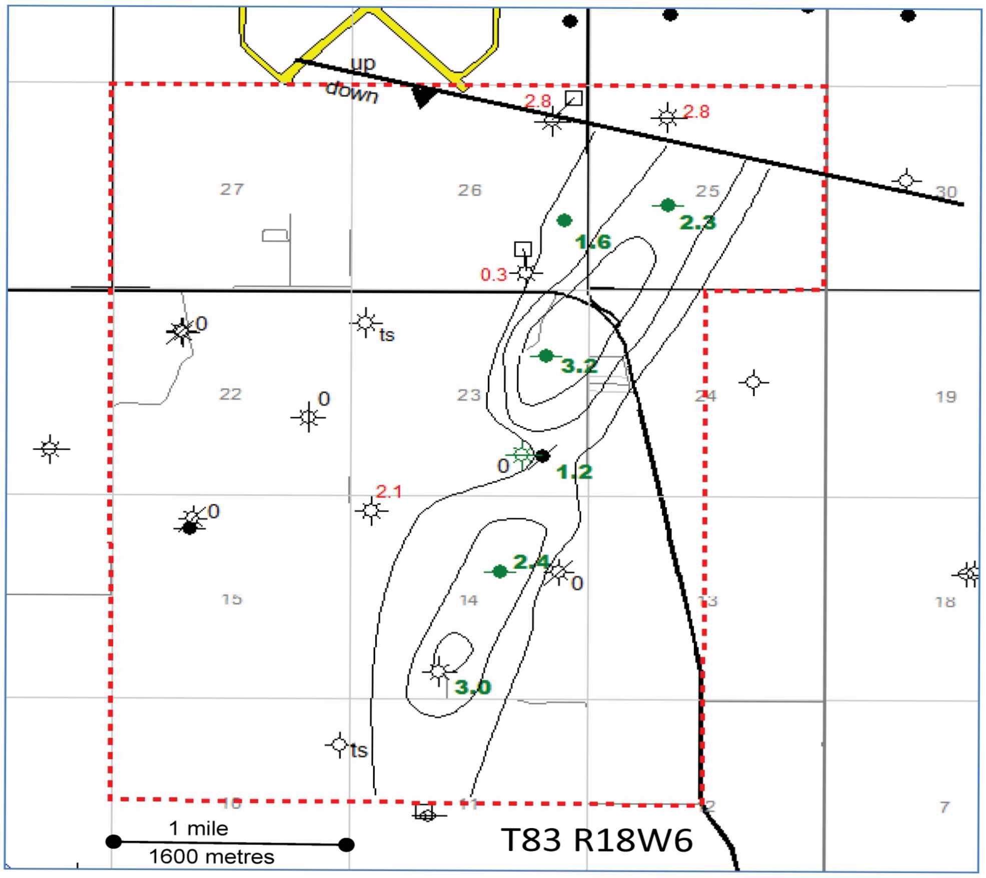

Figure 9. North Pine A pool; net oil pay North Pine member: Oil pay numbers are in green and gas pay is in red. Contour interval is 1 m net oil pay. The contours suggest a constriction in the central portion of the pool more or less coinciding with somewhat different pressure regimes between north and south. The extent to the south is not well defined. Faulting limits oil pay to the north.

ACKNOWLEDGMENTS

Thanks are due to Dave Richardson, Manager of Geology at the British Columbia Ministry of Natural Gas Development, for reading a draft and providing helpful comments. Fil Ferri, Director of Petroleum Geology at the British Columbia Ministry of Natural Gas Development, provided a critical review and suggestions for improvement. Co-op student Matthew Griffiths provided descriptions and pictures of drill cuttings.

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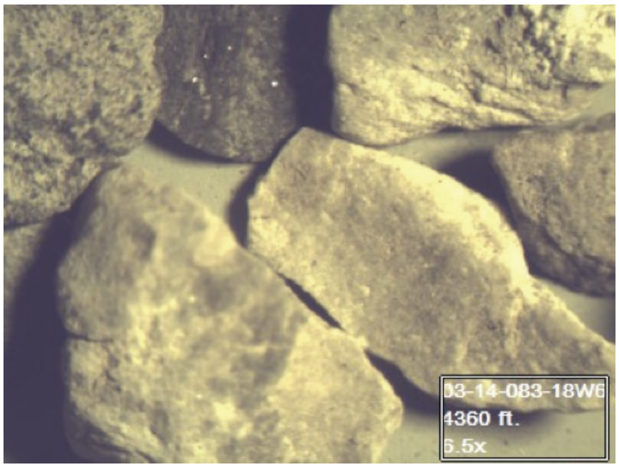
APPENDIX A

FORT ST. JOHN – NORTH PINE A

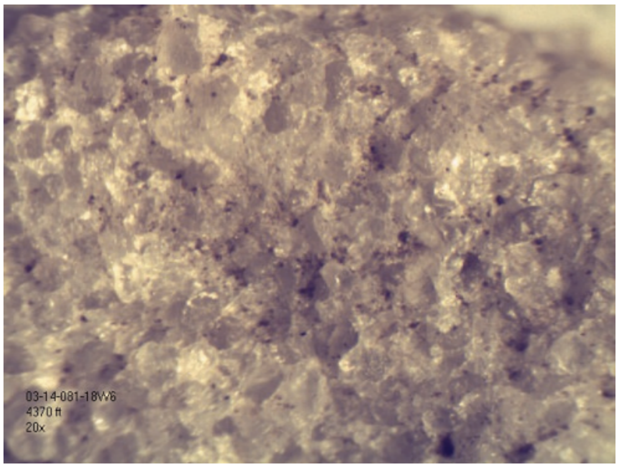
Discovery well 100/03-14-083-18W6/02

Intervals are given in feet as found on the sample vials; top North Pine member is at 4349 ft., perf interval is 4356–4365 ft.

