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Cross-formational Fluid Flow in Upper Devonian to Lower Cretaceous Strata, West-Central Alberta, Canada

by

Benjamin Jay Rostron

A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfillment of the requirements for the degree of Doctor of Philosophy

Department of Geology

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Benjamin Jay Rostron
1518 Early Drive
Saskatoon, Saskatchewan, Canada
S7H 3K2

Date: ______________

And if you think that you've really got an answer
You've got to move with all your heart
And if it feels like it's taking you a lifetime
It's just the start...

(chorus from the song "Be Right" by
G. Kelly, J. Knutson, J. Mann of
Spirit of the West, 1986)

For Catherine

University of Alberta

Faculty of Graduate Studies and Research

The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled Cross-formational Fluid Flow in Upper Devonian to Lower Cretaceous Strata, West-Central Alberta, Canada submitted by Benjamin Jay Rostron in partial fulfillment of the requirements for the degree of Doctor of Philosophy.

J. Tóth

J. Tóth, Supervisor

Hans-G. Machel

H.G. Machel

P.E. Gretener

P.E. Gretener

Carl Mendoza

C.A. Mendoza

B. Jones

E.R. K

E.R. Kanasewich

J.D. Bredehoeft, External Examiner

Date: JULY 14/1995

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ABSTRACT

Upper Devonian to Lower Cretaceous strata form part of, and are influenced by, two regional-scale hydrogeologic flow-regimes in west-central Alberta. The lower Paleozoic regime comprises the Upper Devonian Hydrogeologic Group and the Mississippian Hydrogeologic Group. The upper Jurassic-Lower Cretaceous regime consists of the Mannville Group Aquifer and the Viking Group Aquifer. Cross-formational flow of formation fluids occurs between and within these flow regimes.

Significant cross-formational flow of water, oil, and gas occurs across the Ireton, Wabamun Group, and Joli Fou aquitards. Saline waters and hydrocarbons cross the Ireton aquitard where it is thin or absent over underlying reef structures. Ascending fluid flow and the thickness of the Ireton aquitard exert a primary control on hydrocarbon trapping in the study area. Upward moving saline water and hydrocarbons cross the Wabamun aquitard where it subcrops the Mannville Group. Cross-formational migration of Paleozoic brines create a saline plume (>100,000 mg/l total dissolved solids) in the Mannville Group aquifer. Results also show the Joli Fou Formation cannot act as an impermeable seal for formation fluids because this aquitard is absent in the southwest corner of the study area. Furthermore, where the aquitard is present, flow rates on the order of 2.3 to 5.3 x 10^{-4} metres/year across the Joli Fou shale are calculated, based on measured hydraulic gradients and published permeabilities from similar shales.

Study results demonstrate that regional fluid flow and cross-formational flow play important roles in hydrocarbon migration and entrapment in the subsurface. Hydrogeological and hydrochemical evidence support a hydraulically continuous rock-framework in west-central Alberta. There is no evidence for sealed compartments in the study area. The concept of vertical migration through shales can be used to explore for petroleum reservoirs given the hydraulically continuous rock-framework in the area.

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1.0 INTRODUCTION

1.1 BACKGROUND

For more than a century, hydrogeologists have studied the regional flow of groundwater in the subsurface, with the goal of locating and exploiting sources of drinking water (Bredehoeft et al., 1983). However, the importance of groundwater goes far beyond a mere source of drinking water. During the past few decades, moving groundwater has gained acceptance as a full-fledged geologic agent, able to modify pore-pressures; dissolve, transport, and deposit organic and inorganic chemical species; and transport heat, while moving through a rock framework. Flowing groundwater can generate or modify hydrologic, hydraulic, chemical, mineralogical, vegetal, soil mechanical, rock mechanical, geomorphologic, and transport/accumulation phenomena in sedimentary basins (Tóth, 1984).

Of particular importance is the genetic relationship between groundwater flow and the transport and accumulation of hydrocarbons (Hubbert, 1953; Tóth, 1980, 1988). In the petroleum-rich Western Canada Sedimentary Basin (WCSB), active regional groundwater flow systems were first recognized by Hitchon (1969a, 1969b). Since then, Hitchon's regional flow systems have been used to explain the origin of the Oil Sands deposits (Garven, 1989), the distribution of chemical species dissolved in formation waters (Hitchon and Friedman, 1969; Connolly et al., 1990a, 1990b), and the distribution of heat (Majorowicz et al., 1985) in the subsurface of the WCSB. Although the role of groundwater flow in the long-range migration of hydrocarbons is not often recognized by most oil industry workers, the process of long-range oil migration in the WCSB is acknowledged to have played a key role in the formation of many of the oil and gas deposits found within it (Creaney and Allan, 1990, 1992; Piggot and Lines, 1991; Creaney et al., 1994).

Despite volumes of work published on the regional flow of formation fluids, these long established theories of fluid migration are under attack. Opponents of regional-scale fluid flow propose instead that the subsurface is divided into isolated compartments, each separated by areally extensive bodies of rock that are impermeable (e.g., Hunt, 1990; Powley, 1990; Bradley and Powley, 1994). In the sealed compartment model, geologic basins are broken up into a series of variably-sized isolated containers, each with similar pressures within. Once established, sealed compartments and the enclosed fluids will not interact with any other compartment in the subsurface unless breached by erosion or fracturing. Supporters of the sealed compartment model have suggested the presence of sealed compartments in the WCSB (Hunt, 1990; Bradley and Powley, 1994).

Thus, there is fundamental disagreement over the process of migration of fluids in sedimentary basins. Given the potential importance of the flow of formation fluids in sedimentary basins, it is clear that steps must be taken to determine which model (hydrogeologic: regional flow; or sealed compartment: no flow) is best suited to describe the conditions in the WCSB.

1.2 PROBLEM

At the centre of the controversy between sealed compartmentalists and hydrogeologists is what appears to be the simple question of whether or not water (or hydrocarbons) can move through rocks of extremely low permeability. The flow of water, oil, and gas in a basin is ultimately controlled by the distribution of these low permeability strata (Bredehoeft et al., 1983; Neuzil, 1986, 1994; Belitz and Bredehoeft, 1988; and others). Thus, the question of whether or not formation fluids can flow across low permeability rocks on a regional scale is an important one.

Those who support the sealed compartment model argue that certain rocks, for example halite or compacted shale, have zero intrinsic permeability. If a rock did have zero permeability then any applied fluid-potential gradient would not result in any flow, regardless of the time scale involved. Furthermore, sealed compartmentalists believe that certain geologic processes can occur (e.g., mineral precipitation) to convert otherwise highly-permeable rocks into rocks of zero permeability. If these low permeability strata do exist and they combine to isolate portions of the subsurface, then there can be no flow of formation fluids on a regional scale.

Hydrogeologists take a different view of the situation. Numerous laboratory and field studies have reported measurable and non-zero values of permeability for every rock tested (Brace, 1980; Neuzil, 1986, 1994; Clauser, 1992; Le Guen et al., 1993). If every rock has a finite permeability then a subsurface flow domain made up of different rocks will always have continuous permeability pathways through it. Such a flow domain would be called hydraulically continuous (Tóth, 1991) because a pressure disturbance applied in one part of the flow domain will eventually be felt in all other parts of the domain. In a hydraulically continuous domain, perceptible flow in geologic basins is controlled by the distribution of permeabilities, the applied boundary conditions, and the time scale of observation. An apparent lack of flow across a low permeability stratum is then explained as an artifact of too short an observation scale. Many of the observations in support of the existence of sealed compartments (e.g., Hunt, 1990) can be better explained by a model based on a hydraulically continuous rock framework (Tóth et al., 1991).

The general question of whether the subsurface flow of fluids in geologic basins is best described by the model of sealed compartments or hydraulically continuous rock framework is a difficult one to answer. Both groups of workers, sealed-compartmentalists and hydrogeologists, can cite extensive scientific publications in support of their work. The key argument remains whether regional fluid flow occurs in basins or not. But, direct measurements of flow rates are precluded because of the subsurface nature of the problem and the long time periods required for significant amounts of flow to occur. Indirect lines of evidence must be used but unfortunately, using indirect evidence to support one model or the other does not always provide definite answers because indirect evidence can be interpreted in different ways.

One step towards answering the larger question of cross-formational flow in geologic basins is to answer the specific question of cross-formational flow in the WCSB. The WCSB is an ideal candidate for study because of numerous factors. First, the WCSB is typical of the size, shape, and thickness of sediment found in other major basins throughout the world. Some authors recognize the WCSB as the type-example of a Foreland Basin (e.g., Macqueen and Leckie, 1992). By demonstrating that cross-formational flow occurs at the scale of the WCSB, that is, through typical sediments of a foreland basin, the argument that cross-formational flow predominates in sedimentary basins will be strengthened. Second, the WCSB has been abundantly explored by subsurface drilling for oil, gas, and mineral resources. Best estimates place the total number of wells drilled to date at over 200,000 (Shetsen and Mossop, 1994). This exploration has spanned over 50 years and continues today. This sheer volume of data allows the subsurface geology and flow systems to be mapped in great detail. Third, and probably most important, subsurface data are publicly available from the provincial government agencies that control exploration in the WCSB (e.g., the Alberta Energy Resources Conservation Board). Publicly available data ensures easy access for original study and future access for independent verification and re-examination. Fourth and finally, both the regional fluid flow (e.g., Hitchon, 1969a, 1969b, 1984; Tóth, 1978; Garven, 1989; Hitchon et al., 1989a, 1989b; Bachu and Undershultz, 1993; and others) and sealed compartment (Hunt, 1990; Powley, 1990; Bradley and Powley, 1994) models have been proposed for the basin.

If cross-formational flow can be demonstrated in the WCSB, then based on the above factors it seems logical to assume that dynamic conditions and cross-formational flow should occur in other geologic basins as well. The goal of this thesis is to answer to the question of whether or not there is cross-formational flow in the WCSB.

1.3 OBJECTIVES

The main objective of this thesis is to demonstrate that cross-formational fluid flow has occurred and/or is occurring across one or more of the basin-wide shales in the WCSB. Once fluid flow across the shales has been demonstrated, that is, that a hydraulically continuous rock framework exists in the basin, then the flow rates and directions of formation fluids (water, oil, and gas) can be calculated (e.g., Hubbert, 1940). A primary objective is to show that mapped distributions of fluid potentials, water chemistries, and hydrocarbons in an area of the WCSB form a hydraulically-continuous flow system. Furthermore, it will be shown that underpressured regions in the basin are not sealed compartments as proposed by Hunt (1990).

Specifically, this study will present a hydrogeological analysis of part of the WCSB, in order to:

1) Characterize the subsurface field of fluid-potentials and estimate flow-directions and flow-rates for the aquifers present.
2) Analyze the subsurface distribution of water chemistries.
3) Integrate the observed fluid potential and water chemistry data into a model of regional fluid flow for the study area.
4) Identify areas of cross-formational flow, focusing particularly on the basin-wide shales (Colorado, Joli Fou, Ireton formations) in the study area.
5) Calculate rates of cross-formational flow.
6) Describe the effects and implications of cross-formational fluid flow on the migration and distribution of hydrocarbons in the subsurface.

1.4 OUTLINE

This thesis is presented in a "paper" format. It consists of four main chapters in addition to this introduction and a concluding chapter. The general theme of this thesis is that cross-formational fluid flow does occur in the subsurface of west-central Alberta

(Townships 36 to 45, Ranges 21 west of the fourth Meridian to Range 10 west of the fifth Meridian). The thesis identifies specific formations and areas where cross-formational flow is occurring. It further relates the effects of cross-formational flow to the distribution of fluid potentials, water chemistries, and hydrocarbon migration and trapping in the study area.

The thesis begins with a chapter titled "Numerical simulations of how cap rock properties can control differential entrapment of oil". This paper discusses the mechanics of the formation of hydrocarbon plumes above breached reef reservoirs. It proposes an explanation for the anomalous distribution of hydrocarbons found in the Rimbey-Meadowbrook reef trend that currently cannot be explained by the standard model of differential hydrocarbon entrapment. Numerical modelling of a simple two reef system is used to show how the hydraulic properties of the cap-rocks above individual reefs control leakage of oil through overlying cap-rocks and ultimately the distribution of fluids in the entire reef trend. Thus, the paper demonstrates how cross-formational flow in a hydraulically continuous rock-framework can be used to explain the distribution of hydrocarbons in the Rimbey-Meadowbrook reef trend.

The second paper, titled "Ascending fluid plumes above Devonian reefs: numerical modelling and field example from west-central Alberta, Canada", overlaps with the first in that the mechanics of the formation of plumes of oil and water above reefs are again reviewed. Once the mechanism for leakage is established, the paper presents results of subsurface mapping in the west-central Alberta study area documenting this leakage and the creation of plumes of saline water and hydrocarbons from breached Leduc Formation reefs. The paper shows how saline brines move from the Leduc aquifer, across the Ireton aquitard through direct breaches in the aquitard, into the overlying Nisku aquifer. Direct breaches in the Ireton aquitard were previously undocumented in the WCSB. Once into the Nisku aquifer, the saline brines, and by extension hydrocarbons, move further upward as part of an ascending flow regime in the northeast corner of the study area. Upward moving saline brines and hydrocarbons cross the Wabamun Group aquitard and flow into the overlying Mannville Group aquifer. The intersection of the upward-moving saline Devonian brines and hydrocarbons with the fresher laterally-moving Mannville Group aquifer creates a large saline plume in the Mannville Group aquifer. This saline plume has been previously unrecognized, and its discovery has lead, in part, to a potential new type of mineral deposit in the WCSB. This study closes with a discussion of how mapping of saline plumes (subsurface and surface) can be used to detect underlying reefs.

The third paper, "Basin-scale fluid flow, hydrochemistry, and petroleum entrapment in Devonian reef complexes, west-central Alberta, Canada" provides a detailed look at the flow systems and hydrochemistry of the Devonian formations in the study area. It documents the existence of large-scale flow systems in the two main Devonian aquifers, and relates the dominant regional flow direction in these aquifers to the thickness of the Ireton aquitard. The main focus of this paper is to demonstrate the existence of "holes" in the regionally extensive Ireton aquitard, and to show how the distribution of these "holes" plays a key role in the sourcing and trapping of hydrocarbons on both sides of the shale. Having established that cross-formational migration plays a key role in hydrocarbon migration and trapping in the study area, the paper proposes new areas in which to search for Nisku Formation petroleum reservoirs.

The fourth paper, "Cross-formational fluid flow and the generation of a saline plume of formation waters in the Mannville Group, west-central Alberta" describes the hydrogeology and hydrochemistry of the Devonian to Lower Cretaceous strata in the study area, and examines the formation of the saline plume in the Mannville Group aquifer. In this paper, cross-formational flow from the Paleozoic aquifers (Elkton-Shunda aquifer and Upper Devonian hydrogeologic group) into the Mannville Group aquifer is shown. Also, flow across the so-called "impermeable" Joli Fou aquitard is proposed in two areas: in the southwest where the Joli Fou aquitard is absent; and in the northeast where flow rates on the order of 5.7×10^{-4} to 1.3×10^{-3} metres/year across it are calculated using measured hydraulic gradients and published shale hydraulic conductivities. Cross-formational flow systems documented in this paper demonstrate that flow occurs across the basin-wide aquifers in the WCSB and that the model of sealed compartments, therefore, does not apply in this basin.

The thesis closes with a concluding chapter highlighting the salient conclusions of the individual papers. The scientific contributions or "new knowledge" presented in this work are summarized as a set of nine "theses" or statements, that are presented separately at the end of the concluding chapter.

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2.0 NUMERICAL SIMULATIONS OF HOW CAP ROCK PROPERTIES CAN CONTROL DIFFERENTIAL ENTRAPMENT OF OIL*

2.1 INTRODUCTION

For many years, Gussow's model of differential entrapment has been used to explain the systematic distribution of oil and gas pools in continuous reservoir trends (Gussow, 1953, 1954, 1968; Schowalter, 1979). Worldwide examples include: the Alberta Basin, Canada (Gussow, 1954); numerous basins in the Middle East (Gussow, 1954); the Anadarko (Walters, 1958) and Michigan Basins (Gill, 1979), USA; the Eromanga Basin, Australia (Bowering, 1982); and many others.

In geologic environments where differential entrapment has taken place, the model predicts that each structure will be filled to its spill point and that there will be a systematic change in fluid-type along the reservoir trend. However, examples can be found where differential entrapment has obviously taken place, but the final hydrocarbon distribution does not meet one (or both) of these two generalizations (Gussow, 1953, 1954, 1968).

To fit the observed pool distributions to the ideal model, early workers (Gussow, 1953, 1954, 1968; Walters, 1958) invoked a number of post-emplacement operative mechanisms that would modify the differentially emplaced hydrocarbons. By including these modifying processes into the general model of differential entrapment, a satisfactory agreement between actual and ideal distributions was obtained.

One example of a reservoir trend where the observed hydrocarbon distribution does not fit the model is the Rimbey-Meadowbrook reef trend in central Alberta, Canada. Gussow (1953, 1954, 1968) used this example as key evidence for the existence of differential

* A version of this chapter has been published as B.J. Rostron, 1993, "Numerical Simulations of How Cap Rock Properties Can Control Differential Entrapment of Oil", SPE Paper 26442, in: Proceedings 1993 SPE Annual Technical Conference and Exhibition, Formation Evaluation and Reservoir Geology Volume, Oct. 3-6, 1993, Houston, Texas, p. 263-275.

entrapment, while at the same time recognizing that certain traps were not filled to their spill points, and that oil legs were present in the down-dip reservoirs where there should only be gas. These discrepancies were explained by post-emplacement formation of secondary gas caps.

In a much later study of the same reef trend, Stoakes and Creaney (1984, 1985) attributed the differences to permeability restrictions at the base of individual reefs: the so-called leaky pipeline theory.

These explanations seem reasonable, but since they all assume that the cap-rocks above the reservoirs are impermeable, (i.e., any hydrocarbon leakage has to be past the bottom spill point), they ignore leakage of hydrocarbons upward through the reservoir cap-rocks. The effect of reservoir/seal capillary pressure relationships on differential entrapment remained unstudied.

This paper presents the results of a series of numerical simulations conducted to study the effect of including capillary pressures in Gussow's model of differential entrapment. Results show that by including capillary pressures it is possible to produce traps not filled to their spill points, and that leakage through the cap-rock may account for some of the differences between what the original model predicts and what is observed in nature.

The paper begins with a review of the basic concepts of differential entrapment, then briefly describes the Rimbey-Meadowbrook reef trend (on which the simulations were based), and the numerical model and dataset. Results of two simulations are presented in detail, followed by a brief discussion of the effect of capillary pressures on differential entrapment.

2.2 THEORY OF DIFFERENTIAL ENTRAPMENT

To fully understand the simulation results presented here, a brief review of the fundamentals of differential entrapment is warranted. The basic processes and results of the theory will be summarized using simple schematic figures. For further details, interested readers are referred to the original publications by Gussow (1953, 1954, 1968).

2.2.1 Differential Entrapment - Single Trap

The first fundamental of differential entrapment is the process of gravity-induced segregation of immiscible fluids in a single trap (Figure 2.1). Two layers are present: a slightly dipping, permeable, regional carrier-bed; and an overlying impermeable cap-rock. Structural flexure creates a single, local trap along the top of the carrier-bed. Prior to the start of differential entrapment, the carrier-bed is devoid of any hydrocarbons.

Hydrocarbons are supplied to the system via separate-phase secondary migration (Gussow, 1954, 1968, Schowalter, 1979) in the carrier-bed. Entrapment begins when up-dip migrating oil reaches the local trap (Figure 2.1a). Oil moves to the crest of the structure, preferentially displacing water downwards and out of the trap. The oil/water contact moves down until it reaches the spill point (Figure 2.1b). After the spill point is reached, the trap is full. Any further supply from below causes an equal amount of oil to be pushed past the spill point, and oil migrates farther up-dip in the carrier-bed.

If, at a later time, the supply of hydrocarbons changes to a lighter gas phase (i.e., source rocks are now generating gas instead of oil), gas will migrate up-dip towards the previously oil-filled trap. At the trap, because it is lighter than oil, gas will preferentially move towards the crest of the structure (Figure 2.1c). As gas accumulates, oil is displaced by a downward movement of the gas/oil contact. Oil is pushed from the trap past the spill point, and allowed to continue migrating up-dip in the carrier-bed. Eventually, all of the originally-trapped oil is driven past the spill point.

Once the gas/oil contact reaches the spill point, the trap is now filled with gas (Figure 2.1d), and gas begins to spill from the reservoir. After the trap is full, any further supply of gas results in an equal amount of spillage and subsequent up-dip migration in the carrier-bed.

2.2.2 Differential Entrapment - Multiple Traps

For differential entrapment to take place on a regional scale, there must a number of local traps connected to the carrier-bed (Figure 2.2). Early in the differential entrapment process, oil fills the first trap to its spill point, then moves farther up-dip into the second trap (Figure 2.2a). During this stage of differential entrapment, the oil distribution in the reservoir trend will exhibit three characteristics: 1) farthest down-dip traps filled to their spill points; 2) farthest up-dip traps filled with water; and somewhere in between, 3) a partially filled trap with a distinct oil/water contact higher than the spill point.

Later, once gas begins to displace oil from the first trap (Figure 2.2b), two processes take place: 1) gas filling of down-dip traps; and 2) re-migration and continued up-dip movement of oil. This process of trap-filling, fluid displacement, and up-dip migration occurs until there is no longer a down-dip supply of hydrocarbons.

With no additional fluids moving up from below, the process of differential entrapment is complete. The final hydrocarbon distribution along the reservoir trend (Figure 2.2c) exhibits the systematic variation in fluid type and amount that results from the process of differential entrapment. Along the reservoir trend, there will be a segregation of the type of hydrocarbons found in each trap: from gas (farthest down-dip); towards gas and oil; then to oil-filled; to oil and water; and finally to water-filled structures (farthest up-dip). Each trap will be filled to its spill point, except for the most up-dip trap containing either fluid, which will be partially full. These two generalizations about the hydrocarbon distribution (spill point control of amount, and position within trend controlling type), summarize the ideal end-result of differential entrapment.

2.2.3 Modifications After Ideal Differential Entrapment

The ideal hydrocarbon distribution predicted by the model needs to be modified to account for a number of naturally-occurring geologic processes. These processes include:

1) pressure-volume-temperature relationships; 2) post-emplacement tilting; 3) migration by-pass; and 4) faulting and/or seepage.

Pressure-volume-temperature relationships refer to a broad group of phenomena relating to one of the fundamental assumptions of the model: migration of immiscible fluids. Undoubtedly, subsurface oils can, and do, carry dissolved gasses within them. Exsolution of gas from an emplaced oil column, or the dissolving of a gas cap back into an oil leg could occur if pressure conditions changed in a reservoir after entrapment (Gussow, 1953, 1954, 1968). Such pressure changes could be induced, for example, by deeper burial of a reservoir, causing decreased gas volumes and a subsequent rise in the gas/water contact (leading to the reservoir not being filled to the spill point). Thus, it is possible to modify the ideal hydrocarbon distribution after emplacement if pressure changes occur in, or along, the reservoir trend.

Post-emplacement tilting refers to any process that may act to alter the dip of the carrier-bed, either uniformly or locally, after hydrocarbon emplacement, which can affect hydrocarbon distributions. For example, in large reservoir trends, it may be possible to elevate one or more of the reservoirs preferentially, causing physical spilling of trapped hydrocarbons up- or down-dip. It may also be possible to tilt the entire carrier-bed, re-initiating differential entrapment along the trend.

Migration by-pass or the so-called leaky pipeline theory (Stoakes and Creaney, 1984, 1985) can also act to modify the hydrocarbon distribution during emplacement. If the migrating stream of oil happens to "branch" or travel around a particular trap, that trap will be by-passed and either devoid of, or partially filled with, hydrocarbons. Proponents of the leaky pipeline theory (Stoakes and Creaney, 1984, 1985) suggest that permeability restrictions at the base of individual traps can assist by-pass, producing empty traps. These same permeability restrictions can selectively hold heavier fluids out of traps because the lighter fluids will have proportionally higher vertical driving-forces, and therefore be able to penetrate the permeability restrictions and enter the traps.

The final modifying mechanism, referred to as faulting and/or seepage, deals with cap-rock competency. If a cap-rock is breached by faulting or erosion, the fluid column in the underlying reservoir will no longer be controlled by the spill point. This process could occur either before, during, or after emplacement, causing large discrepancies between observed and predicted hydrocarbon distributions.

Discrepancies between the ideal model and what is observed have been noted by many authors (e.g., Gussow, 1953, 1954, 1968; Walters, 1958; Gill, 1979). These differences were explained using a combination of one or more of the preceding modifying mechanisms. Each of the preceding mechanisms assumes that the cap-rocks are impermeable, except for the case where the cap-rock is directly breached. In the context of differential entrapment, the hydraulic properties of the cap-rocks, such as capillary pressure or relative permeability, have been ignored to date. This paper shows that the hydraulic properties of the cap-rocks do affect migration and differential entrapment.

2.3 RIMBEY-MEADOWBROOK REEF TREND

One of Gussow's original examples of differential entrapment was in the Rimbey-Meadowbrook reef trend in central Alberta, Canada (Figure 2.3). This prolific reef trend has produced hydrocarbons since 1947, and is still an active exploration target today. It contains more than $310 \times 10^6 m^3$ original oil-in-place and $112 \times 10^9 m^3$ original gas-in-place (Barfoot and Ko, 1987). This, coupled with the wealth of geological information available (Andrichuk, 1958a, 1958b; Amthor et al., 1993), make the Rimbey-Meadowbrook reef trend an ideal candidate for a modelling study of differential entrapment.

2.3.1 Geology

The reservoirs that make up the Rimbey-Meadowbrook trend are Late Devonian (Frasnian) age rocks that comprise the Woodbend Group. The Woodbend Group consists of: a thick sequence of shallow water platform-carbonates (Cooking Lake Formation); upon which have grown numerous platform margin reef-buildups (Leduc Formation); capped by basin-filling shales and limestones (Ireton and Duvernay formations) (Andrichuk, 1958a, 1958b; Barfoot and Ko, 1987; Amthor et al., 1993). Along the central core of the Rimbey-Meadowbrook trend, the Cooking Lake and Leduc formations consist of crystalline dolomite (Amthor et al., 1993). Each of the biohermal buildups are to some degree connected to the underlying Cooking Lake aquifer (Barfoot and Ko, 1987; Amthor et al., 1993). The relative thickness of each of the units is shown in a cross-section along the reef trend (Figure 2.4). The Woodbend Group is bounded below by the relatively-impermeable calcareous shales and limestones of the Waterways Formation (Beaverhill Lake Group) (Andrichuk, 1958a, 1958b; Amthor et al., 1993), and above by the relatively-permeable Nisku Formation (Winterburn Group).

2.3.2 Observed Fluid Distributions

The pre-production distribution of hydrocarbons shows several interesting patterns (Figure 2.4). First, in a general sense, gas is present in the more down-dip reservoirs (Homeglen-Rimbey to Bonnie Glen), and oil is present in up-dip reservoirs (Acheson, Big Lake, and St. Albert). Second, most of the reservoirs are filled to their spill points (from Homeglen-Rimbey to Bonnie Glen). These two general observations led Gussow (1953, 1954, 1968) to the conclusion that differential entrapment had acted to create the oil and gas accumulations in the Rimbey-Meadowbrook trend.

2.3.3 Discrepancies

It is quite obvious that there are two major inconsistencies between the observed hydrocarbon distributions and the ideal distributions predicted by the model. Most obvious is the fact that Homeglen-Rimbey, Westerose South, and Westerose reservoirs have oil legs, where there should be none (assuming separate-phase gas migration having just reached Bonnie Glen) and the gas cap at Leduc is farther up-dip than expected.

Furthermore, a number of traps are not filled to their spill points (Wizard Lake to St. Albert). If "ideal" differential entrapment had operated, then none of the reefs past Wizard Lake should contain any hydrocarbons.

These inconsistencies have not gone unnoticed. Gussow (1953, 1954, 1968) explained them by invoking pressure-volume-temperature relationships and migration by-pass. He proposed that the Leduc-Woodbend gas cap formed from exsolved-oil spilt from Glen Park and that the gas caps at Westerose and Bonnie Glen were caused by partial by-pass of Westerose South sourced gas. Furthermore, Gussow proposed that the oil legs at Homeglen-Rimbey and Westerose South were created by either small amounts of oil which where incompletely flushed out of the traps, or exsolved from the gas cap after gas emplacement. Gussow (1953, 1954, 1968) did not explain why certain traps were not filled to their spill points.

Other authors (Stoakes and Creaney, 1984, 1985) have explained these inconsistencies in a general sense by invoking the mechanism of migration by-pass. They postulated that there must be permeability restrictions in the Cooking Lake Formation at the base of the reefs that were not filled to their spill points (Glen Park, Leduc-Woodbend, Acheson, and Big Lake). Thus preventing oil from completely filling these structures. Selective by-passing of reefs along the Cooking Lake aquifer led to the aquifer being called a leaky pipeline, a model which offered an apparently satisfactory explanation for the differences.

Previous modeling studies (Rostron and Tóth, 1989, 1992) dealing with secondary migration of oil generated the idea for incorporating capillary pressures into the model of differential entrapment. Earlier results showed that capillary pressures play an important role in oil migration, and the possibility existed that the capillary pressure properties of the Ireton Formation shales could have an influence on differential entrapment in the Rimbey-Meadowbrook reef trend. Numerical simulations were thus conducted to test whether capillary properties played a role in differential entrapment.

2.4 NUMERICAL SIMULATIONS

Simulations were performed using the transient, two-dimensional, multiphase, finite-difference flow model SWANFLOW (Faust, 1985).This model was originally developed to study shallow migration of immiscible contaminants, but was found to be applicable to petroleum-related problems such as this, with minor simplifying assumptions (Rostron and Tóth, 1989, 1992). In this study, the numerical code was coupled to the National Center for Supercomputer Applications IMAGE program, using their Hierarchical Data Format libraries. This modification facilitated the production of contour plots of saturation profiles at various time steps and of colour-animated "movies" of the transient saturation distributions. Runs were conducted on a Macintosh IIfx microcomputer and a Silicon Graphics Personal Iris workstation, with elapsed execution times of approximately 9 and 1.5 hours per simulation, respectively.

More than 40 separate simulations were completed, varying the capillary pressure curves, cap-rock permeabilities, oil densities, and regional formation-fluid gradients of the system. Two complete transient saturation-profiles and a series of final-time oil saturations are presented here to illustrate the essential results of the study.

2.4.1 Simulation Data

Structural data were used to construct a hypothetical, vertical cross-section through two typical reefs of the Rimbey-Meadowbrook trend (Figure 2.5). A 60 by 15 block finite-difference grid was used to discretize the flow domain which was made up of three different rock types: a lower carrier-bed running the length of the grid; and above that, two regions representing the cap-rocks for each trap. The hydraulic properties within the carrier-bed were identical everywhere, while the cap-rock properties above each reef were specified differently for each model run.

Boundary conditions for the model remained the same for each run, except when the magnitude of the horizontal hydraulic-gradient was varied. Along the top and bottom of the grid, no-flow boundaries were used, simulating the confinement of the cross-section between some hypothetically-existing ultra low-permeability strata. For the upstream and downstream vertical boundaries (grid right and left, respectively), two different types of boundaries were used: for the cap-rock, no-flow boundaries were imposed; and for the carrier-bed, specified constant-heads were used. Using this combination of boundary conditions, it was possible to set up a horizontal flow-field through the carrier-bed, and still allow for vertical migration into and within the cap-rock.

In order to facilitate comparison of model-derived results, a "base-case" input dataset was defined (Table 2.1). For each simulation, one or more of the base-case input parameters was changed. A list of all varied parameters is shown (Table 2.1). The relative permeability and capillary pressure curves used in the simulations are shown on Figure 2.6. Modelled relative permeability curves were identical for the cap-rock and carrier-bed, and were held the same in each simulation shown here. The input parameter that was varied most-often was the capillary pressure curve. To keep track of the different capillary pressure curves used, an informal descriptive value called "critical oil column" was defined for this study. Since the simulation results depend strongly on the selected critical oil columns, further explanation of this nomenclature is warranted below.

Variations in capillary pressure curves can be referred to using a critical oil column, COC, which is defined as: the height of oil column, of a specified oil density, required to build up sufficient buoyant pressure under static conditions, to equal the entry pressure of a given cap-rock. Mathematically COC is written as:

$$COC = \frac{(Pe_{cr} - Pe_{cb})}{(\rho_w - \rho_o)g} \quad \text{..(2.1)}$$

where: COC: the critical oil column for a specified oil density and a given pair of carrier-bed/cap-rocks [metres]; Pe_{cr}: the entry capillary pressure of the cap-rock [Pascals]; Pe_{cb}: the entry capillary pressure of the carrier-bed [Pascals]; ρ_W: water density [kg/m^3]; ρ_O: oil density [kg/m^3]; and g: gravitational constant [m/s^2]. A single value of COC refers to a pair of capillary pressure curves and a pair of fluid densities, under static conditions. Five different COC values (Table 2.1) were used as inputs for the various simulations.

These data, although real in the sense that they represent actual rock-derived parameters, were selected arbitrarily. A good example of this arbitrary selection process is the oil injection rate. The actual hydrocarbon source-rate (and duration) for the reef trend is unknown. In the simulations, a source rate was specified so that oil would migrate across the grid within a reasonable amount of computer execution time. This was justified because of the lack of a complete real dataset and because the purpose of the modelling was only to study the effect of including cap-rock properties, and not to accurately model differential entrapment in the Rimbey-Meadowbrook trend. Arbitrary selection of input parameters does not invalidate the modelling, it just makes the results conceptual in nature, and precludes any quantitative comparison with other secondary migration studies.

Each simulation was conducted in two parts: establishment of steady-state fluid potentials across the grid; and a subsequent transient (migration) phase. At specified time increments, the numerical model output the oil saturation distribution to the graphics package, which provided a color contour plot of oil saturation. At the end of each run, the individual contour plots could be viewed as an animated sequence of oil migration through time. Simulations were halted once the migrating stream had reached the downstream end (grid left) of the carrier-bed, or once all oil had leaked through a reef into the cap-rock above.

For this study, only oil and water migration was modelled because of the complicated nature of the gas-oil-water system and the additional computer time required for the simulations.

2.4.2 Simulation results: "Impermeable" cap-rocks

Results of the base case simulation (Figure 2.7) illustrate the effect of having a COC for both cap-rocks much higher than the height of the trap. The cap-rocks can be thought of as impermeable to oil, because the crest to spill point height of each trap is 100 metres, and the COC of the cap-rock/carrier-bed is 289 metres. It is impossible to build up an oil column higher than the COC, therefore oil will never be able to penetrate the cap-rock. Since the cap-rocks are effectively impermeable to oil, this case replicates Gussow's model of differential entrapment.

At T=0 years, oil is introduced into the upstream end of the carrier-bed. Oil moves under the combined influence of a horizontal water gradient and a vertical buoyancy gradient, traveling generally upward along the top of the carrier-bed (Figure 2.7a). The migrating oil front has formed a stringer of oil, the mobile portion of which is outlined by the 20 percent saturation contour in Figure 2.7a. Oil saturations in the stringer reach only 21 percent because as the saturation at the tip reaches the irreducible oil saturation, S_{oi}, (20 percent) further downstream migration occurs. As the stringer moves, there is no large increase in oil saturations above the S_{oi}.

At about T=10,000 years, the stringer reaches the crest of the reef structure. Once at the crest, oil accumulation past the S_{oi} begins, because the stringer can no longer move upward. Oil saturations reach 55 percent, a limiting value imposed by the 45 percent irreducible water saturation, S_{wi}. Once at 55 percent oil saturation, no further accumulation at the crest is possible, so the area of accumulation begins to expand downward (Figures 2.7b-c). From 10,000 to 30,000 years, the oil/water contact moves downwards, displacing water from the reef. At T=30,000 years the oil/water contact reaches the spill point of the first reef.

Once the oil/water contact reaches the spill point, there is no further increase in oil saturation in the first reef. Oil spills from the reef, creating a second oil stringer that moves downstream towards the second reef (Figure 2.7d). Once the stringer reaches the crest of the second reef (about 40,000 years), the filling process (described above) repeats itself. The simulation ends at T=75,000 years, when the third stringer (emanating from the second reef) reaches the downstream end of the grid (Figure 2.7e).

The final saturation distribution (Figure 2.7e), showing two reefs each filled to their spill points, provides numerical confirmation of Gussow's ideal case of differential entrapment for oil (compare to Figure 2.1b or 2.2a). Results of the base case (impermeable cap-rock) simulation can be summarized as follows: 1) each reef is filled by a stringer of oil migrating along the top of the carrier-bed; 2) accumulation of oil begins at the crest of the reef; 3) water is displaced from successive traps by downward migration of the oil/water contact; 4) a tilted oil/water contact is produced inside the reef because of vertical buoyancy and horizontal water gradients acting on the oil; and 5) the spill point controls the height of the oil column in each reef.

2.4.3 <u>Simulation results: "Leaky" cap-rocks</u>

In the next example, the COC of the first cap-rock was reduced to 25.9 metres while maintaining the COC of the second cap-rock at 289 metres. In this case, the cap-rock cannot retain the entire oil column in the trap because the COC (25.9 metres) is less than the crest to spill point height of the trap (100 metres). Oil will leak from the reef into the cap-rock, leading to the reef being described as having a leaky cap-rock. This simulation result illustrates the effect that capillary pressures can have on differential entrapment (Figure 2.8).

From T=0 to 9,000 years the oil stringer forms and then moves through the carrier-bed to the crest of the reef, as in the first simulation.

Oil reaches the crest of the reef after 10,000 years (Figure 2.8a), and begins concentrating to 55 percent. Once the saturation levels reach 55 percent (at about 11,000 years), the oil/water contact begins moving downward. As the oil/water contact descends, it generates a column of oil, pushing up on the cap-rock. Once a 25.9 metre oil column is generated, oil begins to penetrate into the cap-rock, because the height of the column is equal to the COC of the cap-rock. At this point, the reef is leaking oil into the cap-rock.

From 11,000 to 45,000 years, oil travels in two directions in the flow domain (Figures 2.8b-d): upwards in the cap-rock, as a "chimney" from the reef; and downwards, as part of the descending oil/water contact.

At 45,000 years, the oil/water contact reaches the spill point, and oil begins to spill from the reef into the carrier-bed. From 45,000 years to the final saturation distribution at 50,000 years (Figure 2.8e), a second stringer forms, and begins migrating downstream towards the second reef. This simulation was terminated at 50,000 years because the second cap-rock's COC of 289 metres produces a reef filling pattern identical to the base case (Figure 2.7d-e).

Past 30,000 years, oil accumulates along the top boundary of the flow domain (Figures 2.8d-e). This accumulation is caused by the no-flow boundary along the top of the finite difference grid. In reality, oil would likely continue migrating vertically until reaching another carrier-bed, trap, or the ground surface. Increased oil saturations in the cap-rock along the upper boundary of the flow domain have little or no affect on trapping conditions within the carrier bed.

This simulation shows that even though the cap-rock "leaked" and allowed oil to migrate vertically out of the reef, the reef still filled to its spill point. Oil entered the trap from below faster than it could leak out through the cap-rock, hence the trap filled.

Simulation results for leaky cap-rock cases can be summarized as follows: 1) the critical oil column (COC) of the cap-rock controls whether oil will begin to leak from the reef; 2) once the height of the oil column in the reef reaches the COC, oil moves into the cap-rock; 3) even though oil may be leaking into the cap-rock, the trap may still be filled if the oil source rate exceeds the rate of oil loss; 5) a reef may never completely fill, if the rate of oil loss exceeds the rate of source; and 6) by including the capillary pressure properties of the cap-rocks, it is possible to generate traps that are not filled to their spill points.

2.5 DISCUSSION

The preceding two simulations were selected for presentation because they illustrate how cap-rock properties can control differential entrapment. In the first case with impermeable cap-rocks, the spill point controls migration and entrapment. In the second case, the spill point still plays a part, but additional factors influence oil entrapment. Simulation results show that when capillary properties are included, final oil distributions are controlled by the interaction of the sealing and leaking factors of the system.

2.5.1 Sealing Factors

Sealing factors are defined as those physical properties or processes that act to retain hydrocarbons within reservoirs. Simulation results show the two sealing factors are the entry capillary pressure and the intrinsic permeability of the cap-rock.

Initial trap leakage is controlled by the magnitude of the critical oil column of the cap-rock. If the accumulating oil column builds sufficient height to equal the COC, oil will begin to leak from the trap (e.g., Figure 2.8). If sufficient oil column cannot be built up to equal the COC (e.g., Figure 2.7), then the cap-rock can be considered to be impermeable to oil.

If oil does manage to penetrate into the cap-rock, then the second sealing factor, intrinsic permeability, controls accumulation. Once oil is within the cap-rock, its rate of movement is governed by the intrinsic permeability of the cap-rock. If the permeability is low enough, the cap-rock still acts as an effective seal for the trap below even though oil is moving into the cap-rock. Conversely, if the permeability of the cap-rock is high, such as in fractured shale, then oil is quickly lost from the trap once oil penetrates the cap-rock.

Variations in COC produce vastly different final-time oil distributions (Figure 2.9). With the COC greater than the trap height (Figure 2.9a) no oil leaks from the trap. When the COC equals the trap height (Figure 2.9b), trace amounts of oil still leak from the trap because the COC is only a static measure of trapping capacity. In a hydrodynamic environment a small vertical component of the regional water gradient acts in conjunction with the buoyancy force to exceed the COC. Because the vertical component of the regional water gradient is small, very little oil is able to penetrate the cap-rock.

If the COC values are much less than the trap height, leakage will occur (Figures 2.9c-d). The difference in the amounts of oil above the first reef in Figure 2.9c and Figure 2.9d is caused by the difference in COC. In the case where the COC is 25.9 metres (Figure 2.9d), the oil column reaches this value sooner than in Figure 2.9c, where the COC is 78 metres. At 50,000 years, the reef with the lower COC has been leaking longer, and its cap-rock contains more oil.

The effect of varying the intrinsic permeability of a leaky cap-rock can be seen in Figure 2.10. In each case, the COC of the first trap is equal to 25.9 metres. The intrinsic permeability of the cap-rock has been increased from 1×10^{-4} millidarcies (Figure 2.10a) to 1×10^{-1} millidarcies (Figure 2.10d). This sequence shows that a cap-rock with a low enough intrinsic permeability can still hold an oil column, even though it is leaking.

2.5.2 Leaking Factors

Leaking factors are defined as those physical properties or processes that act to drive hydrocarbons from or into reservoirs. Simulation results show that the two main leaking factors are buoyancy caused by the oil-water density contrast, and the regional hydraulic-gradient of water.

Buoyancy forces are generated by density differences between the immiscible phases, with the magnitude of the forces proportional to the density contrast. In a static environment, buoyancy forces act vertically. In hydrodynamic environments, a component of the regional water hydraulic-gradient provides an additional vertical driving force. Changing the oil density or water hydraulic gradient or both can alter the process of differential entrapment and the resulting hydrocarbon distribution. Simulation results illustrating some of these changes are shown in Figures 2.11 and 2.12.

When the oil density is reduced from 850 to 700 kg/m^3 (i.e., the density contrast is doubled), two effects on the final oil distributions are evident. First, decreasing the oil density flattens the tilt of the oil/water contact (Figures 2.11a-b). Second, doubling the density contrast increases the vertical driving force on the oil. If the cap-rocks are "impermeable" then increasing the oil density is not sufficient to drive oil into the cap-rock (Figures 2.11a-b). On the other hand, if the cap-rock were able to leak with 850 kg/m^3 oil, then doubling the density contrast increases the amount of oil entering the cap-rock (Figures 2.11c-d). In this case, doubling the vertical driving force on a cap-rock with an COC of 25.9 metres creates a situation where a trap cannot fill to its spill point (Figure 2.11d). The COC of the cap-rock calculated with the lower density is approximately half the original value (Equation 2.1).

A second example of varying the leaking factors is shown in Figure 2.12. Here, the regional hydraulic gradient is increased by a factor of four (from 0.02 to 0.08 metres/metre). For the case where the cap-rocks are impermeable (Figures 2.12a-b) the increased leaking factor is still not sufficient to drive oil into the cap-rock, but the increased water gradient causes a greater tilt of the oil/water contact. The steeper oil/water contact results in less volume of trapped oil. If the cap-rocks are leaky and the gradient is increased, then the tilt of the oil/water contact steepened and the rate of oil leakage from the reefs is increased as well (Figures 2.12c-d).

2.5.3 Implications for Differential Entrapment

This modelling shows that it is possible to explain some of the differences between what is observed in the Rimbey-Meadowbrook reef trend and what is predicted by the ideal theory of differential entrapment. If the reefs leak oil vertically into the cap-rocks, then it is possible to explain how certain traps may not be filled to their spill points because the cap-rocks cannot retain full oil columns. Vertical oil leakage could explain why the Leduc-Woodbend, Acheson, Big Lake, and St. Albert reefs are not filled to their spill points. These results also suggest that certain cap-rocks may be able to retain a full oil column but may not be able to retain the same column of gas due to the increased density contrast.

2.5.4 Implications for Petroleum Exploration

Numerical simulations illustrate that it may be possible to have a trapped pool of oil even though the trap is leaking (if the COC is exceeded by the oil column). If the intrinsic permeability of the cap-rock is low enough and/or if the time elapsed from the initiation of leakage is short enough, a leaky cap-rock may still hold an oil accumulation. For exploration, this means that traps with low COC values should not be discarded until the intrinsic permeabilities of the cap-rocks are determined.

Results also show that it is possible to overestimate the sealing capacity of the cap-rock if only the entry pressure of the cap-rock is used. The entry pressure of the cap-rock must be reduced by the entry pressure of the carrier-bed in order to correctly calculate the retaining capacity of the seal. Another factor that can reduce the sealing capacity of a cap-rock is strong vertical water gradients. If water gradients are ignored, then errors could be made when calculating sealing capacity in strong hydrodynamic environments.

2.6 CONCLUSIONS

Numerical simulations of differential entrapment in a reef trend have shown:

1) The spill point controls the height of the fluid column if the cap-rocks are impermeable.

2) The interaction of the sealing factors (capillary pressure, intrinsic permeability) and leaking factors (oil density, regional hydraulic gradient) control the amount and type of hydrocarbons in each trap if cap-rocks have some permeability.

3) Certain traps cannot fill to their spill points because oil leaks through the cap-rock during emplacement.

4) Capillary pressures play an important role in the process of differential entrapment, and the inclusion of cap-rock properties in the model of differential entrapment could better explain the observed discrepancies between the ideal model and the conditions observed in the Rimbey-Meadowbrook reef trend.

5) The difference between the entry pressures of the cap-rock and carrier-bed defines the sealing capacity. The sealing capacity may be overestimated if only the entry pressure of the cap-rock is used.

6) Even if a trap is leaking, there may still be a hydrocarbon accumulation because the intrinsic permeability of the cap-rock may be low enough to maintain an oil column in the trap.

7) The hydraulic properties of low permeability cap-rocks (intrinsic permeabilities, relative permeability to oil and gas, and capillary pressure curves) need to be measured to enable more accurate modelling of differential entrapment.

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Number 7 (1985), Carbonates in Subsurface and Outcrop: Tulsa, Society for Sedimentary Geology, p. 343-375.

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Constant Properties

Number of Grid Blocks:	60 x 15 (horizontal x vertical)
Flow Domain:	1400 x 300 m (horizontal x vertical)
Fluid Viscosity:	2.0×10^{-3} Pa.s (oil); 1.0×10^{-3} Pa.s (water)
Water Density:	1000 kg/m^3
Porosity:	20% carrier-bed; 5% cap-rock
Carrier-bed Permeability:	100 md
Formation Compressibility:	1.0×10^{-10} kPa^{-1}
Injected Fluid Composition:	90% water; 10% oil
Oil Injection Rate:	3.71×10^{-1} m^3/year
Irreducible Oil Saturation:	20%
Irreducible Water Saturation:	45%
Timestep Length:	50 years

Variable Properties

	Base Case:	*Other Cases:*
Oil Density:	850 kg/m^3	700, 1000 kg/m^3
Regional Hydraulic Gradient:	0.02 m/m	0.005, 0.08, 0.2 m/m
Cap-rock Permeability:	0.1 md	0.0001, 0.001, 0.01, 100 md
Crtical Oil Column:	289 m	25.9, 78, 100, 143 m

Table 2.1. Simulation Data.

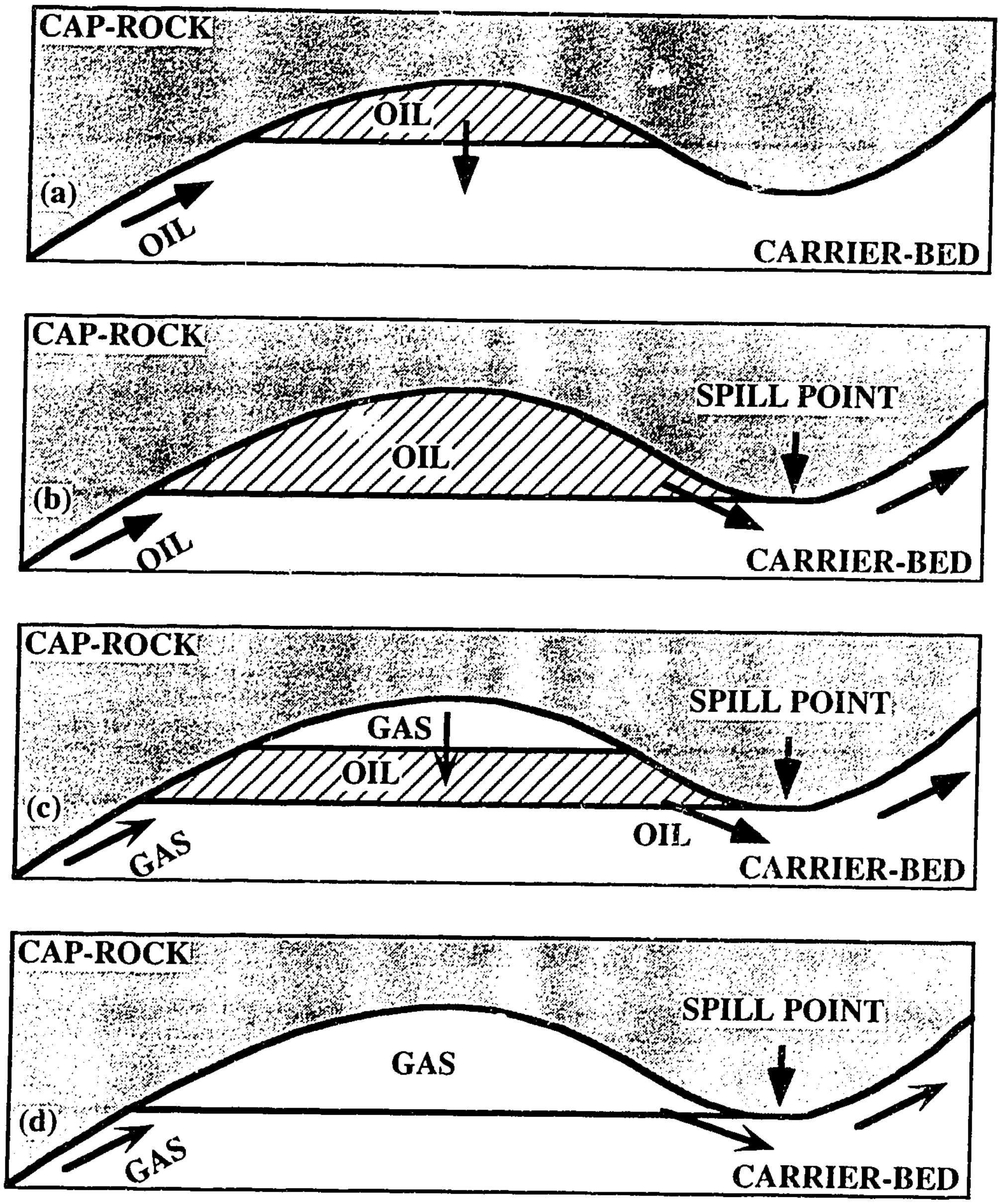


Figure 2.1. Schematic of the process of differential entrapment in a single trap.