Depth (ft.)	Description
3560–3570	Shale (100%): dark grey, soft-moderate hardness, flaky, silty, micaceous.
4060–4070	Sandstone (60%): orange, quartz arenite, very fine grained, rounded, well sorted, well cemented, dolomite cement, 15% intergranular/fracture porosity.
	Shale (40%): dark grey, silty, micaceous.
4270–4280	Sandstone (70%): white, quartz arenite, very fine grained, subangular, well sorted, well cemented, calcite cement, 7% (2% visual) intergranular porosity, micaceous, minor pyrite, trace garnet.
	Shale (25%): dark grey, hard, silty, pyrite, silica.
4280–4290	Shale (100%): dark grey, flaky, soft, micaceous, trace pyrite.
4330–4340	Shale (85%): gray, brittle, silty, fine- to medium-grained, calcareous in part.
	Sandstone (15%): white, quartz arenite, very fine to fine-grained, subrounded, locally well sorted, well cemented, calcite cement, 11% (3% visual) intergranular porosity.
4340–4350	Sandstone (75%): white, quartz arenite, very fine grained, subangular, well sorted, well cemented, dolomite cement, trace pyrite, 12% (5% visible) intergranular porosity.
	Shale (25%): dark grey, medium hardness, silty, micaceous, moderately cemented, minor silica sand.
4350–4360	Shale (80%): dark grey, silty, calcite crystallization, soft, fissile.
	Sandstone (20%): white, quartz arenite, very fine grained, subrounded, well sorted, very well cemented, calcite cement, trace garnet, 9% (1% visual) intergranular porosity.
4360–4370	Shale (70%): dark grey, silty, moderate hardness, micaceous, glauconitic.
	Sandstone (30%): white, quartz arenite, medium-grained subangular moderate sorting, well cemented, dolomite cement, 10% intergranular porosity.
4440–4450	Siltstone (60%): white to light grey, angular, well sorted, well cemented, calcite cement, quartz, 12% intergranular porosity
	Shale (40%): dark grey, silty, hard, micaceous



Selected drill cuttings from 4360’ showing a fine-grained representative nature of the majority of the North Pine member. Magnification is 6X.



Close-up view at 20X magnification of a single chip. Fair to good textural relief indicates good intergranular porosity. Only minor detrital material is present among the predominant quartz grains.

THERMAL MATURITY AND REGIONAL DISTRIBUTION OF THE MUSKWA FORMATION, NORTHEASTERN BRITISH COLUMBIA

Filippo Ferri[1] and Matthew Griffiths[2]

ABSTRACT

The Muskwa Formation represents an areally extensive, organic-rich horizon (up to 8 wt.% total organic carbon) that has become the focus of exploration for unconventional hydrocarbon resources in western Canada. Found throughout northeastern British Columbia, the Muskwa Formation is time-equivalent to the Duvernay Formation in Alberta and the Canol Formation in the Northwest Territories and the Yukon. This unit can be traced from the Peace River Arch area northwestward into the Horn River and Liard basins, where it becomes part of the Horn River Formation and eventually part of the Besa River Formation. The Muskwa Formation is less than 10 m thick in the Peace River Arch region, exceeds 40 m in thickness in the Horn River and Liard basins and reaches its thickest in the Rocky Mountain Foothills and near the Bovie Lake structure, where it exceeds 70 m. Compositionally, it is a silica-rich, silty shale to shale and is variably calcareous. In the NTS 094I block, vitrinite reflectance and converted bitumen reflectance fall between 1.3 and 1.8%, confirming that the Muskwa Formation has potential for in-situ gas and condensate generation.

Ferri, F. and Griffiths, M. (2014): Thermal maturity and regional distribution of the Muskwa Formation, northeastern British Columbia; *in* Geoscience Reports 2014, *British Columbia Ministry of Natural Gas Development*, pages 37–45.

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Keywords: Muskwa Formation, Horn River Formation, thermal maturity, condensate, oil, Horn River Basin, Liard Basin

INTRODUCTION

The Muskwa Formation is a Late Devonian (Frasnian) unit that conformably underlies the Fort Simpson shale and is likely found throughout all of northeastern British Columbia, except in the region of the Peace River high (Fig. 1; Williams, 1990). In northeastern British Columbia, the Muskwa Formation also overlies the Slave Point, Waterways and Keg River formations (Evie reef complex) and Otter Park carbonates as its lower contact moves from shelf to basin (Fig. 1). In the Horn River Basin of British Columbia, Muskwa strata have been placed within the Horn River Formation and reduced to member status (Fig. 1; Williams, 1983). The base of the Muskwa Formation has been proposed as a widespread unconformity (Griffin, 1965), although this has been disputed by others (Pugh, 1983; Williams, 1983). In the type well south of Fort Nelson, British Columbia, and near the southern boundary of the Horn River Basin (a-95-J/94-J-10; Fig. 2), the Muskwa overlies the Otter Park member of the Horn River Formation. The Muskwa Formation is an approximate stratigraphic equivalent to the Duvernay Formation in Alberta (Switzer et al., 1994) and the Canol Formation in the Northwest Territories (Pugh, 1983). In northwestern British Columbia, the Muskwa and the Horn River Formation become a subset of the Besa River Formation as one approaches the deformation belt.