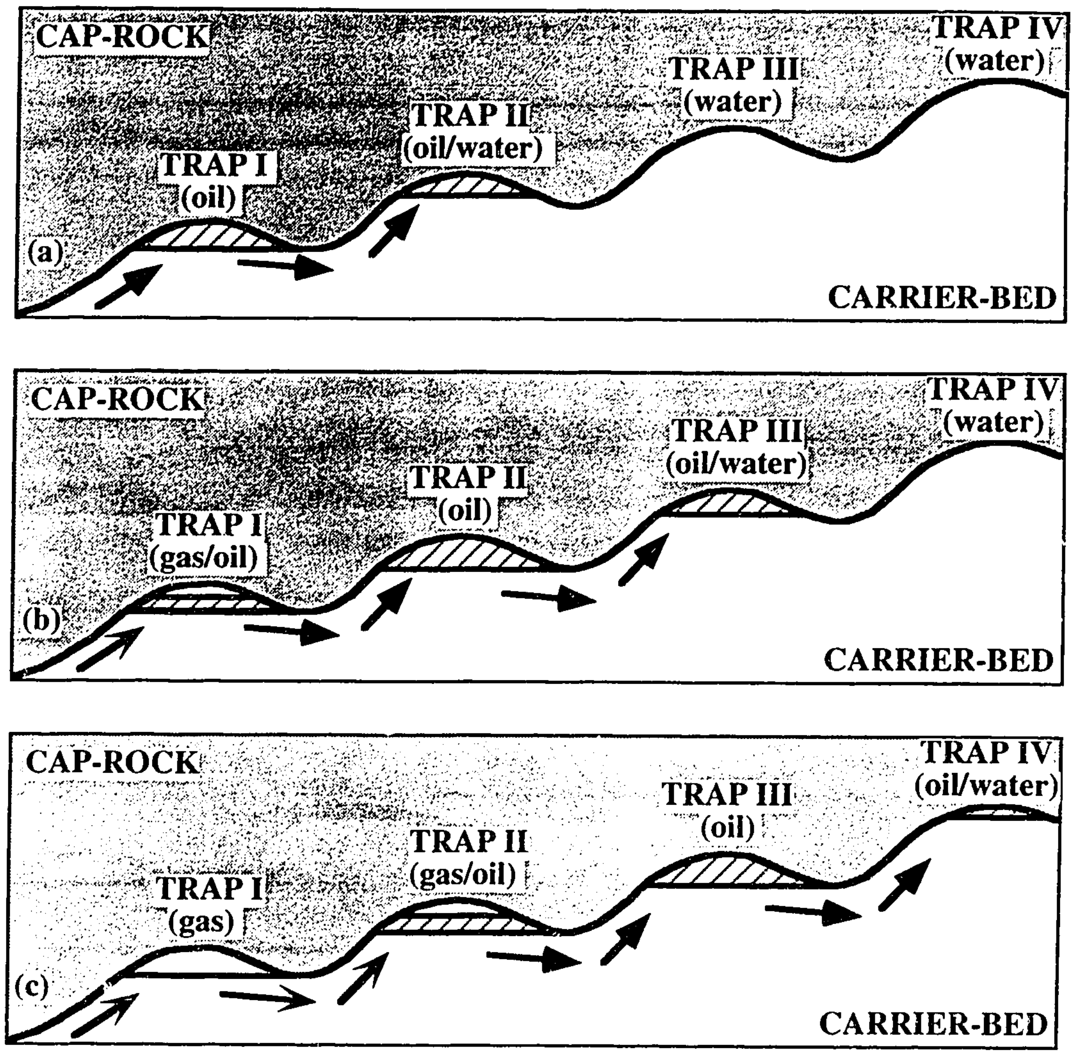


Figure 2.2. Schematic of the process of differential entrapment in multiple traps.

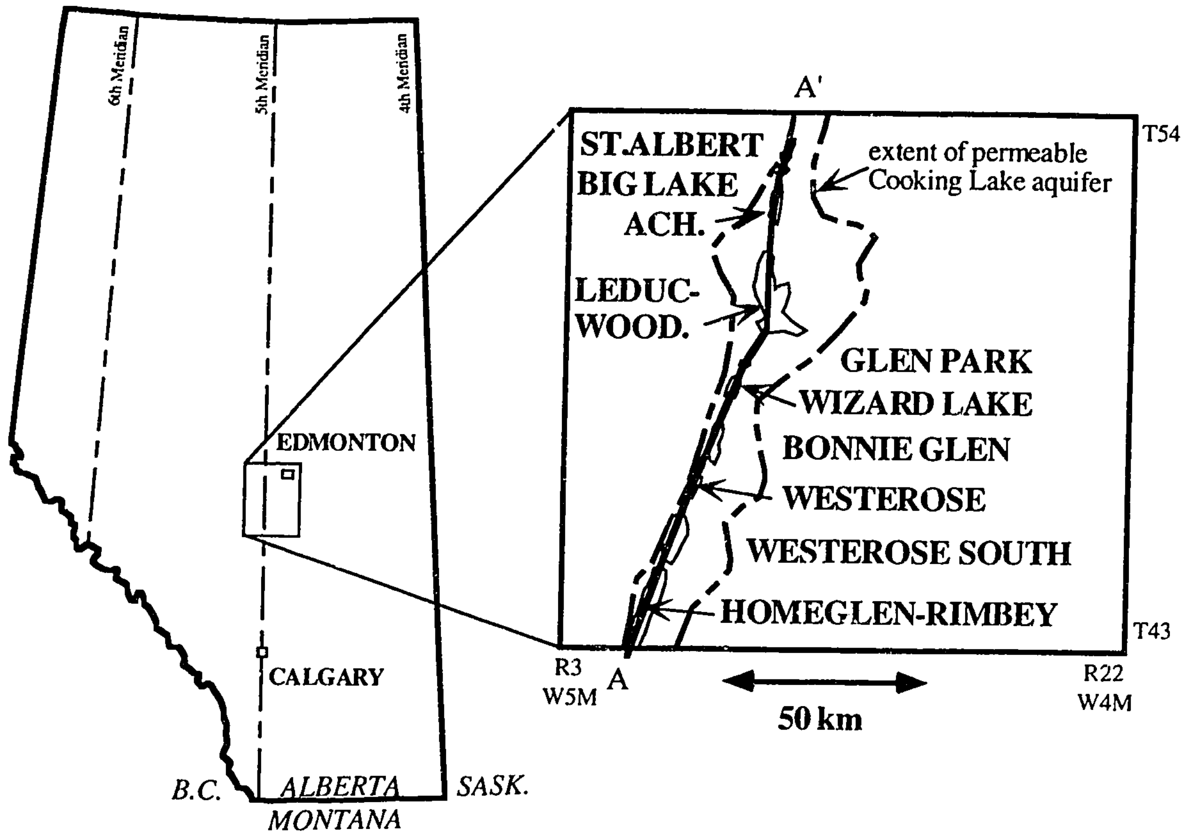


Figure 2.3. Location map of the central part of the Rimbey-Meabowbrook reef trend, Alberta, Canada (modified after Barfoot and Ko, 1987).

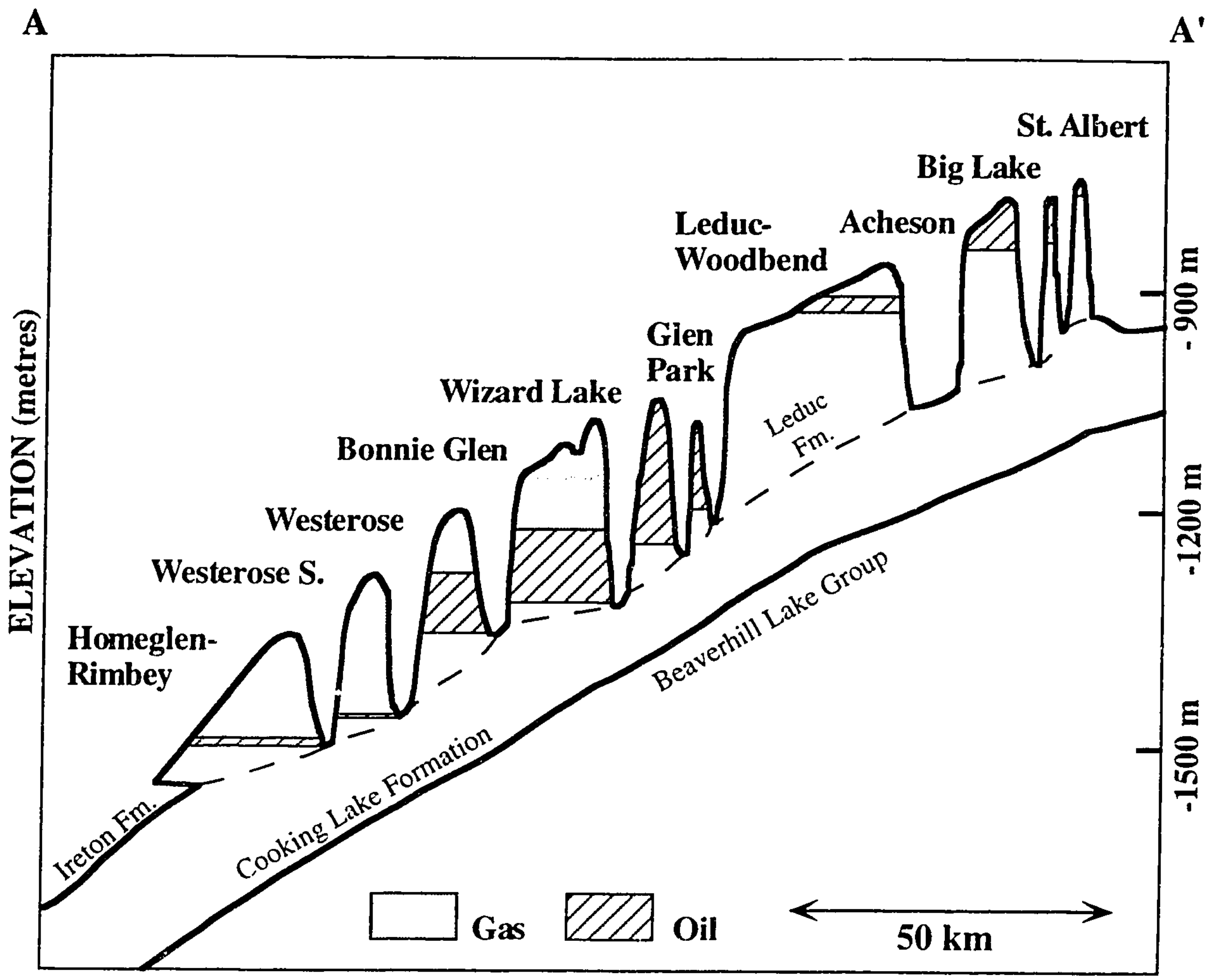


Figure 2.4. Structural cross-section through the Rimbey-Meadowbrook reef trend (modified after Gussow, 1954; Barfoot and Ko, 1987). Location of section is shown on Figure 2.3.

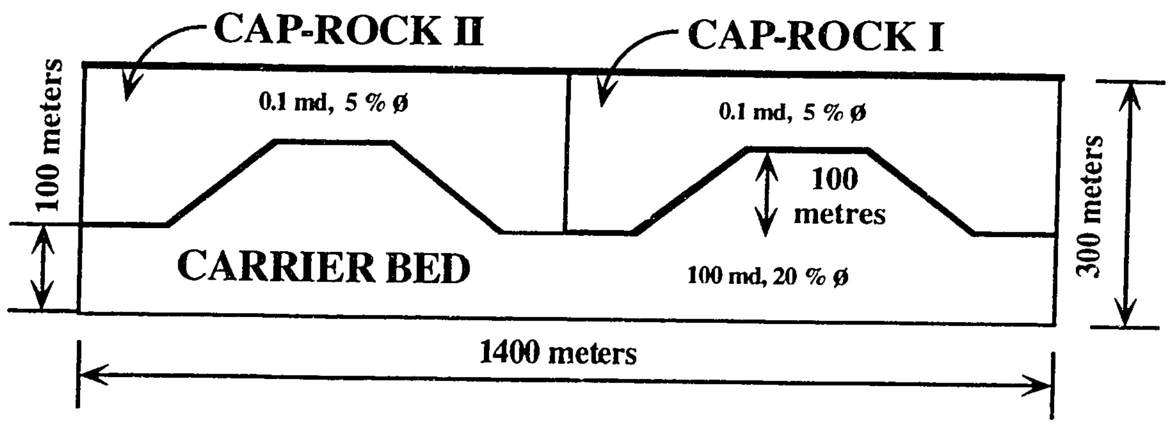
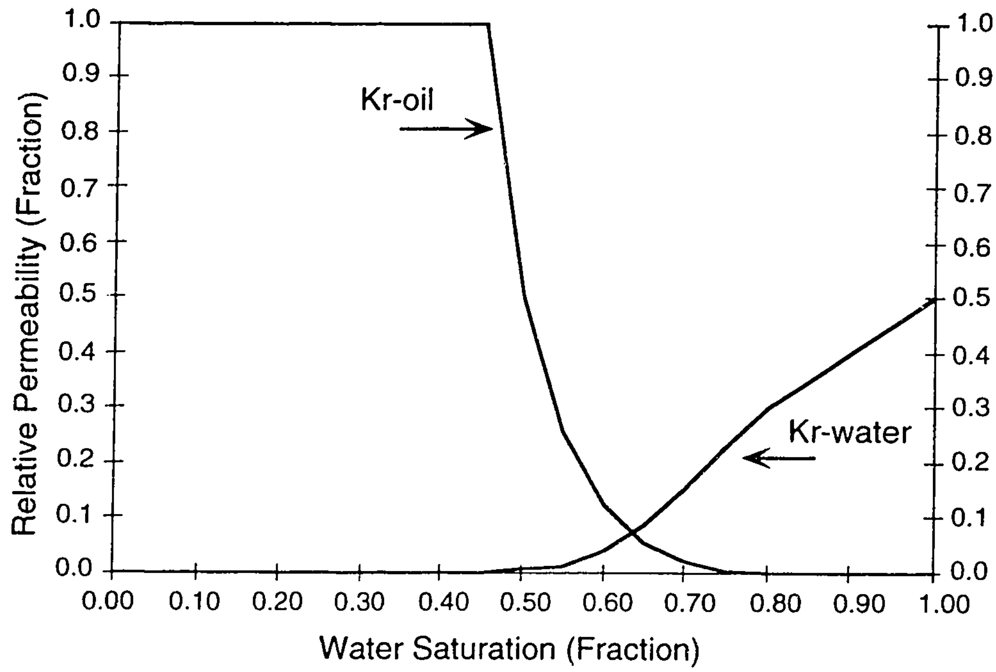


Figure 2.5. Schematic of the flow domain.

a)



b)

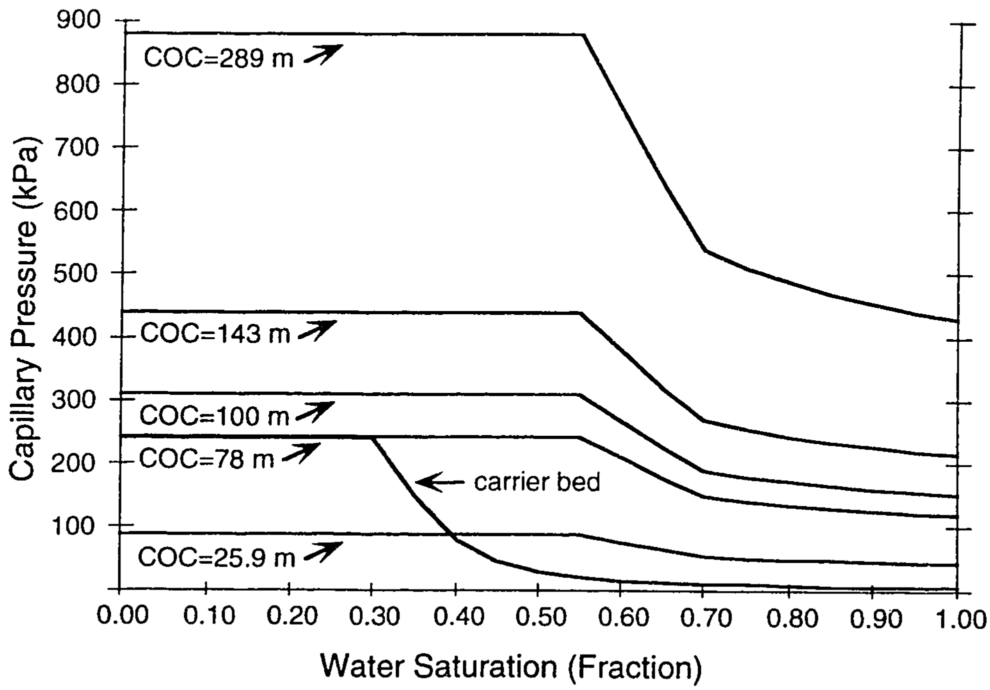


Figure 2.6. Simulation input data: a) relative permeability curves; b) capillary-pressure curves.

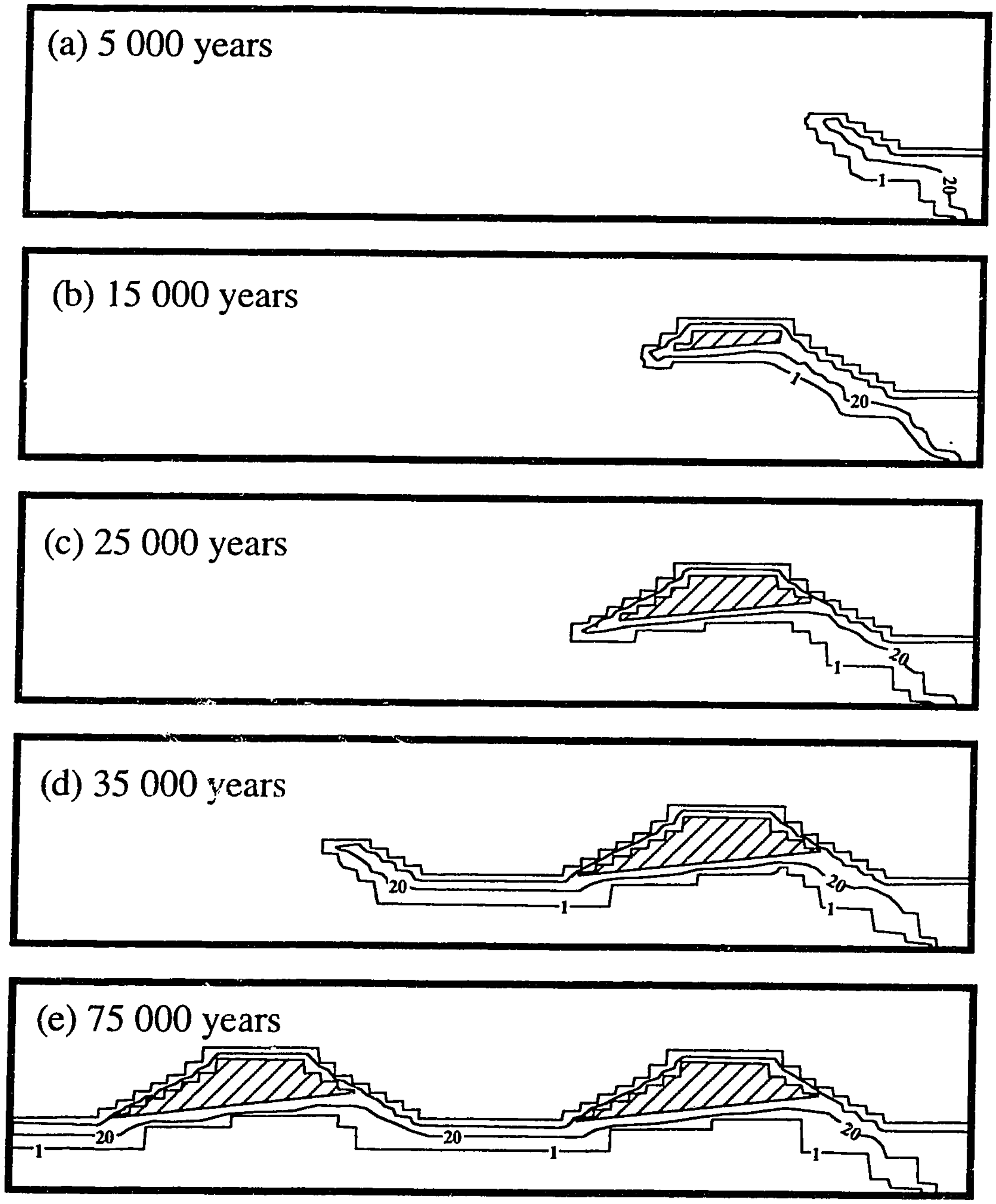


Figure 2.7. Oil Saturation Distributions - Base Case ("Impermeable" Cap-rocks). Contours are specified in percent oil saturation, shaded area is 55 percent oil saturated.

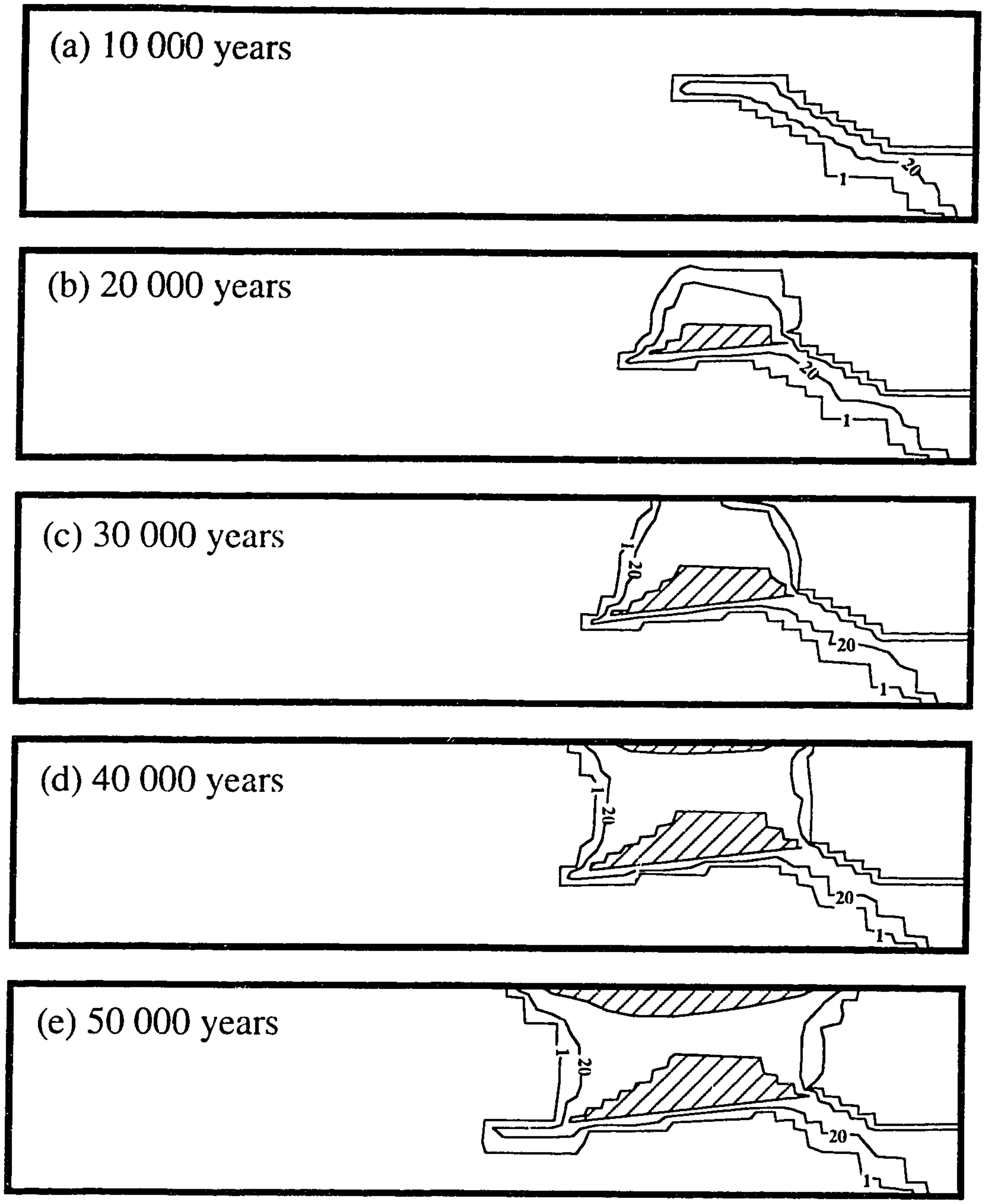


Figure 2.8. Oil Saturation Distributions - COC 1st Trap=25.9 metres ("Leaky" Cap-rocks). Contours are specified in percent oil saturation, shaded area is 55 percent oil saturated.

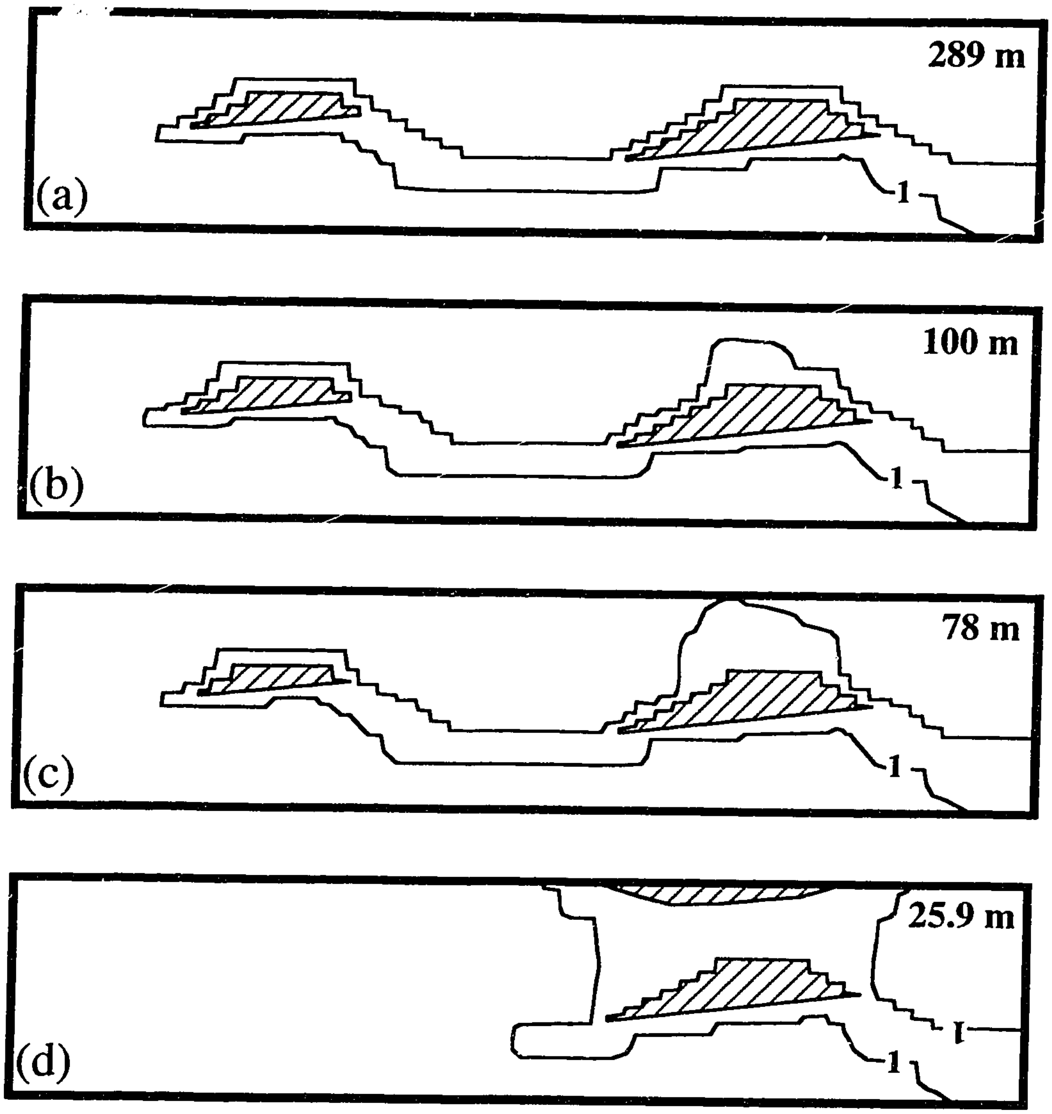


Figure 2.9. Oil saturation distributions at 50,000 years - Varying the COC in the 1st reef. Contour defines 1 percent oil saturation, shaded area is 55 percent oil saturation.

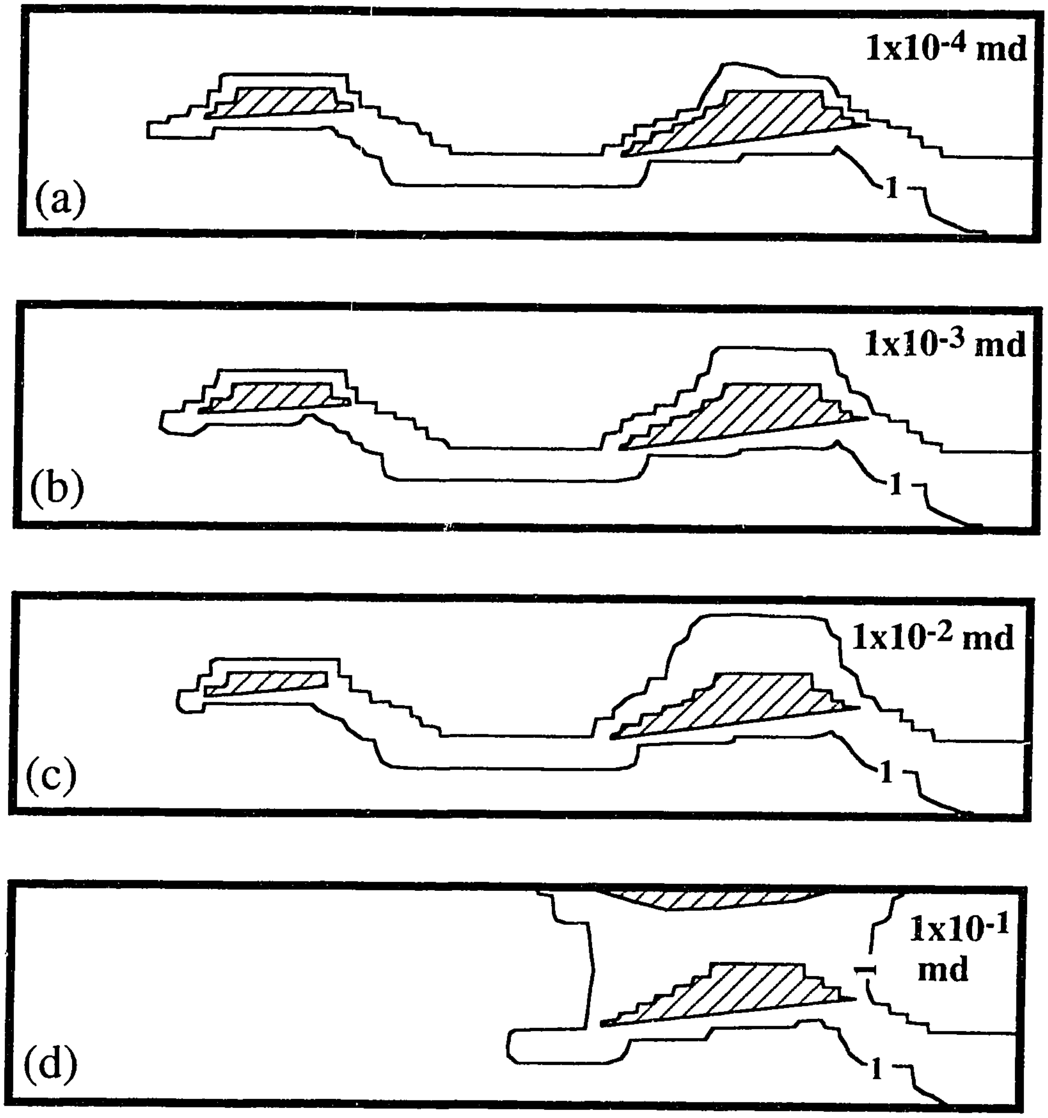


Figure 2.10. Oil saturation distributions at 50,000 years - Varying the intrinsic permeability of the 1st cap-rock. COC equals 25.9 metres. Contour defines 1 percent oil saturation, shaded area is 55 percent oil saturation.

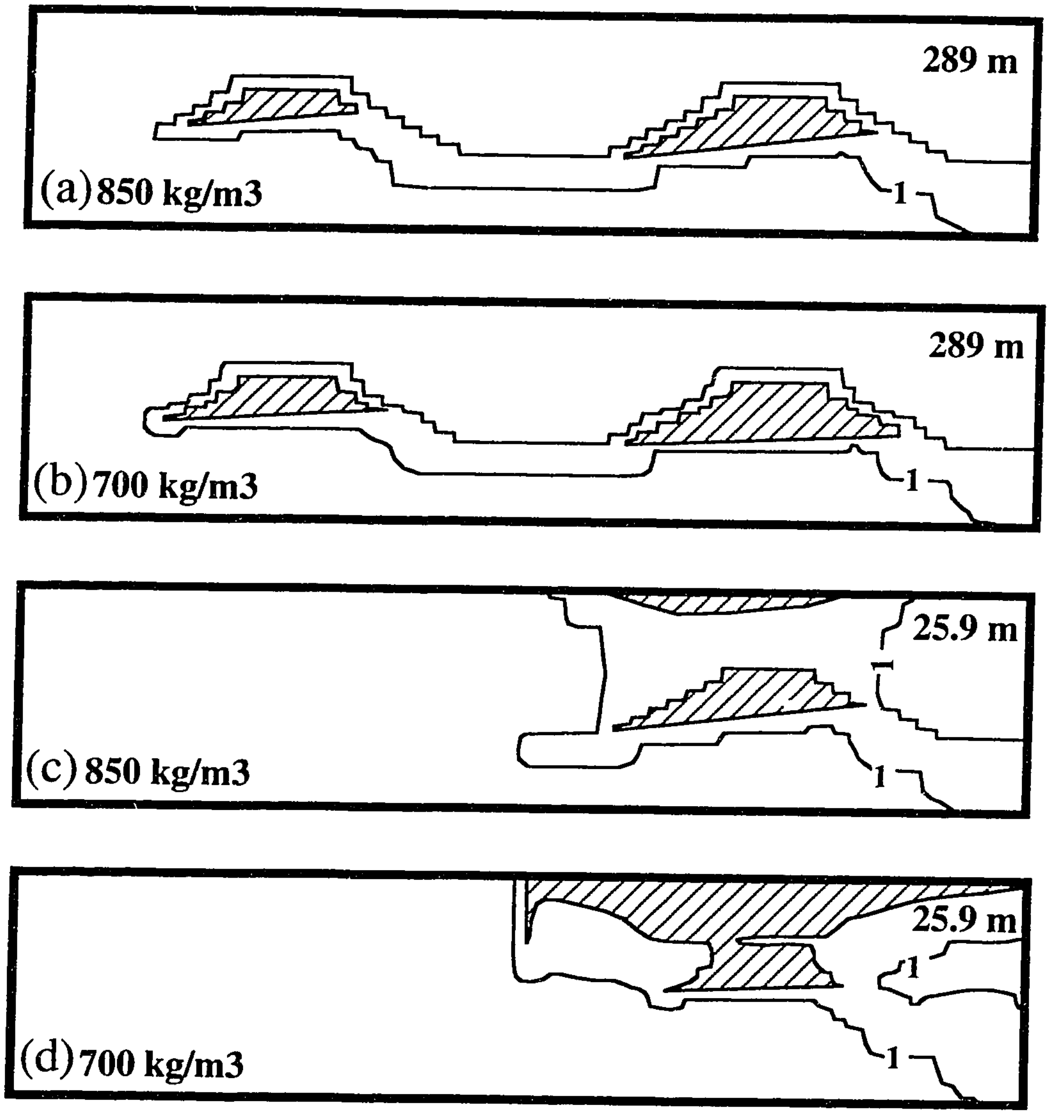


Figure 2.11. Oil saturation distributions at 50,000 years - Varying the COC and the oil density. Contour defines 1 percent oil saturation, shaded area is 55 percent oil saturation.

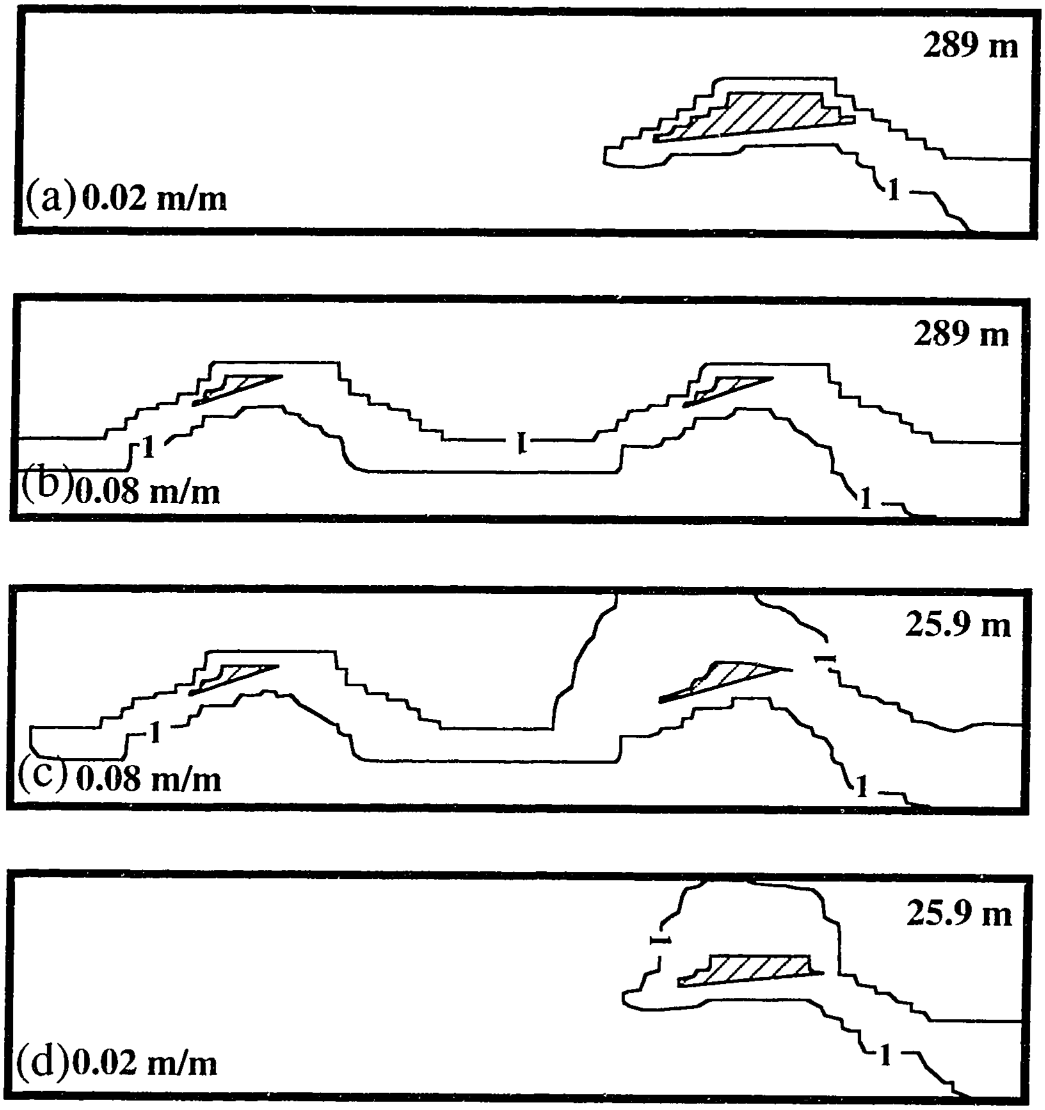


Figure 2.12.Oil saturation distributions at 25,000 years - Varying tne COC and the regional hydraulic gradient. Contour defines 1 percent oil saturation, shaded area is 55 percent oil saturation.

3.0 ASCENDING FLUID PLUMES ABOVE DEVONIAN REEFS: NUMERICAL MODELLING AND FIELD EXAMPLE FROM WEST-CENTRAL ALBERTA, CANADA*

3.1 INTRODUCTION

Most geochemical exploration techniques are based on the principle that a hydrocarbon plume moving through the subsurface alters the physical, chemical, electrical, magnetic, and thermal properties of the rock framework and fluids through which it passes. If the resultant alteration effects, such as a geochemical chimney or a resistivity anomaly, are strong enough to be detected, then it may be possible to locate the plume and trace it back to its source at a leaking reservoir. In the past, the controls on plume generation and migration have not been clearly understood or have been ignored, to the detriment of geochemical exploration techniques (Davidson, 1994). The processes that control both the origins of the plume, and its subsequent migration path, must be clearly understood in order to accurately predict the location of the reservoir. The purpose of this paper is to demonstrate the importance of hydrogeology and the hydraulic properties of the rock framework in the creation and migration of a hydrocarbon plume. Geochemical exploration programs can benefit from a better understanding of plume generation and migration in the subsurface.

From a hydrogeological perspective, two key aspects of plume generation and migration remain problematical. First, the effects of formation-fluid flow on plume migration are commonly disregarded. In static environments, the basic mechanisms of plume generation are well understood. Seal failure, or plume generation, is controlled either by capillary failure (Hubbert, 1940; Berg, 1975; Schowalter, 1979, Watts, 1987) or by

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fracturing of the seal unit (Watts, 1987; Sales, 1993). In hydrodynamic systems, the treatment of plume generation has not received as much attention. Hydrodynamic effects are either ignored or limited to simple correction factors applied in the calculation of maximum hydrocarbon heights (Schowalter, 1979; Watts, 1987). Vertical migration of oil in dynamic subsurface environments following seal failure has only been dealt with in a qualitative manner (e.g., Sales, 1993), and the implications of vertical migration between the trap and the surface remain unstudied. There is a similar lack of quantitative studies on the effects of lateral fluid flow on the surface expressions of vertical hydrocarbon migration (Davidson, 1994), with some notable exceptions (Holysh, 1989; Machel and Burton, 1991; Holysh and Tóth, 1994).

The second problem is the lack of hydraulic data on the low-permeability rock units that comprise the flow systems. This lack of data limits quantitative analysis of plume generation and migration. At the present time, the author is unaware of any published example(s) of a comprehensive hydraulic dataset (intrinsic permeability, relative permeability, and capillary pressures curves) from a low-permeability hydrocarbon "seal". This lack of data appears to result from the high cost of obtaining such data, the perceived futility of measuring permeabilities on so-called "impermeable" rocks, and the lack of use of these data in reservoir-trap studies (as mentioned above). The paucity of actual hydraulic data has lead to many misconceptions about the role of low permeability rocks in fluid migration in basins (Neuzil, 1986; Tóth, 1991).

This paper presents results of a two-part study conducted to address some of these concerns. First, results of a numerical modelling study of plume generation and migration from breached reef-reservoirs are presented. Simulations were conducted using a flow domain based on the Devonian-aged reefs that form two large-scale reef-trends in the Western Canadian Sedimentary Basin: Rimbey-Meadowbrook and Bashaw (Figure 3.1). These reefs are suitable candidates for study for several reasons: they are prolific hydrocarbon producers; there are abundant publicly-available geologic data; and it has been postulated that they leak hydrocarbons (Davis, 1972; Creaney and Allan; 1990; Rostron, 1993). Second, a field hydrogeological and hydrogeochemical study of the Bashaw Reef Complex is presented. A primary goal of the field study was to locate hydrocarbon plumes above leaky reef reservoirs. The implications of this study on surface geochemical exploration in general, and for Devonian reefs in the Western Canadian Sedimentary Basin in particular, are discussed.

3.2 NUMERICAL MODELLING OF PLUME GENERATION AND MIGRATION

Numerical simulations were performed with the transient, two-dimensional, multiphase, finite-difference flow model SWANFLOW-2D (Faust, 1985). SWANFLOW-2D was coupled to the IMAGE output analysis program (National Center for Supercomputing Applications, 1991) to produce contour plots of fluid pressure and saturations at specified timesteps for each run. Simulations were conducted using Macintosh microcomputers and Silicon Graphics workstations, with execution times ranging from 1.5 to [illegible] hours per case. More than 40 different simulations were completed while systematically varying the rock permeabilities, capillary pressure curves, oil densities, and regional formation-fluid gradients of the system. Only the results of one run are presented here. This run was chosen as a typical result of a case where a hydrocarbon plume is generated above a leaky reef. Selected end-time saturation distributions for other modelled cases are presented to show the relationship between the hydraulic parameters of the flow system and plume generation and migration. The importance of hydraulic properties on controlling the size and shape of hydrocarbon plumes is illustrated. Surface geochemical techniques would benefit from an understanding of these same factors.

The model results will be summarized briefly, and the implications to plume migration will be explored. Simulation results presented here have been previously presented in more detail (Rostron, 1993).

3.2.1 Simulation Data

Numerical simulations were conducted on a flow system patterned after a typical cross-section through the one of the Devonian-aged reef trends that cut across the Western Canadian Sedimentary Basin (Figure 3.2). Reservoirs in these reef trends belong to the Woodbend and Winterburn Groups which are Late Devonian (Frasnian-Famenian) in age (Switzer et al., 1994). The Woodbend Group consists of three main units. The lowermost unit is a shallow-water platform carbonate (Cooking Lake Formation) that forms a common basal aquifer for the reef trend. On this unit are situated numerous platform margin reef-buildups (Leduc Formation) forming the main reservoirs. These reefs are encased in a layer of basin-filling shales and limestones (Ireton and Duvernay formations). Overlying the Woodbend Group are carbonates, primarily dolomites, of the Nisku Formation (Winterburn Group). Flow is confined to the Woodbend and Winterburn groups by the extremely low-permeability shales and carbonates of the Waterways Formation (Beaverhill Lake Group) and Wabamun Group, situated below and above the modelled strata, respectively.

Geologic structure data were used to construct a hypothetical model through two typical reefs in the reef trend (Figure 3.3). A 60 by 15 block (horizontal x vertical) finite-difference grid was used to discretize the flow domain. Two main rock types were assigned to the grid: a reservoir and cap-rock. Reservoir rock units included the basal aquifer and reefs, with cap-rock comprising the remainder of the domain.

Two different boundary conditions were assigned along the edges of the grid. Along the top and bottom, no-flow boundaries were assigned, confining flow to the carrier-bed and cap-rock. Along the upstream and downstream ends of the domain (grid right and left respectively), no-flow boundaries were specified in the cap-rock, and constant heads were specified in the carrier-bed. This configuration enabled the establishment of a horizontal flow-field for water, and allowed for vertical flow inside the reefs and cap-rock.

The input parameters used in this simulation, and in others in the suite are summarized in Table 3.1. These data, although derived from actual rock samples, were selected arbitrarily. At the time of modelling, capillary-pressure curves and relative permeability curves for the cap-rocks were unavailable, as was the bulk oil source-rate. Parameters were selected so that each simulation could be completed in a reasonable amount of computer time. This arbitrary selection was justified because of the lack of any real data on the system and because the purpose of the simulations was to study the process of plume generation and migration in a conceptual sense. Results of model studies presented herein cannot be used as quantitative measures of migration in the real system of reefs.

Simulations were normally conducted in two stages: an initial stage of no oil input that was conducted to establish a steady state water flow field across the grid and a subsequent transient (oil input) migration phase. Runs were halted once the migrating oil had either filled and by-passed both reefs or leaked out of the reef and accumulated along the top of the grid. In specific cases, such as presented here, a third stage was added where, upon filling of the reservoir, the oil source was discontinued and the system allowed to return to steady state conditions.

In this study, only water and oil flow was considered because of a complete lack of three-phase hydraulic data on low-permeability rocks and computer limitations for simulating three-phase flow.

3.2.2 Simulation Results: Leaky Cap-Rocks

Oil leakage and the creation of a hydrocarbon plume from the top of a reef begins when the combined driving forces on oil, which are provided by buoyancy and hydrodynamic flow, exceed the resistive forces of the cap-rock. Initial resistance to leakage through the cap-rock is provided by the difference in entry pressures between the reservoir and cap-rock. The initial resistive force can be expressed in terms of a "critical oil column" or COC, for a given set of reservoir/cap-rock capillary pressure curves and fluid densities under static conditions. The COC can be expressed mathematically as:

$$COC = \frac{(Pe_{cr} - Pe_{cb})}{(\rho_w - \rho_o)g} \tag{3.1}$$

where: COC is the critical oil column for a specified pair of oil/water densities and a given pair of carrier-bed/cap-rocks [metres]; Pe_{cr} is the entry capillary pressure of the cap-rock [Pascals]; Pe_{ch} is the entry capillary pressure of the carrier-bed [Pascals]; ρ_w is the water density [kg/m³]; ρ_o is the oil density [kg/m³]; and g is the gravitational constant [m/s²].

The COC (with its units of length) provides a useful measure of sealing capacity of a cap-rock. To initiate leakage in a hydrostatic system, the vertical component of the hydrocarbon column must exceed the COC. If the maximum attainable column height for a reservoir (defined as the vertical distance between the crest of the trap and the spill point) is less than the COC, then the trap will not leak and no hydrocarbon plume will form. On the contrary, if the COC is less than the maximum attainable column height, then it is highly probable that the trap will leak.

For the purposes of this paper, a modelled result of a potentially leaky trap where the COC of the cap-rock/reservoir pair (25.9 metres) is less than the maximum attainable hydrocarbon column (100 metres), is presented.

Oil saturation distributions through time for a typical "leaky" reef are shown in Figure 3.4. At time (T)=0 years, oil is introduced into the upstream end of the carrier-bed. Oil moves downstream under the combined influence of a horizontal water gradient and a vertical buoyancy driving-force. Once introduced into the flow domain, the oil forms a stringer that moves to the top of the carrier-bed. Inside the stringer, oil saturations remain below 21 percent. This occurs because as oil saturations in the grid blocks at the saturation front increase above the irreducible saturation of 20 percent, oil becomes mobile in those grid blocks. Once mobile, the front moves downstream into the next grid block(s). Oil saturations within the stringer never exceed 21 percent unless the stringer encounters some type of boundary. In these simulations, the stringer encounters a boundary when it reaches the crest of the reef structure.

At T=10,000 years (Figure 3.4a) oil reaches the crest of the reef. At the crest, oil saturations quickly reach 55 percent, the maximum permitted with the specified irreducible water saturation of 45 percent. Once the pore space reaches 55 percent saturation, no further increase in saturation is possible so the area of accumulation begins to expand downwards. In this case the downward movement of the oil/water contact begins about T=11,000 years.

As the oil/water contact descends, it generates an increasingly taller column of oil pushing up on the cap-rock. When the oil column equals the height of the COC (in this case 25.9 metres), oil penetrates into the cap-rock (Figure 3.4b) producing a hydrocarbon plume in the cap-rock above.

In the cap-rock the hydrocarbon plume moves vertically upwards, reaching the top (the grid at approximately 24,000 years. Oil begins to accumulate along the top boundary of the flow domain (Figures 3.4d-e) solely as a result of the imposed no-flow boundary along the top of the grid. In reality the plume would freely migrate vertically until reaching the ground surface.

Inside the reef, the oil/water contact moves downward with continued oil input through time (Figures 3.4b-d). Once the oil/water contact reaches the spill point, a second stringer with 21 percent oil saturation forms in the carrier-bed and continues to move downstream (Figure 3.4e). Once the stringer reaches the second reef structure, the filling and subsequent plume generation stage is repeated.

The final phase of the simulation was conducted to study the effects of dissipation of the plume and entrapped oil after the discontinuation of the upstream source of oil. At T=50,000 years the upstream source of oil was shut off. With no new input from below, the oil/water contact moves upward displacing previously emplaced oil in the reef into the cap-rock (Figure 3.4f). Oil that leaks out of the reef is added to an ever expanding oil plume in the cap-rock.

By T=110,000 years, the oil/water contact has risen approximately 75 metres, leaving about a 25 metre column of oil inside the reef. At this time, the oil column has been reduced to the COC. The oil column inside the reef becomes stable once the column height decreases to the COC because a column of oil larger than the COC is necessary for leakage to occur (Rostron, 1993). From this time on, no changes in saturation occur within the reef.

Outside the reef, the plume continues to spread above the reef (Figure 3.4g). The final saturation profile at T=150,000 years (Figure 3.4g) illustrates the 25 metre oil column retained within the reef, and a large hydrocarbon plume above. The saturation distribution at T=150,000 years reflects steady state conditions for this reef/cap-rock system. Past this time negligible changes occur in the saturation distribution because of the boundaries imposed on the flow domain.

In this simulation the plume does not penetrate the cap-rock above the second reef because the COC of the second cap-rock (Table 3.1 and Figure 3.3) is equal to 289 metres. Thus the vertical discontinuity in the saturation distribution at the midpoint of the grid is solely an artifact of the imposed COC for the second cap-rock.

In this case, the trap filled to its maximum capacity; that is, the oil/water contact descended to the spill point, even though a plume formed above the reef. Complete filling and plume formation was possible because the rate of inflow from upstream was greater than the rate leaking into the cap-rock. In other modelled cases, the reef was unable to fill to the spill point because the bulk of the oil entering the reservoir leaked into the cap-rock. This would lead erroneously to the conclusion that the larger the plume above the reef, the smaller the accumulation within the reef itself. This conclusion cannot be universally applied without examining the hydraulics of the flow system. A knowledge of the hydraulics of the flow system leads to a better understanding of flow directions, flow rates, and event timing. Only after the hydraulics of the flow system are known, can the distinction be made between a large plume that has resulted from catastrophic draining of a reservoir (such as in Figure 3.4), or slow leakage from a relatively full reservoir. Formation of oil plumes and migration/entrapment in reefs depend on the interaction between the factors driving migration ("leaking factors") and those resisting migration ("sealing factors"). The role of these interactions are discussed below.

3.2.3 Role of Sealing Factors in Plume Generation and Migration

Sealing factors are defined as those physical properties or processes that act to retain hydrocarbons within reservoirs. Simulation results show the two sealing factors are the entry capillary pressure and the intrinsic permeability of the cap-rock.

Initial formation of a hydrocarbon plume is governed by the magnitude of the critical oil column of the cap-rock and carrier-bed pair. If the vertical component oil column equals the COC, oil will begin to leak from the trap (Figure 3.4). If sufficient oil column cannot be built up to equal the COC then a plume will not form.

Varying the COC component of the sealing factors produce vastly different final-time oil distributions (Figure 3.5). With the COC greater than the trap height (Figure 3.5a), no plume forms above the reef. When the COC equals the trap height (Figure 3.5b), trace amounts of oil still leak from the trap because the COC is only a static measure of trapping capacity (Rostron, 1993). In hydrodynamic environments such as this, an additional driving force on the oil particles is provided by water flow. In this case, the vertical component of water flow combined with the buoyant force generated by the column of oil exceeds the static COC. Even though the regional water flow field has been set up for horizontal flow, a small component of vertical flow arises when water flows from the carrier-bed into the reservoir. In this case, the small size of the plume above the trap reflects the relatively small component of localized vertical water flow.

For the intermediate case with an COC equal to 70 metres, the plume at T=50,000 years (Figure 3.5c) is significantly smaller than in the original case (Figure 3.4e). The difference in plume size above the reef in the two figures is directly related to the COC. In the first case (COC = 25.9 metres) the oil column reaches the COC value sooner than in the second case (COC = 78 metres). With a longer period of time for oil to leak into the cap-rock, a larger plume is generated in the first case.

If a plume does form, the second sealing factor controls its subsequent migration. Oil movement within the cap-rock is governed by the intrinsic permeability of the cap-rock, subject to the overall hydrodynamic conditions of the flow system. If the intrinsic permeability of the cap-rock is reduced, the plume sizes above the leaky reef are likewise smaller (Figure 3.5d-5f). End-time saturation profiles for step-wise magnitude decreases in intrinsic permeability show that for the case where the intrinsic permeability of the cap-rock has been reduced to 1×10^{-4} millidarcys (Figure 3.5f), that there is almost no plume in the cap-rock above. This sequence of saturation distribution profiles demonstrates how reducing the intrinsic permeability of the cap-rock decreases the size of the plume and has the same effect as reducing the COC. Also, with a low enough intrinsic permeability the saturation distribution appears as though the cap-rock has not failed, even though it has.

3.2.4 Role of Leaking Factors in Plume Generation and Migration

Leaking factors are defined as those physical properties or processes that act to drive hydrocarbons from or into reservoirs. Simulation results show that the two main leaking factors are buoyancy caused by the oil-water density contrast and the regional hydraulic gradient of water.

Buoyancy forces are generated by density differences between the immiscible phases, with the magnitude of the forces proportional to the density contrast. In a static environment, buoyancy forces act vertically. In hydrodynamic environments, a component of the regional water hydraulic-gradient provides an additional vertical driving force. Changing the fluid densities or water hydraulic gradient can affect the formation and subsequent migration of a hydrocarbon plume. Results show how varying these leaking factors influences the end-time saturation distributions (Figure 3.6).

When the oil density is reduced from 850 to 700 kg/m^3, the net effect is to double the density contrast and to double the leaking factor. With increased buoyancy forces, the size of the hydrocarbon plume in the cap-rock (Figure 3.6a) is increased dramatically from the originally modelled case. Reducing the density from to 700 kg/m^3 for a given cap-rock entry pressure effectively reduces the COC of the cap-rock by approximately one half the original value (Equation 3.1). The resulting end-time saturation distribution (Figure 3.6a) illustrates the case where a trap cannot fill to its spill point, as most of the migrating oil passes through the trap into the cap-rock. Lighter oils generate larger leaking forces and therefore larger plumes.

Plume size and shape also depend on the regional water hydraulic gradient. Increasing the gradient increases both the horizontal and vertical driving forces on the oil. This results in faster downstream migration through both the carrier-bed and the cap-rock. If the hydraulic gradient is increased by a factor of four (from 0.02 to 0.08 metres/metre), then the oil reaches the downstream boundary of the flow domain in less than 25,000 years (Figure 3.6b). With increased horizontal hydraulic gradients, the plume emanating from the breached reservoir is offset from the crest of the trap approximately 100 metres downstream. When the saturation distribution under the increased hydraulic gradient (Figure 3.6b) is compared to the saturation distribution at T=25,000 years for the original case (Figure 3.6c), it is clear that the increased lateral driving force offsets the plume and increases its size within the cap-rock. These results demonstrate the importance of lateral fluid flow in controlling the size and shape of hydrocarbon plumes and their position above the hydrocarbon source.

Results of modelling leaky reefs can be summarized as follows: 1) the critical oil column of the cap-rock and carrier-bed controls whether oil will begin to leak from the trap, and whether or not a hydrocarbon plume will form; 2) when the vertical component of the hydrocarbon column reaches the COC, a plume will begin to form in the cap-rock; 3) once the plume begins to leak from the cap-rock, the hydraulic properties of the cap-rock and the flow domain control its migration path to surface; 4) after the source of hydrocarbons is terminated, leakage from the trap (i.e., plume sourcing) will continue until equilibrium conditions are reached between the oil column height and the COC of the cap-rock and carrier-bed; and 5) the interaction between the factors driving migration (leaking factors) and the factors resisting migration (sealing factors) will determine whether or not a plume will form, and what its migration path will be.

3.3 HYDROCARBON AND SALINE WATER PLUMES IN THE SUBSURFACE

The preceding modelling results illustrate three points: 1) reefs can leak and create plumes in the cap-rocks above them; 2) leakage is controlled by the rock properties of the reservoir and cap-rock; and 3) a knowledge of the subsurface hydrogeology is required to understand plume generation and subsequent migration. To corroborate the numerical modelling, a field study was conducted to search for evidence of plumes emanating from breached Devonian reefs.

3.3.1 Field Study Area and Geology

The field study examined the hydrogeology and hydrochemistry of the Devonian and Cretaceous formations in an 18,000 km^2 area of west-central Alberta, Canada (Figure 3.7). The study area encompasses the Bashaw reef complex and the southern portion of the Rimbey-Meadowbrook reef trend. In addition to the Cooking Lake, Leduc, and Ireton formations discussed previously, the subsurface mapping included (in ascending order): the permeable Nisku Formation carbonates overlying the Ireton Formation shales; the relatively impermeable Wabamun Group (Devonian) dolomites and anhydrites; the highly permeable sandstones, siltstones, shales, and carbonates of the Mannville Group (Lower Cretaceous); the thin shales of the Joli Fou Formation; and finally the highly-permeable sandstones, siltstones, and conglomerates of the Viking Formation (Lower Cretaceous -

Albian Age). Structural relationships between these units are illustrated in a cross-section running approximately SSW to NNE through the Bashaw Reef Complex (Figure 3.2).

Abundant geologic, formation pressure, fluid chemistry, and hydrocarbon production data were available from the more than 11,000 oil and gas wells drilled within the study area. Formation pressures used in the study were obtained from more than 5500 drill-stem-test (DST) pressures obtained from the Alberta Energy Resources Conservation Board. Extrapolated DST data were processed to remove pressures influenced by production induced drawdown, using the method described elsewhere (Bachu et al., 1987; Barson, 1993; Rostron, 1994). Approximately 7500 water chemistry analyses were obtained and screened to remove non-representative analyses such as drilling fluids or spent acid-frac fluids, using standard culling techniques (Hitchon and Brulotte, 1994).

Geological, hydrogeological, hydrochemical, and petroleum production data were used to synthesize the three-dimensional flow field in the study area. For each aquifer, pressures were converting into equivalent freshwater hydraulic heads using:

$$h = z + \frac{p}{\rho_w g} \tag{3.2}$$

where: h is the equivalent freshwater hydraulic head at a point [metres]; z is the elevation of the point of measurement with respect to sea level [metres]; p is the formation pressure [Pascals]; ρ_w is the density of freshwater [kg/m^3]; and g is the gravitational constant [m/s^2].

Equivalent freshwater heads were used in this study because tests of the relative effects of density-driven flow showed that for the most part density-related flow effects were insignificant. Tests of the relative effects of density flow were made using the Driving Force Ratio (DFR) method developed by Davies (1987). In the DFR method, the relative strength of the hydraulic gradient is compared to the relative strength of the density-related forces. If the DFR is greater than 0.5, then a divergence of more than 30 degrees will exist between the horizontal flow directions indicated by the equivalent freshwater head distribution and the true flow direction (Davies, 1987). Driving Force Ratios depend on: 1) the slope of the aquifer, with lesser density effects proportional to lower formation dips and no density effects in horizontal aquifers; 2) the density contrast between ambient formation fluids and freshwater, with lower density effects the closer the formation water salinity is to freshwater; and 3) the magnitude of the gradient of equivalent freshwater head, with higher freshwater head gradients resulting in lower density-related flow effects (Davies, 1987).

For all aquifers but the Nisku aquifer, the calculated DFR's where less than 0.5, indicating no significant density-related flow effects. Thus, in most aquifers equivalent freshwater heads were used to interpret flow directions. For the Nisku aquifer, DFR's calculated outside the steeply-dipping downdip area to the southwest (Figure 3.2) were less than 0.5, again indicating no large-scale density effects. This is consistent with DFR's calculated for nearby areas in the Nisku aquifer by Paul (1994). Thus, over most of the study area, equivalent freshwater heads can be used to infer flow directions in the Nisku aquifer. In areas to the southwest and in areas of rapid salinity change over underlying Leduc Formation reefs (discussed below), flow directions were interpreted using pressure versus depth (p[d]) plots.

Potentiometric surfaces for each aquifer were created by contouring the distribution of equivalent freshwater hydraulic-heads in each aquifer. Horizontal flow directions in each aquifer were inferred from each potentiometric surface. Pressure versus depth (p[d]) and pressure versus elevation (p[z]) plots were constructed for various locations and used to interpret vertical flow directions. Chemical data were converted to maps of major ion chemistry and total dissolved solids (TDS) for each aquifer. Oil- and gas-field production data were used to delineate known areas of hydrocarbon production. Results from this mapping identified a large-scale saline water plume in the study area.

3.3.2 Hydrogeology

Hydrogeologic mapping delineated three major hydrostratigraphic units related to the Devonian reefs in the study area. They are, in ascending order: the Upper Devonian hydrogeologic group (UDHG); the Mannville Group aquifer (MGA); and to a lesser extent Viking Group aquifer (VGA). The structural relationship between these three hydrostratigraphic units is shown in Figure 3.2. Although there appears to be evidence that Devonian fluids have affected or are affecting the Viking Group aquifer, the visible effects are small in comparison to those in the Mannville Group aquifer. The details of a possible interaction between Devonian reefs and the Viking aquifer go beyond the scope of this paper which focuses only on the relationship between the Upper Devonian hydrogeologic group and the Mannville Group aquifer.

3.3.2.1 *Upper Devonian Hydrogeologic Group (UDHG)*

The UDHG consists of two main aquifers: the Cooking Lake-Leduc aquifer and the Nisku aquifer. Fluid flow in the UDHG is exemplified by the potentiometric surface of the Nisku aquifer (Figure 3.8). Hydraulic heads in the Nisku aquifer range from values exceeding 750 metres over the Bashaw Reef Complex, down to values under 450 metres in the northeast corner of the study area. There are two distinct areas of fluid flow in the Nisku aquifer, defined based on the outline of the underlying Bashaw Reef Complex in the Leduc Formation. Where the Bashaw Reef Complex underlies the Nisku aquifer there is a mounding of hydraulic heads in the potentiometric surface of the Nisku aquifer. Horizontal flow directions inferred from the potentiometric surface generally radiate outwards from the reef complex. Pressure versus depth plots constructed in the Bashaw Reef Complex indicate vertical fluid flow from the Leduc aquifer upward into the Nisku aquifer (Paul, 1994). A typical p[d] plot from the Bashaw Reef Complex (Figure 3.9) illustrates how the measured vertical pressure-gradient in the UDHG (13.4 kPa/m) exceeds the density-corrected nominal value (11.2 kPa/m), indicating upward flow (Tóth, 1978). In the core of the complex there are several localized spikes in the surface, indicating excellent communication with the higher-potential Leduc aquifer beneath.

The second flow system in the Nisku Formation is a regionally [illegible]ving system that exists outside the area of the Bashaw Complex. Fluid flows up-dip, from values of fluid potential greater that 600 metres in the southwest, toward values under 450 metres in the northeast corner of the study area.

Flow directions in the Nisku aquifer are controlled by the connection with the underlying Cooking Lake-Leduc aquifer. Although not shown here, fluid potentials in the Cooking Lake-Leduc aquifer are elevated 50 to 100 metres above potentials at similar locations in the Nisku aquifer. Where the intervening Ireton aquitard is thinner over the Leduc Formation reefs (Figure 3.10), a preferential pathway is provided for fluids to move upward from the Cooking Lake-Leduc aquifer into the Nisku aquifer. Over the Bashaw Complex, the Ireton aquitard is generally less than 25 metres thick (Figure 3.10). Where the Ireton aquitard is thicker, for example over the Rimbey-Meadowbrook Reef Trend, the higher potentials in the Cooking Lake-Leduc aquifer do not increase hydraulic heads on the Nisku aquifer. Where not affected from below by the Cooking Lake-Leduc aquifer, flow in the Nisku aquifer is laterally up dip.

3.3.2.2 *Mannville Group Aquifer (MGA)*

Fluid flow patterns inferred from the potentiometric surface of the MGA (Figure 3.11) are much more complicated than flow patterns in the Nisku aquifer. Both the MGA and the UDHG exhibit regional-scale lateral up-dip flow and both aquifers are intersected from below by vertical flow. However, three major differences exist between fluid flow in the MGA and the UDHG.

The first major difference between the aquifers is that in the MGA there is a boundary with the Deep Basin (Masters, 1979) that passes through the study area (Figure 3.11). To the west of the boundary line, the pore space is hydrocarbon saturated, mostly with gas.

Wells producing from the Deep Basin produce negligible amounts of formation water, leading to speculation that the pore water is in a discontinuous state (Masters, 1979). To the east of the boundary line, "conventional" hydrocarbon pools are found where wells produce hydrocarbons with varying amounts of water. In this study area the position of the Deep Basin boundary was defined based on well production data and DST recoveries. Since little or no mobile formation water is present west of the boundary line, pressure data from the Deep Basin were not included in the construction of the potentiometric surface used to infer water flow patterns.

The second major difference is in the much more subtle nature of the lateral flow in the MGA versus the UDHG. Examination of the potentiometric surface (Figure 3.11) reveals that hydraulic heads in the MGA range from under 300 metres to over 700 metres, but with no systematic decrease in any one direction. Numerous closed areas of high and low values of hydraulic head are shown on the potentiometric surface. To discern the regional flow system, one must examine basin-scale potentiometric surfaces of the Mannville Group (Hitchon, 1969; Abercrombie and Fullmer, 1992) that illustrate lateral flow from the southwest to northeast across the Western Canadian Sedimentary Basin. Fluid flow in this study area can be tied to the regional scale system by careful examination of the potentiometric surface (Figure 3.11). Generally values of higher hydraulic heads (greater that 650 metres) are found in the southwest corner, to the west, and south of the study area. Intermediate values (500 metres) are found along a band running generally north-south through Range 26, and there is a systematic decrease towards values approaching 400 metres toward the northeast (ignoring, for the moment, the values under 300 metres in the southeast corner). With this in mind, a very subtle decrease in hydraulic heads from southwest to northeast across the study area can be observed. The cause of the hydraulic heads under 300 metres in the southeast corner of the study area is unknown at the present time, but this area appears to be at the northern edge of a regional-scale underpressured region noted previously (Hitchon, 1969).

The third major difference between the MGA and the UDHG is the lack of uniform decrease in hydraulic heads across the study area. Numerous closed areas of low and high fluid-potentials are superimposed on the large-scale up-dip flow system. Examples of closed low areas include: Township 43, Range 1 and Township 40 Ranges 3-4. Closed high areas are found in Township 41, Range 25 and Township 43-44, Range 23. Closed features on potentiometric surfaces are indicative of significant components of vertical flow in heterogeneous aquifer systems. Since the potentiometric surface only provides a measure of the horizontal component of flow, upward or downward flow directions plot as closed areas of high and low potential on a potentiometric surface. The perturbations in the potentiometric surface of the MGA appear to be caused by the presence of sub-aquifers within the MGA. These sub-aquifers are relatively thin, up to 50 metres thick, compared to the overall thickness of the MGA in the study area, which varies between 175 and 225 metres. Although they are relatively discontinuous, the sand bodies that comprise the Glauconite Formation and Ellerslie Formation sub-aquifers are reservoirs for many of the hydrocarbon pools in the study area.

As mentioned previously, the final component of the flow system in the MGA is the reflection in the potentiometric surface of the intersection with the vertically ascending UDHG. This intersection occurs in the northeastern corner of the study area, where there is relatively little variation in hydraulic heads around 450 metres. The noticeable flattening of the potentiometric surface in this area reflec[illegible] decrease in the lateral hydraulic gradient because a large component of the fluid flow-field is directed in a vertical direction. Pressure versus depth plots constructed in Townships 43-45, Ranges 21-24 (not shown here), indicate measured vertical pressure-gradients up to 13.4 kPa/m, well above the nominal gradient for the MGA of 10.6 kPa/m. As will be s[illegible] later, the verti[illegible]w system in this area produces a plume of saline water in the MGA.

3.3.3 Hydrogeochemistry

The chemical characteristics of formation waters were examined by plotting distributions of major ions and of total dissolved solids (TDS) for the different aquifers comprising the two main hydrogeologic groups. Differences between formation waters are best illustrated on Stiff Diagrams of averaged chemical composition for each aquifer (Figure 3.12). All of the formation waters in the study area are brines, according to the classification scheme of Hem (1985).

3.3.3.1 *Upper Devonian Hydrogeologic Group*

Formation waters from the Cooking Lake-Leduc aquifer are Na-Ca-Cl brines (Connolly et al., 1990). They are the most concentrated waters found in the study area with average TDS values of 205,000 mg/l (Figure 3.12a). There is little variation in the dissolved solids content across the study area, with all 269 samples in the range of 183,00 and 227,000 mg/l TDS. This tight range does not warrant a separate figure of TDS distribution. Chloride is the dominant anion in the samples. Sodium and potassium are the dominant cations, but, as is typical for Cooking Lake-Leduc waters in the basin, a significant proportion of the cations are made up of calcium. Average ratios of reacting value of sodium to reacting value of chloride (rNa/Cl) are 0.65, indicating deep subsurface conditions, possibly stagnant, and favorable for the preservation of hydrocarbon accumulations (Collins, 1975). It has been proposed that these brines owe their origin to a mixing between an end member that underwent varying degrees of sea water evaporation beyond halite solution and an end member that represents meteoric water (Connolly et al., 1990)

Waters of the Nisku aquifer, although similar to the underlying Cooking Lake-Leduc waters, are typically less concentrated. Total dissolved solids for the Nisku aquifer average 181,000 mg/l (Figure 3.12b). There is a greater range in dissolved solids throughout the study area, with values falling between 151,000 and 211,000 mg/l, but again this variation does not warrant the inclusion of a separate map of TDS distribution. Proportionally, these waters contain slightly less calcium, which likely indicates a slightly different origin and dilution history (Connolly et al., 1990).

3.3.3.2 *Mannville Group Aquifer*

Formation waters in the MGA have a more variable chemical composition than waters in the UDHG. Total dissolved solids range between 20,000 and 150,000 mg/l within the study area. There is a general trend of increasing TDS from southwest to northeast (Figure 3.13), with the highest values of TDS clustered in the northeast corner of the study area.

There appears to be a mixture of two types of formation waters in the MGA. The first type of water is referred to as "typical" Mannville aquifer formation-water. These waters are characterized by a rNa/Cl value of approximately 0.95 (Figure 3.12c), with TDS values ranging between 20,000 and 60,000 mg/l. This chemical composition is similar to waters found elsewhere in the Mannville Group in the Western Canadian Sedimentary Basin (Connolly et al., 1990; Cody and Hutcheon, 1994; Abercrombie et al., 1994). Ambient Mannville Group formation-waters owe their origin to a mixture between meteoric water recharging in southern and western Alberta (Cody and Hutcheon, 1994) and a brine of concentrated sea water (Connolly et al., 1990).

The second "type" of water in the MGA, referred to here as the saline plume, is characterized by higher TDS values and lower rNa/Cl values. Total dissolved solids in the saline plume generally exceed 100,000 mg/l, with some values up to 140,000 mg/l. These are some of the highest values of TDS found in this aquifer throughout the entire basin (Abercrombie et al., 1994). Average rNa/Cl values for the 114 samples in the plume are 0.78 (Figure 3.12d). The origin of the saline plume of formation water in the MGA is explained in the next section.

Water samples with TDS values between 60,000 and 100,000 mg/l are interpreted as mixtures between typical Mannville Group formation-water and the saline plume. These waters are found in an approximately 20 kilometer wide band bounded by the 60,000 mg/l contour on the west and south, and the 100,000 mg/l contour in the northeast (Figure 3.13). Chemical characteristics of these samples are highly variable depending on the relative proportions of the two end members present.

3.3.4 Origin of the Saline Plume of Formation Waters in the Mannville Group Aquifer

The geology, hydrogeology, and hydrochemistry of the formations and fluids at this particular location in the Western Canadian Sedimentary Basin all contribute to the production of a saline plume in the Mannville Group aquifer.

Three factors are responsible for the creation of the saline plume in this area. First, there is leakage of saline water and hydrocarbons through the tops of Devonian reefs. This leakage occurs where the cap-rock, in this case the Ireton aquitard, is thin or absent (Figure 3.10). Second, the ascending nature of the formation-fluid flow in the Bashaw area (vertical flow from p[d] plot: Figure 3.9) both assists the leakage of fluids out of the reefs and drives fluids upwards out of the Nisku aquifer.

The third key factor in the creation of the saline plume in this particular location is the nature of the subcrop of the UDHG beneath the MGA (Figure 3.2). The relatively impermeable dolomite, anhydrite, and minor halite that comprise the Wabamun Group aquitard separates the UDHG from the MGA. In the northeast corner of the study area, the Wabamun Group aquitard subcrops the MGA (Figure 3.14). Outside of the area of subcrop, the aquitard is in excess of 200 metres thick. Northeast of the line of subcrop, the aquitard thins to under 60 metres at the boundary of the study area (Figure 3.14). The thinning of the Wabamun Group aquitard in the northeast corner of the study area provides the pathway for the vertically-ascending Devonian waters to pass upward into the Mannville Group aquifer, creating the saline plume. Comparison of the map of total dissolved solids for the MGA (Figure 3.13) with the isopach map of the Wabamun Group aquitard (Figure 3.14), shows that the plume is found in the Mannville Group aquifer where the aquitard begins to thin along the subcrop line.

The chemical composition of the formation fluids supports the argument that the saline plume originates from the Upper Devonian Hydrogeologic Group. Formation waters that make up the UDHG are markedly different in composition from the regional waters in the MGA (Figure 3.12). With their characteristically high TDS values, high proportion of calcium cations, and low rNa/Cl ratios, they are recognizable, even when mixed with more dilute waters. The Stiff diagrams reveal that the overall shape of a typical "saline plume" water is very similar to the shape of the water from the Cooking Lake-Leduc aquifer. The saline plume and Cooking Lake-Leduc aquifer waters only differ in the magnitude of their respective TDS concentrations. The characteristically high calcium content of waters from the UDHG that are also found in the saline plume is also diagnostic. Typical analyses for other formations in the study area (not shown here), do not match the Stiff Diagram pattern of the saline plume. Furthermore, none of the other formation fluids exhibit the elevated amounts of calcium found in the UDHG and in the saline plume waters.

It could be argued that the saline plume is simply caused by laterally moving "typical" MGA formation-waters dissolving the carbonates of the Wabamun Group aquitard. It is possible that the low TDS MGA waters are undersaturated with respect to calcium (or other ions) and when they came into contact with the carbonates and evaporites in the subcrop area, there could be an increase in TDS. This is possible, but unlikely because such a TDS increase is not supported by the flow system in the MGA as p[d] plots illustrate the vertical rather than lateral nature of fluid flow in the area of the saline plume. The fact that the fresher "typical" Mannville waters come into contact with the carbonates of the Wabamun Group aquitard probably only plays a minor role in the formation of the saline plume.

Organic geochemical analyses of produced oils from Mannville Group reservoirs east of the study area further support the input of UDHG fluids into the MGA. Riediger et al., (1994), used Gas Chromatography-Mass Spectrometer analysis of hydrocarbons and source-rocks from the Provost Field (3-17-40-12 W4M) to demonstrate that Mannville Group oils contain a significant component of Devonian-sourced hydrocarbons. It is logical to assume that if oil can be shown to be migrating from the Devonian, then other formation fluids can also follow similar flow pathways, although results presented here do not include any oil-source rock correlations.

Based on these geological, hydraulic, and geochemical data, it is reasonable to conclude that the saline plume in the Mannville Group aquifer is formed by formation fluids emanating from reefs in the Leduc Formation. Implications of the dynamic nature of saline plumes on geochemical exploration, in general, and for Leduc Formation reefs, in particular, are discussed below.

3.4 IMPLICATIONS FOR SURFACE GEOCHEMICAL EXPLORATION

Improved understanding of the mechanics of formation of a plume above a breached reef can improve the exploration efficiency of surface geochemical techniques.

3.4.1 Surface Expression Versus Hydrocarbon Retention

Creation of a plume or initiation of leakage from a reservoir can have both positive and negative aspects, depending on whether one is interested in the surface expression of that leakage or the amount of trapped hydrocarbons in the reservoir (Table 3.2).

If there is no leakage from the trap, and no formation of a hydrocarbon plume, there will be no surface expression, hence no surface indication of a subsurface reservoir. This would be positive from a trapping perspective because it means the cap-rock did not fail, and the trap could be filled to its spill point height. These situations occur when the COC of the cap-rock exceeds the leaking factors (column height and hydraulic-gradient), allowing no penetration of oil into the cap-rock (Rostron, 1993).

The complete leakage case is the extreme opposite to the no leakage case. If the cap-rock cannot impede sufficient hydrocarbons to allow for trap filling (for example Figure 3.6a), then the reservoir cannot fill to capacity. In this case there is a minimal amount of retained hydrocarbons because the bulk of the migrating hydrocarbons have been lost to leakage. However, from the exploration perspective of obtaining the strongest possible surface expression of the presence of the trap, this is the best case. In other words, the best surface expression of the subsurface presence of a reef is obtained when the least amount of hydrocarbons are retained in the subsurface trap.

The optimum case for both trapping and surface expression of migration lies between the complete and no leakage end-members (Table 3.2). Ideally, traps would leak enough to form a detectable plume while retaining as much hydrocarbons as possible in the trap. The cap-rock above the reef must fail to be detectable by surface geochemical methods. To maximize the retained hydrocarbons once failure has occurred, the trap must either be found while being actively sourced (as in Figure 3.4e), or before the emplaced hydrocarbons escape (as in Figure 3.4g).

The applicability of surface geochemical techniques to a given trap depends on the degree of leakage from the trap. A trap's position on a "leakage spectrum" depends on the sealing-leaking factor interaction that occurs in each trap. Numerical results and field mapping show that sealing-leaking factor interactions depend on rock properties including CCC and intrinsic permeability. Furthermore, the subsurface flow fields affect both initiation of plume generation and subsequent migration towards the surface. Thus measured values of rock parameters and a good understanding the subsurface flow distribution are critical to the successful application of surface geochemical exploration techniques. Hydrogeologic studies must be completed as part of any surface geochemical exploration program.

3.4.2 Implications to Geochemical Exploration for Devonian Reefs

Results of field mapping presented here have four implications for the surface expression of hydrocarbon migration from Devonian reefs. First, reefs of the Leduc Formation in the Bashaw Reef Complex are leaking, or have leaked, hydrocarbons and saline water upward into overlying formations. This leakage is occurring where the Ireton aquitard is very thin or absent over individual reefs. Formation fluids have crossed the Ireton aquitard into the Nisku aquifer under the influence of buoyancy and the generally ascending fluid flow in the UDHG. Within the Nisku aquifer, these individual plumes coalesce, and continue to migrate up dip. Where the Wabamun aquitard subcrops and thins, formation fluids in the Nisku aquifer rise up into the MGA. This generates the saline plume in the Mannville Group aquifer.

Second, there is a definite mappable signature of Devonian hydrocarbons and saline water occurring in the Mannville Group aquifer. Within the saline water plume, the TDS of the formation waters are two to five times higher than the ambient Mannville Group formation-waters. This plume is easily recognizable over large parts of the study area and is a direct indicator of upward-moving Devonian formation-fluids. Mapping the TDS of formation waters in the Mannville Group could be used to find other areas where Devonian oils are entering the Mannville Group. Mapping TDS distributions elsewhere in the basin could lead to the discovery of as-yet unknown reefs and/or unknown areas where flow systems bring Devonian hydrocarbons closer to the surface. Saline plumes are useful because they can be detected easily using water salinities derived from geophysical well-logs.

Third, the geochemical signature of the Leduc Formation reefs is best mapped at the MGA level, since the flow system at the Mannville Group level changes from a dominantly vertical one to a more lateral one. Once in the MGA, formation fluids are re-directed into a laterally moving flow field, causing any hydrocarbon plume above leaky reefs to be offset. The fact that hydrocarbons from the UDHG are offset laterally from the leakage conduit in this study area is shown in two ways: by Devonian sourced hydrocarbons produced from Mannville pools up dip of the study area (Riediger et al., 1994); and by the extension of the saline plume up-dip beyond the limits of the study area (Abercrombie et al., 1994).

Fourth, it is unlikely that the saline plume in the MGA and any associated hydrocarbons have any surface expression in this study area, for two reasons: 1) between the MGA and the surface are two regionally extensive aquitards (Joli Fou and Colorado Group aquitards) with a combined thickness of over 300 metres of shale, serving to restrict upward fluid migration; and 2) the hydraulics of the overlying formations include strong underpressures in shallower aquifers and surface groundwater recharge (Hitchon, 1969) to act against upward flow. Previous surface geochemical studies on an area overlapping to the south the present area (McCrossan et al., 1972) found little correlation between surface soil-gas anomalies and underlying Leduc hydrocarbon pools.

Thus, surface geochemical methods would not be useful to search for Devonian reservoirs in this area. However, this does not preclude saline plumes from reaching the surface in other areas of the basin where conditions such as thinner overlying shales, stronger ascending flow, or shallower Mannville Group exist.

3.5 CONCLUSIONS

Numerical modelling and field mapping of saline plumes emanating from Devonian reefs have shown the following:

1) The formation of saline plumes above reefs is controlled by the "sealing-leaking factor" interaction of the flow system. The sealing factors (capillary pressure curves and intrinsic permeabilities) and leaking factors (fluid densities and regional hydraulic gradients) are measurable quantities and can be predicted. Measurements of these properties, especially on the cap-rocks, must be conducted to quantify the formation of hydrocarbon plumes and their subsequent migration to surface. Exploration efficiency can be improved by an understanding of the hydraulics of the flow system.

2) Devonian reefs in the Bashaw reef complex of west-central Alberta, Canada are leaking saline water and hydrocarbons. These fluids are carried upward by ascending flow in the Paleozoic aquifers. Where these saline brines intersect the Mannville Group aquifer they create a [illegible] plume of saline waters in the study area. Mapping such plumes in the Mannville Group aquifer can indicate areas of upwelling Devonian oils and indicate the

presence of as-yet undiscovered reefs beneath the Mannville Group.

3) Geochemical exploration for Devonian reefs and hydrocarbon plumes has to be conducted at the Mannville Group level, because the Mannville Group aquifer intercepts the vertically ascending fluid flow and re-direct it laterally up-dip.

4) There will be little, if any, surface expression of Devonian hydrocarbon plumes in west-central Alberta because of the lateral interception of the plume by the Mannville Group and the isolation of the Devonian and Mannville aquifer-systems from the surface by the Colorado Group aquitard. There may be surface expressions of hydrocarbon migration in other areas of the basin where the Mannville Group is closer to the surface or where an ascending fluid flow reaches the surface.

5) Regional fluid flow and cross-formational migration play an important role in migration and entrapment in the subsurface. These factors affect surface expressions of hydrocarbon migration. An understanding of subsurface hydrogeology and hydrochemistry as shown in this paper can increase the exploration efficiency of surface exploration techniques.

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Flow Domain:	1400 x 300 m (horizontal x vertical)
Fluid Viscosity:	2.0×10^{-3} Pa.s (oil); 1.0×10^{-3} Pa.s (water)
Water Density:	1000 kg/m^3
Porosity:	20% carrier-bed; 5% cap-rock
Carrier-bed Permeability:	100 md
Formation Compressibility:	1.0×10^{-10} kPa^{-1}
Injected Fluid Composition:	90% water; 10% oil
Oil Injection Rate:	3.71×10^{-1} m^3/yr
Irreducible Oil Saturation:	20%
Irreducible Water Saturation:	45%
Timestep Length:	50 yr
Oil Densities:	700, 850, 1000 kg/m^3
Regional Hydraulic Gradients:	0.005, 0.02, 0.08, 0.2 m/m
Cap-rock Permeabilities	0.0001, 0.001, 0.01, 0.1, 100 md
Critical Oil Column of Cap-rock:	25.9, 78, 100, 143, 289

Table 3.1. Simulation Data

	Possibility of Surface Expression:	Possibility of Retention:
1) No Leakage	None	Excellent
2) Partial Leakage	Some	Some
3) Complete Leakage	Excellent	None

Table 3.2. Implications of the Sealing-Leaking Factor Interaction on the Subsruface Expression of Hydrocarbon Migration

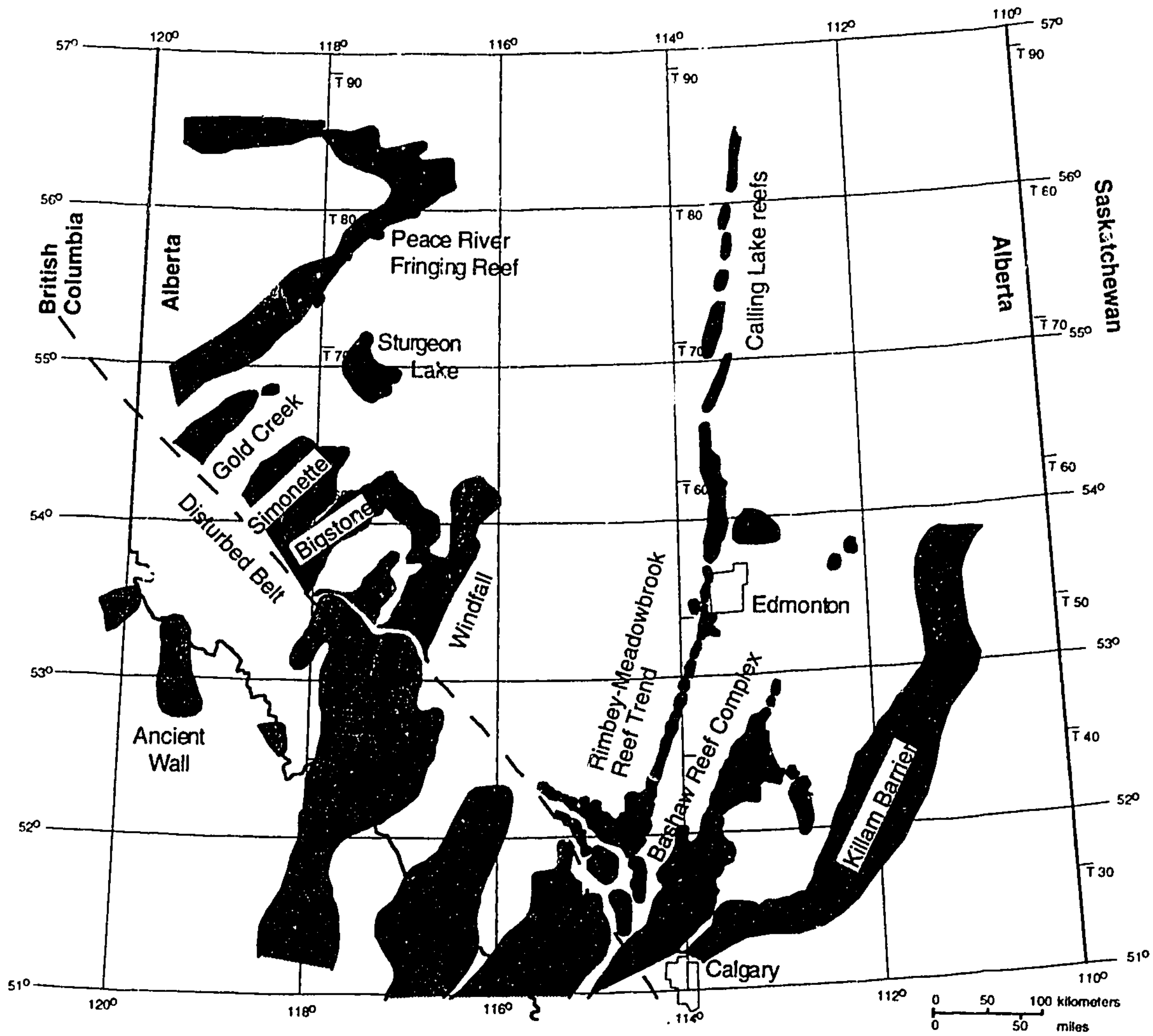

Figure 3.1. Woodbend Group equivalent (Upper Devonian) reef trends in the Western Canadian Sedimentary Basin. Lighter shading to the west of the disturbed belt indicates where reefs have been palinspastically restored (modified after Switzer et al., 1994 and many others).

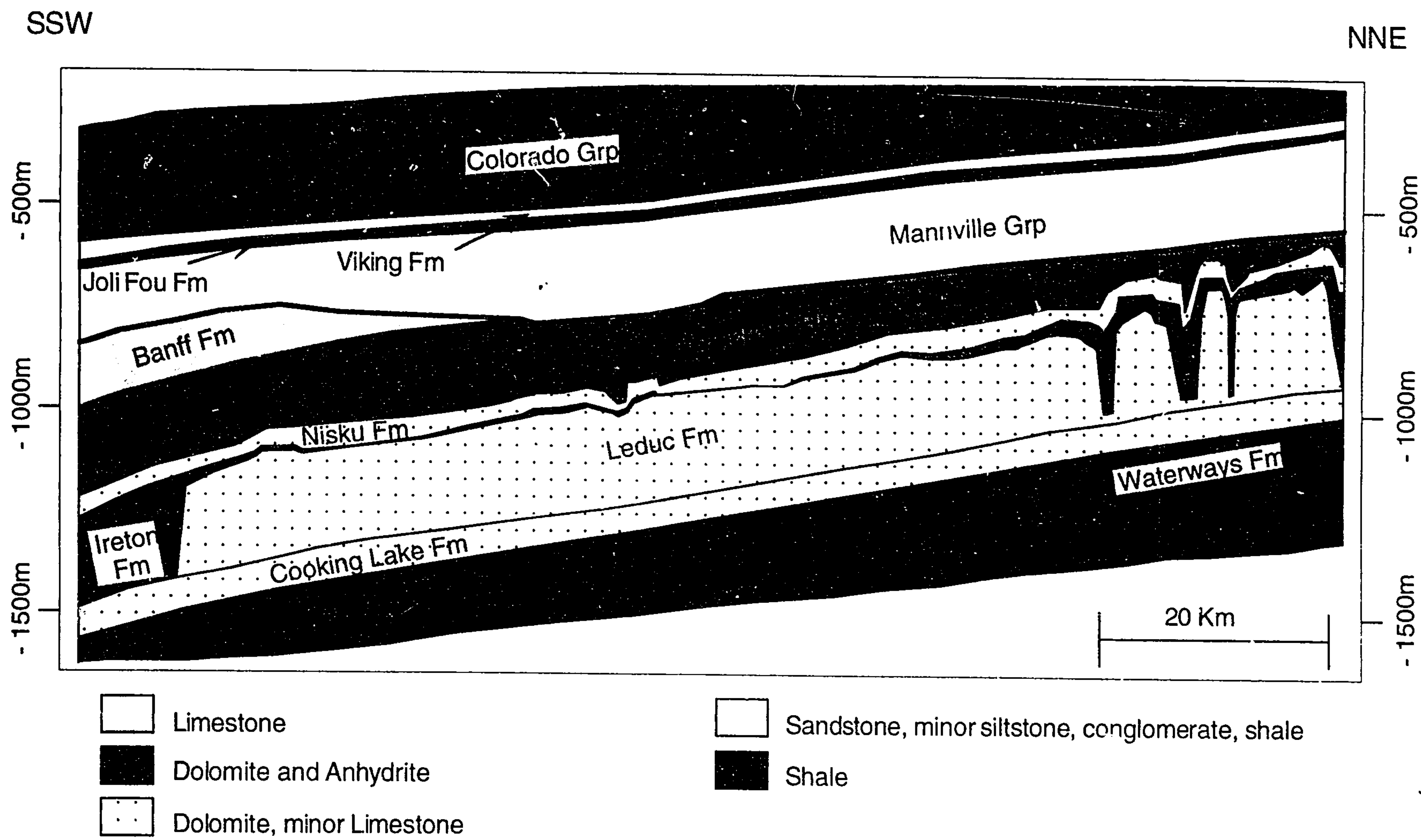

Figure 3.2. Structural cross-section from south-southwest to north-northeast through the Bashaw Reef Complex.

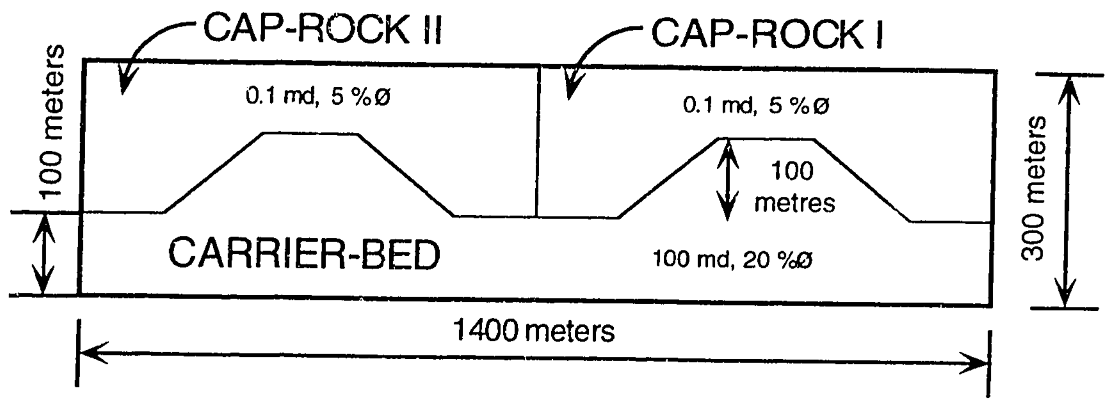

Figure 3.3. Schematic of the flow domain.

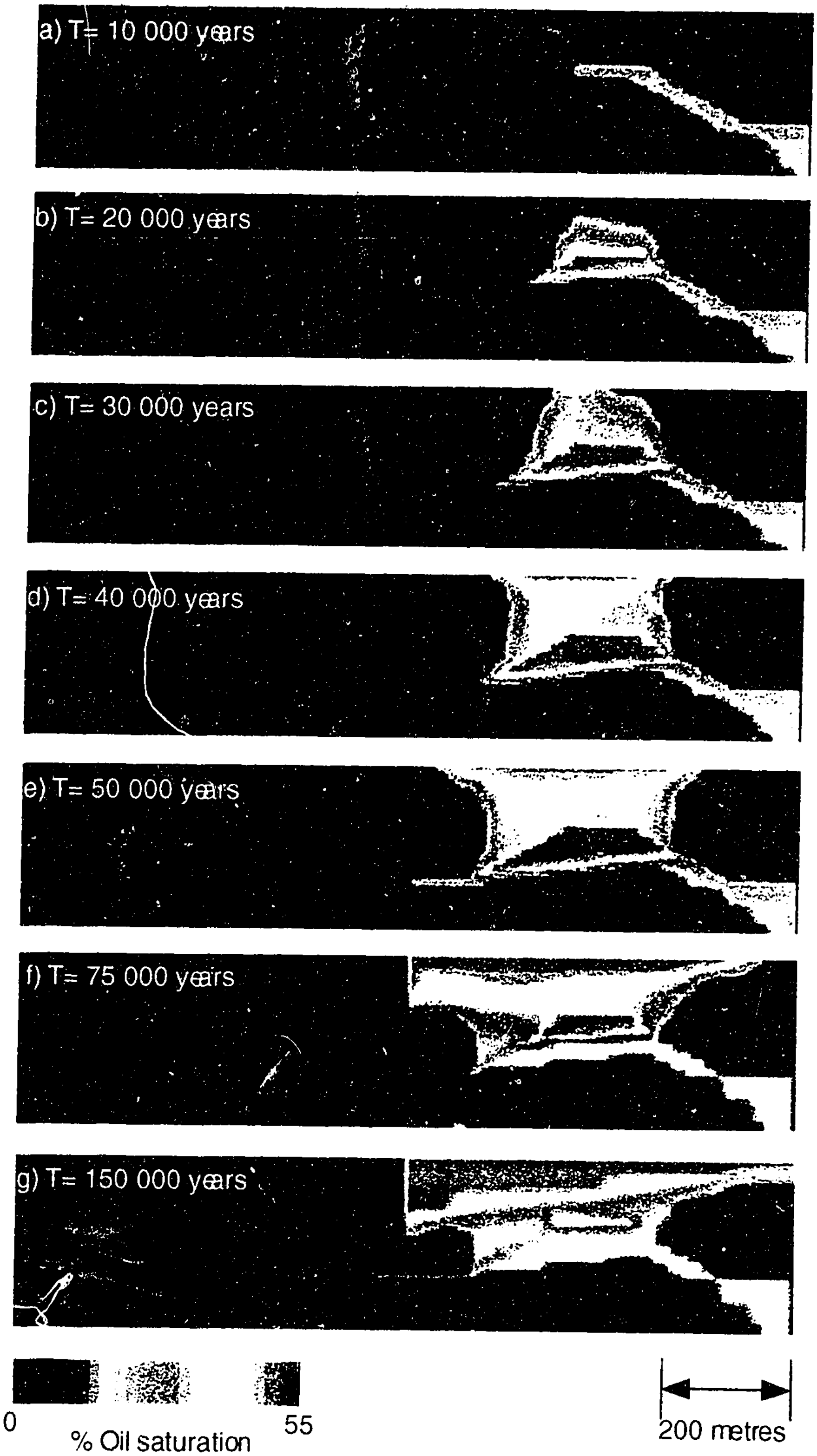

Figure 3.4. Oil saturation distributions through time for a typical leaky pinnacle reef (COC = 25.9 metres). No vertical exaggeration.