The Muskwa Formation is a pyritic, siliceous, variably calcareous and generally organic-rich dark grey to black shale and is viewed as a principal source horizon in the Western Canada Sedimentary Basin

(Williams, 1990). Total organic carbon (TOC) ranges from 0.14 to 8.39 wt.% with a mean of 2.75 wt.%, based on 474 samples taken from 56 wells (Ferri et al., 2013). Considering the typical overmature nature of this unit (based on limited thermal maturity data), it was likely a very rich source rock prior to the generation of hydrocarbons. In logs, it is characterized by high radioactivity and resistivity. The upper contact is picked by an increase in the gamma-ray and resistivity, as readings quickly transition from the inorganic Fort Simpson grey shale into the organic-rich Muskwa Formation. The lower contact is typically characterized by a drop in radioactivity, the intensity depending on whether it is positioned above shelf carbonates or basinal calcareous shales. Outside of the Horn River Basin, much of the Muskwa Formation sits on platform carbonates represented by the Slave Point Formation. The Muskwa Formation is relatively thin along the top of the Slave Point Formation and thickens into the Horn River Basin (Fig. 3).

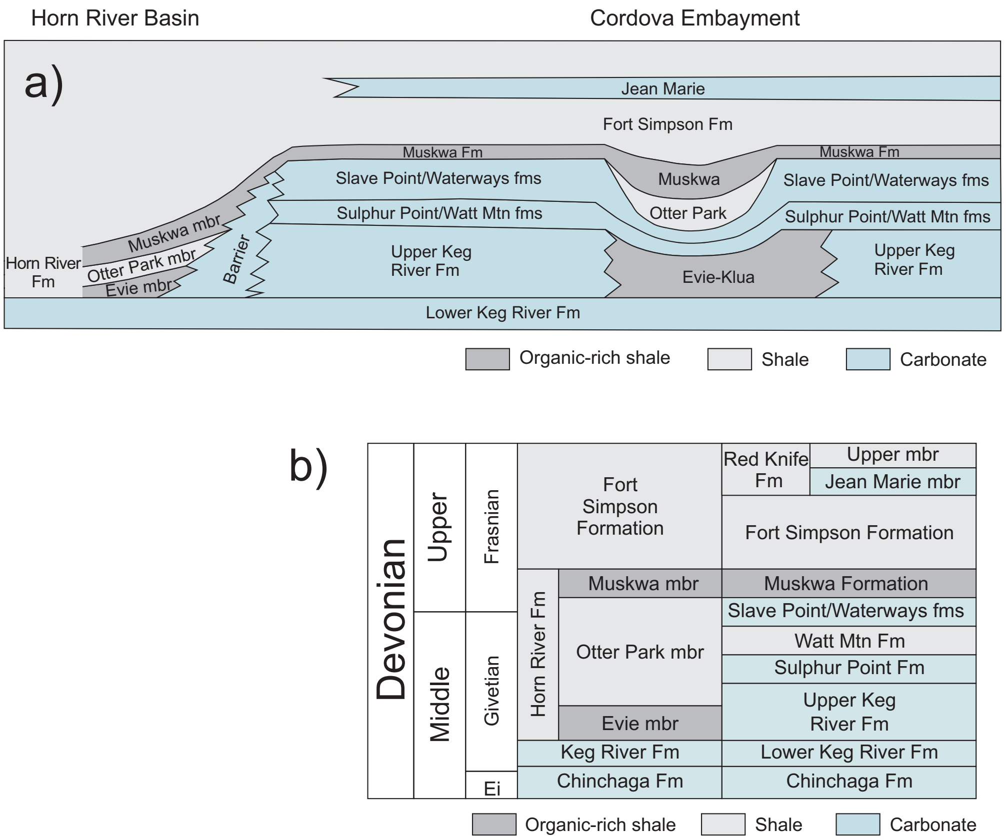

Figure 1. Stratigraphic relationships of Muskwa shales with other units: a) diagrammatic relationship of Muskwa shales to other units and b) time–stratigraphic chart. Ei: Eifelian.

General trends in thermal maturity for Muskwa shales suggest that the unit is overmature and within the dry gas window throughout much of northeastern British Columbia (Creaney et al., 1994). Yet, production data from the Jean Marie Formation in certain parts of NTS 094I in northeastern British Columbia show considerable condensate content (Fig. 4). It is unlikely that the organic-lean shales of the Redknife or Fort Simpson formations sourced this condensate. A more likely scenario is that the scattered nature of this production reflects localized faulting that has tapped the Muskwa shales, allowing this condensate to migrate through the thick Fort Simpson shales. Thermal maturity data collected from the Muskwa Formation on trend in Alberta and the Northwest Territories support this hypothesis (Stasiuk and Fowler, 2002; Beaton et al., 2010; Rokosh et al., 2012), because the units there are interpreted to be in the oil or wet gas thermal maturity windows. Extrapolation into British Columbia would suggest the Muskwa shales in the far northeast corner of northeastern British Columbia are likely in the wet gas zone. This assumption is supported by the recent test of Muskwa shales in the Bivouac area of NTS 094I, where Husky HZ Bivouac a-55-B/94-I-8 initially produced 19.5 bbl condensate/mmcf gas (bbl: barrel; mmcf: million cubic feet; 110 m^3 condensate/1000 m^3 gas).