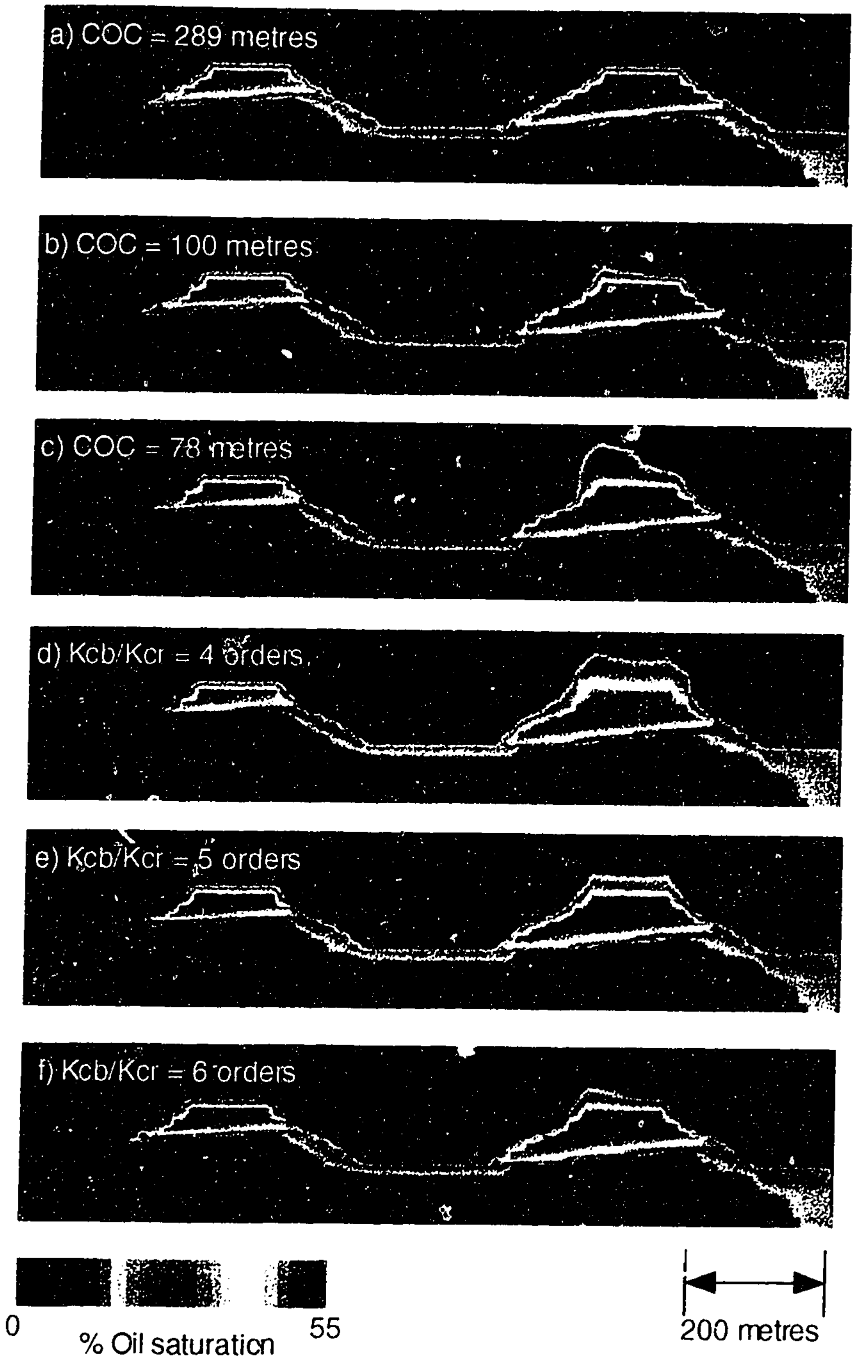

Figure 3.5. Oil saturation distributions at T=50,000 years - varying the COC and intrinsic permeability of the first cap-rock. No vertical exaggeration.

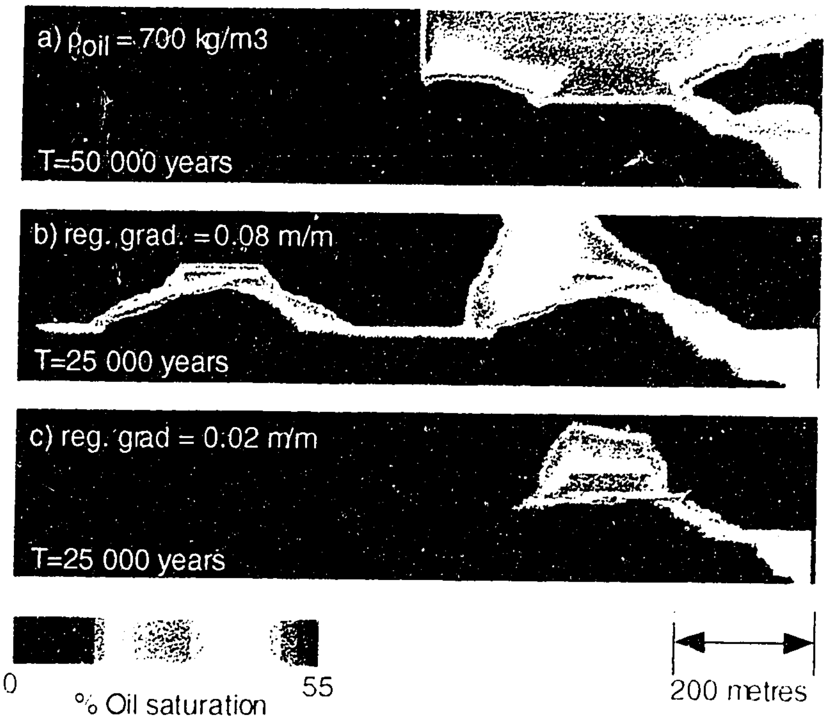

Figure 3.6. Oil saturation distributions with a constant COC of 25.9 metres - varying the oil density and regional hydraulic gradient. No vertical exaggeration.

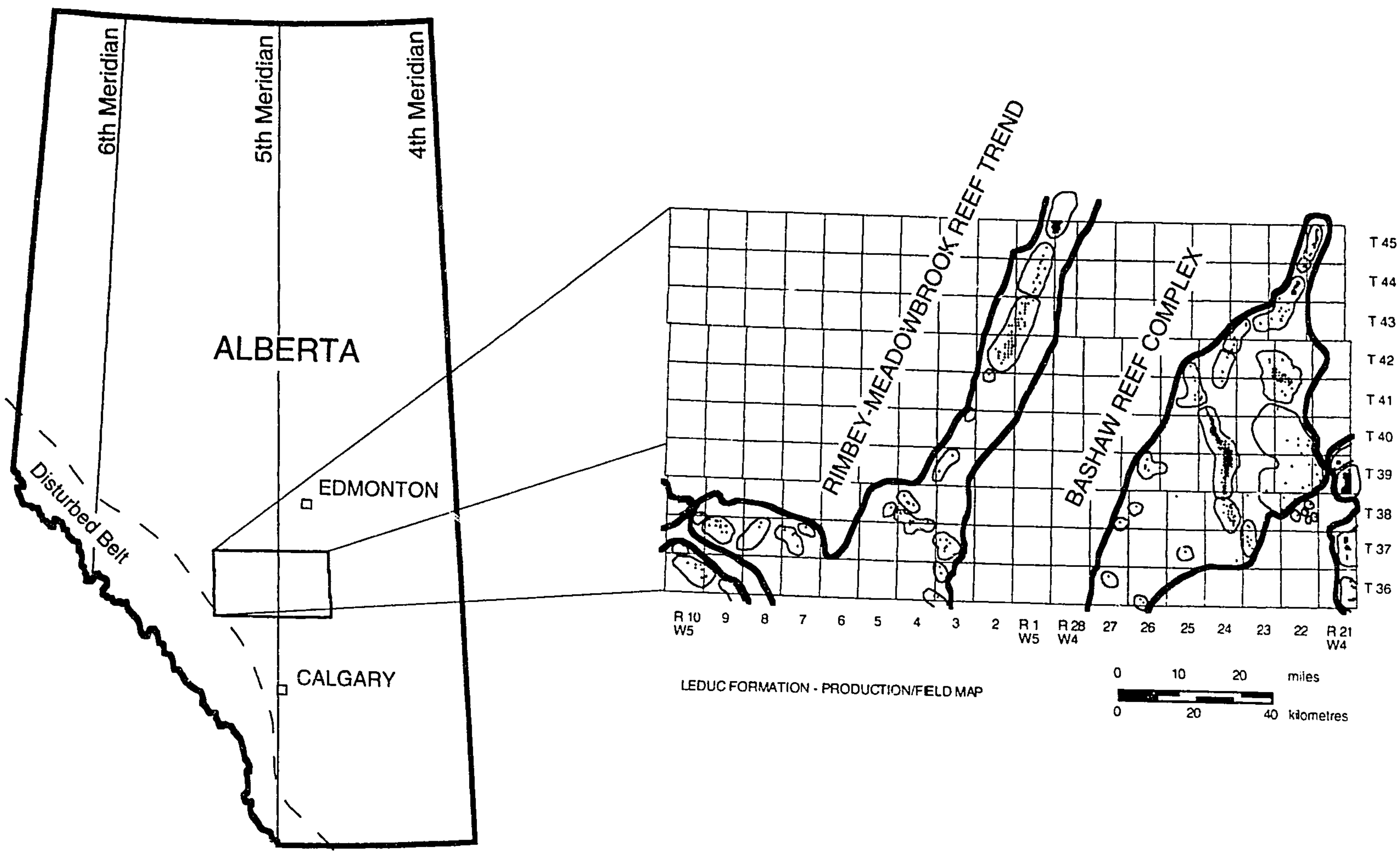

Figure 3.7. Field study area, west-central Alberta, Canada. Data points indicate wells producing from the Leduc Formation. Known reef structures are outlined.

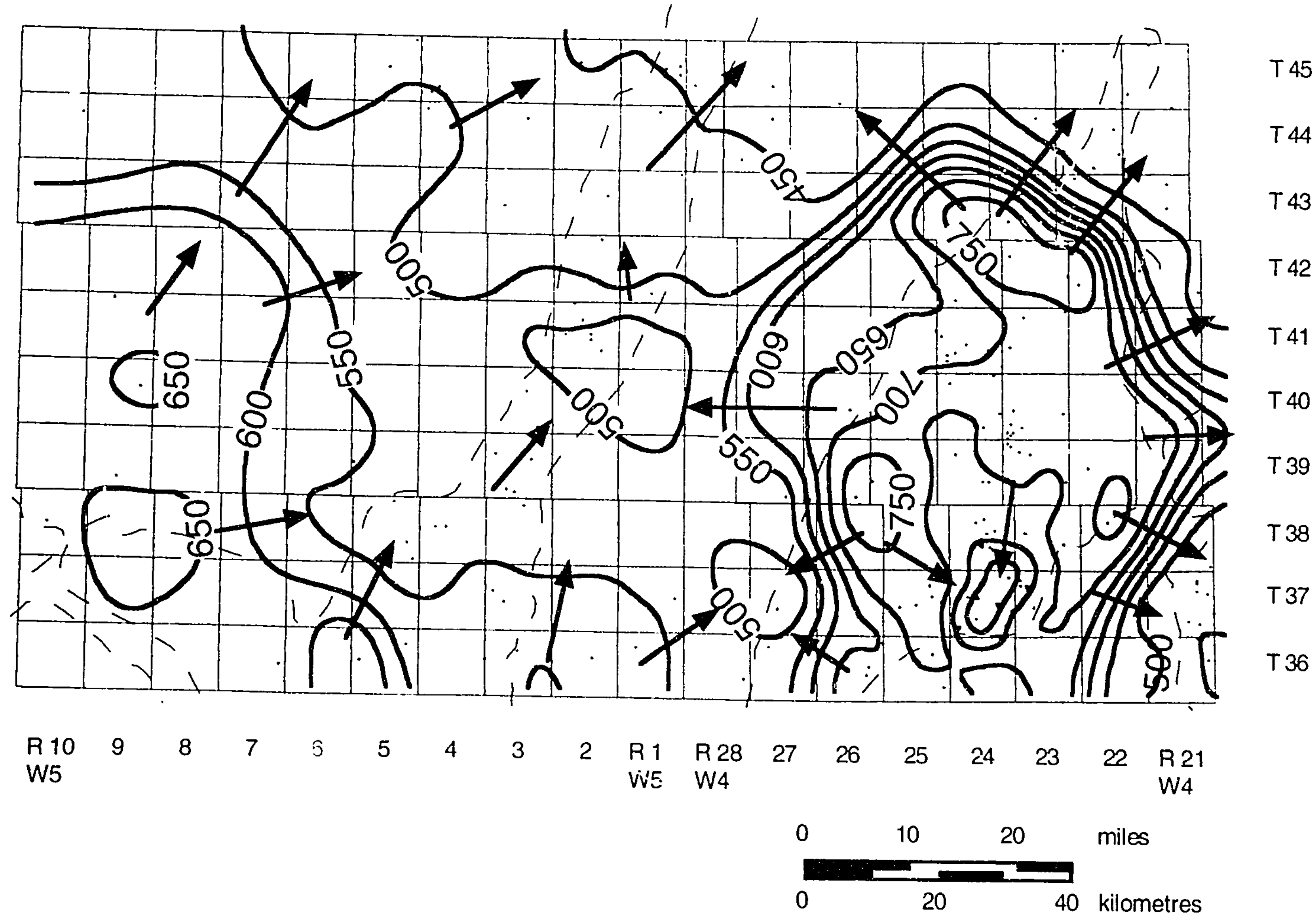

Figure 3.8. Hydraulic head distribution in the Nisku aquifer. Dashed line indicates the limits of the highly-permeable areas in the underlying Leduc and Cooking Lake formations. Contour interval equals 50 metres of equivalent freshwater hydraulic head.

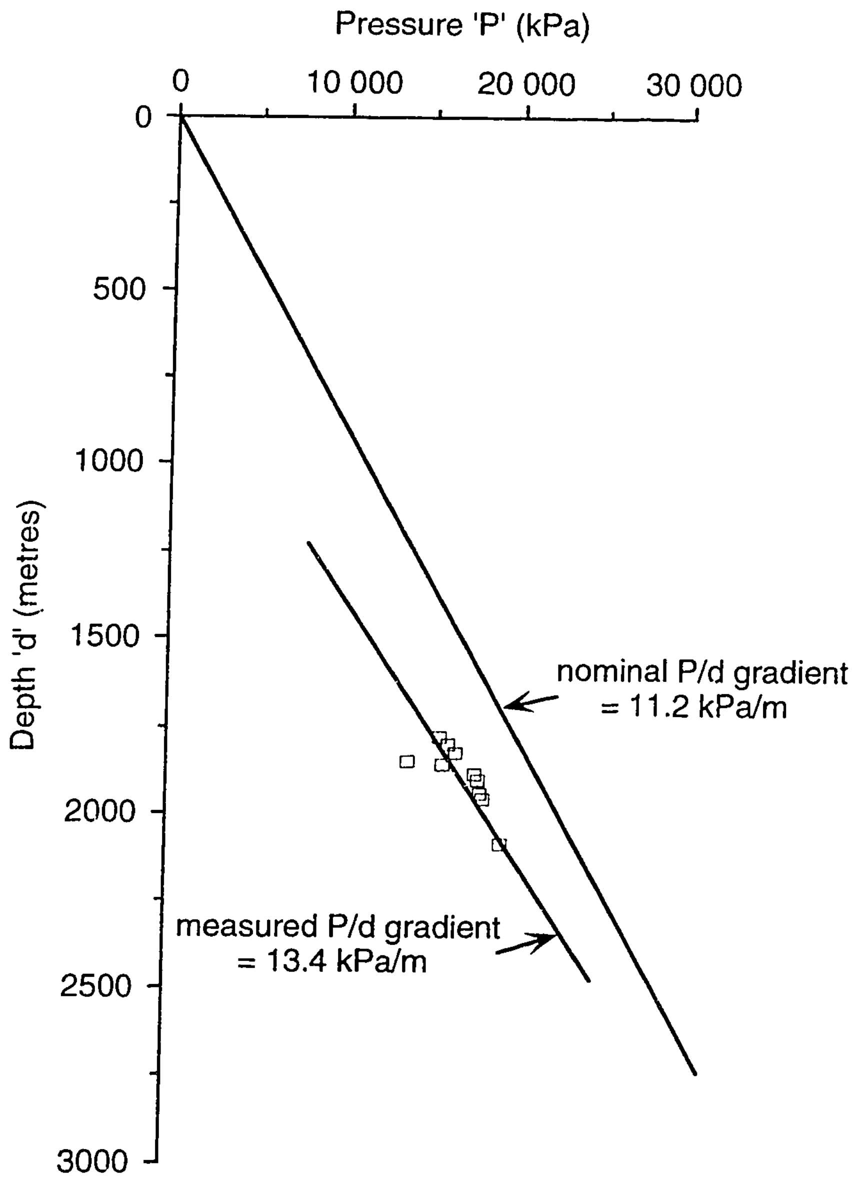

Figure 3.9. Pressure-Depth plot from the Leduc Formation in the Bashaw Reef Complex (modified after Paul, 1994).

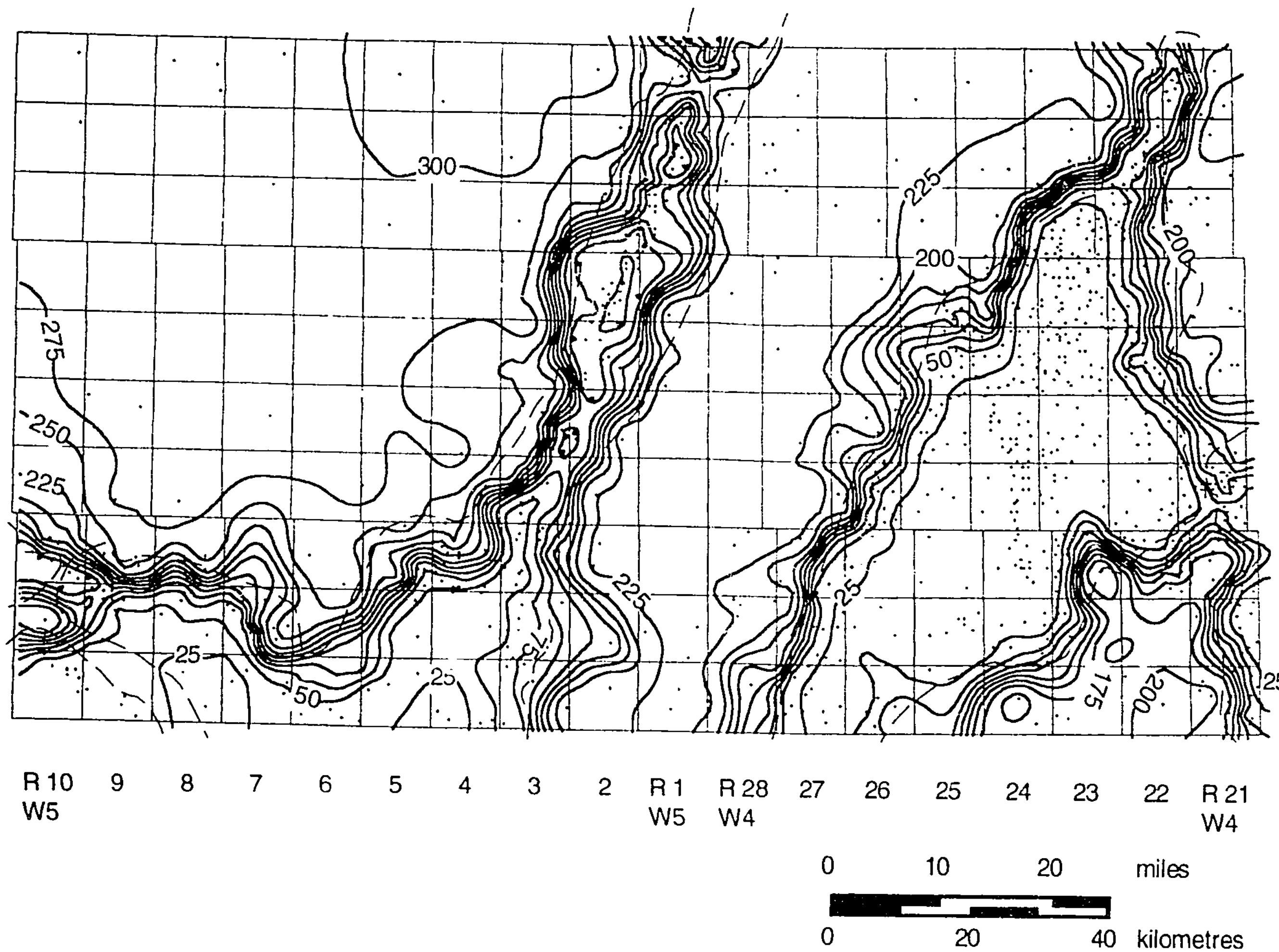

Figure 3.10. Isopach map of the Ireton aquitard. Dashed line indicates the limits of the highly-permeable areas in the Leduc and Cooking Lake formations. Contour interval equals 25 metres.

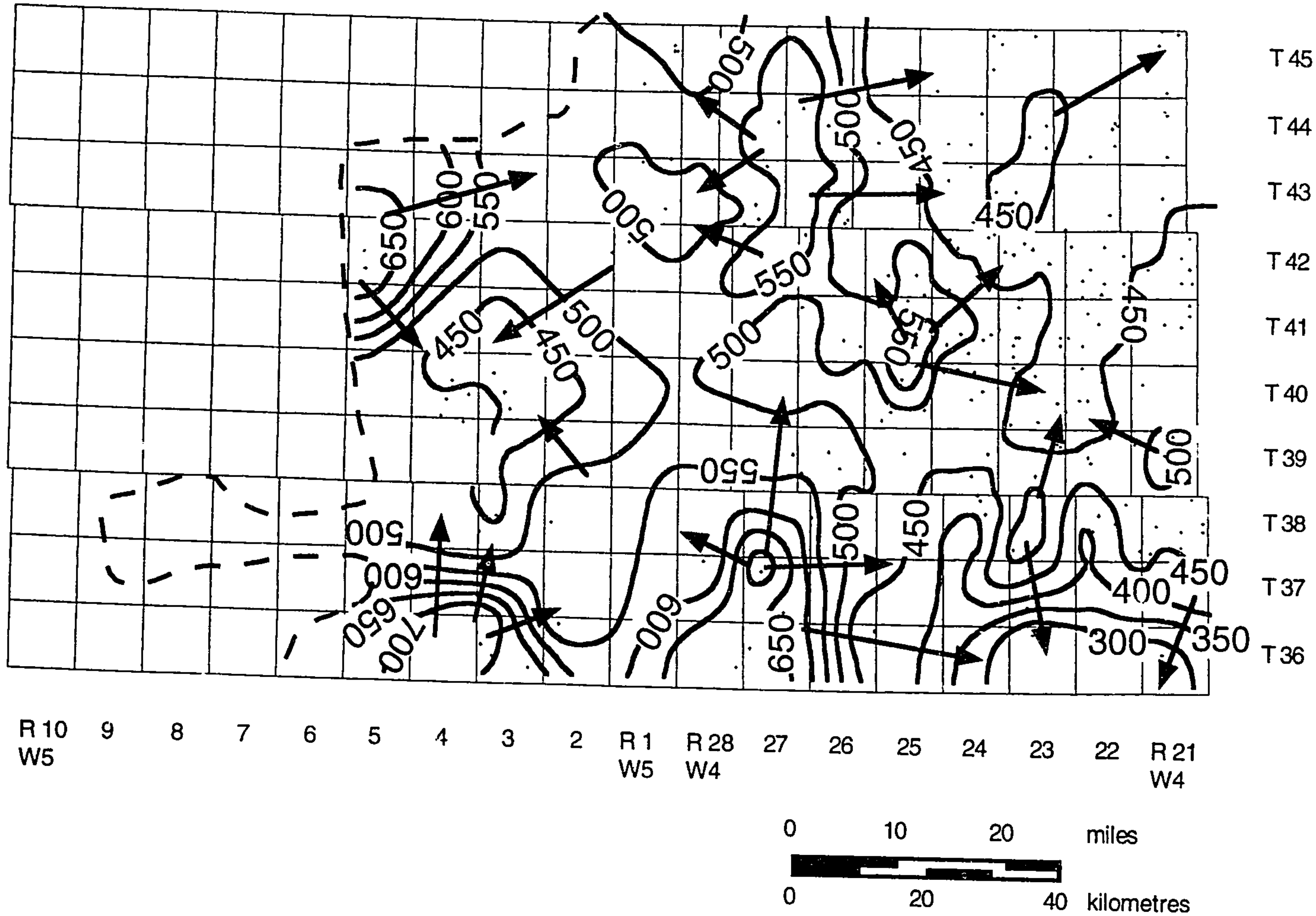

Figure 3.11. Hydraulic head distribution in the Mannville Group aquifer. Contour interval equals 50 metres of equivalent freshwater hydraulic head. Dashed line indicates the boundary with the Deep Basin.

a) Leduc aquifer
TDS ~ 205,000 mg/l (+/- 22,000)
Na/Cl = 0.65
n = 269

Na + K = 2456
Ca = 1031
Mg = 273

Cl = 3570
HCO3 = 13
SO4 = 14
CO3 = 0

b) Nisku aquifer
TDS ~ 181,000 mg/l (+/- 30,000)
Na/Cl = 0.68
n = 203

Na + K = 2234
Ca = 787
Mg = 245

Cl = 3135
HCO3 = 11
SO4 = 18
CO3 = 0

c) "typical" Mannville Group aquifer
TDS 20,000 - 60,000 mg/l
Na/Cl ~ 0.95
n = 125

Na + K = 659
Ca = 41
Mg = 15

Cl = 671
HCO3 = 23
SO4 = 11
CO3 = 1.4

d) Saline plume (MGA)
TDS 100,000 - 150,000 mg/l
Na/Cl ~ 0.78
n = 114

Na + K = 1707
Ca = 373
Mg = 100

Cl = 2157
HCO3 = 7
SO4 = 7
CO3 = 0

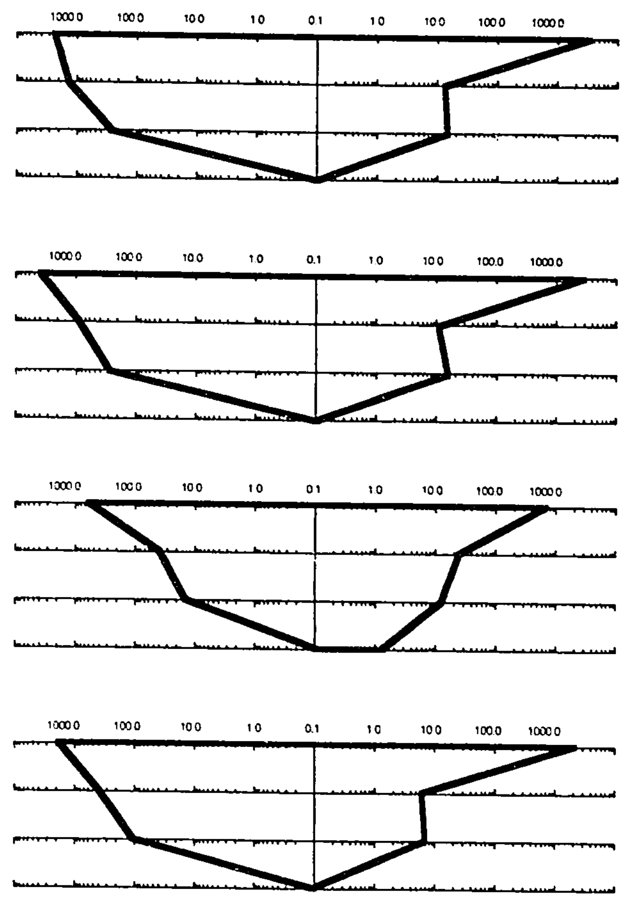

Figure 3.12. Stiff diagrams of averaged formation-water composition from the Upper Devonian hydrogeologic group and Mannville Group aquifer. All chemical data are expressed in units of milliequivalents per litre.

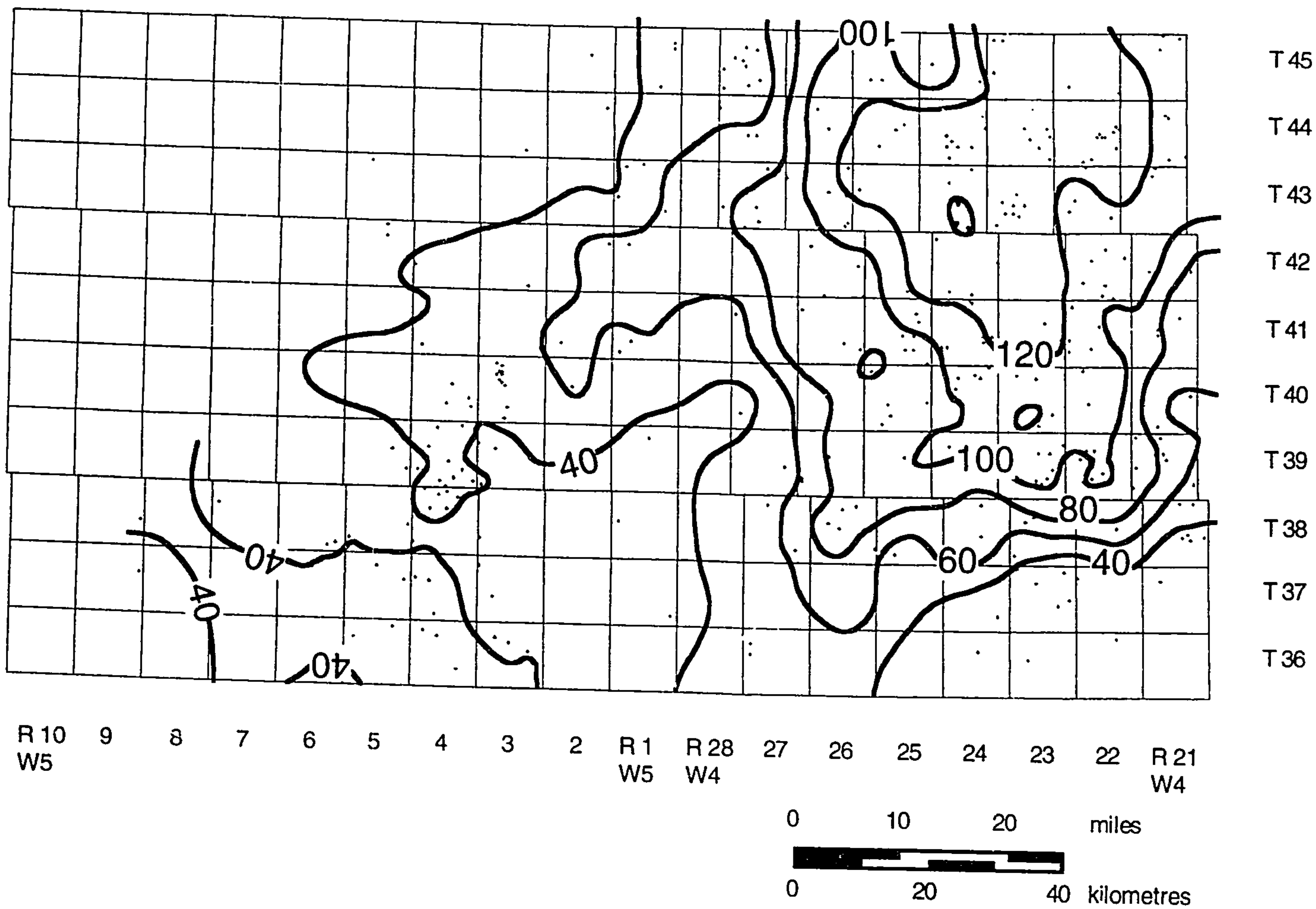

Figure 3.13. Total dissolved solids distribution for the Mannville Group aquifer. Contour interval equals 20 000 milligrams per litre.

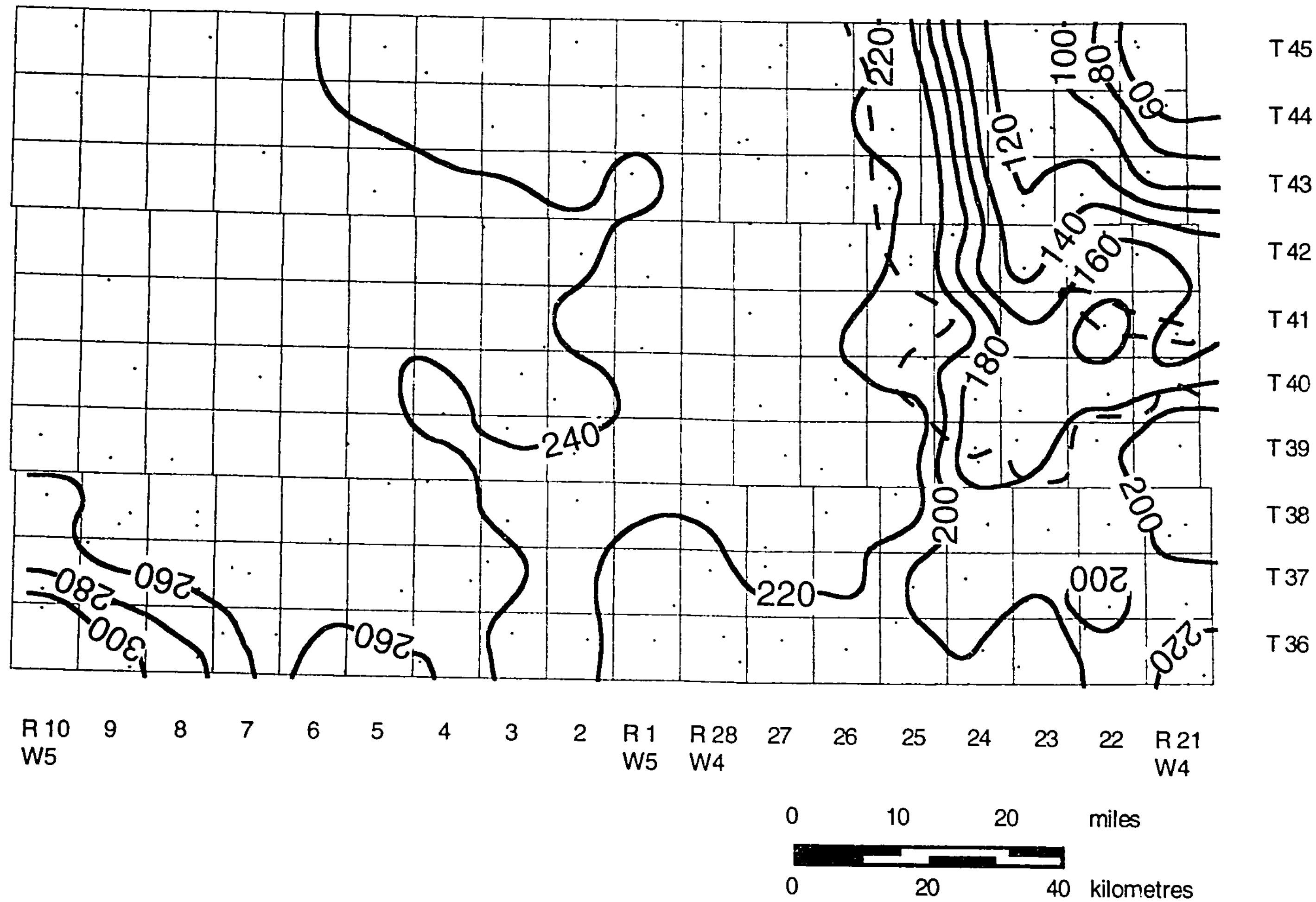

Figure 3.14. Isopach map of the Wabamun Group aquitard. Contour interval equals 20 metres. Dashed line indicates where the Wabamun Group aquitard subcrops the Mannville Group aquifer.

4.0 BASIN-SCALE FLUID FLOW, HYDROCHEMISTRY, AND PETROLEUM ENTRAPMENT IN DEVONIAN REEF COMPLEXES, WEST-CENTRAL ALBERTA, CANADA*

4.1 INTRODUCTION

The 120 km long Upper Devonian Bashaw reef complex and the nearby 320 km long Upper Devonian Rimbey-Meadowbrook reef trend, with the underlying Cooking Lake platform act as regional subsurface fluid conduits in the Western Canada Sedimentary Basin (WCSB) for oil, gas, and water. Evidence of regional fluid migration in these reef trends includes: 1) huge deposits of hydrocarbons that originate from a single source rock (proven reserves of $875 \cdot 10^6$ m^3 oil and $391 \cdot 10^9$ m^3 gas: Podruski et al., 1988; Reinson et al., 1993) that have migrated up dip for hundreds of kilometres (Creaney and Allan, 1990); 2) basin-scale studies of water movement indicating that these reefs funnel fluids from nearby formations through the deeper parts of the basin towards its edge (Hitchon, 1969, 1984; Hugo, 1990); and 3) extensive pervasive dolomitization of the carbonate reservoir rocks by a mechanism attributed to long-distance fluid migration (Amthor et al., 1993). There have been very few studies of the hydrogeology of the Upper Devonian carbonates in central Alberta, despite the obvious economic importance of these carbonates, and the large number of published geological/petroleum papers. The basin-scale hydrogeology of the Woodbend Group in the WCSB was presented by Hitchon (1969) but Hitchon's maps did not distinguish between the individual aquifers within this group. Hugo (1990) studied migration in Leduc reefs in more detail, and although Hugo's study area overlaps the northern half of the present study area, he too did not differentiate between individual

* A version of this chapter was submitted as "Basin-Scale Fluid Flow, Hydrochemistry, and Petroleum Entrapment in Devonian Reef Complexes, South-Central Alberta, Canada" by B.J. Rostron, J. Tóth, and H.G. Machel, to the SEPM Special Volume on Fluid Flow and Basin-Wide Diagenetic Patterns, May, 1995.

formations in the Woodbend Group. Paul (1994) examined fluid flow and hydrochemistry in the central part of the Rimbey-Meadowbrook reef trend, but did not study hydrocarbon migration or entrapment. Pressure versus elevation plots have been presented for two of the Devonian reef trends in the basin (Dickey, 1972; Hitchon, 1984), but these have not been integrated with lateral variations in fluid potentials or hydrochemistry. Oil migration in the Devonian formations of the WCSB has been the subject of intensive investigations, primarily by organic geochemists using oil to source-rock correlations (Stoakes and Creaney, 1984, 1985; Creaney and Allan, 1990; Allan and Creaney, 1991; Creaney et al., 1994; and others). However, none of these geochemical studies has made use of quantitative mapping of fluid potentials and hydrochemistry to integrate fluid flow with hydrocarbon trapping in the subsurface.

In this paper, results are presented from a petroleum hydrogeological study on the Bashaw reef complex and the lower part of the Rimbey-Meadowbrook reef trend in west-central Alberta. The major objectives of this study are to describe the flow-field and hydrochemistry of formation waters in these Upper Devonian strata and to investigate any links between hydrogeology and hydrocarbon trapping in the Bashaw and Rimbey-Meadowbrook reef trends.

4.2 STUDY AREA

The study area is situated in west-central Alberta, Canada (Figure 4.1). It covers approximately 18,000 km^2 over an area defined south to north by Townships 36 to 45 (52° 3' to 52° 56' north latitude), and east to west between Range 21 west of the fourth meridian and Range 10 west of the fifth Meridian (112° 52' to 115° 27' west longitude). Excellent subsurface data control is available from the more than 12,000 oil and gas wells drilled in the area.

Central Alberta is in the heart of the hydrocarbon producing region of the Western Canadian Sedimentary Basin (WCSB). Devonian-aged reservoirs are of particular importance in the WCSB, hosting 60 percent of the conventional oil and about 27 percent of the gas reserves in the basin (Reinson et al., 1993). The present study area covers most of the Bashaw reef complex and the southern portion of the Rimbey-Meadowbrook reef trend (Figures 4.1 and 4.2) which are two of the major Devonian carbonate complexes that traverse over 300 kilometres of the basin. In the study area, oil and gas have been and are being produced from many Devonian fields that include Westerose, Homeglen-Rimbey, Strachan, Duhamel, New Norway, Joffre, Clive, and Wood River fields (Figures 4.2 and 4.3).

4.3 DATA DESCRIPTION AND PROCESSING

The geologic framework for this area was established based on the examination of more than 2000 well logs that penetrate all or part of the Devonian strata. Formation pressures were obtained from two sources: as extrapolated drill-stem-test (DST) pressures from the Canadian Institute of Formation Evaluation; and as initial field pool-pressures from the Alberta Energy Resources Conservation Board (AERCB). Water chemical analyses from DST or produced fluids were obtained from Rakhit Petroleum Consulting Limited, Calgary. Well histories and production information were extracted from the CD-ROM version of the AERCB well database provided by the CDPubco Company, Calgary.

Pressure data were processed to remove values influenced by production-induced drawdown (PID). Details of these techniques are described elsewhere (Bachu et al., 1987; Barson, 1993; Rostron, 1994). Water chemical analyses were screened to remove poor quality, incomplete, or non-representative analyses (e.g., drilling mud or spent acid-frac fluids), using standard culling techniques (e.g., Bachu et al., 1987; Hitchon and Brulotte, 1994).

Geologic data were converted into cross-sections, isopach, and structural maps. Production data were used to delineate reservoir extents and in the data culling procedures. Pressure data were used for pressure versus depth plots (p[d]), pressure versus elevation plots (p[z]), and converted potentiometric surfaces and hydraulic cross-sections. Chemical data were mapped both as total dissolved solids (TDS), and as individual major ions. All four major datasets were synthesized into a regional picture of fluid flow and hydrocarbon migration for the study area.

4.4 GEOLOGICAL FRAMEWORK AND HYDROSTRATIGRAPHY

The subsurface stratigraphy of the Upper Devonian formations in west-central Alberta is shown schematically in Figure 4.4. Structural cross-sections oriented NNE-SSW through the Rimbey-Meadowbrook reef trend (Figure 4.5a) and the Bashaw reef complex (Figure 4.5b), based on log correlation and previous studies (Geological Staff, Imperial Oil Limited, 1950; Andrichuk, 1958a, 1958b; Belyea, 1964; Stoakes, 1980; Stoakes and Wendte, 1987; Amthor et al., 1993; Switzer et al., 1994; Wendte, 1994; and others), illustrate the subsurface geologic relationships in the study area. The section of interest consists of rock units belonging to four major geologic units, which are, in ascending order: the Beaverhill Lake Group; the Woodbend Group; the Winterburn Group; and the Wabamun Group (Figures 4.4 and 4.5).

At the base of the section are the limestones and calcareous shales of the Waterways Formation (Beaverhill Lake Group). The Waterways Formation varies in thickness between 150 and 200 metres across the study area (Oldale and Munday, 1994) and is conformably overlain by the Woodbend Group.

The Woodbend Group consists of three main units. The lowermost unit, the Cooking Lake Formation, is a sequence of shallow-water platform carbonates approximately 75 metres thick that extends over most of the southwest and eastern parts of the study area (Figure 4.2). The shelf margin of the Cooking Lake Formation is located immediately west of the Rimbey-Meadowbrook reef trend. Situated on top of the Cooking Lake Formation are numerous platform margin reef-buildups belonging to the Leduc Formation. Leduc reefs attain thicknesses of up to 250 metres and are usually comprised of coarse-crystalline, highly porous and permeable dolostones (Amthor et al., 1993, 1994). These dolostones are capped by the basin-filling shales and marls that belong to the Ireton and Duvernay formations. Some authors (e.g. Stoakes, 1980; Switzer et al., 1994) recognize an additional shale-encased dolomitic carbonate layer, the Camrose Member, near the top of the Woodbend Group. The Camrose Member extends over approximately the eastern half of the study area and reaches a maximum thickness of 20 metres.

Conformably overlying the Woodbend Group are three formations that make up the Winterburn Group. Lowermost in the section are the shallow-water shelf carbonates of the Nisku Formation. Like the underlying Leduc Formation, the Nisku Formation has been completely altered to dolomite throughout the study area. The Nisku Formation is capped by the areally-extensive but relatively thin (less than five metre thick) shaley and silty Calmar Formation. The top of the Winterburn Group is generally recognized by the presence of a silt or grit marker, the Graminia Formation. In the study area, the Nisku Formation comprises over 90 percent of the thickness of the Winterburn Group.

The uppermost part of the Devonian in the study area comprises the mixed carbonates of the Wabamun Group. The nomenclature of the Wabamun Group is confusing, partly due to regional lithologic changes from northwest to southeast across the WCSB. In the northwestern part of the study area, the Wabamun Group consists mainly of dolomitic-limestones. Farther to the southeast there is a gradational shift towards increasing dolomite content, reaching 100 percent dolomite near the center of the study area. Towards the east there is a shift to increased anhydrite content and in the southeastern corner of the study area the Wabamun Group contains up to 20 metres of halite (Anderson et al., 1988). Across the eastern half of the study area, the Wabamun Group is divided into two recognizable units: a thin upper unit made up of limestones and shale (Big Valley Formation), and a lower, much thicker unit of dolomite and anhydrite (Stettler Formation).

Sedimentary rocks younger than Devonian were also examined in this study. The lithology of these units depends on location throughout the study area. In general, the rocks range from Mississippian carbonates (Banff Formation) to clastic sandstones, siltstones, and shales of the Mannville Group (Figure 4.5).

Subsurface geology, hydraulic properties, and flow-field behavior were used to create a hydrostratigraphic division of the Upper Devonian strata in west-central Alberta (Figure 4. 4). The flow regime encompasses five hydrostratigraphic units which, in ascending order, are the: 1) the Waterways aquitard; 2) the Cooking Lake-Leduc aquifer; 3) the Ireton aquitard; 4) the Nisku aquifer ; and 5) the Wabamun Group aquitard. Flow is confined to the Cooking Lake-Leduc aquifer and Nisku aquifer by the extremely low-permeability shales and carbonates of the Waterways and Wabamun Group aquitards, situated below and above the main aquifers, respectively.

4.5 RESULTS AND DISCUSSION

4.5.1 Hydrogeology

Hydrogeologic and hydrochemical mapping of the Phanerozoic strata in the study area reveal that the flow systems in the Upper Devonian strata belong to one large-scale hydrogeologic group, called here the Upper Devonian Hydrogeologic Group (UDHG). The UDHG consists of five hydrostratigraphic units (Figure 4. 4). It is bounded above and below by relatively-impermeable strata of the Wabamun Group and the Waterways aquitards, respectively. The two main aquifers within the UDHG, the Cooking Lake-Leduc aquifer and the Nisku aquifer, are separated by the relatively low-permeability Ireton aquitard.

4.5.1.1 *Cooking Lake-Leduc aquifer*

The potentiometric surface for the Cooking Lake-Leduc aquifer (Figure 4.6) illustrates substantial variations in hydraulic heads across the study area. Values of hydraulic head range from highs in excess of 2100 metres in the southwestern corner of the study area, down to lows under 500 metres in the north-central and southeastern parts of the area. In three areas the contour lines are tightly serried: between the reef trends, and in both the southwest and southeast corners of the study area. Also a number of closed contours of fluid potential (high and low) are found west of, and scattered throughout, the Bashaw reef complex.

In the Rimbey-Meadowbrook reef trend, the highest values of fluid potential occur in the southwest corner of the study area (Figure 4.6). Fluids move away from these high potential areas and flow laterally eastward toward the base of the main part of the reef trend. Once in the main reef trend, the flow direction changes to north-northeast. Flow is channeled up the permeable portion of the Rimbey-Meadowbrook reef trend within a relatively narrow conduit that is defined in the west by the edge of the Cooking Lake platform margin and in the east by the limit of the dolomitized part of the Cooking Lake Formation (Amthor et al., 1993). Lateral up-dip fluid flow in the Rimbey-Meadowbrook reef trend continues northward past the limits of this study area, covering over 300 kilometres of the basin (Hitchon, 1969; Hugo, 1990; Paul, 1994). Hydraulic heads decrease very slowly up the reef trend at an average gradient of approximately 0.0014 (50 metres/35 kilometres). Even with such low gradients, average flow rates on the order of 0.6 metres/year are possible because of the relatively high permeability of these carbonates (Hugo, 1990; Paul, 1994).

The origin of the unusually high fluid potentials in the southwest corner of the study area is unknown at the present time. There appears to be some association between these high fluid potentials and the zero edge of the underlying Swan Hills Formation platform margin (Figure 4.6). Unfortunately, there are no DST pressures available from the Swan Hills Formation in the study area. However, initial field pressures are of the magnitude of the fluid potentials in the Swan Hills Formation. It is possible, therefore, that the presence of a Swan Hills reef could have caused thinning of the Waterways aquitard, thus creating a permeable connection between the Swan Hills reef and the overlying Cooking Lake aquifer.

High potentials in the southwest drop quickly in a series of rapid decreases of fluid potential that take place over a distance of approximately 20 kilometres. Such tightly grouped contours of hydraulic head reflect the rapid loss in hydraulic energy across the shale barriers that exist in the Cooking Lake Formation between the Ricinus reefs and the "west" Strachan buildup (Figures 4.2 and 4.6). It appears that once fluids reach the main part of the reef trend near Chedderville (Figure 4.2) they enter a hydraulically continuous pathway through the Cooking Lake platform margin and travel up dip throughout the rest of the study area.

In contrast to the generally lateral flow system in the Rimbey-Meadowbrook reef trend, fluid flow directions in the Bashaw reef complex are generally vertical, as indicated by a combination of the fluid potential data (Figure 4.6) and pressure-depth (p[d]) plots. Over most of the Bashaw reef complex, values of hydraulic head are relatively uniform, and fall between 700 and 750 metres (Figure 4.6). Pressure-depth plots constructed in the Bashaw reef complex indicate vertical fluid flow in the Leduc aquifer, as measured vertical pressure-gradients in the Leduc aquifer of 13.4 kPa/m exceed the density-corrected nominal value (11.2 kPa/m), indicating upward flow (Tóth, 1978; Paul, 1994). Areas of closed fluid potential, such as those located in Township 39, Range 22 W4 or Townships 38-39, Range 24 W4 (Figure 4.6), thus reflect areas where significant vertical flow components are present.

West of the Bashaw complex, close to the fifth meridian (Figure 4.6), hydraulic heads in the Cooking Lake aquifer reach values up to 860 metres, that is, about 100 metres higher than potentials in the Leduc aquifer within the Bashaw complex. Potentiometric surface maps constructed using only pressure data from the Cooking Lake aquifer reveal that hydraulic heads in the lower part of the Cooking Lake-Leduc aquifer are higher, in general, than heads in the overlying Leduc Formation reefs (not shown). This is in agreement with the p[d] data that indicate upward vertical flow in this area. Thus, the mapped lower potentials in the Leduc aquifer at Bashaw are due to a reduction in the higher hydraulic heads in the Cooking Lake aquifer by the strong vertical flow. The area of high fluid-potential gradient parallel to the Rimbey-Meadowbrook reef trend along the fifth meridian appears to be related to the edge of the permeable conduit in the Rimbey-Meadowbrook reef trend.

The final feature of note in the potentiometric surface of the Cooking Lake-Leduc aquifer is the relatively-rapid eastward decrease in fluid potentials between the Bashaw reef complex and the Fenn-Big Valley complex in the southeastern corner of the study area. It appears that hydraulic heads in the Leduc aquifer decrease to values under 500 metres in the Fenn-Big Valley reef. It is not known if these are real values or some artifact. Since the Fenn-Big Valley field lies along the boundary of the study area, it is possible that the PID culling algorithm is not sufficiently robust to remove bad data points. In view of the possible uncertainly of these features, fluid flow in this area was not considered further.

4.5.1.2 *Nisku aquifer*

Hydraulic heads in the Nisku aquifer range from over 750 metres over the Bashaw reef complex, to values under 450 metres in the northwest corner of the study area (Figure 4.7). Similar to the underlying Cooking Lake-Leduc aquifer, there are two distinct areas of fluid flow in the Nisku aquifer based on the outline of the underlying Leduc Formation in the Bashaw reef complex. Where the Bashaw reef complex underlies the Nisku aquifer there is a mounding of hydraulic heads in the potentiometric surface of the Nisku aquifer and horizontal flow directions in the Nisku aquifer radiate outwards over the area of the underlying reef complex (Figure 4.7). As mentioned above, pressure-depth plots indicate vertical fluid flow from the Leduc aquifer upward into the Nisku aquifer (Paul, 1994). Several localized highs in the potentiometric surface near the centre of the Bashaw reef complex indicate excellent communication with the higher-potential Leduc aquifer beneath.

The area of flow in the Nisku aquifer is a regional system that covers the study area outside of the Bashaw complex. Fluid flow is generally up dip, from values of fluid potential greater than 600 metres in the southwest, to values less than 450 metres in the northeast corner of the study area.

Flow directions in the Nisku aquifer are controlled by the degree of connection with the underlying Cooking Lake-Leduc aquifer. Given the higher fluid-potentials in the Cooking Lake aquifer, the dominant control on fluid potentials in the Nisku aquifer appears to be the thickness of the Ireton aquitard between the Nisku and Leduc-Cooking Lake aquifers. Where the Ireton aquitard is thinner over the Leduc reefs, a preferential pathway is provided for fluids to move upward from the Cooking Lake-Leduc aquifer into the Nisku aquifer. Over the Bashaw complex, the Ireton aquitard is generally less than 25 metres thick (Figure 4.8), and in several places it is absent (Table 4.1). These are the areas of vertical hydrocarbon escape from the Leduc aquifer. Where the Ireton aquitard is thicker, as over the Rimbey-Meadowbrook reef trend, the higher potentials in the Cooking Lake-Leduc aquifer do not lead to increased hydraulic heads in the Nisku aquifer. Hence, where not affected from below by the Cooking Lake-Leduc aquifer, regional flow in the Nisku aquifer is generally up dip.

4.5.2 <u>Hydrochemistry</u>

The chemical characteristics of formation waters were examined by plotting distributions of major ions and of total dissolved solids (TDS) for the different aquifers under consideration.

4.5.2.1 *Cooking Lake-Leduc aquifer*

Formation waters from the Cooking Lake-Leduc aquifer are Na-Ca-Cl brines (Connolly et al., 1990). They are the most concentrated waters found in the study area with average TDS values of 205,000 mg/l. There is little variation and no systematic areal distribution in the dissolved solids concentration across the study area (not shown), with all 269 samples in the range of 183,00 and 227,000 mg/l TDS. Chloride is the dominant anion in the samples. Sodium and potassium are the dominant cations, but as is typical for Cooking Lake-Leduc waters in the basin, a significant proportion of the cations are made up of calcium. Average ratios of reacting value of sodium to reacting value of chloride (rNa/Cl) are 0.65, indicating deep subsurface conditions, possibly stagnant, and favorable for the preservation of hydrocarbon accumulations (Collins, 1975). Connolly et al. (1990) propose that these brines originated as sea water that was concentrated by evaporation beyond halite solution, then diluted by varying degrees with meteoric water.

4.5.2.2 *Nisku aquifer*

Formation waters of the Nisku aquifer, although similar to the underlying Cooking Lake-Leduc waters, are typically less concentrated. Total dissolved solids for the Nisku aquifer average 181,000 mg/l. There is a fairly large range in concentrations across the study area, with values falling between 120,000 and 211,000 mg/l (Figure 4.9). Proportionally, the formation waters of the Nisku aquifer contain slightly less calcium than those in the Cooking Lake-Leduc aquifer, which likely indicates a slightly different origin and dilution history (Connolly et al., 1990).

There are several areas with closed salinity contours, indicating high-salinity plumes or dilution (Figure 4.9). High-salinity plumes in the Bashaw reef complex appear to coincide with areas of thin or nearly absent Ireton aquitard (Figure 4.8). Further, given that the formation waters in the Cooking Lake-Leduc aquifer are more saline and have higher fluid potentials than those in the Nisku aquifer, the plumes in the Nisku aquifer are probably caused by upward migration of Leduc aquifer brines across an ineffective Ireton aquitard.

The observed saline plumes (TDS concentrations over 200, 000 mg/l) above the Rimbey-Meadowbrook reef trend appear to be anomalous, in that no thinning of the Ireton aquitard has been mapped in these parts of the study area. The large plume around Range 4

W5M Townships 36-40 (Figure 4.9) can be explained by examination of the isopach map of the Ireton aquifer (Figure 4.8) which shows the Ireton aquitard thinning towards the south in the area of Townships 4-5 and 8. Hence, a breach of the Ireton aquitard just south of the study area could provide the necessary conduit for Leduc aquifer brines to enter the Nisku aquifer and move northward, thus creating the plume in the Nisku aquifer. This mechanism of lateral migration from a breach outside the study area could also be invoked to explain the single concentration of TDS over 200,000 mg/l in Township 38 Range 10 (Figure 4.9). The origin of the higher than average values of salinity in Township 45 Range 5 W5M (Figure 4.9) is unknown at this time. They could indicate an as-yet unfound thin area in the Ireton aquitard, or they could indicate direct migration through the thick Ireton aquitard.

The areas of lower than average TDS concentrations are also problematic. Large areas to the southeast, east, and northeast where the TDS concentrations are as low as 120,000 mg/l are found (Figure 4.9). The observed dilution of "typical" Nisku formation-water may result from mixing with fresher waters of the Cretaceous formations, considering the proximity to the Cretaceous subcrop (Figure 4.5b) in that area as has been suggested by Paul (1994). At present, no explanation exists for the origin of the relatively dilute formation water samples in the north-central part of the study area.

4.5.3 Saline Plumes Created by the Ascending Flow System

As shown in the previous sections, the general flow direction of formation fluids differs in each reef complex. In the Rimbey-Meadowbrook reef trend, flow is directed laterally up dip in a confined conduit that covers a large part of the WCSB. In the Bashaw reef complex, however, ascending cross-formational flow prevails from the Cooking Lake-Leduc aquifer into the overlying Nisku aquifer.

The Ireton aquitard plays a key role in controlling the observed disparity in the flow directions in the two reef trends. In the Rimbey-Meadowbrook reef trend where the Ireton aquitard is greater than 30 metres thick (Figure 4.8), the lowest hydraulic-potential pathway is along the reef trend, up dip toward the subcrop of the Devonian formations in northern Alberta (Hitchon, 1969, 1984; Hugo, 1990; Paul, 1994). In contrast, throughout the Bashaw reef complex the Ireton aquitard is almost always less than 25 metres thick, and in many locations it is less than one metre thick. In the Bashaw reef complex the Ireton aquitard consists of fairly permeable argillaceous carbonates and marls (M. Hearn, personal communication). The greatly thinned Ireton aquitard permits upward cross-formational fluid migration in the Bashaw reef complex.

A second result of the ascending flow in the Bashaw reef complex is the creation of a saline plume in the Cretaceous Mannville Group aquifer (MGA). The MGA is the next major hydrogeologic group in the Phanerozoic section above the UDHG (Figures 4.4 and 4.5). Mapped distributions of concentrations of total dissolved solids in the MGA range from 20,000 to 150,000 mg/l across the study area (Figure 4.10). There is a general trend of increasing TDS concentrations from southwest to northeast, with the highest values clustered in the northeast corner of the study area. There appears to be a mixture of two types of formation waters in this aquifer. The first type of water is characterized by TDS values between 20,000 and 60,000 mg/l and is referred to as "typical" Mannville formation water, similar in chemical composition to waters found elsewhere in the Mannville Group in the WCSB (Connolly et al., 1990; Cody and Hutcheon, 1994; Abercrombie et al., 1994). The second type of formation water in the MGA is a saline plume that is characterized by much higher TDS concentrations. Total dissolved solids in the saline plume generally exceed 100,000 mg/l, with some values up to 150,000 mg/l.

The saline plume in the MGA owes its origin to the ascending flow in the Bashaw reef complex and the nature of the subcrop of the UDHG beneath the Mannville Group. The Wabamun Group aquitard forms the uppermost hydrostratigraphic unit in the Devonian, and separates the UDHG from the MGA (Figure 4.5). In the northeast corner of the study area, the Wabamun Group aquitard subcrops the Mannville Group aquifer. In the subcrop area the aquitard is reduced in thickness from over 200 metres to under 60 metres. Hence, thinning of the Wabamun Group aquitard provides the pathway for the vertically-ascending Devonian waters to pass upward into the Mannville Group aquifer. Considering that erosional thinning in itself does not change the hydraulic properties of a rock, the Wabamun Group aquitard may have become more permeable in two ways: thinning may have rendered the rocks more brittle, and thus more susceptible to later fracturing; or, the aquitard may have become more permeable via intercrystalline dissolution caused by unconformity-derived formation waters.

Further evidence for a Devonian origin to the saline plume in the Mannville Group aquifer is obtained from: 1) comparison of the chemical compositions of the different waters indicating a Devonian origin; 2) further analysis of p[d] plots in the saline plume area of the MGA; and 3) organic geochemical analyses of produced oils from Mannville Group reservoirs in the Provost Field (east of the study area), that point towards a significant component of Devonian-sourced hydrocarbons intermixed with Mannville Group oils (Riediger et al., 1994). If Devonian hydrocarbons reached the MGA, then other formation fluids including, water and gas, could follow similar pathways.

4.5.4 Hydrocarbon Trapping

The organic-rich lime mudstones of the Duvernay Formation (stratigraphic position shown on Figure 4.4) have been identified as the source rock responsible for the generation of most, if not all, of the hydrocarbons found in the Upper Devonian strata of west-central Alberta (Stoakes and Creaney, 1984, 1985; Creaney and Allan, 1990; Allan and Creaney, 1991; and others). Source rock maturity studies have shown the Duvernay Formation to be mature in the Bashaw reef complex, with the exception of an immature area at the northern-most tip of the complex. There is a trend toward increasing maturity to the west and south, with the onset of the overmature zone roughly located at the base of the Rimbey-Meadowbrook reef trend. (Stoakes and Creaney, 1984). Oil to source-rock correlations have demonstrated long distance (> 100 kilometre) secondary migration up the Rimbey-Meadowbrook reef trend and cross-formational migration of Duvernay Formation oils into overlying Nisku Formation reservoirs in the Bashaw reef complex (Creaney and Allan, 1990; Allan and Creaney, 1991).

The Duvernay Formation is present in inter-reef areas throughout the study area where it lies directly above the Cooking Lake aquifer. This connection with the Cooking Lake-Leduc aquifer provides a pathway for mature hydrocarbons to be expelled from the source rock into the aquifer. Once in the Cooking Lake-Leduc aquifer, hydrocarbons are distributed through the aquifer under the influence of buoyancy and water flow, including trapping in Leduc reefs. However, in order for Duvernay-sourced oils to be present in Nisku Formation reservoirs, hydrocarbons must cross the Ireton aquitard. Thus, the Ireton aquitard plays a key role in oil migration in the two reef trends.

4.5.4.1 *Bashaw reef complex*

Given the ascending flow in the Bashaw reef complex, the critical control on trapping in both the Leduc and Nisku formations appears to be the thickness of the intervening Ireton aquitard. In this study, the term "Ireton aquitard" is used to refer to Ireton-aged tight shale or marl strata that exist between the top of the Leduc or Cooking Lake Formations and the base of the Nisku Formation or Camrose Member, whichever is present in a particular well. It must be pointed out that an absence of the Ireton aquitard does not necessarily imply an absence of the Ireton Formation. The Ireton is known to change lithologically from limestones via marls to shales across the basin (Stoakes, 1980), and even within the relatively small area of the Bashaw reef complex (M. Hearn, personal communication). In the present context however, the only important aspect is whether the Ireton is present as tight shale or marl. This property can be mapped using gamma ray log-responses.

Detailed mapping of the Ireton aquitard using geophysical well logs has identified 28 wells in the Bashaw area (Table 4.1) where the Ireton aquitard is absent, creating holes or direct breaches in the Leduc Formation top-seal. It is through these holes that the vertical movement of water and hydrocarbons takes place.

A stratigraphic section through a typical "breach" in the Ireton aquitard is shown in Figure 4.11 (see Figure 4.12 for the location of this section). The northernmost well in the section (10-13-44-23 W4) illustrates a typical "off-reef" well log profile with approximately 60 metres of Nisku Formation carbonates on top of over 200 metres of Ireton Formation shale. Also visible in this well is a layer of the Camrose Member approximately five to six metres thick. Moving approximately 10 kilometres to the south, up onto the Bashaw reef complex, the next well in the section (12-10-43-23 W4M) shows a typical "on-reef" section with the top of the Leduc Formation clearly visible at the base of the well log. In the 12-10 well, the Ireton aquitard is approximately five metres thick over the Leduc Formation reef. Moving farther to the south, the next well in the section (4-16-42-23 W4M), shows a typical profile through a breach in the Ireton aquitard. Clearly the gamma ray response indicates there is no Ireton aquitard in this well. The expected position of the top of the Leduc Formation can be estimated from the well log by comparison with nearby wells. The final well in the section (16-36-41-23 W4) shows a return to the more "typical" case with approximately five metres of Ireton aquitard overlying the Leduc Formation reef. There is a distinct gamma ray marker visible at approximately 1840 metres in this well, a marker that is visible at roughly the same level in the Leduc Formation in other wells in the area. This marker is also visible in the 4-16 well, and lateral correlation confirms that the 4-16 well is indeed drilled into the Leduc Formation.

The influence of the Ireton aquitard on hydrocarbon trapping in the Bashaw reef complex can be demonstrated by comparison of the detailed isopach of the Ireton aquitard (Figure 4.12) with the distribution of hydrocarbon pools producing from the Leduc Formation (Figure 4.13). The critical value of aquitard thickness appears to be six metres.

With less than six metres of aquitard above a Leduc Formation reservoir, there appears to be an insufficient top seal to retain commercial amounts of hydrocarbons in the Leduc Formation reefs. This six metre thickness has been determined empirically by examining the detailed isopach map (Figure 4.12). Over every producing pool throughout the Bashaw reef complex (Figure 4.13) the Ireton aquitard is at least six metres thick. Although the Haynes, Clive, and Nevis fields appear to be exceptions to this rule, closer examination reveals they are not. In the Haynes field, wells are listed as completed in the "Devonian" or "D2/D3" (old terminology for Nisku/Leduc formations), according to AERCB records. Some of these wells are completed over multiple intervals and considering that there is little or no Ireton aquitard present, the formation that is actually producing is unknown. The majority of the production in the Haynes field probably is from the Nisku Formation. The apparent Leduc Formation production (with less than six metres of Ireton) from the southern tip of the Clive field is an artifact of the data distribution interacting with the computer contouring program. In fact, over the entire Clive field, the Ireton aquitard is at least six metres thick. The Nevis field is similar to the Haynes field. Most of the wells that apparently produce from the Leduc Formation in Township 39, Range 22 W4M, are listed as "Devonian" or "D2/D3" also (Figure 4.13). Careful examination of the shale isopach data and well production information combined with hand-contoured isopach maps (not shown) demonstrate that the Leduc Formation production from the Nevis field occurs where the Ireton aquitard is in excess of six metres thick. Examples in the Nevis field include wells producing in Township 40, Range 22 W4M, Township 39, Range 21 W4M, and the southernmost wells in the pool in Township 38, Range 22 W4M.

There is additional strong evidence in support of the Ireton aquitard acting only as a partially effective seal for vertically migrating hydrocarbons in the Bashaw reef complex. In the Bashaw complex, Leduc Formation reservoirs reach heights in excess of 200 metres (Figure 4.5). Yet published data on fluid contacts (Alberta Society of Petroleum Geologists, 1960, 1969) show that hydrocarbon column-heights in Leduc Formation pools rarely, if ever, exceed 65 metres. Clearly, these traps are only partially filled and this partial filling is unlikely to be caused by deficient amounts of hydrocarbons because large amounts of Duvernay Formation sourced oils are found above the Leduc Formation. This evidence therefore points to a lack of a competent Leduc Formation top seal.

Hydrocarbon distribution in the Nisku Formation in the Bashaw reef complex is further influenced by trap configuration. Structures in the Nisku Formation are associated with draping over underlying Leduc Formation reefs (Reinson et al., 1993). Closure on these drapes is assisted to some extent by up dip facies changes within the Nisku Formation. Moreover, hydrocarbon sourcing and the distribution of hydrocarbon pools in the Nisku Formation appear to be related to the thickness of the underlying Ireton aquitard that thus assumes a second control on hydrocarbon distribution. A comparison of the Nisku Formation pool-distribution map (Figure 4.14) with the isopach of the underlying Ireton aquitard (Figure 4.12) and the Leduc Formation pool-distribution map (Figure 4.13) illustrates the Ireton aquitard control on trapping at both stratigraphic levels. Apparently, hydrocarbons migrated up from the Cooking Lake-Leduc aquifer into traps in the Nisku Formation in three ways: 1) directly through breaches in the Ireton aquitard; 2) by traversing a moderate thickness of Ireton aquitard (less than six metres); and 3) by lateral migration within the Nisku Formation from adjacent breaches in the Ireton aquitard.

Examples of Nisku Formation pools above direct breaches in the Ireton aquitard include the Haynes, Nevis, Alix, Bashaw, and Wood River fields (Figure 4.14). Each of these pools is penetrated by at least one well (see Table 4.1) where Nisku Formation carbonates lie directly on top of Leduc Formation carbonates.

The second major group of hydrocarbon pools in the Nisku Formation do not directly overlie a direct breach in the Ireton aquitard. This larger group can be subdivided into two sub-groups, based on distance and relative position (up dip or down dip) from a direct breach. The first sub-group contains pools that are located within about five kilometres and generally up dip from a breach in the Ireton aquitard. Examples include the Clive, Mikwan, and possibly Malmo and Chigwell fields (Figures 4.3 and 4.14). These fields were probably charged via a two-stage process of migration through a direct breach, with subsequent short-distance lateral migration and entrapment. A second scenario that could act alone or in conjunction with the above two-stage process is direct migration through the Ireton aquitard. This appears possible because in most cases the Nisku Formation pools in this group overlie less than 20 metres of Ireton aquitard. Furthermore, the Ireton aquitard is very carbonate-rich in several locations and has porosities of up to several percent and much lower displacement pressures than Ireton Formation shales or clay-rich marls (M. Hearn, personal communication).

The second sub-group of Nisku Formation pools is located more than 10 kilometres from, and/or down dip of, a direct breach. Examples include Joffre, Lacombe, New Norway, Duhamel, and possibly Hillsdown and Penhold fields. Possible charging scenarios for this sub-group are similar to those previously discussed, with one addition. It is possible that these pools where charged via a hitherto unfound breach in the Ireton aquitard. Direct hydrocarbon migration through the Ireton aquitard is harder to envisage because in most cases the underlying aquitard is greater than 20 metres thick and carbonate-poor (Figures 4.12 and 4.14). Hence, the charging scenario most likely for this sub-group is relatively long-distance lateral migration, either up dip from known breaches (e.g., New Norway, Duhamel), or up dip from unfound breaches within or outside the study area (e.g., Joffre, Lacombe, Penhold).

4.5.4.2 *Rimbey-Meadowbrook reef trend*

Trapping conditions in the Rimbey-Meadowbrook reef trend are quite different from those in the Bashaw reef complex. In the main part of the reef trend, that is, from north of Township 38 across the study area to Township 49, Leduc Formation reefs are filled to their spill points (Stoakes and Creaney, 1984; Barfoot and Ko, 1987), an observation leading in part to the development of the well-known model of differential entrapment

(Gussow, 1954). In this model, oil and gas migration occurs over long distances by a mechanism of buoyancy-driven flow. Trapping occurs when the up dip migrating hydrocarbons encounter antiformal traps with impermeable top seals. The first trap encountered in a reef trend is filled to its spill point, and additional oil migrates up dip to be trapped there. The Rimbey-Meadowbrook reef trend has been widely cited as a "classic" example of differential entrapment (Gussow, 1954; Creaney and Allan, 1990).

North of Township 38, hydrocarbon columns exceed 200 metres in some of the Leduc Formation reefs (Alberta Society of Petroleum Geologists, 1960, 1969; Barfoot and Ko, 1987). Over those same reefs, the Ireton aquitard top seals are always thicker than 35 metres (Figure 4.8). Considering that the potential oil column heights in the Rimbey-Meadowbrook reef trend and in the Bashaw reef complex are roughly the same, the much greater pooled columns in the Rimbey-Meadowbrook reef trend are clearly related to the much greater thickness of the Ireton aquitard. Thus, the trapping of hydrocarbons in the Leduc and Nisku formations in both parts of the study area is controlled, albeit in different ways, by the thickness of the intervening Ireton aquitard.

In the lower part of the Rimbey-Meadowbrook reef trend below Township 38, there is a gradual thinning of the Ireton aquitard towards the south. Ireton aquitard thicknesses are reduced in places to under five metres along the southern boundary of the study area (Figure 4.8). Therefore, there are no Leduc Formation pools in these areas because of the thinned Ireton aquitard and partly because of a lack of closed structures. Closed structures, such as in the Lanaway and Sylvan Lake fields (Figure 4.2), are associated with intermediate values of Ireton aquitard thickness (Figure 4.8). Not surprisingly, these pools are not filled to their spill points (Alberta Society of Petroleum Geologists, 1960, 1969). For other Leduc gas fields in the lower part of the reef trend, such as Ricinus, Ricinus West, and Chedderville, there is inadequate information available to compare hydrocarbon column heights to shale thicknesses. Furthermore, there is some indication that certain pools in the extreme southwestern edge of the Rimbey-Meadowbrook reef trend may not be connected to the main Cooking Lake aquifer (Eric Mountjoy, personal communication, 1994).

Hydrocarbon pools in the Nisku Formation above the lower part of the Rimbey-Meadowbrook reef trend are few in number and widely dispersed (Figure 4.3), although north of the study area, large volumes of hydrocarbons are trapped in Nisku Formation pools above the Leduc Formation reefs of the trend (Gussow, 1954; Reinson et al., 1993). Source-rock studies (Creaney and Allan, 1990; Allan and Creaney, 1991; Creaney et al., 1994) indicate the only Nisku Formation source in the WCSB capable of generating significant quantities of hydrocarbons is the Cynthia Member. However, it is unlikely that the hydrocarbons in the Nisku Formation in this study area are sourced from the Cynthia Member because this hydrocarbon source is located 50 to 100 kilometres northwest of the study area. In order for Cynthia Member sourced oil to reach fields at Lanaway and Sylvan Lake, it would have to migraie a significant distance down dip, against the active regional flow system in the Nisku aquifer, which is unlikely. Thus it appears the hydrocarbons in the Nisku Formation above the Rimbey-Meadowbrook reef trend are sourced from the Duvernay Formation and they must have migrated across the Ireton aquitard.

The exact nature of the cross-formational migration of Duvernay-sourced oils into the Nisku Formation remains unknown. However, two possible scenarios can be envisaged, each with its own implication for future hydrocarbon exploration in the study area. In the first case, it may be that hydrocarbons have migrated directly through the Ireton aquitard. Davis (1972) argued that shale-density anomalies abovc Leduc Formation reefs were created by solutes precipitated out of fluids passing upward into the Nisku Formation. Rostron (1993) argued that the anomalous distribution (compared to Gussow's model) of hydrocarbon fluids and pools further up the reef trend could be explained by a mechanism of "leaky" reefs and localized variations in the capillary properties of the top seals above individual reefs. Although cross-formational migration of hydrocarbons seems unlikely given a shale aquitard over 35 metres thick and Leduc Formation reefs that are filled to their spill points, there are no published hydraulic data to refute this possibility. Fractures in the Ireton aquitard may also play a role in assisting the migration of fluids across the aquitard.

The more plausible explanation for the Nisku Formation oils above the Rimbey-Meadowbrook trend is cross-formational migration through hitherto unfound breaches in the Ireton aquitard. Considering the thinning of the Ireton aquitard south of the study area (Figure 4.8), it is possible that there are one or more breaches in the Ireton aquitard south of the study area. Hydrocarbons could have entered the Nisku Formation there, and then migrated up dip under buoyant and hydrodynamic forces.

In either case, the Nisku Formation above the reef trend remains an excellent exploration target for hydrocarbons. If hydrocarbons have migrated or are migrating across shales above Leduc Formation reefs, then the Nisku Formation above all Leduc reefs in the reef trend should be examined. If, on the other hand, there is an unknown breach in the Ireton Formation to the south of the study area, Duvernay-sourced oils likely spilled into the Nisku Formation across most of the southwest corner of the study area. There is a fairway in the Nisku Formation defined by a parallelogram bounded by the reef trend, perpendicular to the Minnehik-Buck Lake pool, and southwest to the edge of the study area. The unknown breach could also have been responsible for sourcing the Joffre and Hillsdown pools in the Bashaw complex, which would indicate Duvernay Formation charging to potential Nisku Formation reservoirs east of the reef trend as well.

4.6 CONCLUSIONS

1) Upper Devonian strata in west-central Alberta constitute one large-scale hydrogeologic group called the Upper Devonian Hydrogeologic Group (UDHG). This group comprises two major aquifers, the Cooking Lake-Leduc and Nisku aquifers, that are separated by the Ireton aquitard. Flow in the UDHG is confined between the Wabamun Group and Waterways aquitards. Two of the large-scale reef trends that extend across the basin, the Rimbey-Meadowbrook reef trend and Bashaw reef complex, are located within

the Cooking Lake-Leduc aquifer. Flow in the Cooking Lake-Leduc aquifer and in the overlying Nisku aquifer is strongly influenced by the thickness of the intervening Ireton aquitard.

2) Regional-scale flow directions within each aquifer depend upon the relative positions of the reef complexes to the thickness variations in the Ireton aquitard. In the Cooking Lake-Leduc aquifer, regional flow is directed laterally up the Rimbey-Meadowbrook reef trend to the north. In contrast, fluid flow in the Bashaw reef complex is dominantly ascending, out of the Leduc reefs into the overlying strata. Regional flow in the Nisku aquifer is up dip towards the northeast, except over the Bashaw reef complex where it is met from below by the ascending flow system in the Cooking Lake-Leduc aquifer.

3) The ascending flow in the Bashaw reef complex appears to be facilitated by a reduced thickness of Ireton aquitard. Geologic mapping has revealed 28 wells in the Bashaw reef complex where the Ireton aquitard is absent. Thinning of the Ireton aquitard allows higher energy Cooking Lake-Leduc fluids to migrate vertically upward. Cross-formational flow within the study area creates plumes of Cooking Lake-Leduc formation waters in the Nisku and Mannville Group aquifers. These plumes are recognizable because of the observed salinity contrasts between "typical" Cooking Lake-Leduc, Nisku, and Mannville Group formation waters.

4) Hydrocarbon trapping in both the Leduc and Nisku formations is related to the thickness of the Ireton aquitard. Correlations between shale thickness and hydrocarbon pools reveal:

i) with less than six metres of Ireton aquitard there are no pools in the Leduc Formation;

ii) with greater than six metres of Ireton aquitard, trapping occurs in the Leduc Formation, but the traps are not filled to their spill points and there is upward leakage of hydrocarbons;

iii) one group of hydrocarbon pools in the Nisku Formation is located directly over breaches in the Ireton aquitard;

iv) a second group of hydrocarbon pools in the Nisku Formation is located up dip less than five kilometres from direct breaches in the Ireton aquitard; these pools are presumably filled by short distance lateral migration after cross-formational migration or by migration through the Ireton aquitard;

v) a third group of pools in the Nisku Formation is located down dip of direct breaches; these pools are either sourced by unknown breaches farther down dip, or by cross-formational migration through the Ireton aquitard.

5) In the Rimbey-Meadowbrook reef trend, hydrocarbon trapping conditions contrast those in the Bashaw reef complex. Leduc pools have substantially larger hydrocarbon columns and are generally filled to their spill points because the Ireton shale above the reefs in the main part of this trend is at least 35 metres thick. Migration and trapping generally follow Gussow's theory of differential entrapment.

6) Hydrocarbons must have migrated across the Ireton aquitard in the Rimbey-Meadowbrook reef trend because Nisku pools above Leduc reefs in the Rimbey trend contain Duvernay-sourced hydrocarbons. Thus, hydrocarbons must be able to traverse in excess of 35 metres of Ireton aquitard in at least some locations, or there are unfound breaches in the Ireton aquitard to the south of the study area.

7) Using the observations of migration and trapping from the Bashaw reef complex, it may be possible to apply the concept of vertical migration through shales to explore for other hydrocarbon traps above Leduc Formation reefs. One place could be the Rimbey-Meadowbrook reef trend.

8) Regional fluid flow and cross-formational migration play an important role in migration and entrapment in the subsurface. The use of subsurface hydrogeology and hydrochemistry can lead to a better understanding of petroleum migration and entrapment, leading to increased exploration efficiency.

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LSD-SEC-TWP-RNG MER	LSD-SEC-TWP-RNG MER
11-25-37-24 W4M	14-16-41-23 W4M
10-30-38-23 W4M	06-21-41-23 W4M
11-15-38-24 W4M	16-32-41-23 W4M
15-02-38-25 W4M	06-33-41-23 W4M
14-02-39-22 W4M	08-08-42-23 W4M
10-08-39-22 W4M	12-09-42-23 W4M
06-12-39-22 W4M	04-16-42-23 W4M
07-13-39-22 W4M	07-28-42-23 W4M
10-22-39-22 W4M	08-29-42-23 W4M
02-13-39-23 W4M	02-33-42-23 W4M
13-05-40-23 W4M	10-34-42-23 W4M
06-15-40-23 W4M	02-02-43-23 W4M
10-12-40-25 W4M	11-12-43-23 W4M
16-08-41-23 W4M	08-13-43-23 W4M

Table 4.1. Locations of Wells With Zero Thickness of Ireton Aquitard

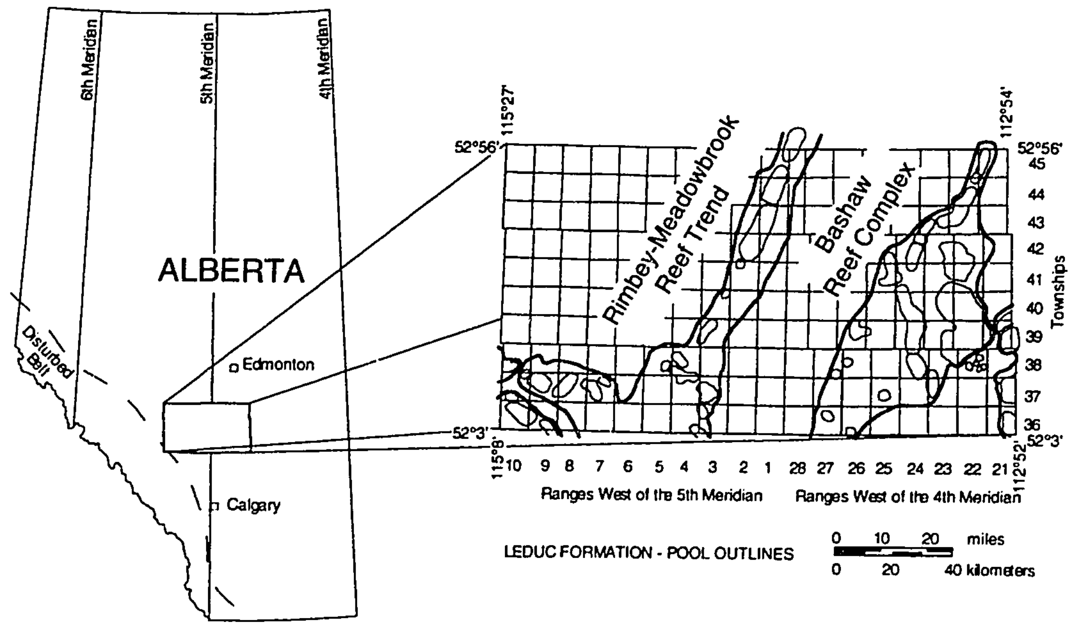

Figure 4.1. Location of the study area in west-central Alberta.

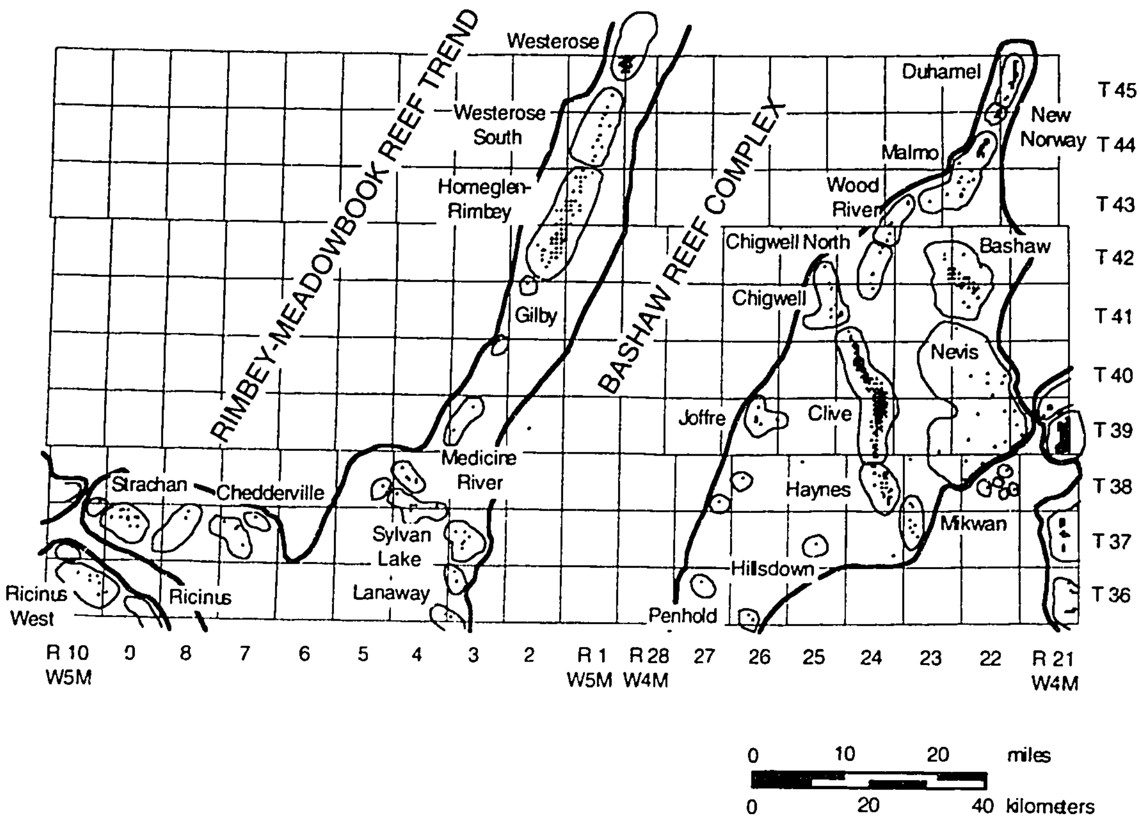

Figure 4.2. Hydrocarbon producing wells and fields in the Leduc Formation in the study area. Heavy solid line denotes the edges of the permeable portions of the Cooking Lake Formation. The western edge of the Rimbey-Meadowbrook reef trend approximates the Cooking Lake platform margin and its eastern edge is defined as the limit of the dolomitized portion of the Cooking Lake Formation. Triangles indicate hydrocarbon producing wells.

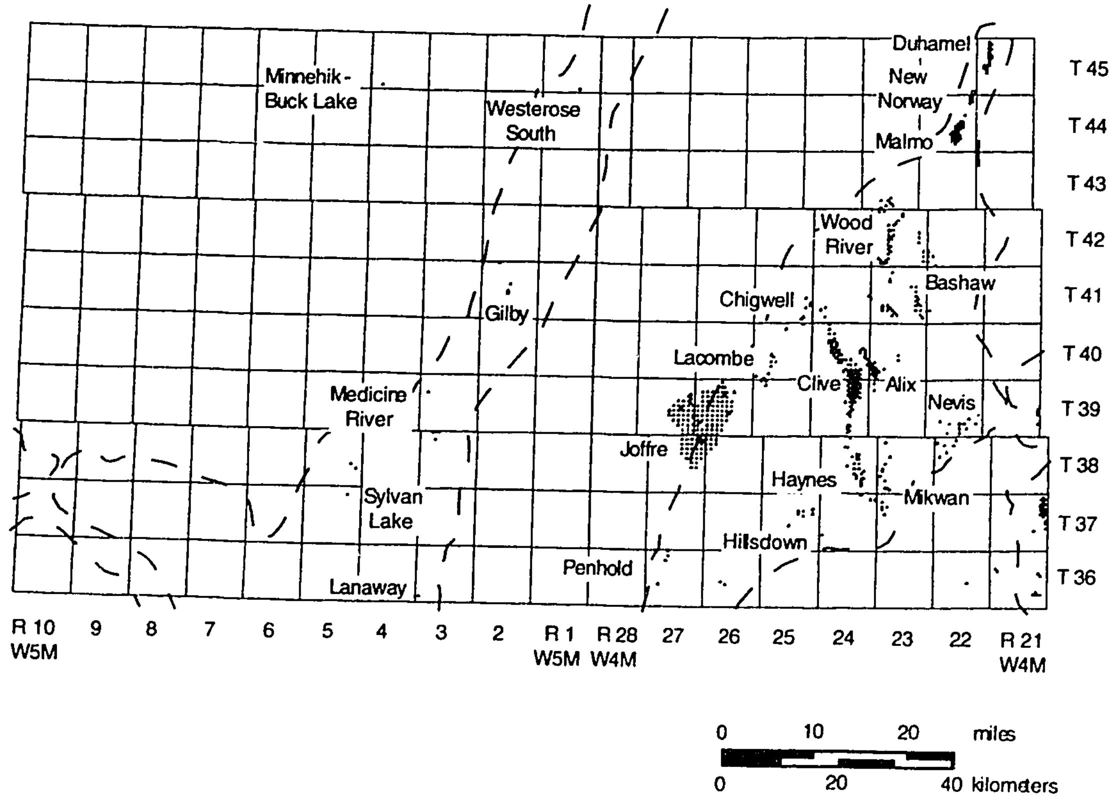

Figure 4.3. Hydrocarbon producing wells and fields in the Nisku Formation in the study area. Dashed lines indicate the outlines of the permeable portions of the underlying reef trends. Triangles indicate hydrocarbon producing wells.

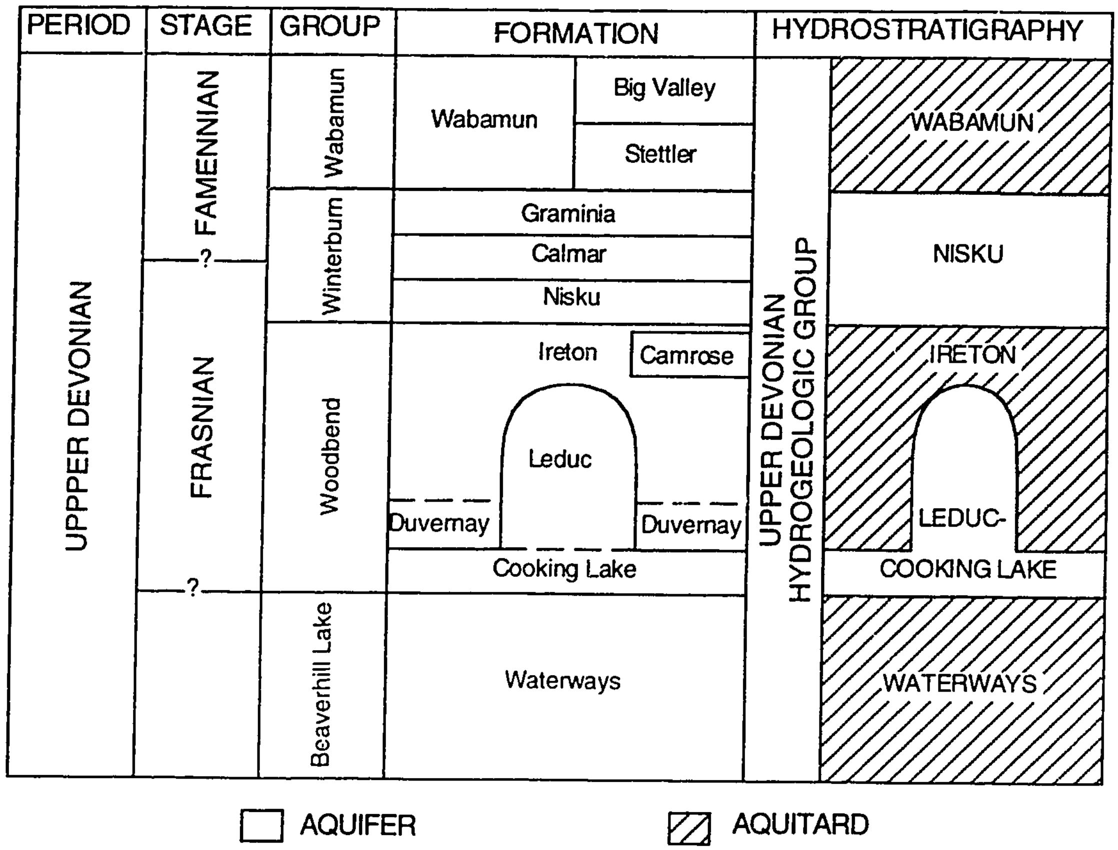

Figure 4.4. Schematic lithostratigraphic and hydrostratigraphic table for west-central Alberta.

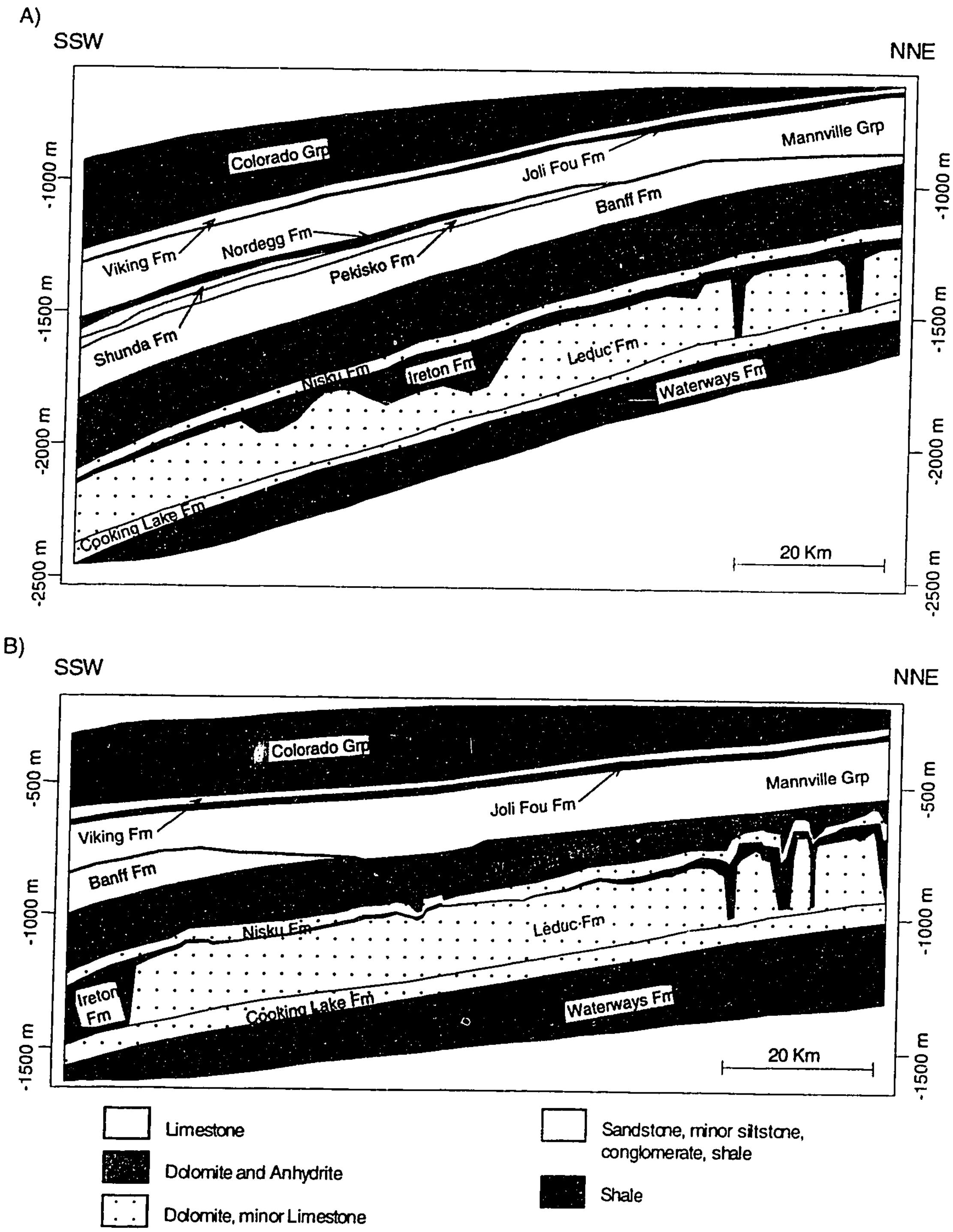

Figure 4.5. Structural cross-sections through Upper Devonian to Lower Cretaceous strata: a) Rimbey-Meadowbrook reef trend; b) Bashaw reef complex.

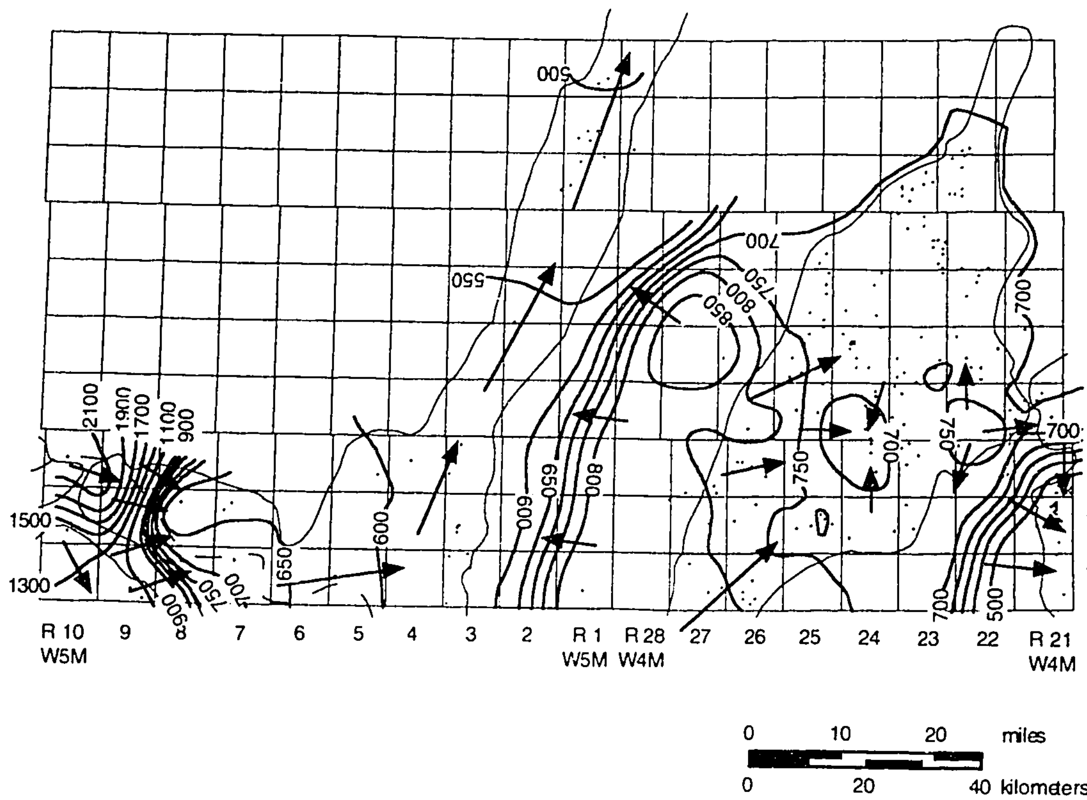

Figure 4.6. Hydraulic head distribution in the Cooking Lake-Leduc aquifer. Contour interval is variable: a) below 900 meters equals 50 meters of equivalent freshwater head; b) above 900 meters equals 200 meters of equivalent freshwater head. Dashed line indicates the limit of the underlying Swan Hills reef margin.

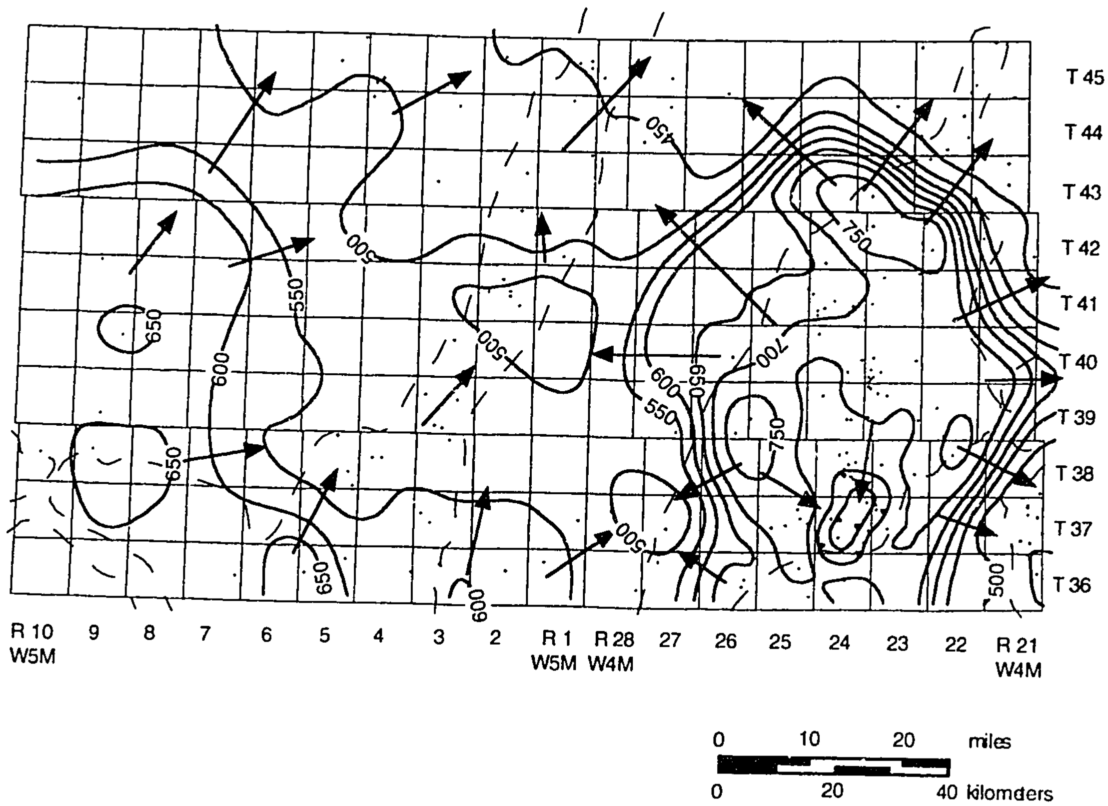

Figure 4.7. Hydraulic head distribution in the Nisku aquifer. Contour interval equals 50 meters of equivalent freshwater head. Dashed lines indicate the outlines of the permeable portions of the underlying reef trends.