This paper will describe the extent, thickness and thermal maturity of the organic-rich Muskwa shale horizon in British Columbia in hopes of defining zones of dry gas, condensate and oil. Unfortunately, there are limited reliable thermal maturity data for the Muskwa Formation in British Columbia; regardless, it can be demonstrated that a portion of the Muskwa Formation in the far northeast corner of northeastern British Columbia is in the condensate window.

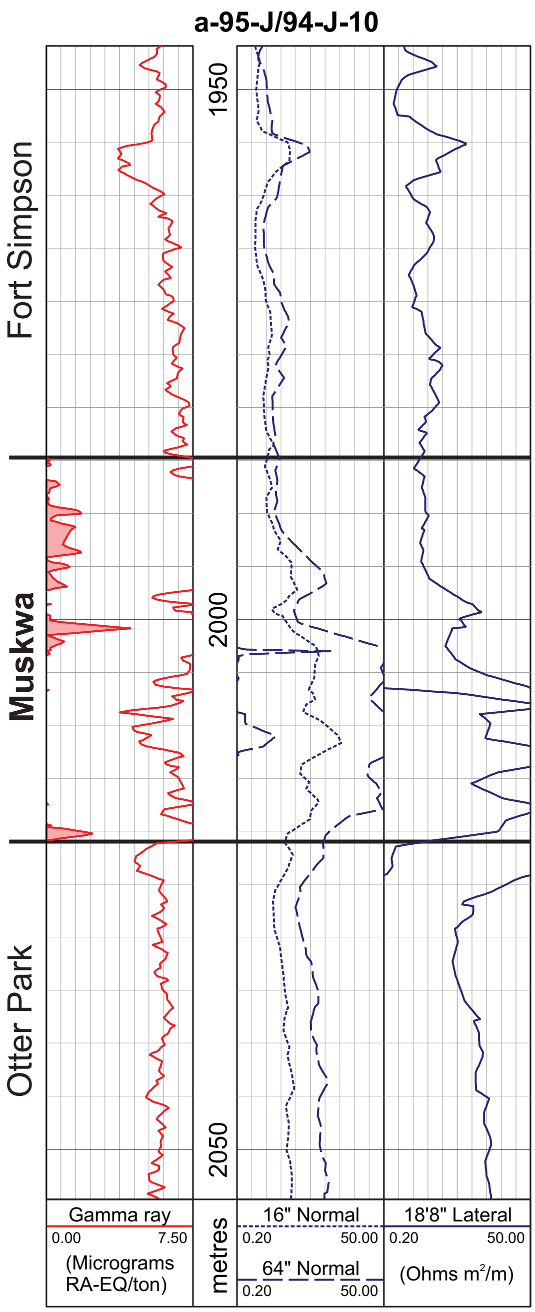

Figure 2. Gamma-ray and resistivity signature of the Muskwa Formation from the type well, a-95-J/94-J-10. RA-EQ/ton: micrograms radium equivalent per ton.

METHODS

A database of the Muskwa interval was compiled based on gamma-ray, resistivity and sonic logs, and by consulting core and cutting descriptions in the well documents. Regional cross-sections were constructed to check the consistency of the Muskwa Formation picks (Fig. 4). These were supplemented by more localized cross sections.

Structural data were then exported from geoSCOUT® to Surfer® contour software and isopach contours were generated using the Kriging method. The top of the Muskwa structure map was contoured using a minimum curvature method to accommodate the Bovie fault. The surface trace of the Bovie fault at the Muskwa Formation level was based on high dip values between wells and published data on the fault (Wright et al., 1994; MacLean and Morrow, 2004).

One parameter of hydrocarbon generation is the peak temperature, or thermal maturity, attained by the source rock. Several thermal maturity indicators (or paleothermometers) are used in hydrocarbon exploration, such as Rock Eval™ pyrolysis and vitrinite reflectance. Due to the possible presence of early oil generation and/or the use of petroleum-based drilling muds, thermal maturity values based on Rock Eval data (T_{max}) are erroneously low for much of the Muskwa Formation in northeastern British Columbia. As a result, only reflectance data were used, and this was of limited areal extent (Fig. 5).

Vitrinite reflectance is a widely accepted paleothermometric technique used to assess coal rank and other organic material. In the Muskwa Formation, reflectance of bitumen has been measured and a vitrinite equivalent value was calculated using an empirical relation described by Jacob (1985).