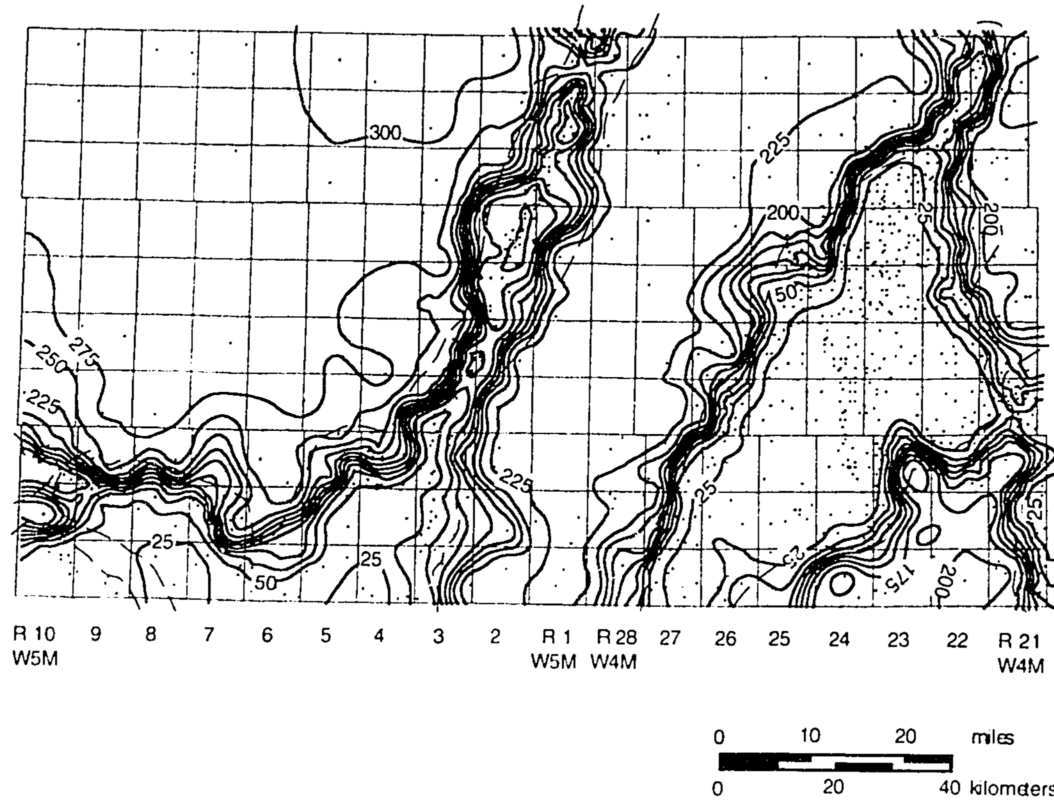

Figure 4.8. Isopach map of the Ireton aquitard. Dashed line indicates the outlines of the permeable portions of the underlying reef trends. Contour interval equals 25 meters.

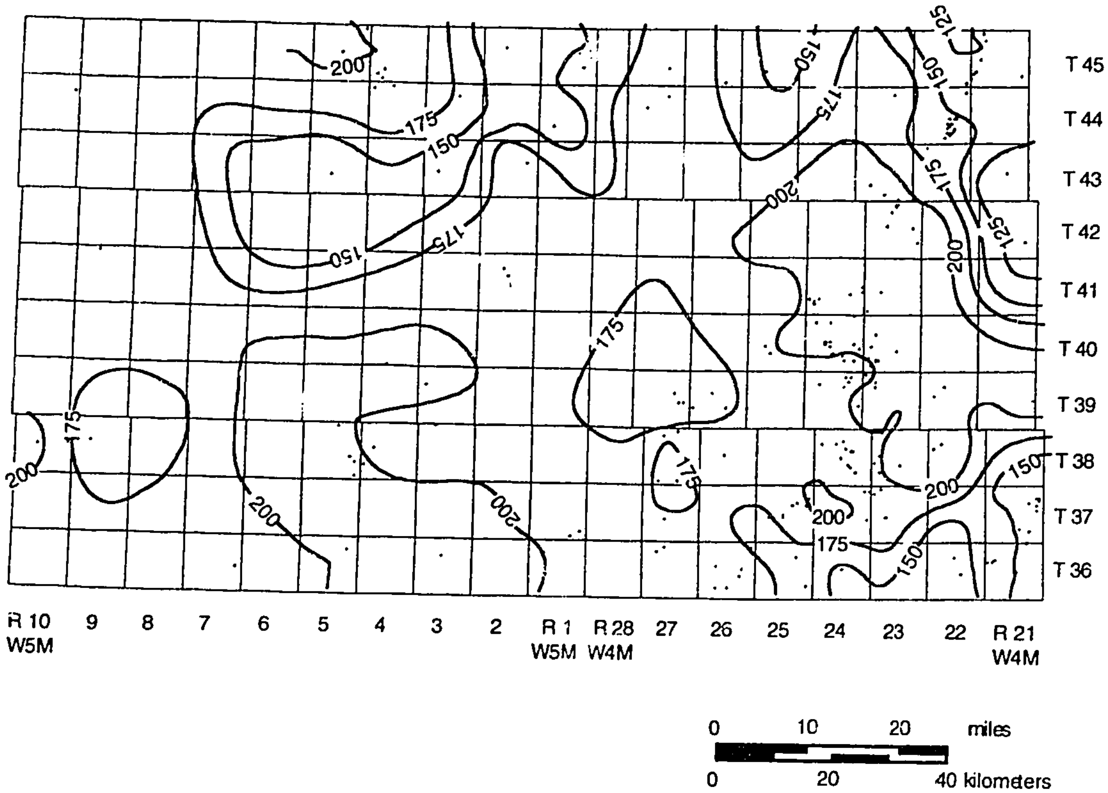

Figure 4.9. Total dissolved solids distribution for the Nisku aquifer. Labeled values are in grams per liter TDS. Contour interval equals 25 000 milligrams per liter.

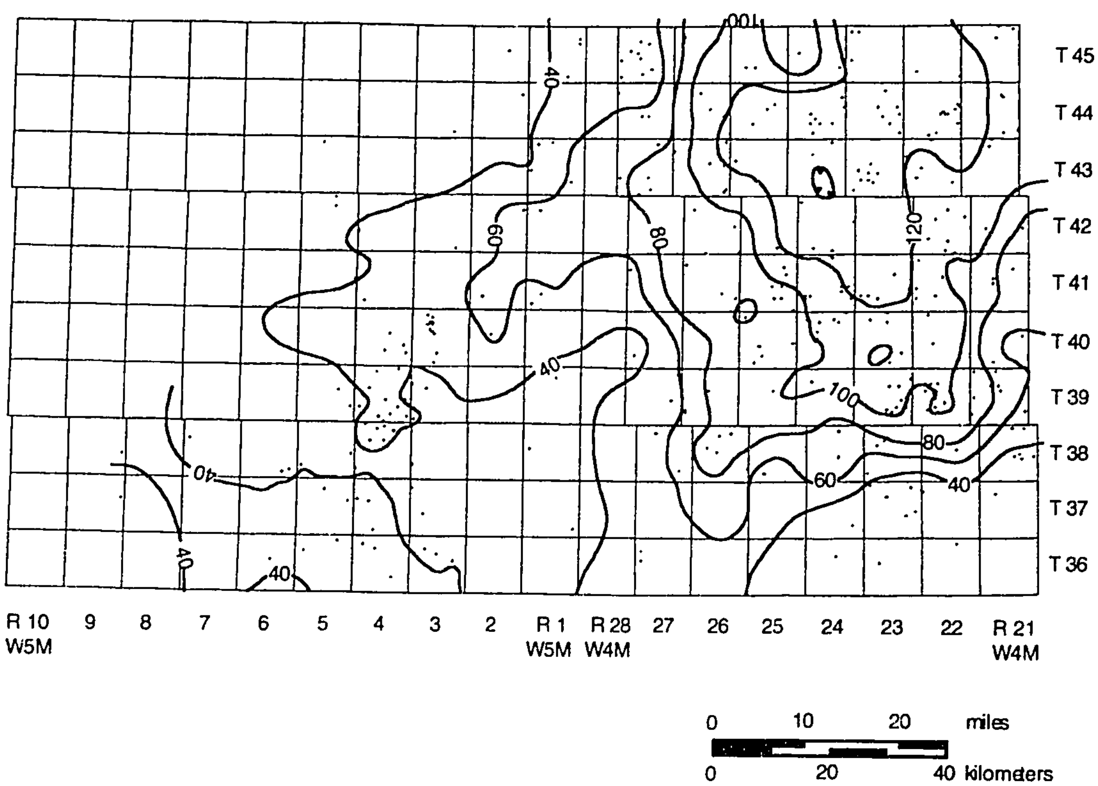

Figure 4.10. Total dissolved solids distribution for the Mannville Group aquifer. Labeled values are in grams per liter TDS. Contour interval equals 20 000 milligrams per liter.

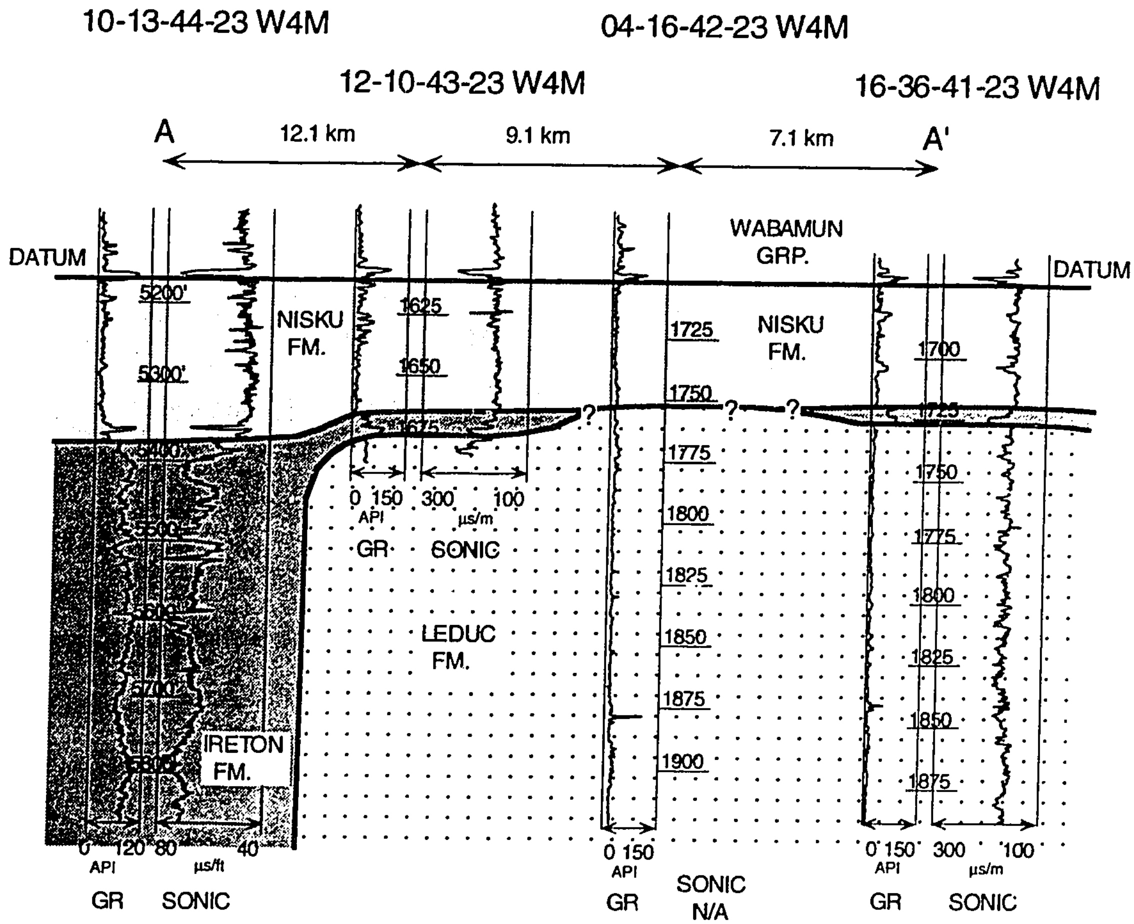

Figure 4.11. Stratigraphic well-log section through a typical breach in the Ireton aquitard. Location of the section is shown on Figure 4.12.

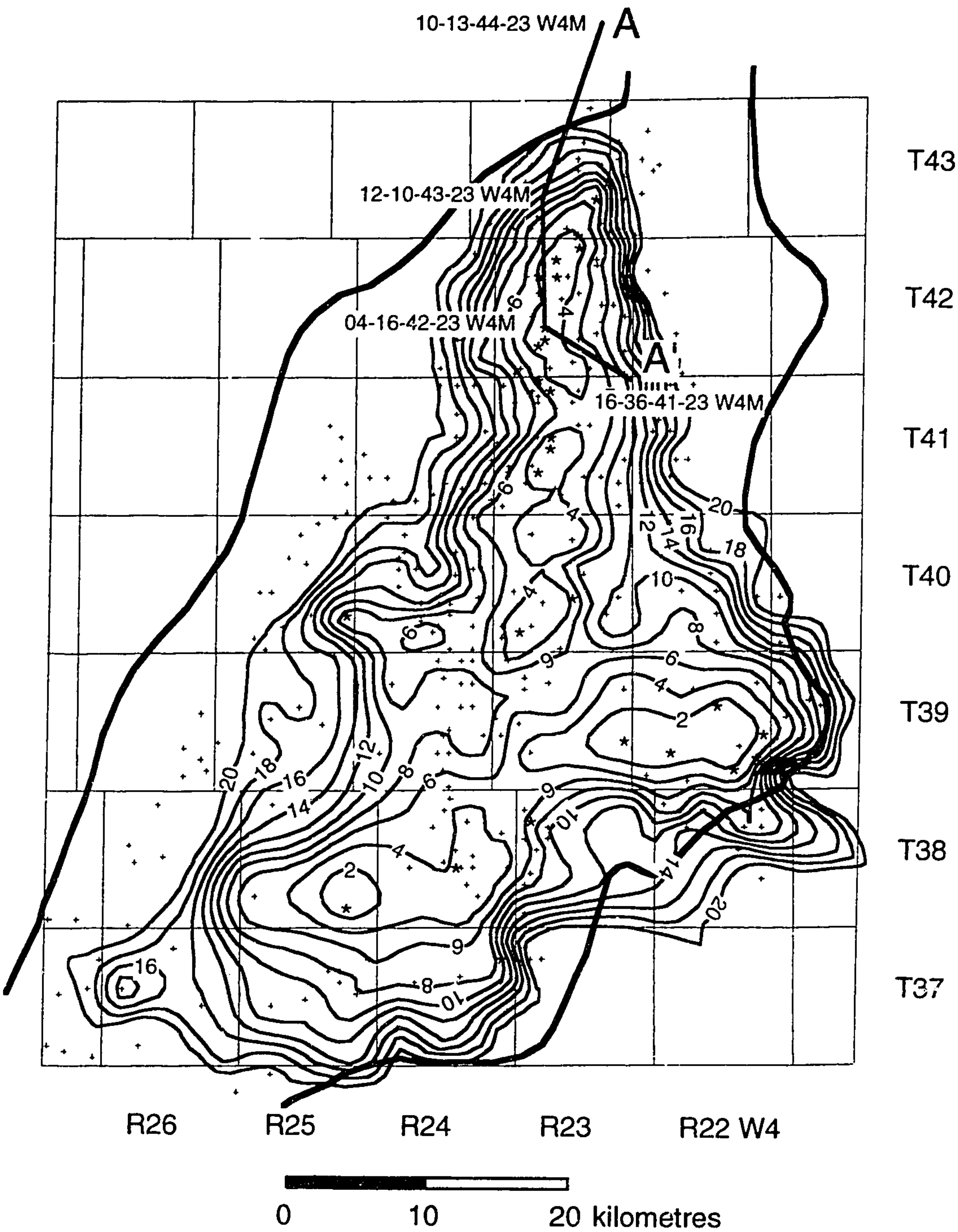

Figure 4.12. Detailed isopach map of the Ireton aquitard in the Bashaw reef complex. Heavy solid line indicates the limits of the underlying Leduc platform. Contour interval equals two meters. For clarity, only wells with a thickness less than 30 meters are shown. Asterisks indicate wells with zero thickness of Ireton aquitard.

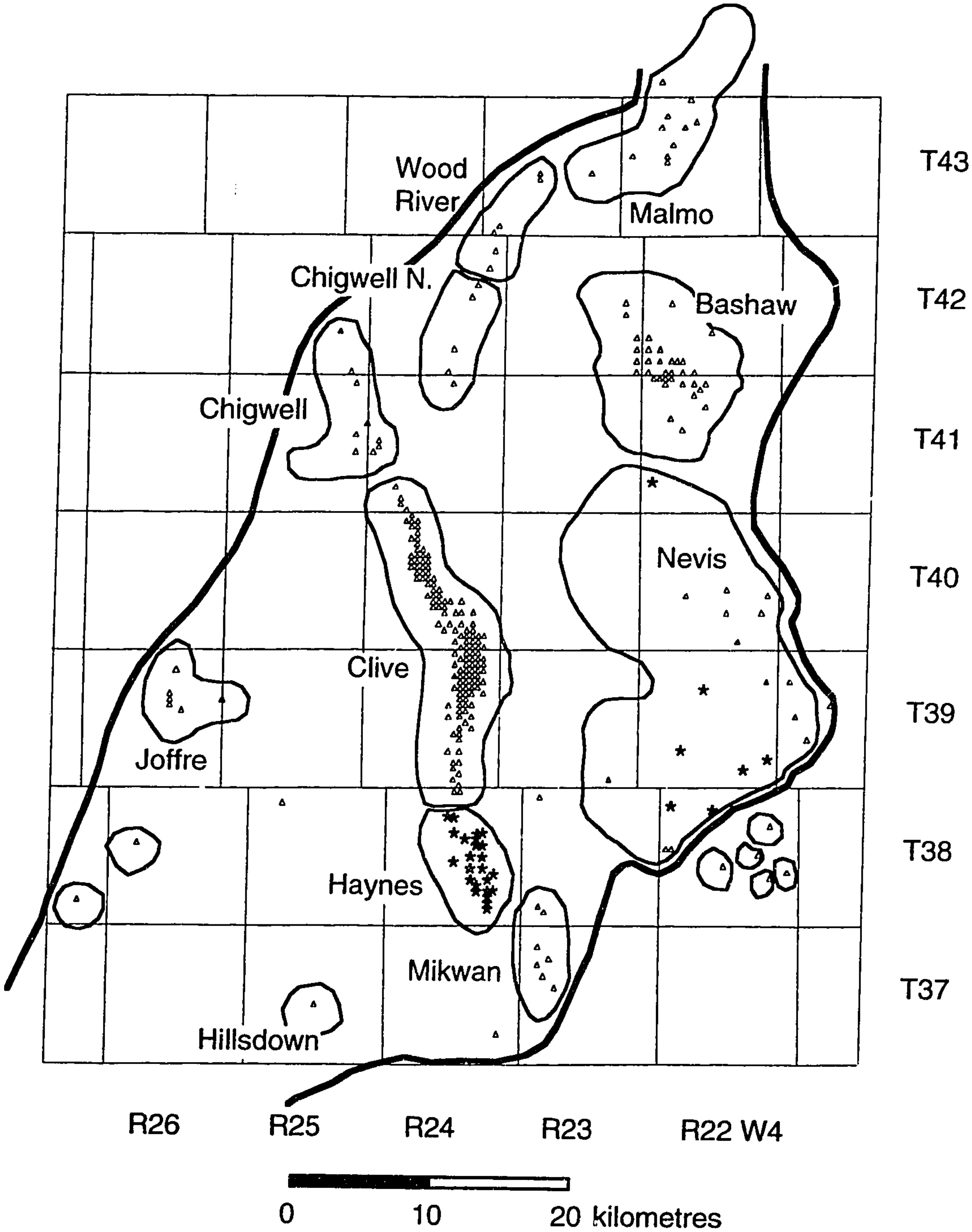

Figure 4.13. Detail of hydrocarbon producing wells and fields in the Leduc Formation, Bashaw Complex. Heavy solid line indicates the limits of the Leduc platform. Asterisks indicate wells listed as undifferentiated Devonian production ("Devonian" or "D2/D3"). Data are from the AERCB and the Alberta Society of Petroleum Geologists (1960, 1969).

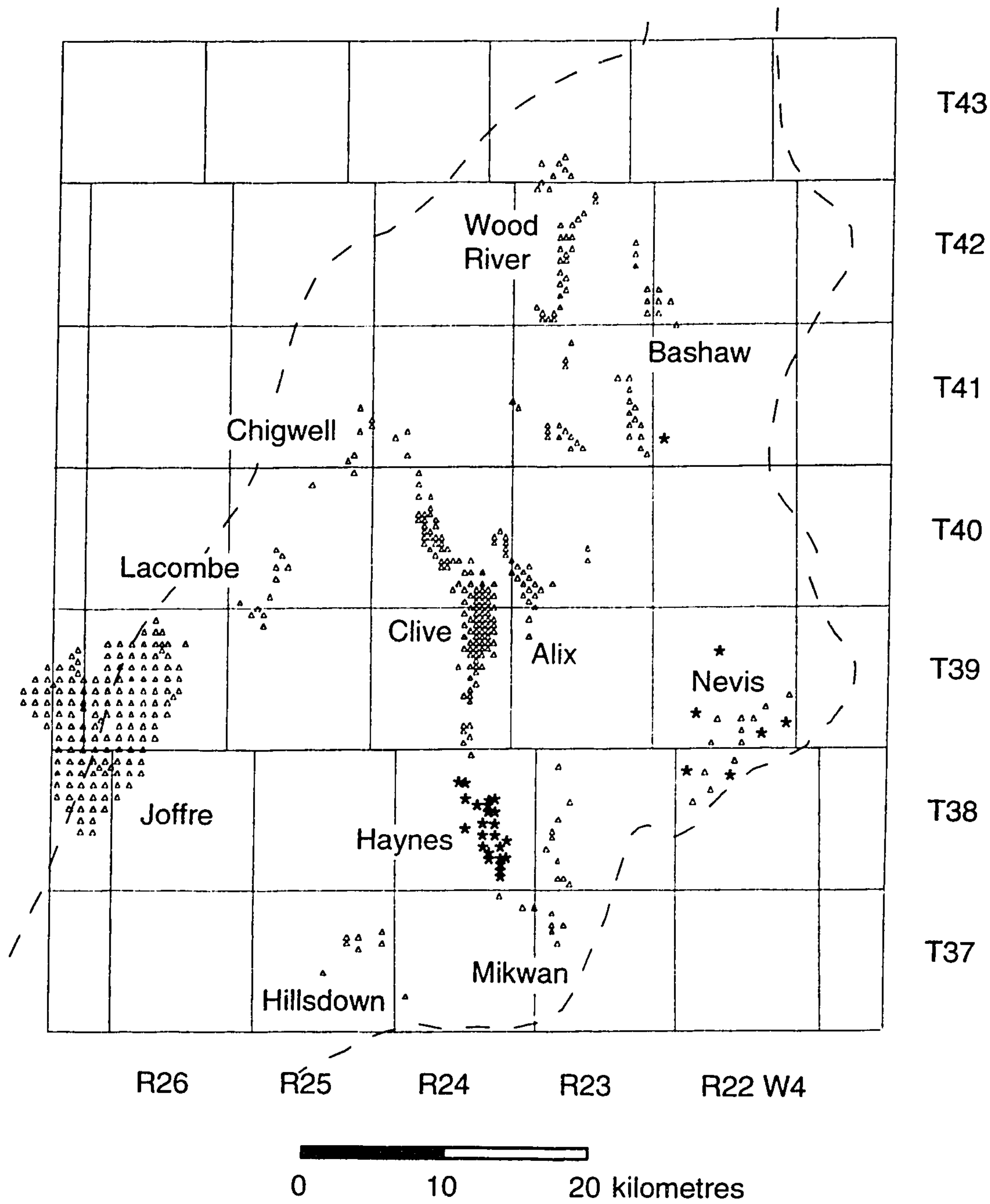

Figure 4.14. Detail of hydrocarbon producing wells and fields in the Nisku Formation, Bashaw Complex. Asterisks indicate wells listed as undifferentiated Devonian production ("Devonian" or "D2/D3"). Data are from the AERCB and the Alberta Society of Petroleum Geologists (1960, 1969).

5.0 CROSS-FORMATIONAL FLUID FLOW AND THE GENERATION OF A SALINE PLUME OF FORMATION WATERS IN THE MANNVILLE GROUP, WEST-CENTRAL ALBERTA*

5.1 INTRODUCTION

Rocks that comprise the Mannville Group and equivalent strata in the Western Canadian Sedimentary Basin (WCSB) contain some of the largest deposits of conventional and non-conventional hydrocarbon resources in the world, with reserves reported at 2.4×10^8 m^3 oil, 9.39×10^{11} m^3 gas, and 195×10^9 m^3 heavy oil, bitumen and oil sands (Porter, 1992). Geochemical evidence suggests the known source rocks within the Mannville Group are incapable of generating such immense volumes of hydrocarbons (Moshier and Waples, 1985; Creaney and Allan, 1990, 1992). Thus, a large influx of formation fluids (water, gas, and oil) into the Mannville Group must have occurred over geologic time.

Cross-formational fluid flow into the Mannville Group has been studied in the past. Previous works on fluid migration into and within the Mannville Group can be divided into two groups: those primarily concerned with tracing the origin and distribution of hydrocarbons in the Mannville Group; and those interested in quantifying the movement of formation fluids in general. To study hydrocarbon origin and distribution, researchers have used oil-source rock correlations to demonstrate that up to five source intervals have contributed hydrocarbons to the Mannville Group, including: Devonian Duvernay Formation; Mississippian Exshaw Formation; Triassic Doig and/or Montney formations; Jurassic Fernie Group and/or "Nordegg" Member; and Cretaceous Ostracode Member of the Mannville Group (Creaney and Allan, 1990, 1992; Piggot and Lines, 1991; Creaney et al., 1994; Riediger et al., 1994). These studies focused on the inferred movements of

* A version of this chapter titled "Cross-Formational Fluid Flow and the Generation of a Saline Plume of Formation Waters in the Mannville Group, West-Central Alberta" by B.J. Rostron and J. Tóth is to be submitted for publication in the CSPG Memoir on the Mannville Group, June 1995.

hydrocarbons only and did not use quantitative mapping of flow systems including flow directions and rates.

Numerous hydrogeologic studies have mapped water flow directions in the Mannville Group both at the basin scale (e.g., Hitchon 1969a, 1969b; Abercrombie and Fullmer, 1992), and in smaller areas at more detailed scales (e.g., Hugo, 1985, 1990; Hitchon et al., 1989a, 1989b, 1990; Thompson and Tóth, 1991; Bachu et al., 1993; Bachu and Undershultz, 1993; Cody, 1993; Cody and Hutcheon, 1994, and others). A different approach was taken by Garven (1989), who used numerical modelling to simulate the formation of the tar sands deposits in Mannville Group in northeastern Alberta. Garven demonstrated that gravity-driven flow systems could be capable of emplacing such enormous volumes of hydrocarbons. However, measured fluid potential data were not used to constrain fluid flow-rates and directions. Only Cody (1993) and Cody and Hutcheon (1994) used fluid potential and geochemical data to investigate flow in the Mannville Group.

None of the aforementioned studies integrated the hydrogeology and hydrochemistry of the Mannville Group and adjacent aquifers/aquitards with a specific focus on cross-formational flow. The question of cross-formational flow and the Mannville Group is especially pressing in light of the recently proposed model of "sealed compartments" in the Alberta Basin that postulates that the Mannville Group is isolated from adjacent strata (Bradley and Powley, 1994).

The present study was completed as part of a larger study of cross-formational flow in the entire Phanerozoic section of west-central Alberta (Rostron and Tóth, 1994, 1995; Rostron et al., 1994, 1995). This paper presents results of hydrochemical and hydrogeologic mapping that describe the water chemistries and flow directions in the Mannville Group and adjacent strata in west-central Alberta. It also documents the existence of two large-scale cross-formational flow domains affecting the Mannville Group. By demonstrating that cross-formational flow into the Mannville Group is taking or has taken place, and the locations where it is occurring or has occurred, I hope to add insight to the broader picture of fluid migration in the basin. Furthermore I demonstrate that the postulated "sealed compartment" enclosing the Mannville Group in the Alberta Basin does not exist.

5.2 DATA BASE AND DATA PROCESSING

The study area covers approximately 18,000 km² of west-central Alberta (Figure 5.1). It includes Townships 36 to 45, from Range 21 west of the fourth meridian to Range 10 west of the fifth Meridian. The eastern boundary of the disturbed belt passes through the extreme southwest corner of the area.

Abundant subsurface geological and hydrogeological data were available from the more than 12,000 wells drilled within the study area. The regional stratigraphic framework for this study was established based upon examination of 225 key geophysical wells, chosen for log quality and largest total depth at a spacing of approximately one per township. Detailed mapping of key isopach thicknesses for the Viking, Joli Fou, Mannville, and Ireton formations required the examination of an additional 2000 well logs. Subcrop edges were further refined using published maps, "WESTCAN" oil field maps, and the CD-ROM version of the Alberta Energy Resources Conservation Board (AERCB) database provided by the CDPubco Company. Formation pressure data were obtained from the Canadian Institute of Formation Evaluation (CIFE). Water chemical analyses were obtained from Rakhit Petroleum Consulting Limited. Well histories and fluid production data were obtained from the CD-ROM version of the AERCB database.

All data were carefully screened to remove inaccurate or non-representative values. Only pressure data with full Horner-type extrapolations and CIFE quality codes A to D were used. Each formation pressure was screened for production-influenced drawdown (PID) effects using techniques described elsewhere (Bachu et al., 1987; Barson, 1993; Rostron, 1994). Pressure tests spanning multiple stratigraphic intervals were eliminated. Chemical data were processed to remove non-representative analyses (e.g. mixtures, drilling mud filtrates, spent acid-fracture fluids) using standard culling techniques (e.g. Bachu et al., 1987; Thompson, 1989; Barson, 1993; Hitchon and Brulotte, 1994).

Geologic data were converted into cross-sections, isopach and structural maps, and were used to create the framework for the hydrogeologic analyses. Pressure data were used for pressure versus depth (p[d]) and pressure versus elevation (p[z]) plots, and were converted into potentiometric surfaces and hydraulic cross-sections. Hydrochemical data were mapped both as individual ions and as total dissolved solids (TDS). In this manner, all the geological and hydrogeological data were synthesized into a regional picture of fluid flow and cross-formational migration for the study area.

5.3 GEOLOGIC FRAMEWORK AND HYDROSTRATIGRAPHY

The subsurface stratigraphy of the Mannville Group and adjacent units in west-central Alberta is shown schematically in Figure 5.2. A dip-oriented structural cross-section from southwest to northeast across the area (Figure 5.3) demonstrates the complex configuration of the units beneath the Mannville Group. The complex subcrop pattern of the Upper Devonian to Upper Jurassic units beneath the Mannville Group (Figure 5.4) plays an important role in the definition of the hydrostratigraphy and fluid flow in the study area, as will be shown in subsequent sections of this paper.

Lithologic units of the section were assigned to 13 hydrostratigraphic units (Figure 5.5). Individual hydrostratigraphic units were combined into hydrogeologic groups based on similar hydraulic properties and/or flow characteristics. These hydrogeologic groups were further combined into two flow domains, based on large-scale flow behavior across the study area.

Mannville Group sediments form part of, and are influenced by, these two hydrogeologic flow-domains (Figure 5.5). The lower Paleozoic domain comprises the Upper Devonian Hydrogeologic Group (UDHG) and the Mississippian Hydrogeologic Group (MHG). The upper Jurassic-Lower Cretaceous flow domain consists of the Mannville Group Aquifer (MGA) and the Viking Group Aquifer (VGA). The geology and hydrostratigraphy of each of these units are reviewed below.

5.3.1 Paleozoic Flow Domain

5.3.1.1 *Upper Devonian Hydrogeologic Group (UDHG)*

The Upper Devonian Hydrogeologic Group (Figures 5.3 and 5.5) is located at the base of the section of interest. Details of the geology and hydrostratigraphy of the UDHG have been previously reported (Rostron and Tóth, 1994; Rostron et al., 1994, 1995) and are only summarized here. The UDHG consists of two aquifers and three aquitards. They include, in ascending order: 1) the relatively low-permeability limestones and calcareous shales of the Waterways aquitard (Beaverhill Lake Group); 2) the highly-permeable dolostones of the Cooking Lake-Leduc aquifer; 3) the relatively-impermeable shales and marls of the Ireton aquitard; 4) the highly-permeable carbonates of the Nisku aquifer (Winterburn Group); and 5) the relatively low-permeability mixed dolomite-anhydrites of the Wabamun Group aquitard. The UDHG subcrops the Mannville Group in the northwestern corner of the study area (Figure 5.4).

5.3.1.2 *Mississippian Hydrogeologic Group (MHG)*

The upper hydrogeologic group in the Paleozoic flow domain is the Mississippian Hydrogeologic Group (MHG). The MHG consists of one aquifer and two aquitards (Figure 5.5). At the base of the MHG is the Exshaw Formation, a relatively thin (less than 7 metre) layer of black shale that was not considered separately due to its relatively thin nature. Overlying the Exshaw Formation is the Banff aquitard which consists of up to 200 metres of mixed cherty and fossiliferous limestones (Martin, 1967). Although of generally low permeability, there are increasing amounts of secondary dolomite towards the top of the Banff aquitard that create localized reservoirs along its up dip edge.

Overlying the Banff aquitard are the coarse-grained fossiliferous limestones and dolomitic equivalents of the Pekisko Formation (Rundle Group). Like the underlying Banff aquitard, the dolomite content of the Pekisko Formation increases upward toward the Paleozoic unconformity, as does its porosity and permeability. Hence, numerous hydrocarbon pools are found along most of the Pekisko Formation subcrop edge (Richards et al., 1994). Qualitatively, the Pekisko aquitard possesses a higher overall permeability than the underlying Banff aquitard, but a lack of measured permeabilities and fluid production beyond a narrow band along the subcrop edge precluded this formation from being assigned as a regional aquifer.

Uppermost in the MHG is the Elkton-Shunda aquifer (Rundle Group). The Shunda Formation consists of up to 55 metres of silty finely crystalline dolomite with increasingly variable lithostratigraphy near the Paleozoic unconformity (Martin, 1967). Overlying the Shunda Formation are the highly-permeable dolomites and crinoidal limestone equivalents of the Elkton Formation. The Elkton Formation is relatively thin in the study area, with a maximum thickness of 37 metres due to post-depositional erosion. Where present, the Elkton Formation forms the best reservoir unit in the MHG (Richards et al., 1994). Due to the difficulty in differentiating the Elkton and Shunda formations in both well logs and AERCB information, especially in the thin subcropping regions, these two formations were combined into one aquifer.

5.3.2 Jurassic-Lower Cretaceous Flow Domain

5.3.2.1 *Mannville Group Aquifer (MGA)*

The lower hydrogeologic group in the Jurassic-Lower Cretaceous flow regime in the Mannville Group aquifer (MGA), which consists of one aquifer and one aquitard. The lowermost hydrogeologic unit in the Jurassic-Lower Cretaceous flow regime is the Fernie Group aquitard (Figure 5.5) which forms the base of the Mannville Group aquifer (MGA). The Fernie Group aquitard reaches a maximum thickness of 60 metres in the extreme southwest corner of the study area (Figure 5.3) and extends eastward across the western third of the study area (Figure 5.4). This hydrogeologic group is made up of four recognizable rock units but because of their relatively thin nature, limited areal extent, and overall relatively low-permeability they were grouped into one low-permeability aquitard. Lithologically these strata are highly variable and difficult to differentiate and/or correlate across the area. Furthermore, most pressure and water chemical data available from these units were tightly grouped along their respective subcrop edges and this data distribution precluded further mapping. All of the strata are reportedly Jurassic in age (Deere and Bayliss, 1969; Poulton et al., 1994) but there is no general agreement as to the exact age of the strata or whether they represent geologic member, formation, or group status. Thus, an informal nomenclature recognizing four "members" was used in this study: the Nordegg, Poker Chip, and Rock Creek members; and the "Fernie shale."

At the base of the Fernie Group aquitard are the chert-rich limestones, and minor sandstones and dolomites of the Nordegg Member (Riediger and Coniglio, 1992). Although dominantly a low-permeability carbonate unit, the Nordegg Member is reportedly highly-permeable in isolated areas along its subcrop edge, similar in character to the underlying MHG units. Unconformably above the Nordegg Member are the dark gray to black micaceous shales of the Poker Chip Member. Where present, the Poker Chip Member reaches 10 metres in thickness and is recognizable by its characteristic signature on gamma ray-sonic logs across the area. Above the Poker Chip Member are the fine-grained quartzose sandstones and siltstones of the Rock Creek Member (Marion, 1984). The Rock Creek sandstone reaches thicknesses of 15 metres in the southwestern area of the study area, but is rapidly thinned by erosion towards the east. The Rock Creek Member is completely removed by about Range 5 west of the fifth meridian (Figure 5.4). West of the Rock Creek subcrop line, the Fernie Group aquitard is capped by the fourth member of the aquitard, an undesignated "Fernie Shale". This shale can reach 35 metres in thickness and is difficult to separate from lowermost Cretaceous strata, except where a thick underlying Fernie Group section is present.

In some areas such as Range 3 W5M, the Fernie Group aquitard is cut by one or more late Jurassic to Cretaceous sandstone units including the so-called "J1", "J2", and "J3" sands identified by Hopkins (1981). These sand bodies are very limited in areal extent and are similarly difficult to differentiate from Lower Cretaceous strata without the use of paleontological techniques. For this study, hydraulic data obtained from these rock units was grouped with the overlying Mannville Group strata.

The bulk of the Mannville Group aquifer consists of 160 to 240 metres of strata belonging to the Mannville Group proper. Depending on their location within the basin, the Mannville Group and equivalents have been divided into various sub-groups, formations, members, and informal units. In this study, four divisions of the Mannville Group (after Rosenthal, 1988) were used as a geologic framework. Those four units, in ascending order are: the Ellerslie Formation; the Ostracode Member; the Glauconite Formation; and the Upper Mannville "Formation". All of these are aquifers, except for the Ostracode Member.

Ellerslie Formation sediments commonly consist of a non-marine series of quartzose sandstones, siltstones, and coals (Stott et al., 1993) up to 60 metres thick, infilling depressions on the well-developed topographic surface on the pre-Cretaceous unconformity. The Ellerslie Formation grades upward into the Ostracod Member, which consists of up to 30 metres of black calcareous shales, sandstones, and limestones (Leckie and Smith, 1992). Above the Ostracode Member is the Glauconite Formation which consists of two main facies: a series of sheet-like open-marine sandstones, mudstones, and shales up to 25 to 30 metres thick (Rosenthal, 1988; Strobl, 1988); and a sequence of quartz-rich sandstones, breccias, and mudstones interpreted as incised channel deposits (Rosenthal, 1988) up to 40 metres thick. The marine sandstones are cross cut by the incising channel sandstones. In places, channel sands of the Glauconite Formation cut through the Ostracode Member into the Ellerslie Formation. The remainder of the MGA comprises undifferentiated "Upper Mannville" sediments above the Glauconite Formation, which reflect a change to continental depositional conditions and thus, comprises a mixture of sandstones, shales, and coal beds with a cumulative thickness of up to 150 metres.

Several factors justified the combination of these four units into one aquifer. First, preliminary mapping of geology, formation pressures, and water chemistries was completed using the four-fold division of the Mannville Group (Ellerslie, Glauconite, and Upper Mannville aquifers; and Ostracode aquitard). Preliminary results indicated no significant differences in regional flow patterns between the individual aquifers. Second, individual sand bodies within the Mannville Group a continuous on a regional scale, even though facies within each of the four units are highly variable. Third, the Ostracode Member which was initially classed as an aquitard, is incised by Glauconite sandstones and is therefore not regionally continuous. Finally, the Clearwater Formation shale used by previous authors (e.g., Abercrombie and Fullmer, 1992) to separate the Mannville Group into upper and lower aquifers is not deposited in this area. Based on these factors, the four fold division of the MGA was discarded in favor of one regional aquifer unit. It must be recognized that the combination of these four units into one aquifer is only valid for regional-scale analyses of fluid migration in the MGA.

5.3.2.2 *Viking Group Aquifer (VGA)*

The upper major hydrogeologic unit of the Jurassic-Lower Cretaceous flow domain is the Viking Group aquifer (VGA). The VGA comprises strata belonging to the Joli Fou and Viking formations (Figures 5.2, 5.4, and 5.5). The Joli Fou aquitard at the base of the VGA consists of the non-calcareous marine mudstones and shales of the Joli Fou Formation (Colorado Group). The Joli Fou aquitard is regionally extensive throughout the WCSB, varying in thickness from 20 to 40 metres across the basin (Leckie et al., 1994).

Previous authors have inferred that the Joli Fou Formation acts as a regional seal for hydrocarbons in the WCSB (Creaney and Allan, 1990, 1992). Geochemical studies show that hydrocarbons from source rocks older than the Joli Fou Formation are not found in strata younger than the Joli Fou Formation anywhere in the basin, and vice versa (Creaney and Allan, 1990). However, detailed geologic mapping in this study has identified a large region in the southwest corner of the study area where the Joli Fou aquitard is absent, probably due to non-deposition (Mellon, 1967; Boethling, 1977), as described below.

The permeable part of the VGA consists of a number of coarsening-upward sequences of sandstone comprising the Viking Formation (Reinson et al., 1994). Cumulative sandstone thickness varies between 20 and 50 metres (Figure 5.3), with occasional thick sections of conglomerate, siltstone, and shale. Hydrocarbon production is controlled on a local scale by the presence of highly-permeable but relatively-thin sandstone and conglomerate bodies. On a regional scale, these sandstone bodies are continuous, forming one of the most hydraulically conductive aquifers in the entire WCSB (Hitchon, 1969a, 1969b; Creaney and Allan, 1990). The Viking Formation fines upward into the shales of the Colorado Group.

The Paleozoic and Jurassic-Cretaceous flow domains are capped by the relatively low-permeability marine shales of the Colorado Group aquitard (Figures 5.3 and 5.5). This aquitard ranges in thickness between 475 and 750 metres across the study area (Leckie et al., 1994), and effectively isolates the two main flow regimes in the study area from overlying aquifers.

5.4 RESULTS AND DISCUSSION

5.4.1 Hydrogeology

5.4.1.1 *Upper Devonian Hydrogeologic Group (UDHG) Aquifers*

The UDHG consists of two main aquifers: the Cooking Lake-Leduc aquifer and the Nisku aquifer. Fluid flow in both aquifers is exemplified by the potentiometric surface of the Nisku aquifer (Figure 5.6). Hydraulic heads in the Nisku aquifer range from over 750 metres in the Bashaw reef complex, down to values under 450 metres in the northeast corner of the study area. Two distinct areas of fluid flow exist in the Nisku aquifer, defined on the outline of the underlying Bashaw reef complex in the Leduc Formation (Figure 5.6).

First, where the Bashaw reef complex underlies the Nisku aquifer, hydraulic heads are mounded in the potentiometric surface of the Nisku aquifer. Horizontal flow directions that are inferred from the potentiometric surface radiate outwards over the area of the underlying reef complex. In the Bashaw reef complex, pressure versus depth plots indicate vertical fluid flow from the Leduc aquifer upward into the Nisku aquifer (Paul, 1994). Several localized highs in the potentiometric surface indicate excellent communication with the higher-potential Leduc aquifer beneath.

The area of flow in the Nisku aquifer is a regional system existing outside the area of the Bashaw complex. Fluid flows up dip, from values of fluid potential greater that 600 metres in the southwest, toward values under 450 metres in the northeast part of the study area.

In general, flow directions in the Nisku aquifer are controlled by its connection with the underlying Cooking Lake-Leduc aquifer. Where the intervening Ireton aquitard is thinner (or absent) over the Leduc Formation reefs, such as in the Bashaw complex area (Rostron et. al., 1994, 1995), a preferential pathway is provided for fluids to move upward from the Cooking Lake-Leduc aquifer into the Nisku aquifer (Figure 5.3). Where the Ireton aquitard is thicker, for example over the Rimbey-Meadowbrook reef trend, the higher potentials in the Cooking Lake-Leduc aquifer are not manifest in the potentiometric surface of the Nisku Aquifer. Fluid flow in the Nisku aquifer is laterally up dip where the Nisku aquifer is not affected from below by the Cooking Lake-Leduc aquifer.

5.4.1.2 *Elkton-Shunda Aquifer*

The hydraulic head distribution in the Elkton-Shunda aquifer (Figure 5.7) shows variations between values over 900 metres in the southwest corner of the study area to under 500 metres along the subcrop line in Range 3-4, Townships 36-39. The pattern of hydraulic heads, and the fluid flow directions that the d[illegible]ibution conveys, strongly depen[illegible] position relative to the subcrop lines of the Elkton and Shunda formations, and the overlying Fernie Group aquitard. Fluid flow in the Elkton-Shunda aquifer can be broken into three distinct systems: 1) a lateral up dip flow system where the highly-permeable Elkton Formation is present; 2) a complex, but generally vertically-ascending flow system in areas where only the Shunda Formation is present; and 3) a dominantly vertically-ascending flow system in the Elkton-Shunda aquifer in areas where the overlying Fernie Group aquitard is absent.

The first main area of flow in the Elkton-Shunda aquifer occurs where mappable amounts of Elkton Formation exist (southwest of the Elkton Formation Subcrop line in Figures 5.4 and 5.7). Hydraulic heads in this portion of the aquifer range from 975 to approximately 800 metres, with lateral up dip flow to the northeast indicated by the potentiometric surface map.

The second main area of flow in the Elkton-Shunda aquifer is caused by erosional truncation of the highly-permeable Elkton Formation. This region is defined by the boundaries of the Elkton Formation subcrop to the southwest and the Shunda Formation subcrop to the northwest, except in the area where the Elkton-Shunda aquifer extends east of the subcrop of the Fernie Group (Figure 5.7). Within this region, fluid potentials rapidly decrease from values over 800 metres to under 500 metres in the aquifer. These rapid losses in hydraulic energy are interpreted to result from a reduction in transmissivity of the aquifer caused by two factors: a reduction in thickness near the subcrop edge; and a reduction in bulk permeability where the highly-permeable Elkton Formation strata (as compared to the Shunda Formation) are not present. In this region, the laterally-moving fluids in the main Elkton-Shunda aquifer are forced up across the Fernie Group aquitard because of the disappearance of the aquifer. Vertical flow in this region is confirmed by the p[d] plot (Figure 5.8), with measured vertical pressure gradients in excess of nominal.

The small remaining area of flow occurs in Ranges 3-4, Townships 36-37 where the Elkton-Shunda aquifer extends east of the subcrop of the overlying Fernie Group aquitard. In this area, the Mannville Group aquifer is in contact with the Elkton-Shunda aquifer (Figure 5.7). The dominant flow direction in this area is vertically upward out of the Elkton-

Shunda aquifer into the Mannville Group aquifer above. Vertical flow in this area is confirmed by super-hydrostatic gradients on the p[d] plot (Figure 5.8).

It should be noted that when formation pressures from the thick portion of the Elkton-Shunda aquifer in the southwest are plotted on a composite p[d] plot (Figure 5.8), that the nominal vertical pressure-gradient exceeds the measured value. According to Tóth (1978) this would indicate downward flow in this area of the aquifer. However, this apparent contradiction from the preceding paragraphs results from plotting pressure data on a composite p[d] plot that are widely spaced (greater than 10 km apart) over an area with large variations in surface topography (hundreds of metres; Figure 5.1). This is an example of when p[d] plots cannot be used to infer vertical flow directions because the surface elevations for each pressure point are not equal. Examination of p[d] plots for individual wells (not shown here) reveal super-hydrostatic vertical pore-pressure gradients, thus indicating slight vertical flow in this region of the aquifer, consistent with flow directions inferred from the potentiometric surface.

5.4.1.3 *Mannville Group Aquifer (MGA)*

Two different datasets were used to examine flow in the MGA: one dataset that included all of the valid pressures, regardless of fluid recovery; and a second subset that included only pressure tests that recovered significant amounts of formation water. Potentiometric surfaces for the MGA constructed from these two datasets are shown as Figures 5.9 and 5.10, respectively.

Fluid saturations within the Mannville Group aquifer are highly unusual because this study area straddles the boundary between the Deep Basin (Masters, 1979; Varley, 1984; Chiang, 1984) and the "normal" part of the WCSB. Within the Deep Basin proper, the pore space is hydrocarbon saturated. Mobile formation water is only found up dip at the boundary with the "normal" part of the basin (Masters, 1979, 1984). Wells producing from the Deep Basin produce negligible amounts of formation water, leading to speculation that the pore water is in a discontinuous state (Masters, 1979). To the east of the boundary line are found "conventional" hydrocarbon pools where wells produce hydrocarbons with varying amounts of water. In this study the position of the Deep Basin boundary was mapped using well production-data and DST recoveries.

The potentiometric surface constructed using all of the available pressure data from the MGA (Figure 5.9) is called here a "pseudo-potentiometric" surface because it contains mixed recovery pressure data from both sides of the Deep Basin boundary (Figure 5.10). Although equivalent freshwater heads can be calculated from pressures measured in the gas phase and plotted as part of a potentiometric surface, no evidence suggests that formation waters will flow according to the distribution of these potentials, especially across regions where the dominant fluid-phase changes. The highest hydraulic heads in the entire MGA, with values reaching 1525 metres (Figure 5.9), are found within the Deep Basin. When the data are sorted according to fluid recovery, and only those that are in the "normal" part of the basin are contoured to make a potentiometric surface (Figure 5.10), all of the high values of potential west of the Deep Basin boundary are eliminated. The high values of fluid potential west of the boundary all represent gas-phase pressures and since the water phase is immobile in this area, they must be excluded from the discussion of water flow in the MGA.

Therefore the actual potentiometric surface for the MGA is shown in Figure 5.10. Hydraulic heads range between 290 and 725 metres of equivalent freshwater head, indicating that the MGA is regionally underpressured across the study area. This can be seen by comparing Figure 5.10 to topographic elevations in Figure 5.1. Although not shown, p[d] plots confirm that all fluid pressures in the MGA fall below the nominal pressure-gradient line (Rostron and Tóth, 1995).

In addition to the regional underpressuring and the presence of the Deep Basin boundary, three more features are evident in the potentiometric surface of the MGA. These include: a regional lateral flow-system; a chaotic local-scale distribution of fluid potentials; and regions of vertical flow.

The first main feature of the MGA in this area is the very subtle nature of the lateral flow system. A cursory examination of the potentiometric surface (Figure 5.10) reveals no apparent systematic decrease in hydraulic heads in any one direction with numerous closed areas of high and low values of potential. Basin-scale potentiometric surfaces of the Mannville Group (Hitchon, 1969b; Abercrombie and Fullmer, 1992) provide clarification of trends of flow in this study area. Those surfaces illustrate lateral flow from the southwest to northeast across the WCSB. Fluid flow-directions in this study area can be tied to the regional-scale system by examining the potentiometric surface (Figure 5.10). Generally, values of higher hydraulic heads (greater that 650 metres) are found in the southwest corner, to the west, and south of the study area. Intermediate values (500 metres) are found along a band running generally north-south through Range 26, and there is a systematic decrease towards values approaching 400 metres toward the northeast. Thus, a very subtle decrease in hydraulic heads from southwest to northeast across the study area can be observed. The cause of the hydraulic heads under 300 metres in the southeast corner of the study area is currently unknown, although this area appears to be at the northern edge of a large underpressured region outside the study area (Hitchon, 1969b).