Thermal maturity data in the form of vitrinite and converted bitumen reflectance were compiled from various sources (Potter, 1998; Stasiuk and Fowler, 2002; Ferri et al., 2013). In addition, regional reflectance data for the Muskwa Formation in Alberta and the Northwest Territories were used in the compilation (Stasiuk and Fowler, 2002; Beaton et al., 2010). Several data points from the bottom of the

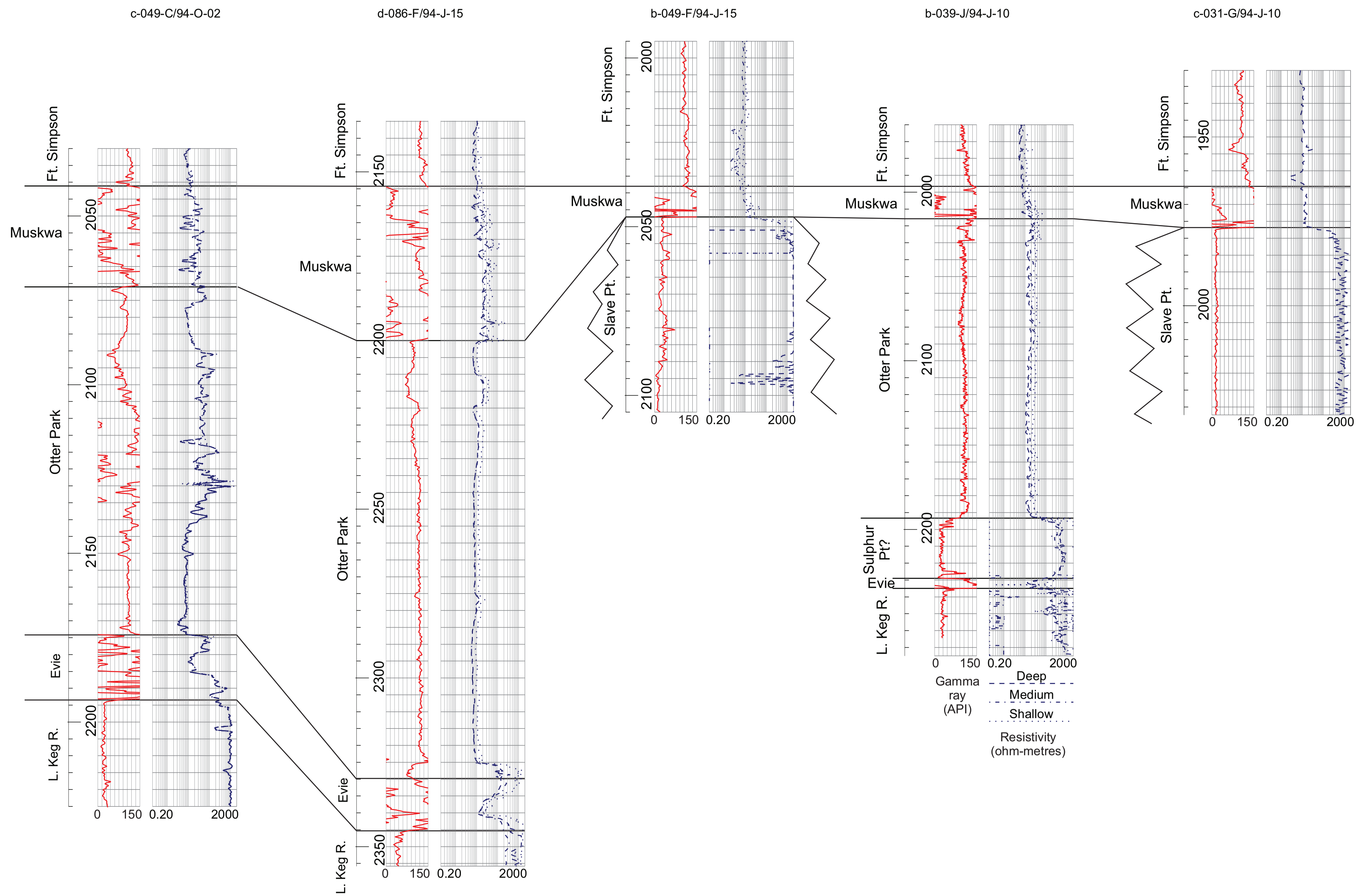

Figure 3. Cross-section showing stratigraphic relationships of Muskwa shales with underlying carbonates and succeeding shales along the western edge of the Horn River Basin. See Figure 5 for location of the cross-section.

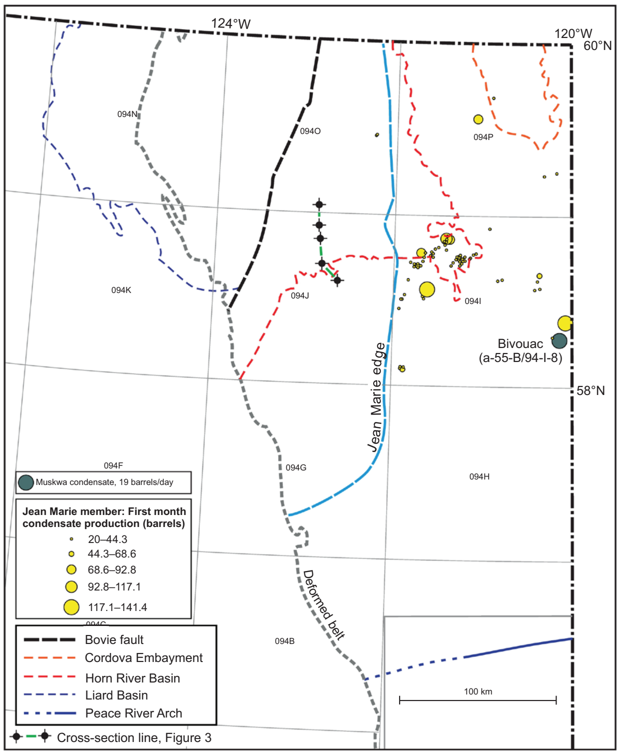

Figure 4. Location of the condensate-rich Jean Marie Formation in northeastern British Columbia with respect to various depositional elements. Also shown is the location of the Husky Bivouac a-55-B/94-I-8 well, which has shown significant condensate production from the Muskwa Formation.

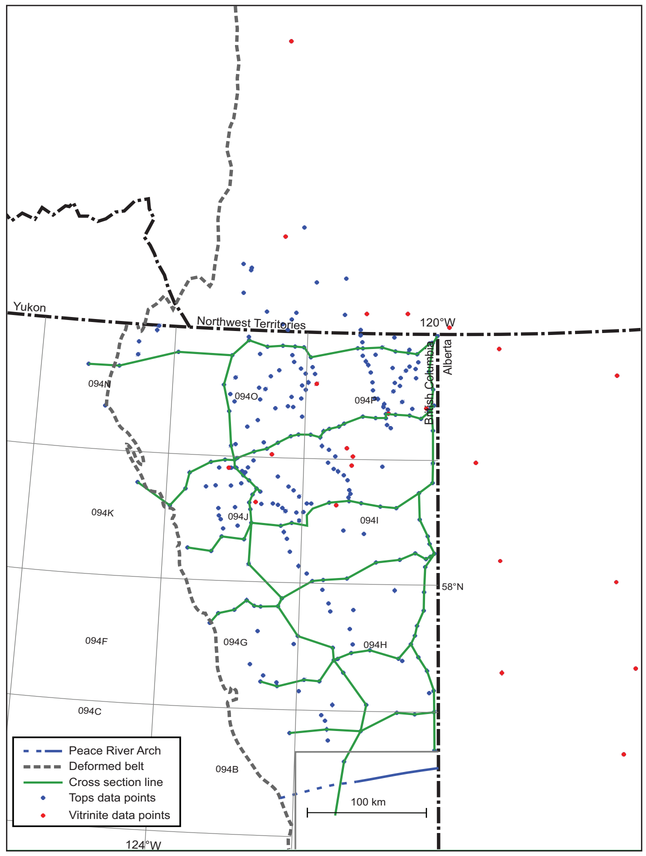

Figure 5. Data points and regional cross-sections used in producing the various maps of the Muskwa Formation. The cross-sections were used to be internally consistent.

Fort Simpson Formation and the top of the Otter Park Formation were also used because they were within 10 m of the Muskwa interval. Vitrinite and vitrinite equivalents were then averaged for each location and isoreflectance contours were generated using the Kriging method in Surfer®.

RESULTS

Regional distribution and structure

Areally, the Muskwa Formation extends from the northern edge of the Peace River Arch (PRA) northward into the Yukon and Northwest Territories and eastward into northern Alberta. Data are lacking south of the PRA in British Columbia where the Muskwa Formation likely lies well in excess of 5000 m within the Deep Basin, but in Alberta the correlative Duvernay Formation is penetrated south of the PRA, suggesting this unit likely extends into British Columbia. In the western Liard Basin, it becomes difficult to distinguish the Muskwa Formation because the thickness of the Fort Simpson Formation decreases dramatically and becomes more organic rich, and the Otter Park Formation thins significantly. It is at this point that the shale units of the Muskwa Formation are amalgamated with the Besa River Formation. The Muskwa Formation is an average of 30 m thick; it is less than 10 m where it overlies platform carbonates, in excess of 70 m thick near the Bovie Lake fault, more than 80 m in the Liard Basin and attains a maximum thickness of just more than 100 m in the Rocky Mountain Foothills (Fig. 6).

The Muskwa Formation is at its shallowest in the far northeast British Columbia (Fig. 7). It deepens southwestward into the Deep Basin and westward into the Horn River Basin. In the study area, the unit is at its deepest within the Liard Basin, where it reaches a depth of 4850 m. This is primarily due to displacement on the Bovie Lake fault, which has a maximum displacement of 1600 m near the Windflower gas field (NTS 094N/11). The shallowing of the Muskwa Formation in the western Liard Basin is likely the result of a disturbance along the Rocky Mountain Foothills.

Thermal maturity

Reflectance data for the Muskwa Formation in British Columbia are mostly confined to the NTS 094P block, with values ranging from 1.59 to 2.45%. Maturity levels are lowest in the east, along the Alberta–British Columbia border, and increase to the west and southwest, the latter due to subsidence within the Deep Basin. Interpolated reflectance values in the NTS 094I block range between 1.4 and 1.8%, indicating that the Muskwa Formation has condensate potential consistent with recent condensate production in the Bivouac field (Figs. 8, 9).

DISCUSSION

Based on limited thermal maturity data for Muskwa shales in NTS 094I, J, O and P, together with data from the adjacent Alberta and Northwest Territories, a zone falling within the upper limit of maximum wet gas generation (approximately 1.4 R_o) is defined along the border with Alberta in NTS 094P and I (Fig. 9). Considering the thermal maturity trends in Alberta and the Northwest Territories, one would have expected this zone to be much wider in British Columbia. The relatively narrow condensate zone in British Columbia and the north-south trend of isotherm is likely a reflection of the higher geothermal gradients in this part of the Western Canada Sedimentary Basin (Bachu and Burwash, 1994).