The second major feature of the hydraulic head distribution in the MGA is the rather chaotic distribution of local-scale in hydraulic heads across the study area. Numerous closed areas of low and high fluid-potentials exist, superimposed on the large scale up dip flow system discussed above. Examples of closed lows include: Township 43, Range 1 and Township 40 Ranges 3-4. Closed high areas are found in Township 41, Range 25 and Township 43-44, Range 23. These closed features on potentiometric surfaces are indicative of significant components of vertical flow in thick heterogeneous aquifer-systems, such as the MGA. Since a potentiometric surface only quantifies the lateral gradient of potential, upward or downward fluid-flow in an aquifer creates closed areas of high and low potential on a potentiometric surface. The perturbations in the potentiometric surface of the MGA appear to be caused by the presence of highly-permeable rock bodies within the MGA.

These pods are relatively thin (up to 50 metres thick) compared to the overall thickness of the MGA, but they host many of the hydrocarbon pools in the study area.

The third major component of the flow system in the MGA is the reflection in the potentiometric surface of the intersection with the vertically ascending UDHG and to a lesser extent the intersection with the Elkton-Shunda aquifer. The UDHG intersects the MGA in the northeastern corner of the study area. The noticeable flattening of the potentiometric surface in this area reflects a decrease in the lateral hydraulic gradient because a large component of the fluid flow-field is directed in the vertical direction. Pressure versus depth plots constructed in Townships 43-45, Ranges 21-24 (not shown here), indicate measured vertical pressure-gradients up to 13.4 kPa/m, well above the nominal gradient for the MGA of 10.6 kPa/m. Similarly, the higher values of fluid potentials in Township 36 Range 3-4 and Township 42 Range 5 likely reflect the intersecting flow from the MHG. The scarcity of pressure data in these areas precluded any p[d] analyses. The two vertical flow-systems produce a plume of saline water in the MGA.

5.4.1.4 *Viking Group Aquifer (VGA)*

Fluid saturations and pore-pressures in the Viking Group aquifer are similar in many ways to the underlying Mannville Group aquifer. As for the MGA, formation pressures for Viking Group aquifer were separated based on fluid recoveries and plotted as both "pseudo-potentiometric" and potentiometric surfaces (Figure 5.11 and 5.12, respectively) which show that the Deep Basin boundary passes through the Viking Group aquifer in this area (Figure 5.12).

If formation pressures are not separated based on fluid recoveries, the well known "pseudo-potentiometric" surface for the Viking aquifer is obtained (Figure 5.11). This pattern of hydraulic heads and their anomalously low values have been noted previously (Hill et al., 1961; Hitchon, 1969b; Hitchon et al., 1990, and others). A unique feature of this distribution is that hydraulic heads ranging from over 1500 metres to under 125 metres imply fluid flow from all directions towards a fluid-potential low in the center of the study area. Given the steady state flow conditions that would be expected on a geologic time scale and lack of any sources or sinks of fluid mass, this distribution of fluid potentials is physically impossible. The origin of the low potentials in the Viking Group aquifer has been the subject of much debate in the published literature (e.g., Hill et al., 1961; Hitchon, 1969b; 1984; Dickey and Cox, 1977; Bradley and Powley, 1994), and a discussion of the origin of these pressures goes beyond the scope of this paper. Discussion here will be limited to the features of the water flow-patterns.

The pseudo-potentiometric surface for the Viking Group aquifer (Figure 5.11) shows relatively higher hydraulic-heads over approximately the western half of the study area, similar to those in the underlying Mannville Group aquifer. In the west, there are numerous areas where high and low fluid potentials can been seen, reflecting focusing of flow in and out of highly permeable reservoir bodies (e.g., Township 37, Range 7 and Township 39 Range 1). The several bands of tightly-grouped fluid potential contours likely reflect regional-scale permeability variations related to facies changes.

The position of the water line was established based on drill stem test recoveries and pool production data. In many of the Viking fields in this area including Gilby, Bentley, and Joffre, waterflooding schemes were initiated soon after discovery. Thus, great care had to be taken in data analysis to separate areas of "waterflood" water and true formation water. The actual position of the water line is difficult to locate because of the uncertainty over whether analyzed samples are formation water or recycled water. Furthermore, in the north, the water line appears to move westward beyond the Crystal field, with "normal" saturation conditions (hydrocarbon over water) reported for that field (Reinson et al., 1988). The occurrence and cause of these Deep Basin boundaries remain problematic (Murray et al, 1994; Varley, 1984; Chiang, 1984; Masters 1979; 1984).

Fluid flows down dip to the southwest in the Viking Group aquifer (Figure 5.12). Fluid potentials decrease from 390 metres to under 125 metres from northeast to southwest.

Hydraulic gradients over most of this area are relatively low, with most of the fluid potential decrease occurring in a northwest-southeast oriented band near the center of the study area (Figures 5.11 and 5.12). Compared to the overlying surface topographic elevations (Figure 5.1), hydraulic heads in the Viking aquifer are abnormally low.

5.4.2 Hydrogeochemistry

The chemical characteristics of formation waters were examined by plotting distributions of major ions and of total dissolved solids (TDS) for the different aquifers. Differences between formation waters are best illustrated on Stiff Diagrams of averaged chemical composition for each aquifer (Figure 5.13). All of the formation waters in the study area are brines, according to the classification scheme of Hem (1985).

5.4.2.1 *Upper Devonian Hydrogeologic Group (UDHG) Aquifers*

Formation waters from the Cooking Lake-Leduc aquifer are Na-Ca-Cl brines (Connolly et al., 1990). They are the most concentrated waters found in the study area with average TDS concentrations of 205,000 mg/l (Figure 5.13a). The total dissolved solids concentrations vary little across the study area, with all 269 samples in the range of 183,00 and 227,000 mg/l TDS. Chloride is the dominant anion in the samples. Sodium and potassium are the dominant cations, but as is typical for Cooking Lake-Leduc waters in the basin, a significant proportion of the cations consist of calcium. Average ratios of reacting value of sodium to reacting value of chloride (rNa/Cl) are 0.65, indicating deep subsurface conditions, possibly stagnant, and favorable for the preservation of hydrocarbon accumulations (Collins, 1975). Connolly et al., (1990) propose that these brines originated as sea water that was concentrated by evaporation beyond halite solution, then diluted by varying degrees with meteoric water.

Waters of the Nisku aquifer, although similar to the underlying Cooking Lake-Leduc aquifer, are typically less concentrated. Total dissolved solids concentrations for the Nisku aquifer average 181,000 mg/l (Figure 5.13b). Total dissolved solids concentrations vary more throughout the study area, with values falling between 151,000 and 211,000 mg/l. Proportionally, these waters contain slightly less calcium, which likely indicates a slightly different origin and dilution history (Connolly et al., 1990). Both waters belonging to the UDHG have characteristically high calcium contents (Figure 5.13).

5.4.2.2 *Elkton-Shunda Aquifer*

Formation waters in the Elkton-Shunda aquifer are much fresher than waters of the underlying UDHG (Figure 5.13c). The average TDS concentration is approximately 58,000 mg/l, with all of the 66 analyses falling between 39,000 and 75,000 mg/l. This lack of variation precludes plotting a map of TDS distribution, although there is a slight correlation with decreasing TDS up dip toward the subcrop. The freshest waters are found in the area where the Fernie Group aquitard is absent and Elkton-Shunda aquifer waters are moving upwards (as discussed previously). Elkton-Shunda aquifer waters have anomalously high bicarbonate contents (average concentration of 1500 mg/l), compared to other formation waters at this depth such as UDHG waters. This can be seen by the relatively straight line on the anion side of the Stiff diagram (Figure 5.13c), as compared to Leduc or Nisku formation-waters (Figures 5.13a and 5.13b). Molar bicarbonate to chloride ion-ratios of Elkton-Shunda aquifer waters average 0.025, almost 6 times the same ratio in sea water, indicating an increase in bicarbonate ion with respect to chloride in these waters. Elevated levels of bicarbonate (values over 2000 mg/l) are also found in other Mississippian and Jurassic waters, although not shown here. High levels of bicarbonate indicate a source of carbon dioxide, which is usually found in shallow meteoric groundwater (Hem, 1985). Such high values of bicarbonate deep in the subsurface either imply very deep penetration of meteoric waters, or some sort of carbon dioxide generating mechanism, such as bacterial sulfate reduction (Hem, 1985; Cody and Hutcheon, 1994). It seems unlikely that the high bicarbonate levels originate as meteoric recharge because of the high TDS concentrations in the formation waters. The origin of the bicarbonate in these waters is the subject of ongoing research.

5.4.2.3 *Mannville Group Aquifer (MGA)*

Formation waters in the MGA are chemically much more variable than waters in the underlying Paleozoic flow domain. Total dissolved solids concentrations range from 20,000 to 150,000 mg/l in the study area with a general trend of increasing TDS concentrations from southwest to northeast (Figure 5.14). The highest concentrations of TDS clustered in the northeast corner of the study area.

Formation waters in the MGA appear to be a mixture of two types. The first type of water is referred to as "typical" Mannville Group formation-water. These waters are characterized by a rNa/Cl value of approximately 0.95 (Figure 5.13d), with TDS values ranging between 20,000 and 60,000 mg/l. This chemical composition is similar to waters found elsewhere in the Mannville Group in the WCSB (Connolly et al., 1990; Cody and Hutcheon, 1994; Abercrombie et al., 1994). Ambient Mannville Group formation-waters originate from a mixture between meteoric water recharging in southern and western Alberta (Cody and Hutcheon, 1994) and a brine of concentrated sea water (Connolly et al., 1990).

The second type of water in the MGA, referred to here as the saline plume, is characterized by higher TDS values and lower rNa/Cl values. Total dissolved solids concentrations in the saline plume generally exceed 100,000 mg/l, with some values up to 140,000 mg/l. These are some of the highest concentrations of TDS found in this aquifer throughout the entire basin (Abercrombie et al., 1994). Average rNa/Cl values for the 114 samples in the plume are 0.78 (Figure 5.13e). The suggested origin of the saline plume of formation waters in the MGA is explained below.

Water samples with TDS concentrations between 60,000 and 100,000 mg/l are interpreted as mixtures between typical Mannville Group formation-water and the saline plume. These waters are found in a band approximately 20 kilometer wide bounded by the

60,000 mg/l contour on the west and south, and the 100,000 mg/l contour in the northeast (Figure 5.14). Chemical characteristics of these samples are highly variable depending on the relative proportions of the two end members present.

5.4.2.4 *Viking Group Aquifer*

Water recoveries in the Viking Group aquifer are confined to the northeast corner of the study area. The average TDS concentrations of Viking Group formation-waters in this area is 42,800 mg/l (Figure 5.13f), the lowest of any of the four main aquifers examined in this study. The distribution of TDS concentrations exhibits a systematic variation between values of 21,000 and 71,000 mg/l in a direction with decreasing TDS concentrations in the direction of flow (Figure 5.15).

Comparing the average Viking Group formation-water with other formations, the Viking formation-water appears most similar to the Elkton-Shunda aquifer and "typical" Mannville Group waters (Figure 5.13). Viking Group formation-waters have similar average TDS values, rNa/Cl values, and elevated bicarbonate levels (HCO_3/Cl ratio of 0.031). But, the rapid change in TDS concentrations over such short distances precludes any sort of temperature-variation related cause, and no change in chemical composition of the rocks of the Viking Formation is apparent. There are two possible explanations for this rapid change in TDS. First, the salinity variation in the Viking Group aquifer could be caused by saline waters from the plume in the Mannville Group aquifer flowing up across the Joli Fou aquitard into the Viking Group aquifer. Or, the elevated TDS values in the northeast corner of the study area must be caused by mixing with a more-saline Viking Group formation-water outside of the study area up dip.

5.4.3 Cross-formational flow in the Mannville Group

5.4.3.1 *Origin of the Saline Plume in the Mannville Group*

Geologic, geochemical, and hydraulic data provide evidence that the saline plume in the

Mannville Group aquifer was formed by formation fluids emanating from reefs in the Leduc-Cooking Lake aquifer.

Three geologic factors are responsible for the creation of the saline plume in this area. First, a source of saline water with TDS concentrations greater than 175,000 mg/l and hydrocarbons flows in the Cooking Lake-Leduc and Nisku aquifers. Second, formation fluids are vertically ascending in the Bashaw reef complex (Paul, 1994: Rostron and Tóth, 1994; Rostron et al., 1994, 1995). Saline waters and hydrocarbons are crossing the Ireton aquitard and flowing up into the Nisku aquifer. This upward flow system in the Bashaw area provides the saline fluids for the Mannville Group aquifer.

The third key factor in the creation of the saline plume is the nature of the subcrop of the UDHG beneath the MGA (Figures 5.3 and 5.4). The MGA is separated from the UDHG by the relatively impermeable dolomite, anhydrite, and minor halite that comprise the Wabamun Group aquitard. In the northeast corner of the study area, the Wabamun Group aquitard subcrops the MGA (Figure 5.4), where it thins from its normal thickness in excess of 200 metres down to under 60 metres (Figure 5.3). The thinned Wabamun Group aquitard provides the pathway for the vertically-ascending Devonian waters to pass upward into the MGA, creating the saline plume. Comparison of the map of total dissolved solids concentrations for the Mannville Group aquifer (Figure 5.14) and the subcrop area of the Wabamun Group aquitard (Figure 5.4), shows that the plume is located in the MGA above the subcrop area.

The chemical composition of the formation fluids supports the argument that the saline plume originates from the Upper Devonian Hydrogeologic Group. Formation waters that make up the UDHG are markedly different in composition from the waters in the MGA (Figure 5.13). With their characteristically high TDS concentrations, high proportion of calcium cations, and low rNa/Cl ratios, UDHG waters are recognizable, even when mixed with more dilute waters. Stiff diagrams reveal that the overall shape of a typical "saline plume" water is very similar to the shape of the water from the Cooking Lake-Leduc aquifer:

the waters only differ in the magnitude of their respective TDS concentrations. The characteristically-high calcium content in both waters is also diagnostic. Typical analyses for other formations in the study area (Figure 5.13), do not match the Stiff Diagram pattern of the saline plume. Furthermore, none of the other formation fluids exhibit the elevated amounts of calcium found in the UDHG and in the saline plume waters.

Organic geochemical analyses of produced oils from Mannville Group reservoirs east of the study area further support the concept that UDHG fluids have moved cross-formationally into the MGA. Gas chromatography-mass spectrometer analyses of hydrocarbons and source-rocks from the Provost Field demonstrated that Mannville Group oils contain a significant component of Devonian-sourced hydrocarbons (Riediger et al., 1994). Because oil can be shown to be migrating from the Devonian, then other formation fluids can also follow similar flow pathways.

The saline plume is not just caused by laterally-moving "typical" Mannville Group formation-waters dissolving the carbonates and evaporites of the Wabamun Group either. Upward moving UDHG fluids are indicated by p[d] plots constructed in the northeast corner of the study area (Figure 5.16). This p[d] plot shows measured vertical pressure gradients in excess of nominal values, indicating vertical flow components in the area of the saline plume. The fact that the fresher "typical" Mannville Group formation-waters come into contact with the carbonates of the Wabamun Group probably only plays a minor role in the formation of the saline plume.

5.4.3.2 *Flow from the Elkton-Shunda aquifer*

Cross-formational flow into the Mannville Group aquifer also occurs in the southwest corner of the study area where water from the Elkton-Shunda aquifer flows upward into the MGA, as is supported by four factors. First, a direct contact exists between the Elkton-Shunda aquifer and the MGA where the Elkton-Shunda aquifer subcrops the Mannville Group, east of the limit of the Fernie Group aquitard (Figure 5.4) which provides a preferential pathway for fluids to move into the MGA. Second, p[d] plots in the underlying Elkton-Shunda aquifer (Figure 5.8) reveal ascending vertical flow-components in the contact area. Third, the water line in the MGA is displaced to the west in the contact area, relative to areas north of the contact area, which implies a source of water to the MGA not present in areas to the north (i.e., outside the contact area of the two aquifers). Finally, hydrochemical data for the MGA (Figure 5.14) show a slight increase in TDS concentrations in the contact area relative to values in the MGA in the western half of the study area. This is counter to the general trend of decreasing salinities in the MGA toward the United States border where salinities approach 5,000-10,000 mg/l (Cody and Hutcheon, 1994). Thus, the contribution of Elkton-Shunda formation-waters in the southwest corner of the study area increases the salinities to the observed values over 40,000 mg/l. Along the southern boundary of the study area, fresher waters moving into the area from the south mix with Elkton-Shunda formation-waters coming up from below. Hydraulic and hydrochemical evidence also shows Elkton-Shunda formation-waters contribute to the MGA, but the scale of the current study, and lack of data in the southern portion of the study area do not permit detailed analyses of this occurrence.

In summary, cross-formational flow of Paleozoic waters into the Mannville Group aquifer occurs from the UDHG in the northeast and from the MHG in the southwest (Figure 5.17).

5.4.3.3 *Flow Across the Joli Fou aquitard*

Another feature of the flow regime of the Mannville Group aquifer is the evidence of flow out of the Mannville Group aquifer. across the Joli Fou aquitard. One of the original objectives of this study was to investigate the possibility of ... w across the Joli Fou aquitard, in light of its supposed impermeable nature (Creaney ... llan, 1990; Bradley and Powley, 1994). To demonstrate the possibility of fluid ... ow across the Joli Fou aquitard, flow rates across the shale unit were calculated. To esti... e flow rates, the shale thickness and the fluid potentials on both sides of the shale were mapped. Besides providing the hydraulic gradient necessary to calculate flow rates, this mapping revealed that the Joli Fou aquitard was discontinuous in the study area.

Shale thickness based on gamma ray, self potential, sonic and density logs were recorded and mapped for over 1000 wells (Figure 5.18). The thickness of the Joli Fou aquitard varies between zero and over 27 metres across the study area, with an average thickness of about 20 metres. The isopach map reveals a large region in the southwest corner of the study area where the Joli Fou aquitard is absent, probably due to non-deposition (Mellon, 1967). In this region the highly-permeable Mannville Group and Viking aquifers are in direct contact. The absence of the Joli Fou shale in parts of the WCSB has been previously documented. Mellon (1967) presented a detailed stratigraphic/well log cross-section (his Figure 11) showing Viking-Joli Fou formation sediments pinching out against the Blairmore Group. Boethling (1977) showed schematically how the sands of the Viking and Manville formations were in direct contact in the foothills of Alberta. And most recently Reinson et al. (1994) discussed indirectly the possibility of contact between sediments of the Viking Formation and the Mannville Group. Unfortunately, none of the previous studies have provided an isopach map of the Joli Fou Formation. Figure 5.18 provides such a map.

Therefore, without even considering its hydraulic properties, the Joli Fou aquitard cannot act as a "regional seal" or hydraulic barrier between these units as it is not continuous across the study area. Because large areas exist where the Joli Fou aquitard is not present, it cannot be the cause of the apparent lack of migration between Upper Cretaceous and underlying petroleum systems. Either the hydrocarbons have migrated across the shales and gone undetected or some other unknown process has occurred. The postulate that the Joli Fou aquitard acts as a regional seal in the basin clearly needs re-examination and further sampling.

The hydraulics of the flow system across the Joli Fou aquitard also support cross-formational flow where the aquitard is present. For fluid flow to occur across the shale, a hydraulic gradient must exist across it and it must have a non-zero permeability value. Hydraulic gradients across the shale ranging from 1.8 to 4.2 (metres/metre) can be calculated by subtraction of the potentiometric surfaces of the two aquifers on both sides of the shale (Figures 5.10 and 5.12) and dividing by the aquitard thickness at the points of calculation (Figure 5.18). In this case, higher fluid potentials in the MGA direct cross-formational flow from the MGA upward into the VGA.

To calculate flow velocity across the shale, three pieces of information are required: the hydraulic gradient (discussed above); the porosity; and the hydraulic conductivity. Magara (1978) presented porosity-depth plots for Tertiary and Cretaceous shales from the Alberta Basin. Selecting wells from Magara's Figures 2.31 and 9.4 (Magara, 1978) closest to this study area, and at the appropriate depth (1000 metres) yields a best estimate of the porosity of the Joli Fou aquitard of approximately 10 percent. Determining an appropriate value for hydraulic conductivity for the Joli Fou aquitard is problematic ... no known values exist for the Joli Fou aquitard in west-central Alberta, although work is in progress at the Geological Survey of Canada to obtain such data (Dale Issler, personal communication, 1995). That shales like the Joli Fou Formation have non-zero permeability is almost certain (Brace, 1980; Neuzil, 1986, 1993, 1994; Tóth, 1991; Deming, 1994, Best and Katsube, 1995, and others). Published values of in-situ hydraulic conductivity of Cretaceous shales vary between 10^{-10} and 10^{-15} metres/second, with "typical" values around 10^{-12} metres/second (Magara, 1972; Bredehoeft et al., 1983; Swanick, 1983; Tóth and Corbet, 1986; Hendry and Schwartz, 1988; Hitchon et. al., 1989a; Phillips et al., 1990; Lies, 1991; Corbet and Bethke, 1992; Neuzil, 1993, 1994).

Flow velocities are calculated using Darcy's Law. Substituting hydraulic gradients of 1.8 to 4.2 metres/metre, in-situ hydraulic conductivities between 10^{-10} and 10^{-15} metres/second, and a porosity of 10 percent yields flow velocities between 5.7 x 10^{-7} metres/year and 1.3 x 10^{-1} metres per year. Using the "best" estimate of the in-situ hydraulic conductivity of approximately 10^{-12} metres/second, gives flow velocities of between 5.7 x 10^{-4} and 1.3 x 10^{-3} metres/year for the hydraulic gradients observed in the study area.

These calculated rates appear quite slow when compared to shallow flow systems, but are moderately fast for regional flow systems on a geologic time scale. For example it would take only 35,000 years for a particle of water to cross 20 metres of Joli Fou aquitard assuming a flow velocity of 5.7 x 10^{-4} metres/year. Even assuming the lowest case of in-situ hydraulic conductivity of 10^{-15} metres/second allows for water to cross the Joli Fou aquitard in approximately 35 million years. Active flow in the WCSB has occurred for over 30 million years (Hitchon, 1984; Garven, 1989), and thus it seems hydraulically unlikely that the Joli Fou aquitard could prevent cross-formational flow between the MGA and the VGA.

Another line of evidence supporting fluid flow across the Joli Fou aquitard comes from dimensional analyses of pressure transients across shales. Deming (1994) presented an equation to calculate the maximum time a layer can function as a seal:

$$t = \left(\frac{z^2}{k}\right) \times 2.4 \times 10^{-27} \qquad (5.1)$$

where: t is the maximum time in million years over which a layer of thickness z and permeability k can function as a seal.

Using a thickness of the Joli Fou aquitard of 20 metres, and the lowest permeability measured for any shale of 1 x 10^{-23} m^2 (Neuzil, 1994; Best and Katsube 1995), gives a maximum "sealing" time of 96,000 years. It is abundantly clear that pressure transients have crossed the Joli Fou aquitard. Furthermore, one can make use of Deming's simple nomograph (his Figure 2) to arrive at a similar result. If one uses the preceding shale properties and Deming's Figure 2, the point of intersection falls in the "no seal" field.

Indirect evidence also exists for water migration across the Joli Fou aquitard. First, the location of the water-saturated portion of the Viking Group aquifer coincides with the area of the saline plume in the MGA. Second, the relatively high concentrations of TDS in the

Viking Group aquifer (values up to 70,000 mg/l) are not found in other Cretaceous aquifers in this area. High TDS concentrations in the VGA imply a source from the UDHG, indicating upward cross-formational flow across the Joli Fou aquitard. Third, the characteristic elevated calcium concentrations in the waters of the UDHG are present in the Viking Group Aquifer. Plots of TDS concentrations versus molar Ca/Cl indicate a correlation between increased TDS concentrations and increased relative calcium ion (not shown). This suggests mixing between formation waters with high TDS and calcium concentrations and a more dilute "typical" Lower Cretaceous formation water (Figures 5.13d and 5.13f).

Cross-formational flow occurs across the Joli Fou aquitard. This is supported by direct evidence of a physical discontinuity in the Joli Fou aquitard, and indirect calculations of flow rates across it. No evidence supports the existence of a "sealed compartment" in the Alberta Basin as postulated by Bradley and Powley (1994). Additional research and refinements are required to determine whether the Joli Fou shale acts as a localized versus regional seal, and whether it restricts the flow of all fluids or just hydrocarbons.

5.5 CONCLUSIONS

1) Strata that constitute the Mannville Group in west-central Alberta comprise one large scale hydrogeologic group, termed here the Mannville Group aquifer (MGA). The MGA, along with the overlying Viking Group aquifer (which comprises the Viking aquifer and Joli Fou aquitard) form the Jurassic-Lower Cretaceous flow domain in the study area. The Jurassic-Lower Cretaceous flow domain is affected by flow from the Paleozoic flow domain (Upper Devonian Hydrogeologic group, UDHG, and Mississippian Hydrogeologic group, MHG).

2) The Mannville Group aquifer (MGA) exhibits five main hydraulic features:

i) regionally, lateral up dip flow occurs towards the northeast;

ii) very complex local-scale flow patterns with areas of down dip flow and many closed areas of high and low fluid potentials. These complexities are attributed to the presence of geologic heterogeneities and vertical flow within the relatively thick MGA;

iii) formation pressures measured in the water phase are sub-normal with respect to hydrostatic throughout the MGA;

iv) a boundary within the MGA separates the hydrocarbon-saturated Deep Basin to the west from the water-bearing sediments to the east. The boundary position varies areally across the study area;

v) pore-pressure distributions in the MGA reflect the intersection of MGA formation waters with the ascending formation fluids of the Paleozoic flow domain;

3) The Mannville Group aquifer (MGA) acts to collect fluids rising from below it. Hydraulic and hydrochemical mapping have identified two areas where Paleozoic fluids flow cross-formationally up into the MGA:

i) ascending formation fluids of the Upper Devonian hydrogeologic group (UDHG) intersect the MGA in the area of the Wabamun Group subcrop in the northeast corner of the study area. Ascending saline brines and hydrocarbons from the UDHG mix with ambient MGA waters creating a saline plume in the Mannville Group aquifer;

ii) formation waters of the Elkton-Shunda aquifer (Mississippian hydrogeologic group) flow into the MGA in the southwest where the Elkton-Shunda aquifer extends beyond the eastern limit of the Fernie Group aquitard. The intersection of these two aquifers creates a source of formation waters in the MGA in the southwest and a smaller-magnitude saline plume in the MGA. This plume is not as distinct as the plume from the UDHG because of local-scale flow and mixing of Elkton-Shunda formation-waters with fresh MGA waters from the south.

4) The Joli Fou aquitard does not act as a regional seal for formation fluids and thus formation fluids are able to flow cross-formationally out of the MGA in the study area. In the southwest, the Joli Fou aquitard is absent which creates a permeable pathway between the MGA and the VGA. In the northeast, present-day flow rates on the order of 5.7×10^{-4} to

1.3 x 10^{-3} metres/year across the Joli Fou aquitard are calculated, based on measured hydraulic gradients and published shale permeabilities. These non-zero flow rates demonstrate the Joli Fou is not an impermeable seal. Furthermore, pressure transient analysis suggests that a 20 metre thick shale cannot act as an impermeable seal over geologic time.

5) In west-central Alberta, aquitard thicknesses play a key role in fluid migration. Regional-scale lateral up dip flows are generally found were thick aquitards can underlying aquifers. Conversely, flow regimes tend to become vertically ascending where overlying aquitards are reduced in thickness due to depositional facies changes, erosion, or non-deposition. This provides a mechanism for formation fluids to migrate cross-formationally across aquitards.

6) Cross-formational flow plays an important part in migration and entrapment of hydrocarbons in the subsurface. A better understanding of the processes leading to, and the results of, cross-formational flow can lead to increased hydrocarbon exploration efficiency.

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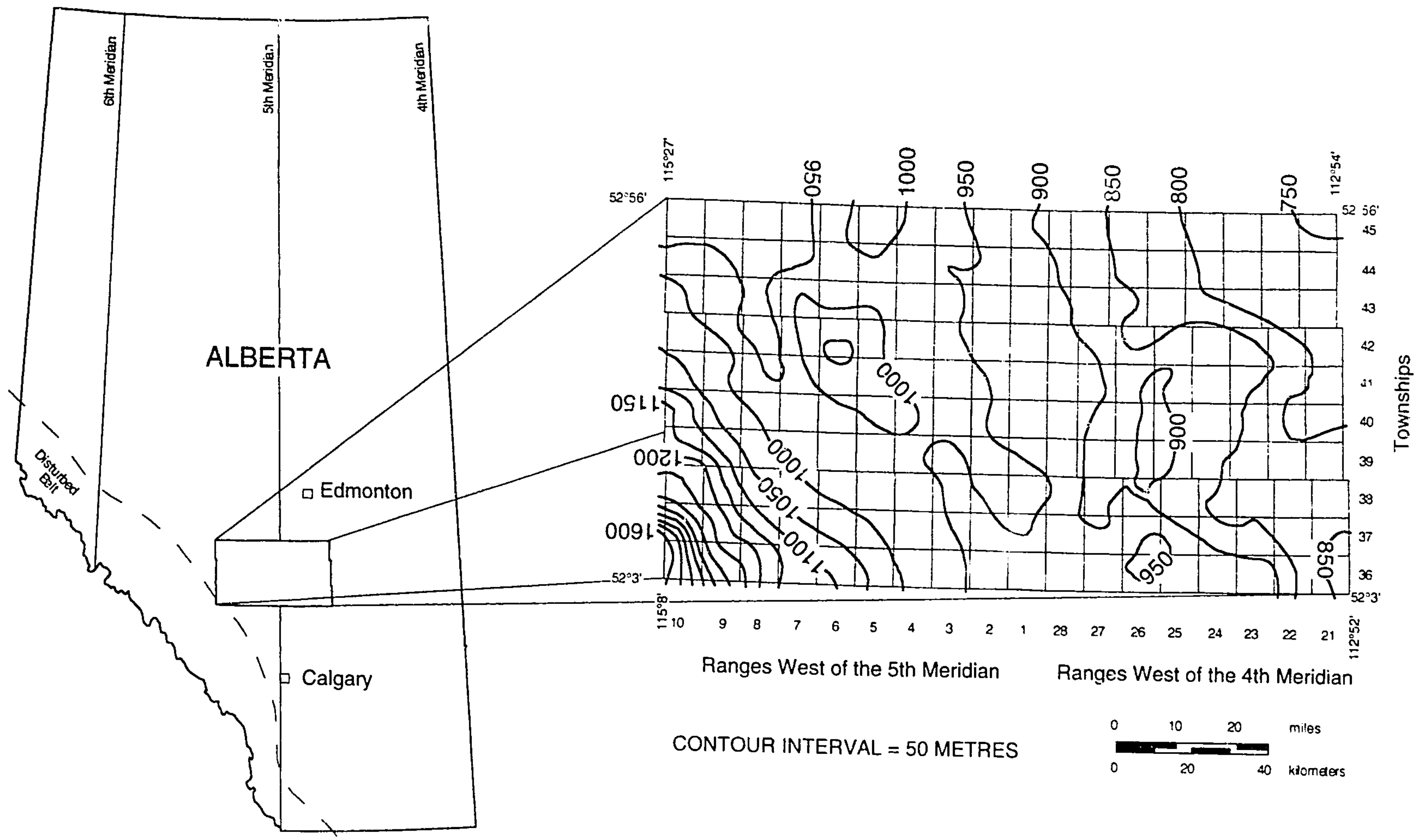

Figure 5.1. Location of the study area in west-central Alberta.

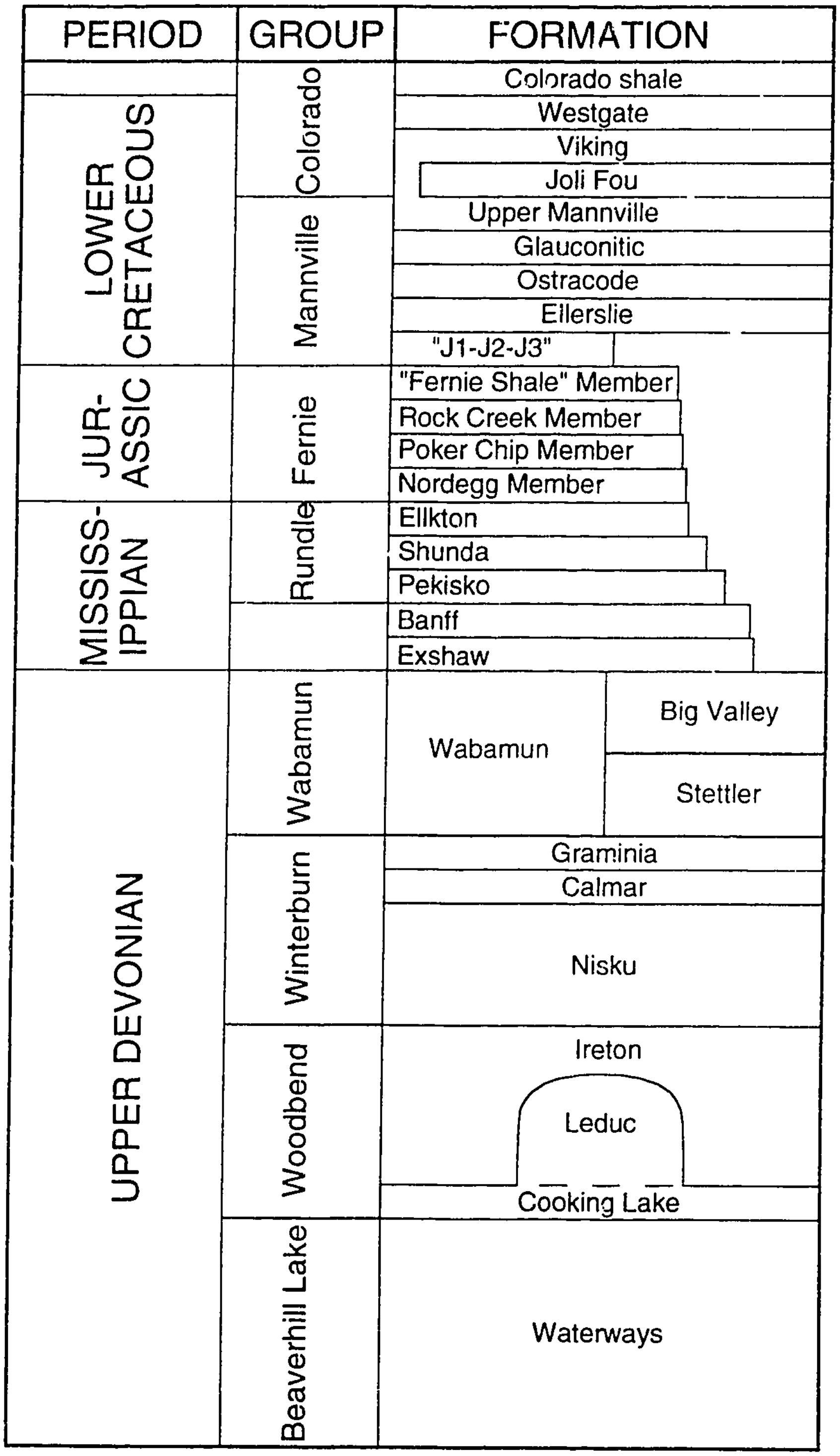

Figure 5.2. Schematic lithostratigraphic and hydrostratigraphic table for west-central Alberta.

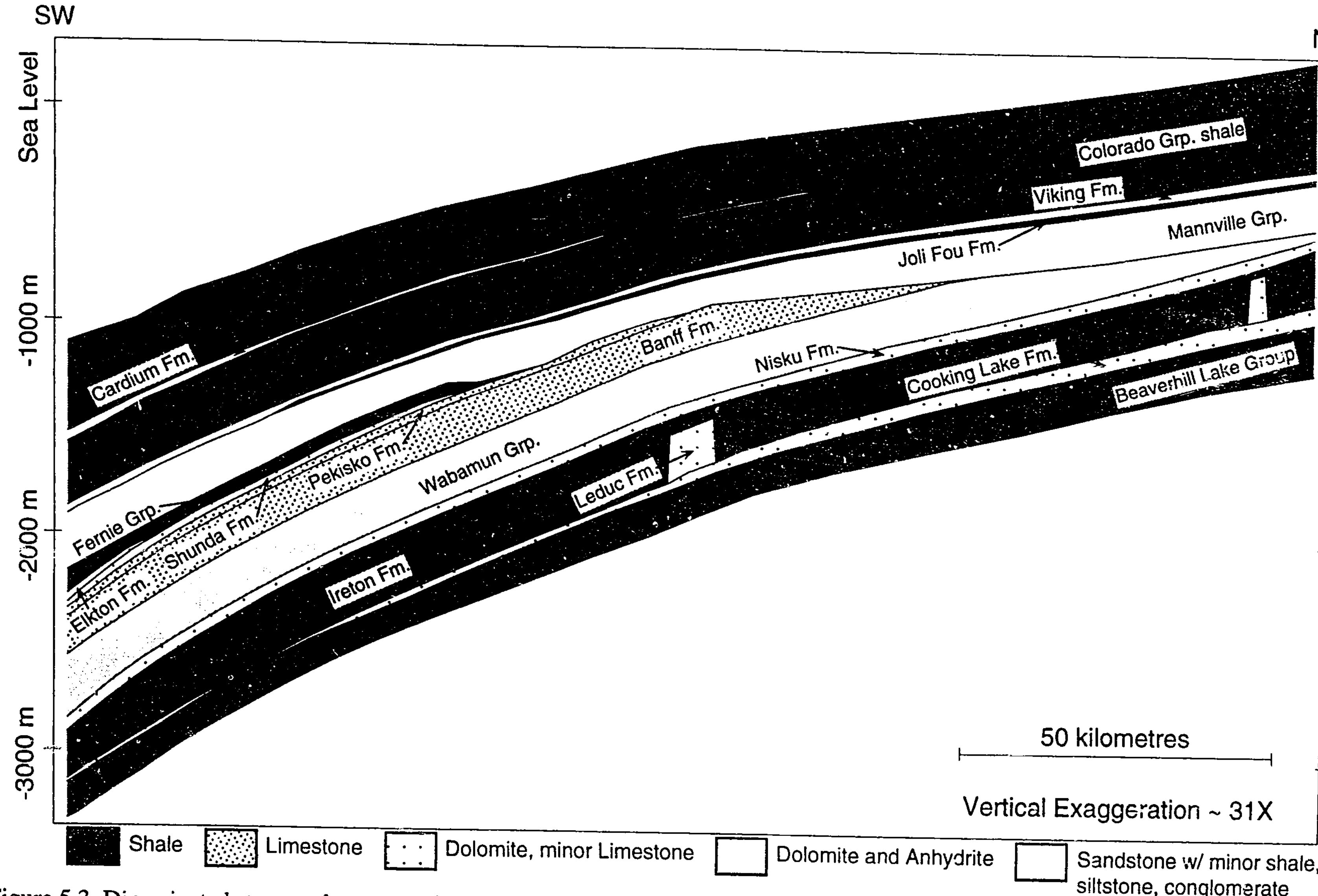

Figure 5.3. Dip-oriented structural cross-sections through Upper Devonian to Lower Cretaceous strata, west-central Alberta.

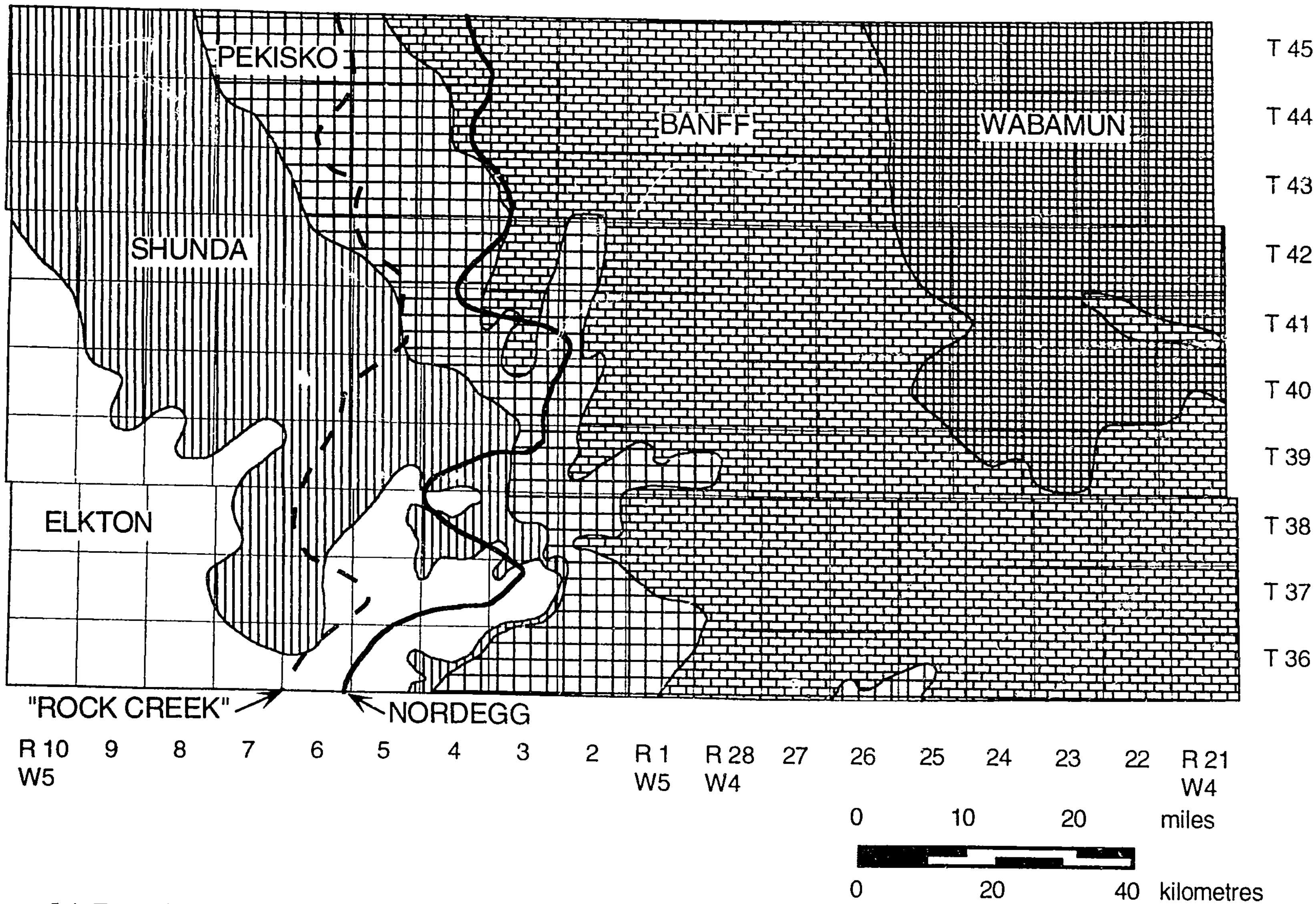

Figure 5.4. Zero edges (subcrop) of Devonian to Jurassic strata beneath the Mannville Group, west-central Alberta.

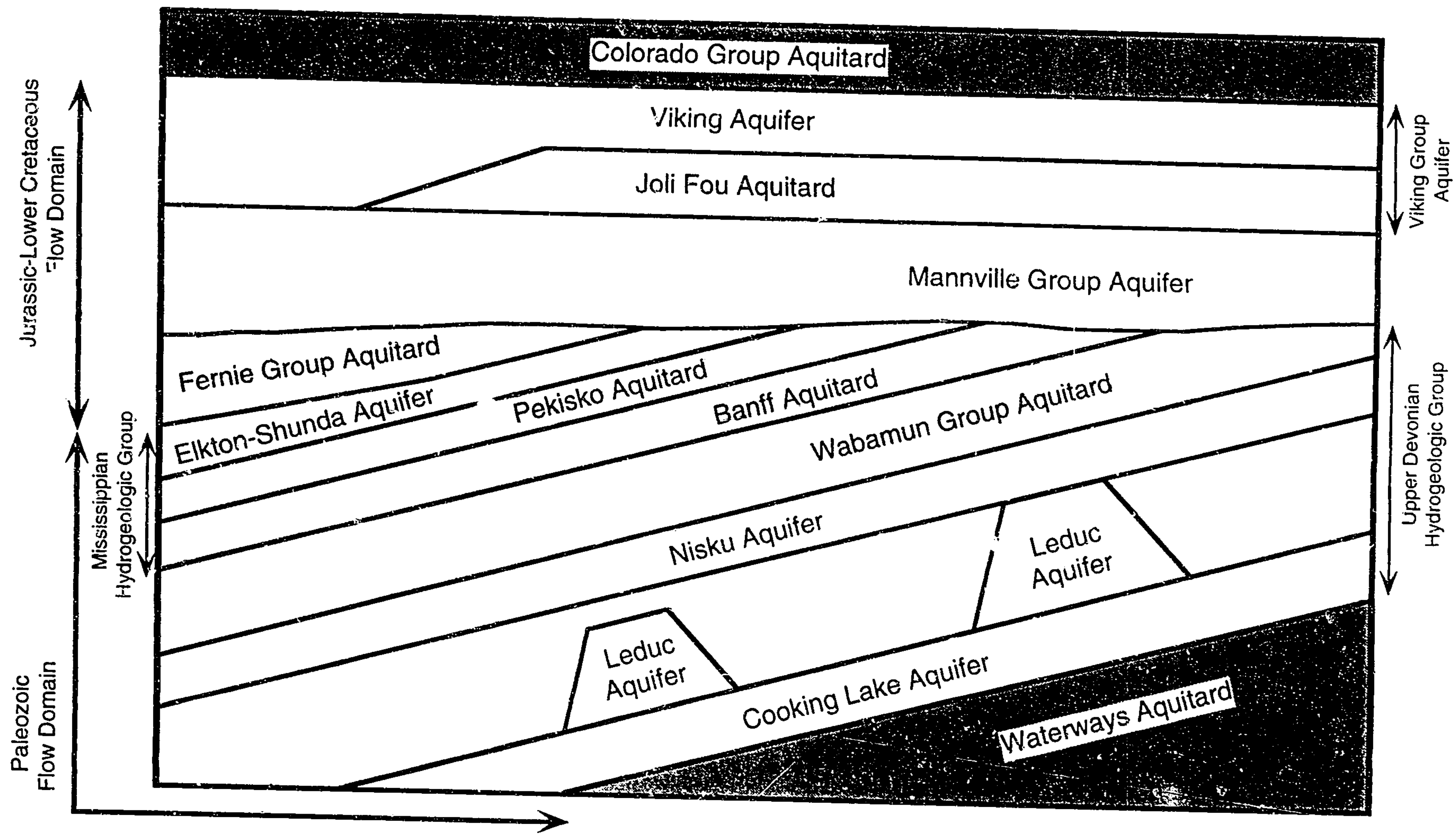

Figure 5.5. Schematic hydrostratigraphy for Upper Devonian to Lower Cretaceous strata, west-central Alberta.

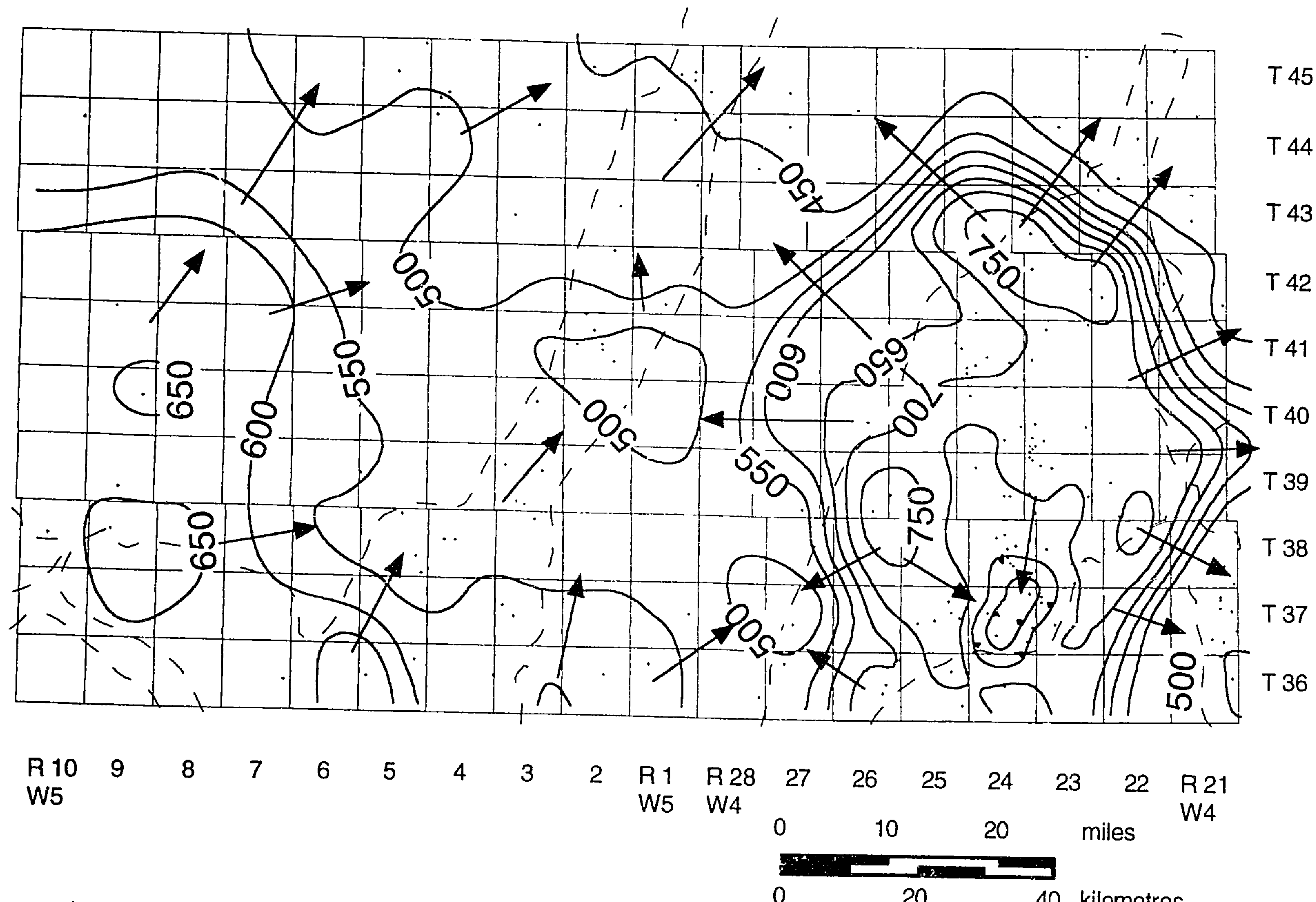

Figure 5.6. Hydraulic head distribution in the Nisku aquifer. Contour interval equals 50 meters of equivalent freshwater head. Dashed lines indicate the outlines of the permeable portions of the underlying Cooking Lake-Leduc reef trends.