Recent exploration of Muskwa shales in this area supports the inference that these rocks are in the upper oil (condensate) window. Data from a recent horizontal well into Muskwa shales (a-55-B/094-I-08) in the Bivouac area by Husky Exploration Ltd. show, in a four-month period, a daily average production of 22 barrels of condensate (3.6 m^3) and 1.15 mmcf of gas (32.3 e^3m^3). The Muskwa Formation is approximately 27 m thick and occurs at a depth of 1820 m. Completion

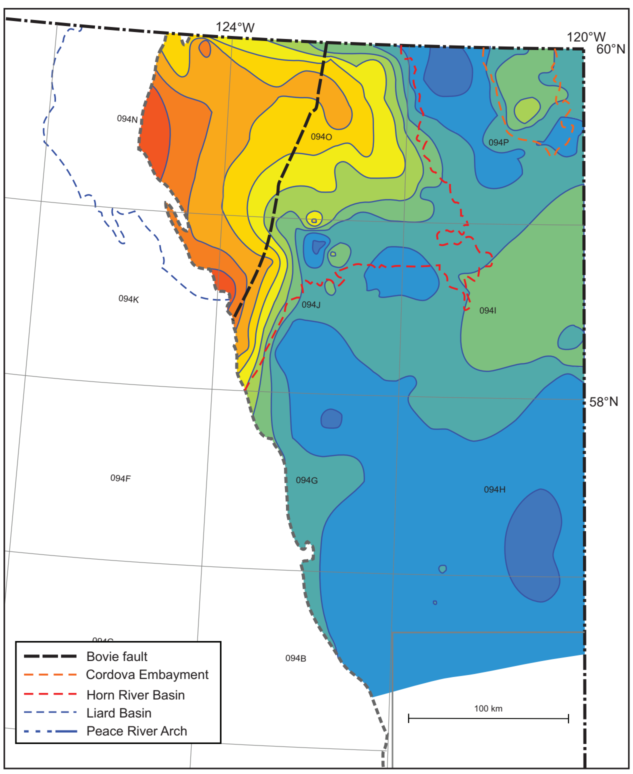

Figure 6. Isopach of the Muskwa Formation, northeastern British Columbia.

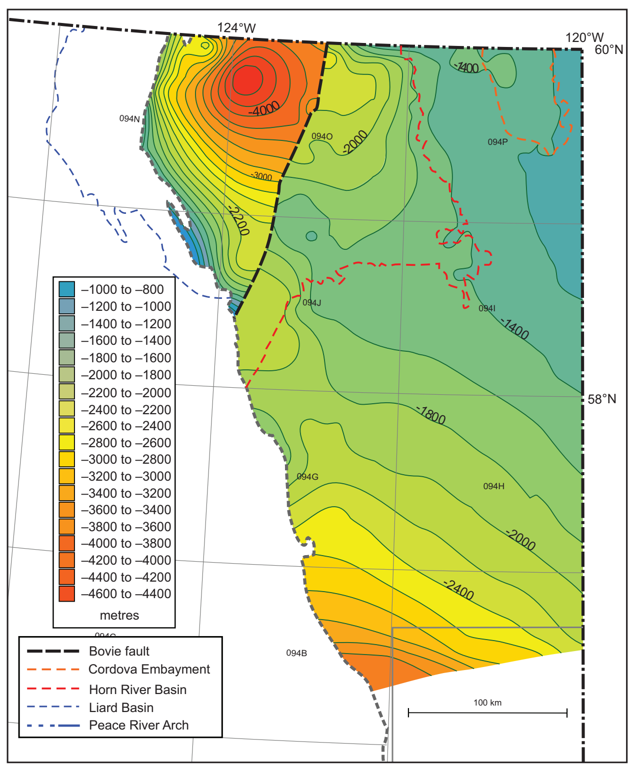

Figure 7. Structure for the top of the Muskwa Formation, northeastern British Columbia.

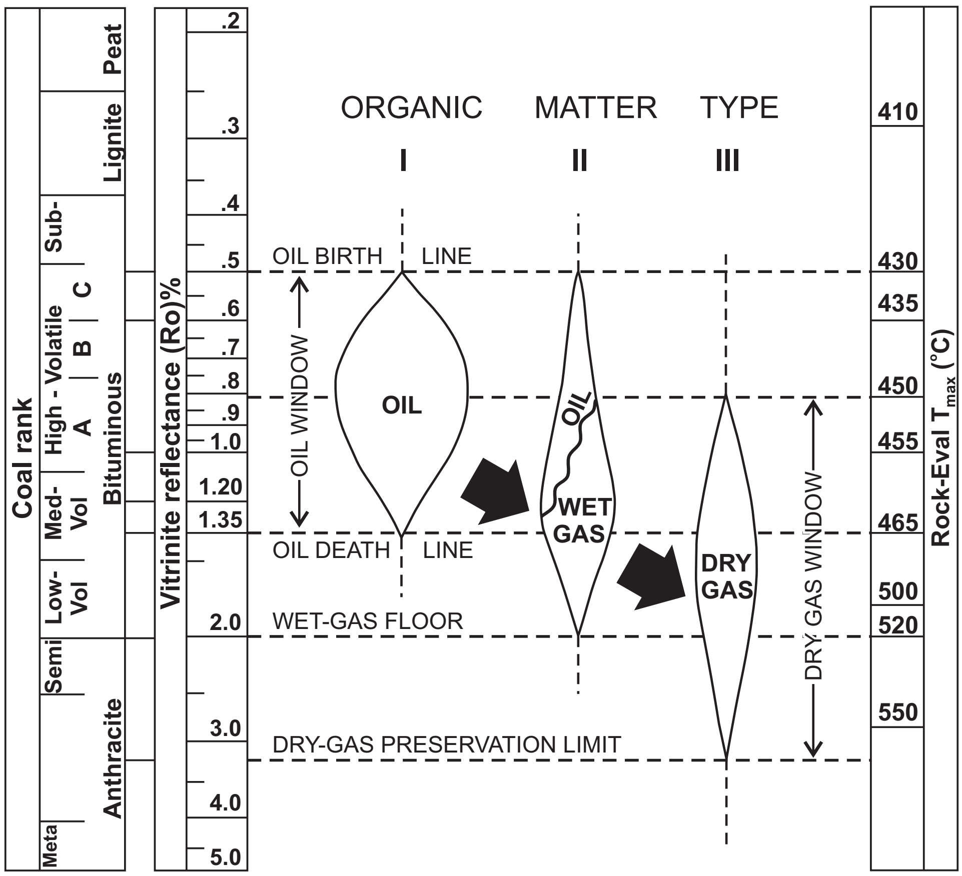

Figure 8. Petroleum thermal maturation zones (modified from Leckie et al., 1988; cf. Dow, 1977; Teichmuller and Durand, 1983).

was along a 1600 m horizontal leg and consisted of an 18-stage hydraulic fracture.

There is sporadic condensate production from Jean Marie carbonates in NTS 094I (Fig. 4). This production roughly defines a northwesterly trend, extending from the Bivouac area to the Jean Marie edge. If Muskwa shales are supplying condensate and light oil to overlying Jean Marie carbonates, this is likely accomplished by fault structures allowing the migration of hydrocarbons through the thick, impermeable Fort Simpson shales. It is uncertain if this trend results from larger, regional faults or from localized structures.

Although condensate production from the Jean Marie member at Bivouac is consistent with thermal maturity values in underlying Muskwa Formation, similar production from this unit in wells to the northwest falls within areas where Muskwa shales are overmature (Fig. 9). Considering the paucity of thermal maturity data, these production data could very well define a low thermal maturity re-entrant within the Muskwa Formation.

In addition, there is higher condensate production within overlying Jean Marie carbonates in this zone of lower thermal maturity defined within the Muskwa Formation (Figs. 4, 9). The assumption is that this condensate is sourced from underlying Muskwa shales as opposed to the organic-lean Fort Simpson shales encompassing the Jean Marie member. Interestingly, there are wells to the northwest of Bivouac with equally high condensate production values in the Jean Marie member, located an area outside the condensate window for Muskwa shales. Perhaps this low thermal maturity re-entrant to the north might be wider than currently defined with the limited data available.

CONCLUSIONS

The Muskwa Formation represents a widespread, organic-rich (mean TOC of 2.75 wt.%) unit in the Western Canada Sedimentary Basin and is identified as one of the principle source-bed horizons. It is commonly between 10 and 25 m thick where it overlies the Slave Point and Waterways formations but thickens significantly into the Cordova Embayment, Horn River and Liard basins, exceeding 40, 60 and 80 m, respectively. The unit is being extensively developed for its shale gas potential in the Horn River Basin and Cordova Embayment, where production is dry gas.

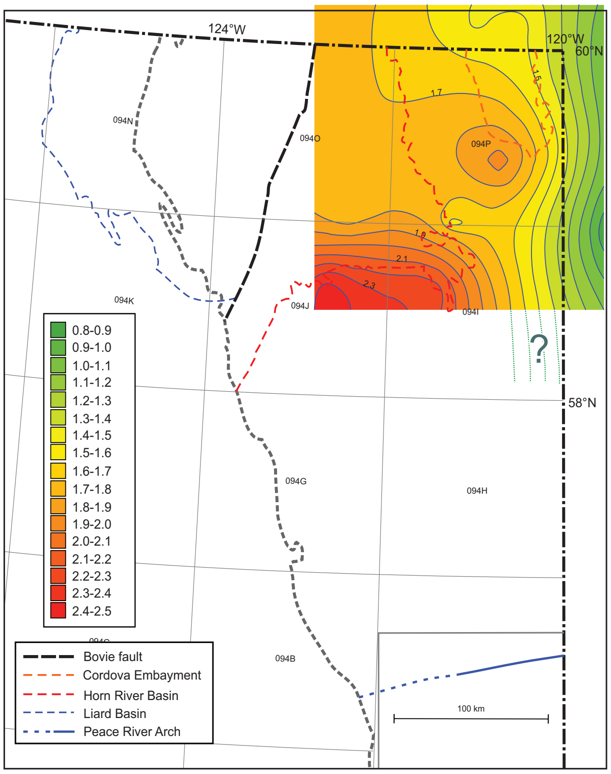

Figure 9. Isoreflectance map of Muskwa shales in northeastern British Columbia; 0.1% contour interval. Contouring was approximately limited to the extent of available data, although extrapolation of contour data to the south suggests some potential.

Robust, regional thermal maturity data for Muskwa shales in British Columbia are lacking. Limited thermal maturity values of 1.3–1.6 R_o along the British Columbia–Alberta border in NTS 094P and 094I, together with similar data in Alberta and the Northwest Territories, define a narrow zone in northeastern British Columbia with condensate potential. More thermal maturity data for Muskwa shales are needed to accurately define the spatial distribution of maturity levels within this unit.

ACKNOWLEDGMENTS

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