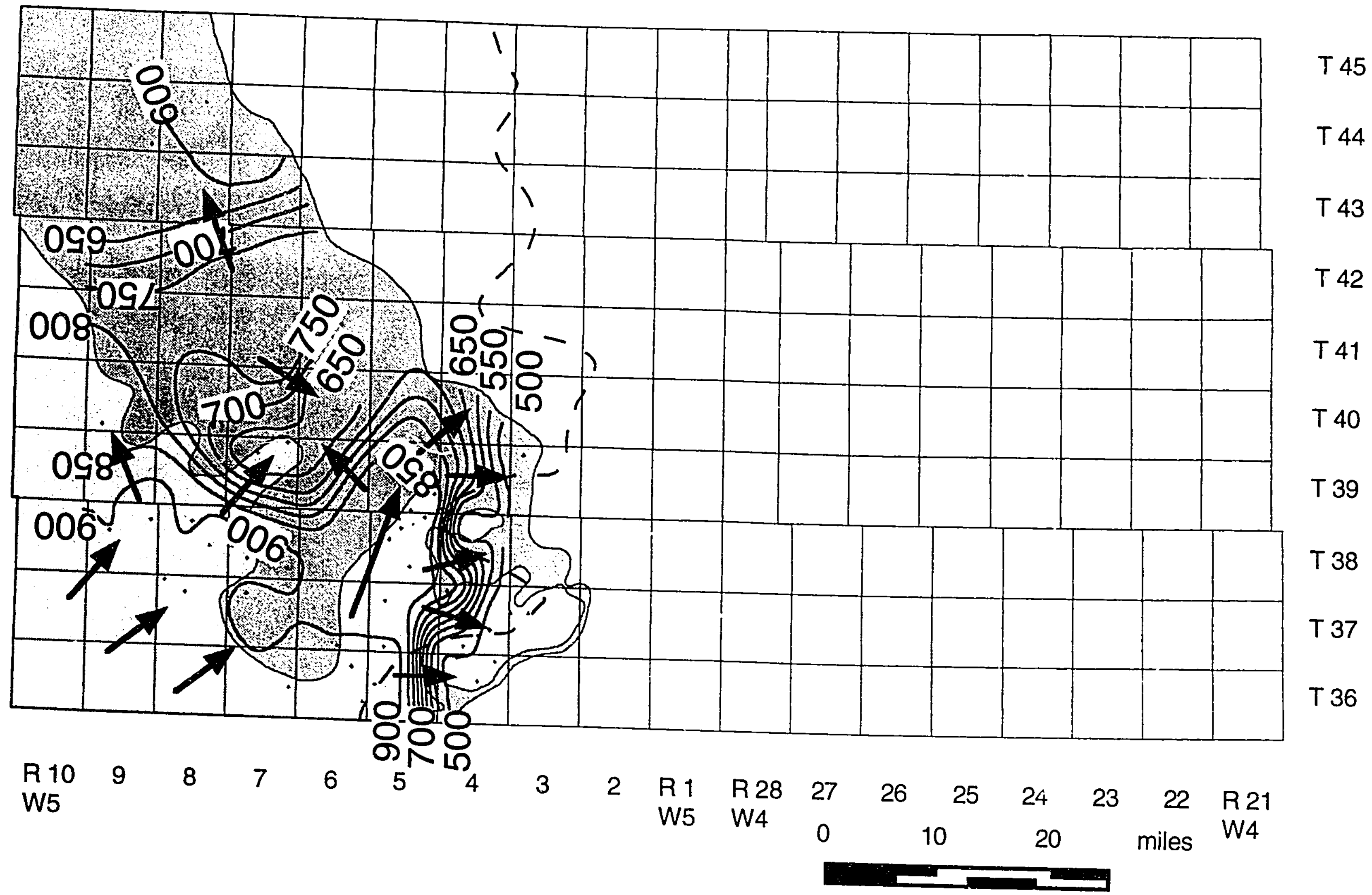

Figure 5.7. Hydraulic head distribution in the Elkton-Shunda aquifer. Contour interval equals 50 meters of equivalent freshwater head. Dashed line indicates the zero edge of the Fernie aquitard. Light shaded area indicates where the Elkton Formation is present. Dark shaded area indicates where the only the Shunda Formation is present.

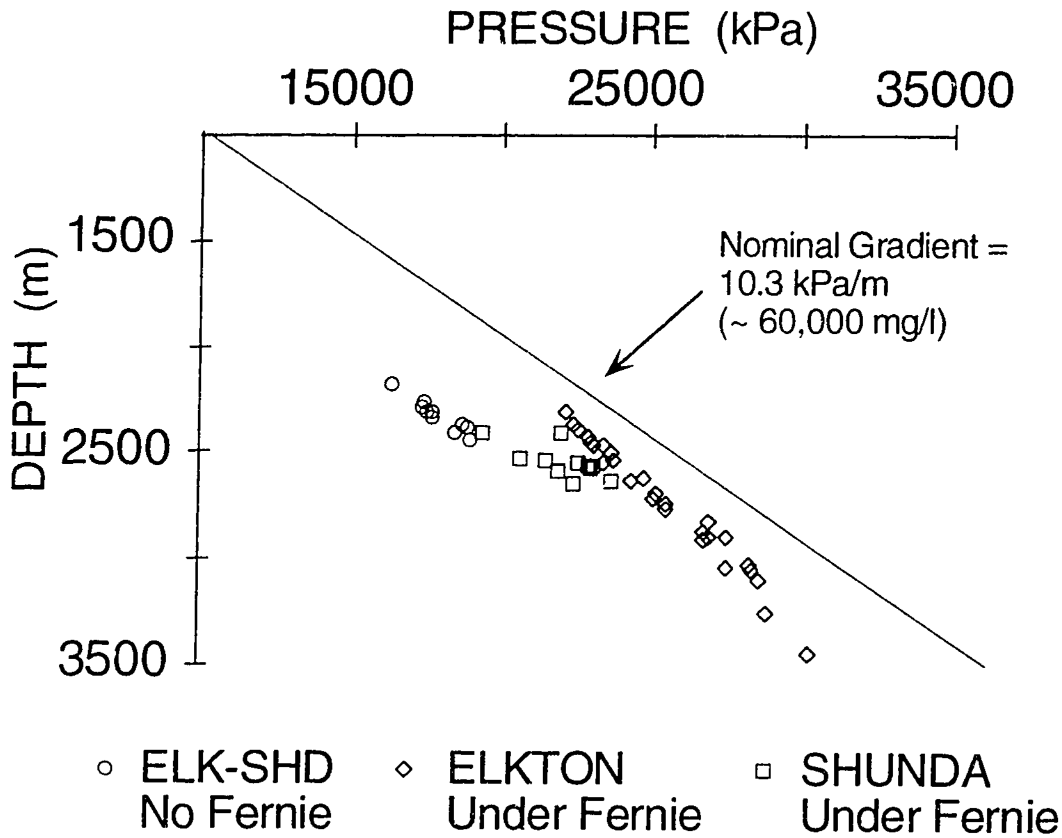

Figure 5.8. Pressure versus depth plot for the Elkton-Shunda aquifer. Pressure data shown in this figure are from pressure tests where water was the dominant fluid-phase recovered.

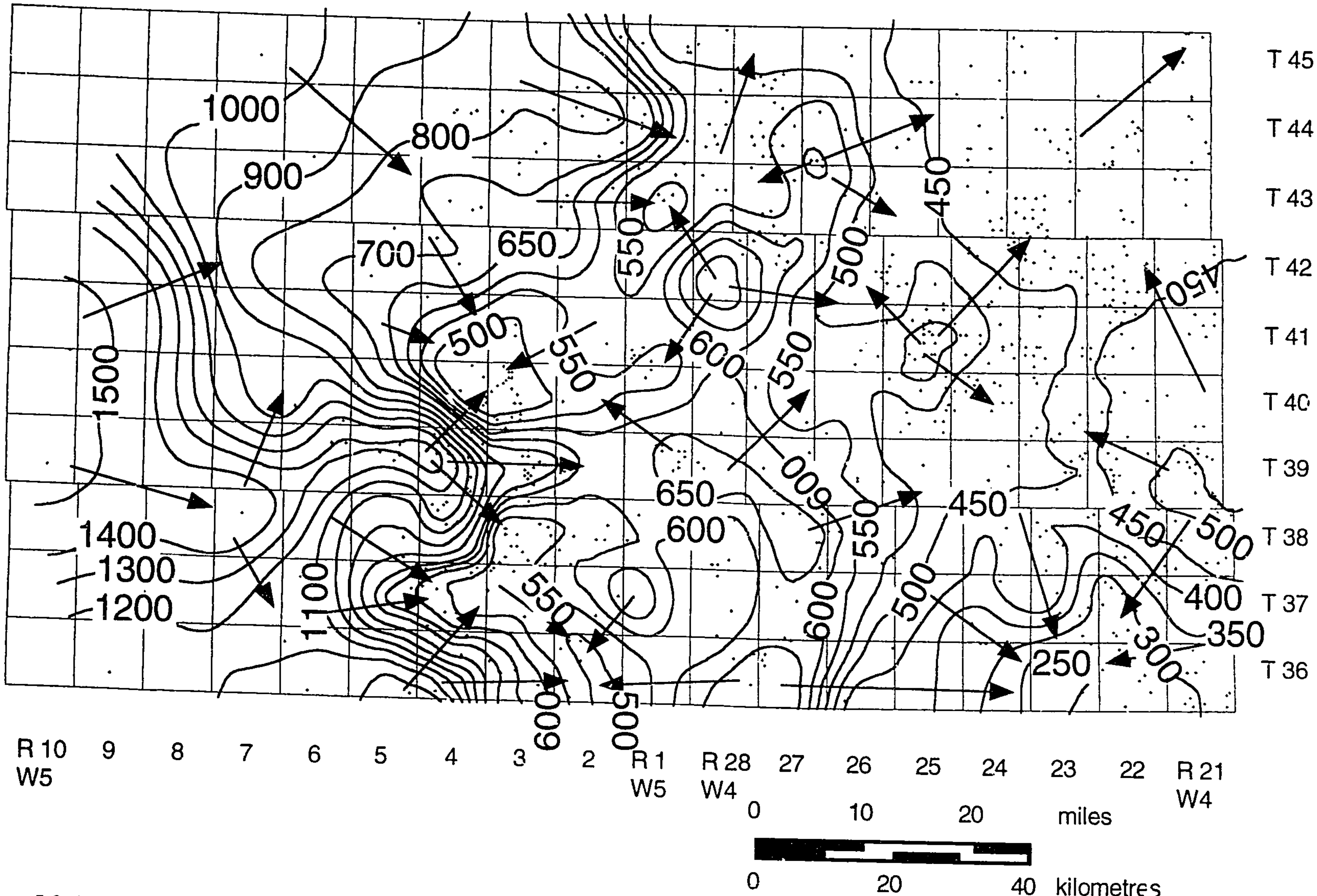

Figure 5.9. "Pseudo-potentiometric" surface of the Mannville Group aquifer. Contour interval is variable: 50 meters of equivalent freshwater head (below 700 metres) and 100 metres of equivalent freshwater head (above 700 metres).

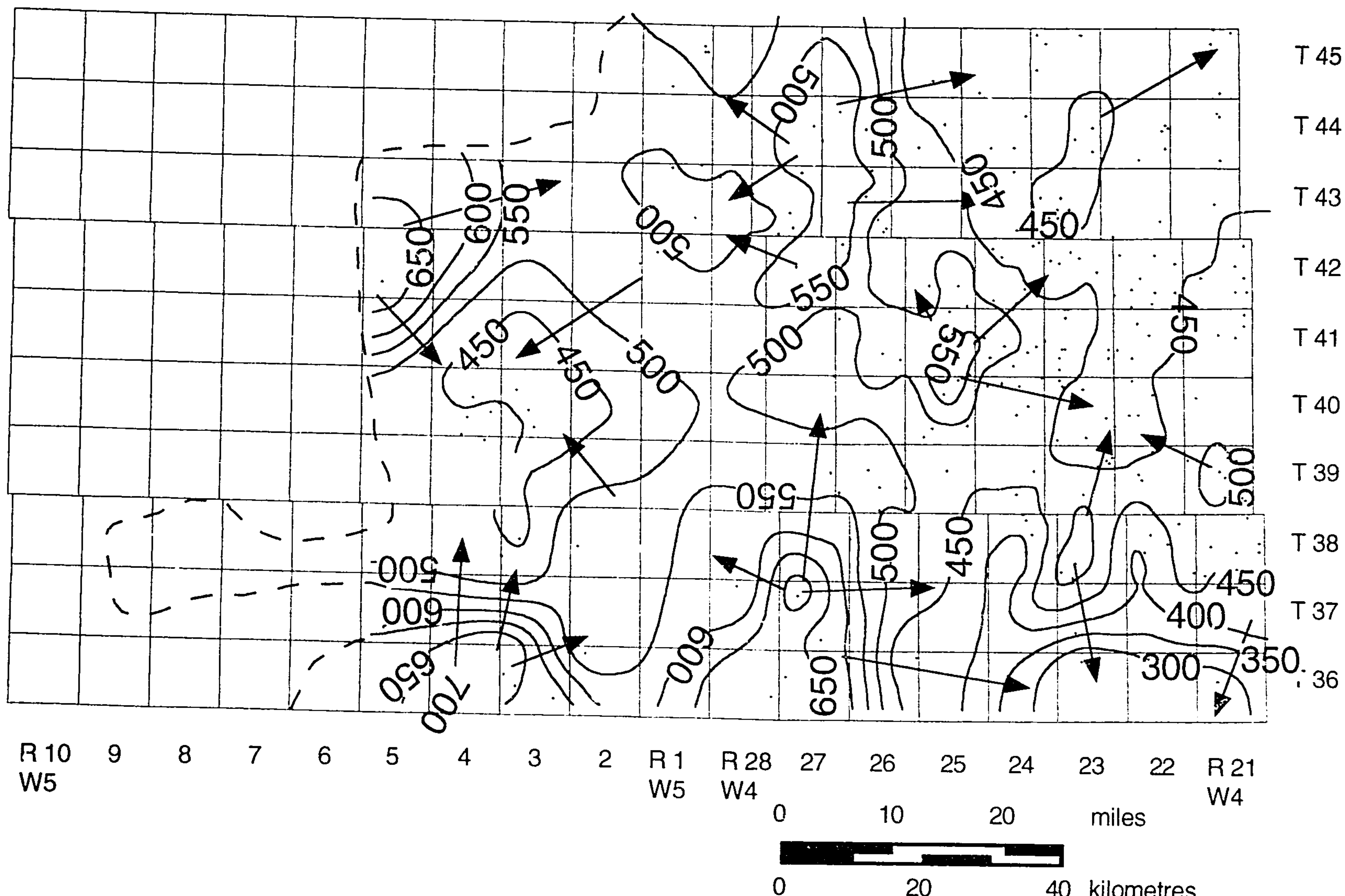

Figure 5.10. Hydraulic head distribution in the Mannville Group aquifer. Contour interval equals 50 meters of equivalent freshwater head. Dashed line indicates the western limit of the water-bearing region in the Mannville Group, that is, the boundary with the Deep Basin.

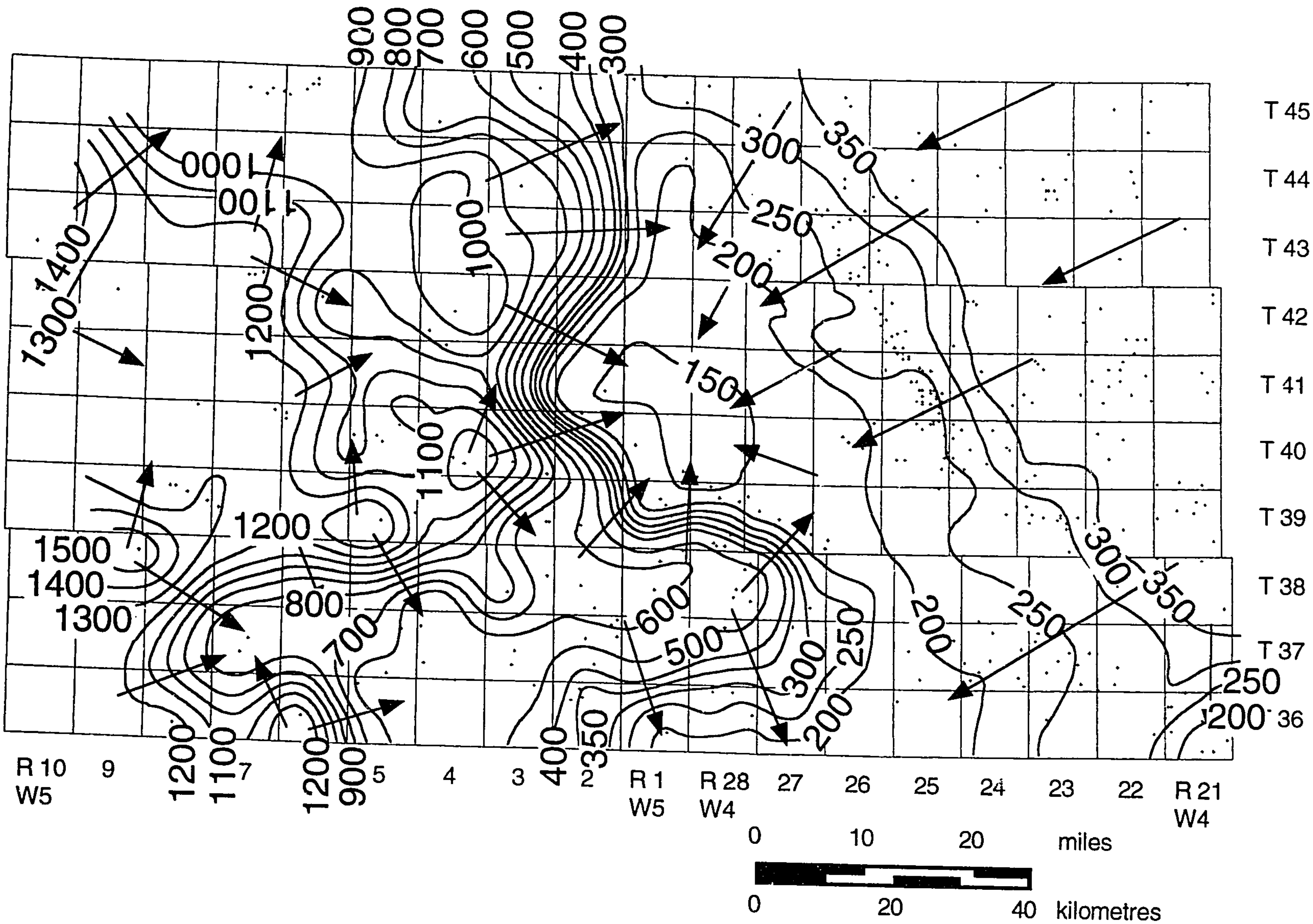

Figure 5.11. "Pseudo-potentiometric" surface of the Viking Group aquifer. Contour interval is variable: 50 meters of equivalent freshwater head (below 400 metres) and 100 metres of equivalent freshwater head (above 400 metres).

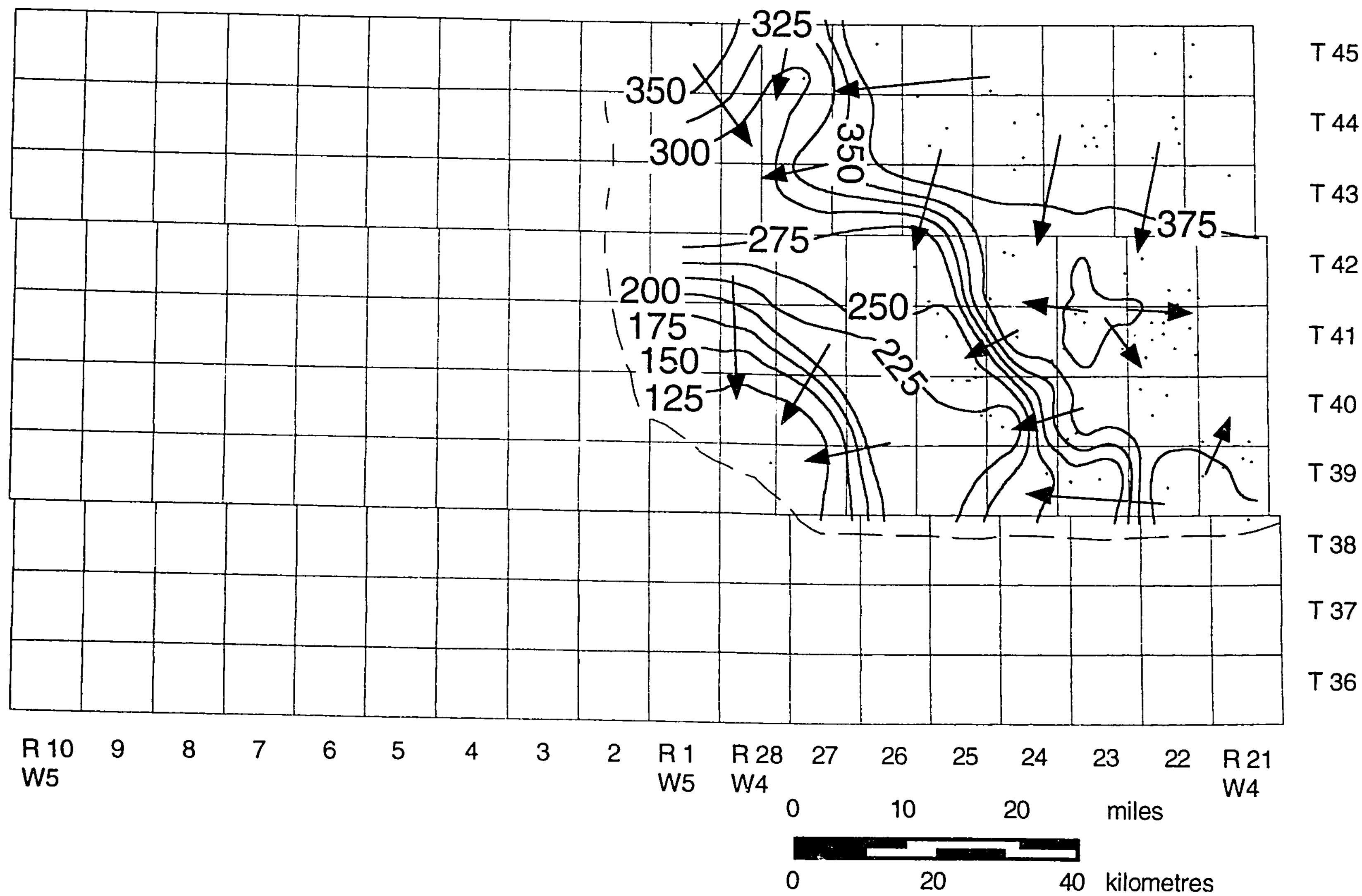

Figure 5.12. Hydraulic head distribution in the Viking Group aquifer. Contour interval equals 25 meters of equivalent freshwater head. Long-dashed line indicates the western limit of the water bearing region in the Viking Formation, that is, the boundary with the Deep Basin. Short-dashed line indicates where the boundary is uncertain.

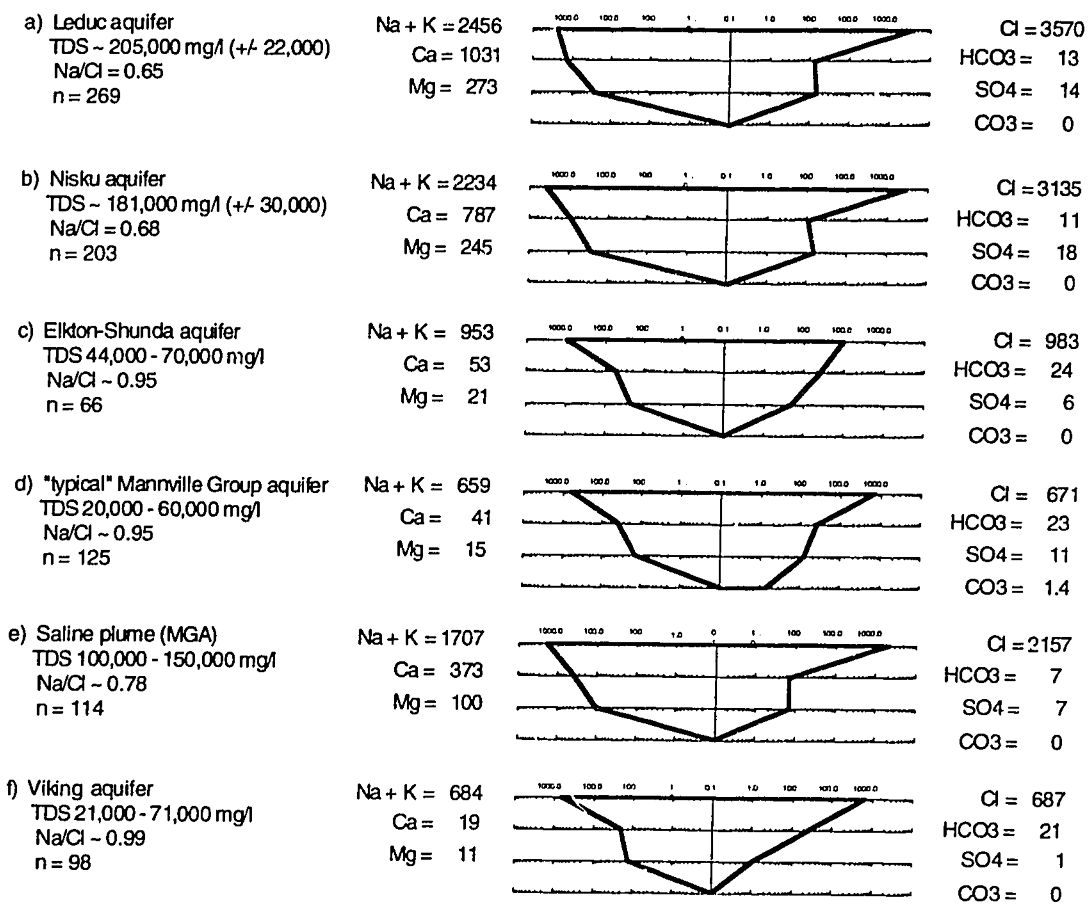

Figure 5.13. Stiff diagrams of averaged formation-water compositions for Upper Devonian to Lower Cretaceous aquifers in west-central Alberta. All chemical data are expressed in units of milliequivalents per litre.

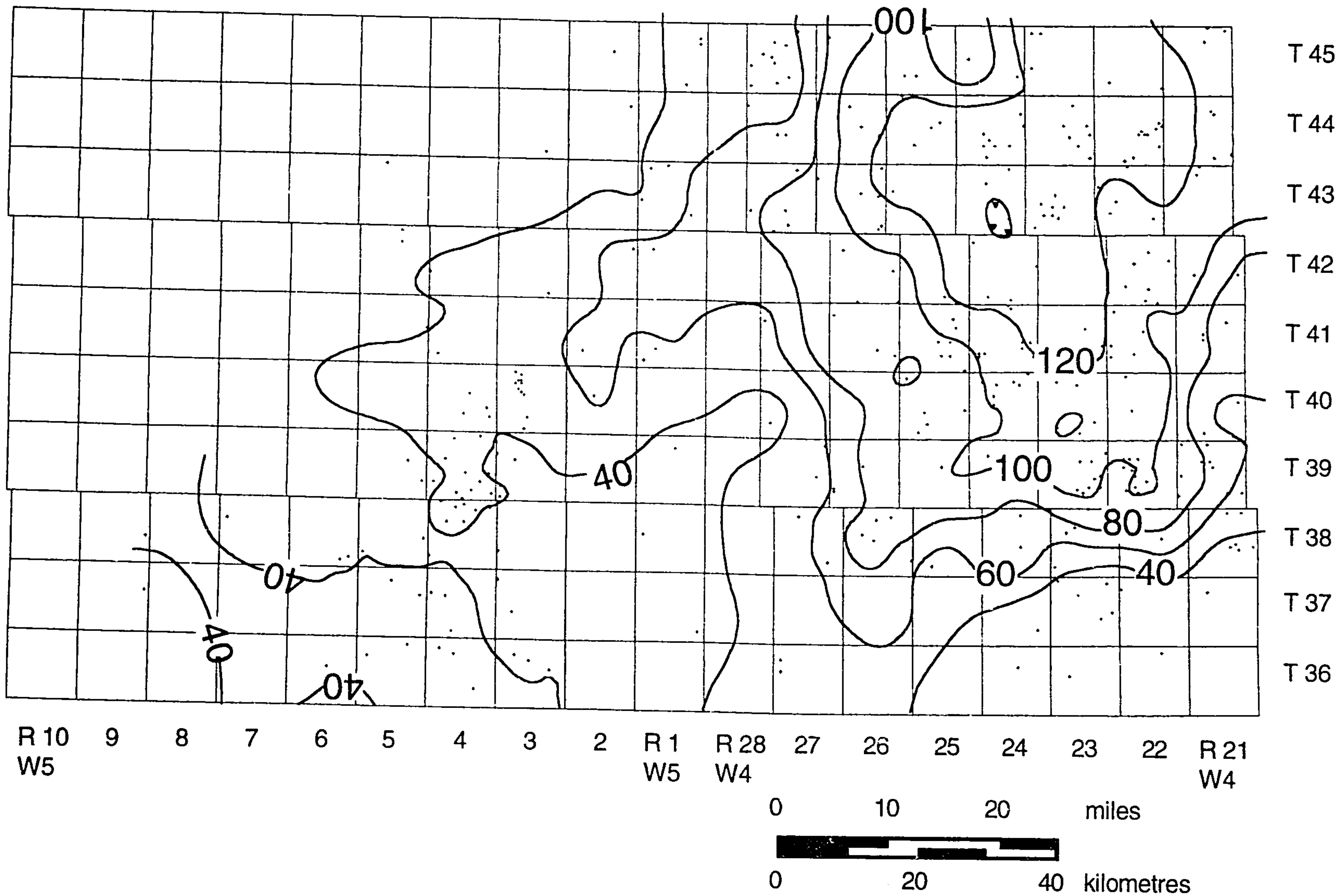

Figure 5.14. Total dissolved solids distribution for the Mannville Group aquifer. Contour interval equals 20 000 milligrams per litre.

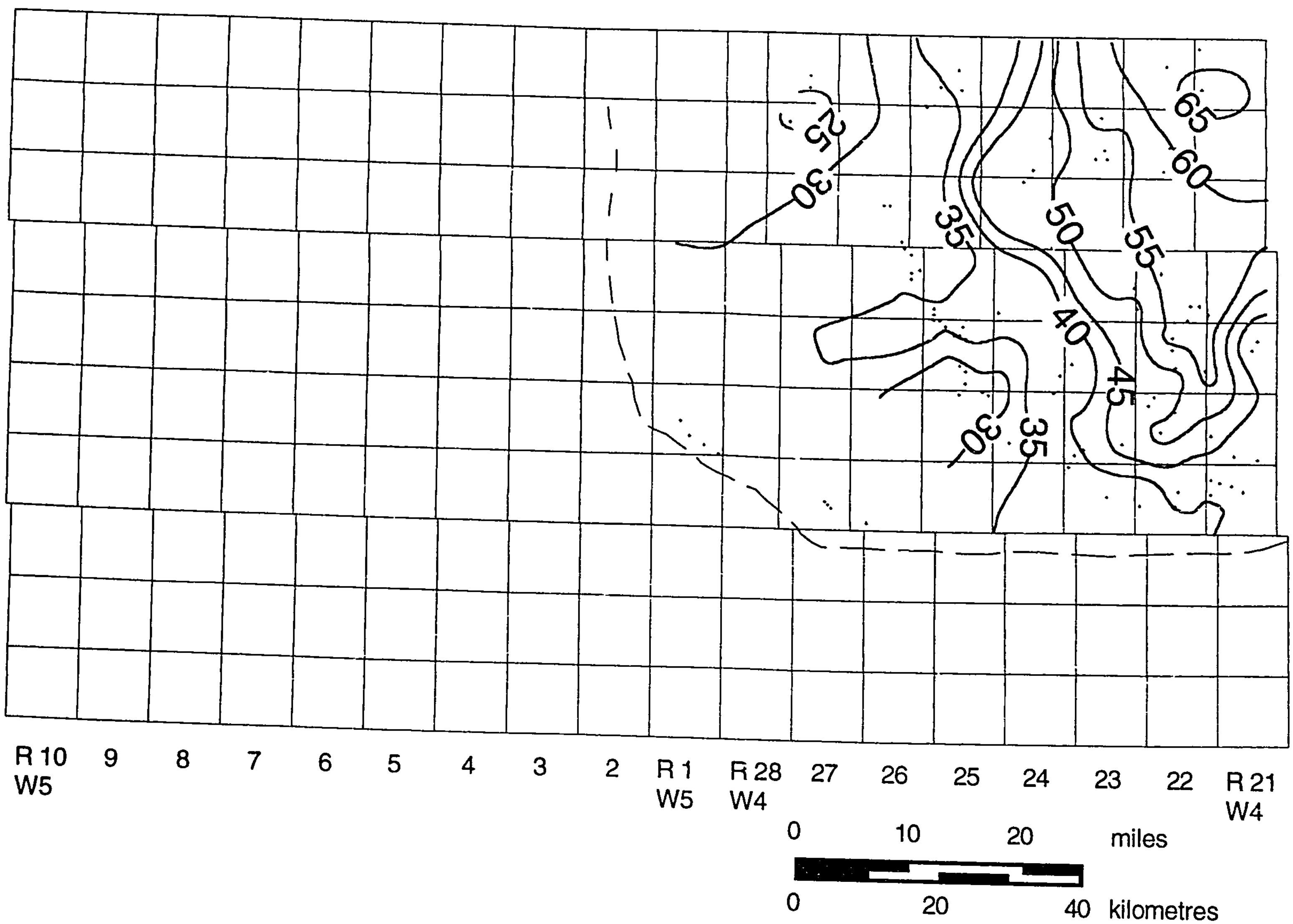

Figure 5.15. Total dissolved solids distribution for the Viking Group aquifer. Contour interval equals 5 000 milligrams per litre.

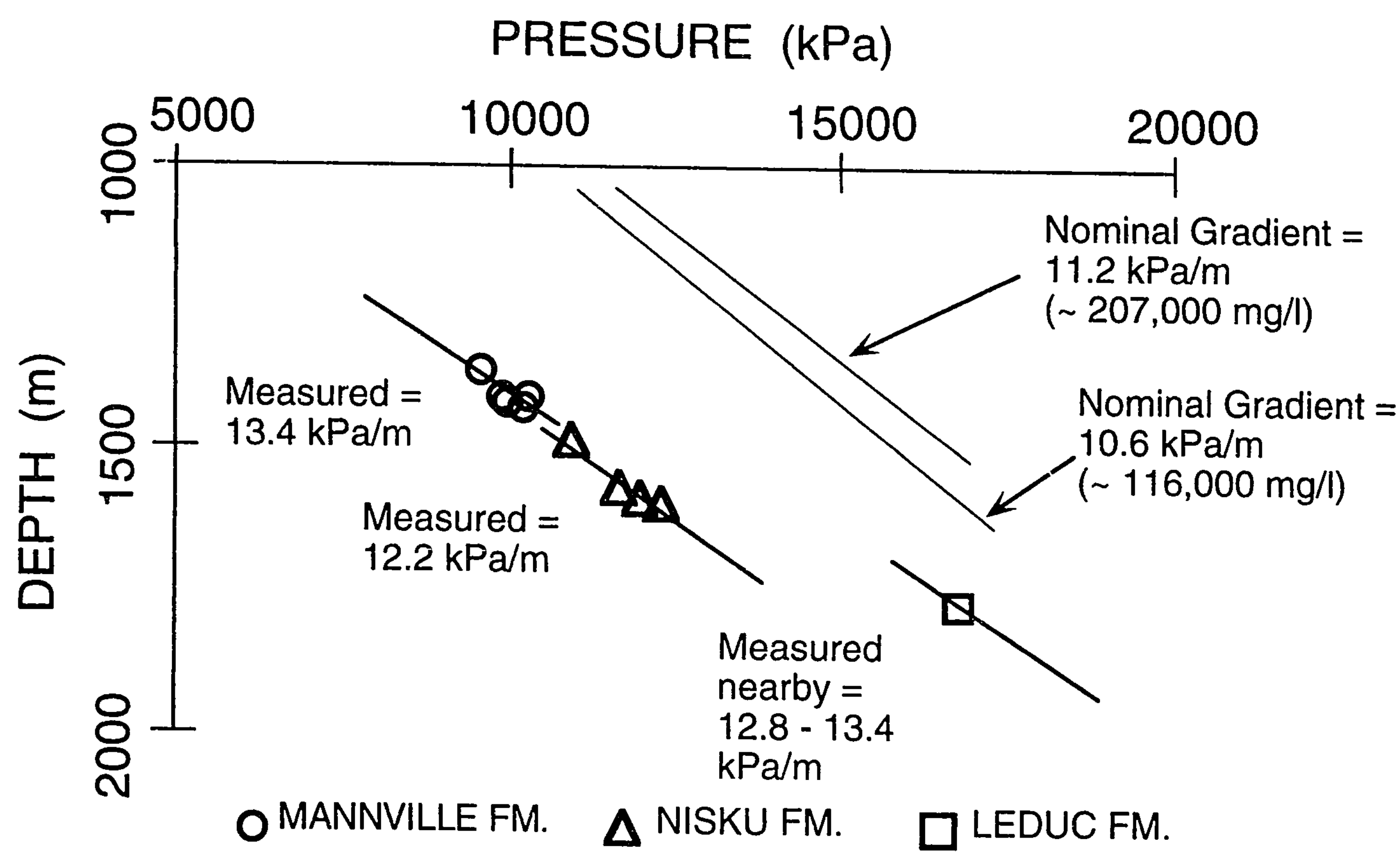

Figure 5.16. Composite pressure versus depth plot for the Leduc, Nisku, and Mannville Group aquifers in the northeastern part of the study area (Township 44, Range 22 W4M). Pressure data shown in this figure are from pressure tests where water was the dominant fluid phase recovered.

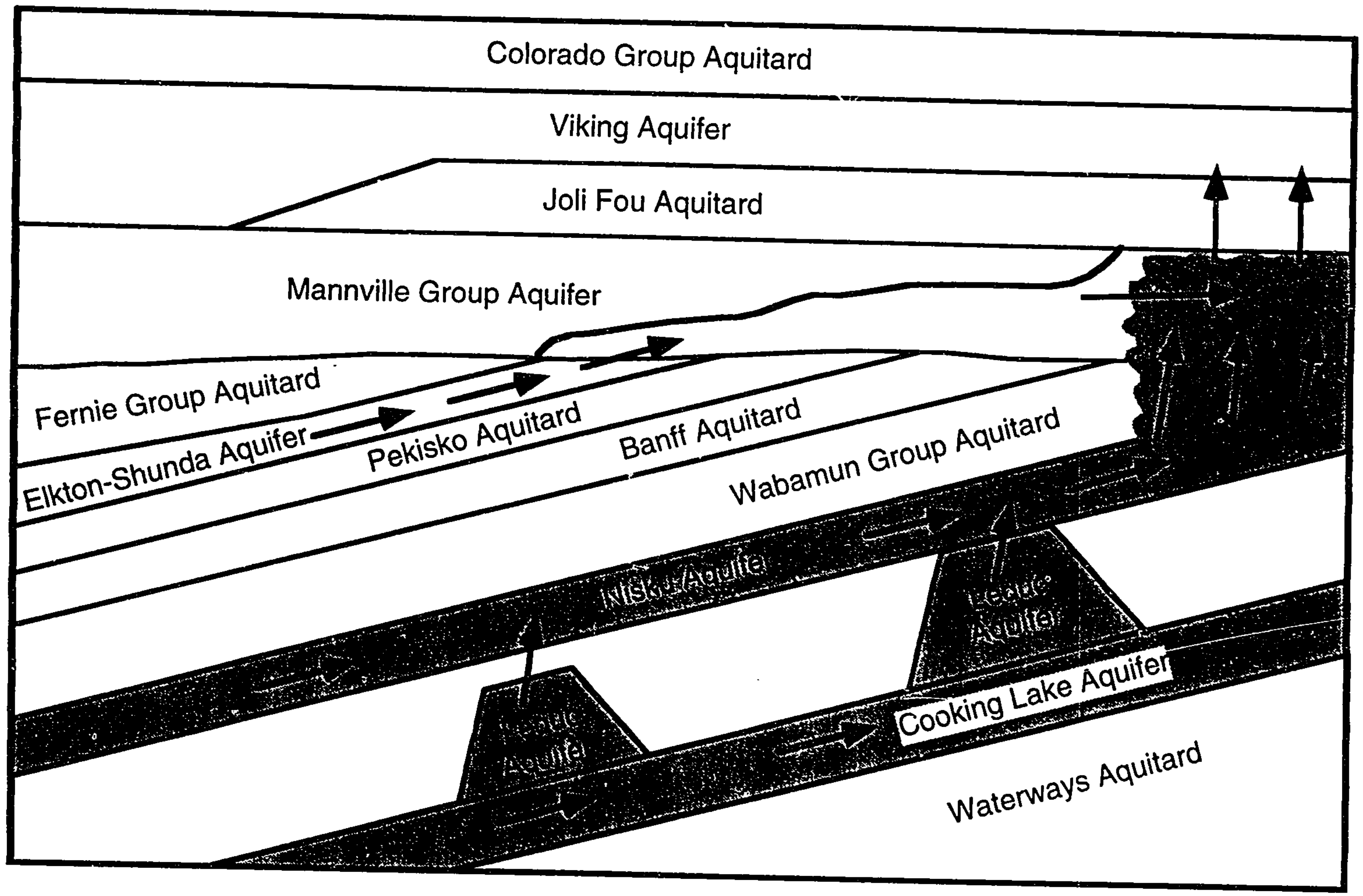

Figure 5.17. Summary of cross-formational flow regimes and their influence on the Mannville Group aquifer, west-central Alberta. Solid dark line in the Mannville Group aquifer schematically indicates the position of the Deep Basin boundary. Heavy-shaded area denotes the saline plume in the Mannville Group aquifer that is sourced from the UDHG.

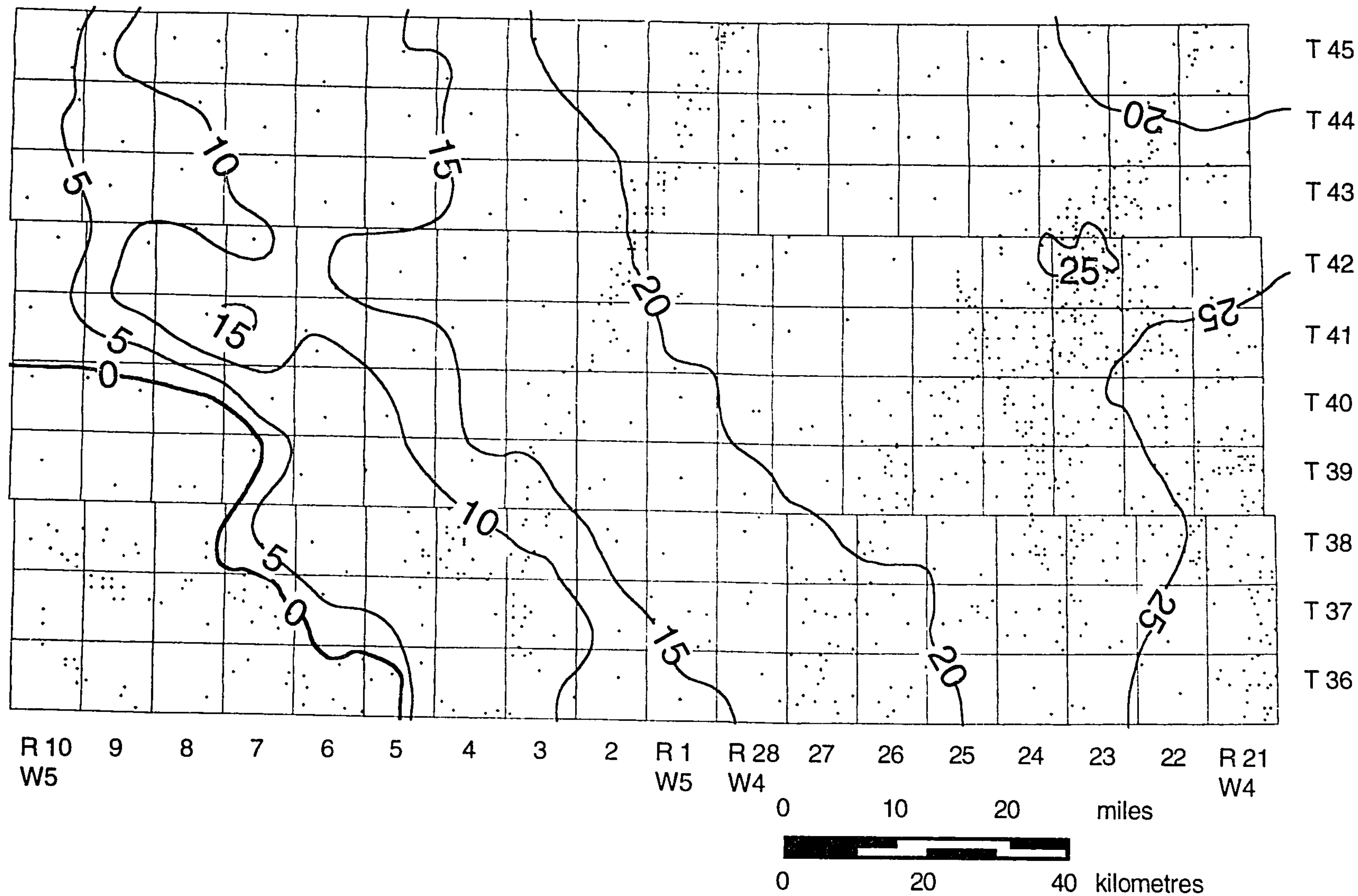

Figure 5.18. Isopach map of the Joli Fou aquitard. Contour interval equals five metres.

6.0 CONCLUSIONS

6.1 GENERAL

The results of this study demonstrate that regional and cross-formational fluid flow are occurring in the study area. It is clear that the subsurface flow field is hydraulically continuous, and not made up of sealed compartments.

In particular, results of mapping and numerical modelling presented in this paper can be grouped into three categories. Each of the three categories is discussed below.

6.1.1 Fluid Flow-Regime

Based on analysis of geology, fluid-pressure, water-chemistry, and hydrocarbon production data from west-central Alberta, the subsurface flow regime in the Western Canadian Sedimentary Basin consists of four large-scale flow domains. They are, in ascending order, the: Paleozoic; Jurassic-Lower Cretaceous; Upper Cretaceous; and shallow (Tertiary-Cretaceous) domains. Detailed descriptions of only the lower two are included here.

The Paleozoic flow domain is made up of two hydrogeologic groups: the Upper Devonian hydrogeologic group (UDHG) and the Mississippian hydrogeologic group (MHG). The three main aquifers in the Paleozoic domain are the Cooking Lake-Leduc aquifer and the Nisku aquifer, within the UDHG, and the Elkton-Shunda aquifer within in the MHG. Regional-scale flow directions in the UDHG depend upon the relative positions of the reef complexes to the thickness variations in the Ireton aquitard. In the Cooking Lake-Leduc aquifer, regional flow is directed laterally up the Rimbey-Meadowbrook reef trend to the north. In contrast, fluid flow in the Bashaw reef complex is dominantly ascending, upwards out of the Leduc Formation reefs into the overlying strata. Regional flow in the Nisku aquifer is up dip towards the northeast, except over the Bashaw reef complex where it is met from below by ascending flow the Cooking Lake-Leduc aquifer. In the Elkton-Shunda aquifer, flow is laterally up dip to the northeast outside the area of subcrop. Where the aquifer is eroded at the subcrop, flow is directed upward into the overlying Mannville Group aquifer (MGA).

Overlying the Paleozoic domain is the Jurassic-Lower Cretaceous flow domain. The Jurassic-Lower Cretaceous flow domain contains two aquifers: the Mannville Group aquifer (MGA) and the Viking Group aquifer (VGA). The Mannville Group aquifer (MGA) exhibits five main hydraulic features: 1) regionally, lateral up dip flow occurs towards the northeast; 2) very complex local-scale flow patterns exist with areas of down dip flow and many closed areas of high and low fluid potentials. These complexities are attributed to the presence of geologic heterogeneities and vertical flow within the relatively thick MGA; 3) formation pressures measured in the water phase are sub-normal with respect to hydrostatic throughout the MGA; 4) a boundary within the MGA separates the hydrocarbon-saturated Deep Basin to the west from the water-bearing sediments to the east. The boundary position varies areally across the study area and vertically in cross-section; and 5) pore-pressure distributions in the MGA reflect the intersection of MGA formation waters with the ascending formation fluids of the Paleozoic flow domain.

In the Viking Group aquifer fluid pressures are strongly underpressured, and flow directions inferred from potentiometric surface maps indicate down dip flow. Mobile formation waters in the VGA are confined to the northeast corner of the study area. Cross-formational flow from the MGA appears to provide the source of the formation water in this area.

6.1.2 Cross-formational Flow

Cross-formational flow was identified across three main aquitards in the study area: the Ireton, Wabamun Group, and Joli Fou aquitards. Cross-formational flow across the Ireton aquitard occurs in the Bashaw reef complex where the Ireton aquitard is less than 25 metres thick. Geologic mapping has revealed 28 well locations in the Bashaw reef complex where the Ireton aquitard is totally absent. Thinning of the Ireton aquitard allows higher energy Cooking Lake-Leduc formation-fluids to migrate vertically upward. Cross-formational flow within the study area creates plumes of Cooking Lake-Leduc formation waters in the overlying Nisku and Mannville Group aquifers. These plumes are recognizable because of the observed salinity contrasts between "typical" Cooking Lake-Leduc, Nisku, and Mannville Group formation waters.

The Mannville Group aquifer (MGA) acts to collect fluids rising from below it. Hydraulic and hydrochemical mapping identified two areas where Paleozoic fluids flow cross-formationally up into the MGA: 1) ascending formation fluids of the Upper Devonian hydrogeologic group (UDHG) intersect the MGA in the area of the Wabamun Group subcrop in the northeast corner of the study area. Ascending saline brines and hydrocarbons from the UDHG mix with ambient MGA waters creating a saline plume in the Mannville Group aquifer; 2) formation waters of the Elkton-Shunda aquifer (Mississippian hydrogeologic group) flow into the MGA in the southwest where the Elkton-Shunda aquifer extends beyond the eastern limit of the Fernie Group aquitard. The intersection of these two aquifers creates a source of formation waters in the MGA in the southwest and a smaller-magnitude saline plume in the MGA. This plume is not as distinct as the plume from the UDHG because of local-scale flow and mixing of Elkton-Shunda formation-waters with fresher MGA waters from the south.

The Joli Fou aquitard does not act as a regional seal for formation fluids. Cross-formational flow of formation fluids occurs out of the MGA in the study area. In the southwest, the Joli Fou aquitard is absent which creates a permeable pathway between the MGA and the VGA. In the northeast, present-day flow rates of approximately 5.7×10^{-4} to 1.3×10^{-3} metres/year across the Joli Fou aquitard were calculated, based on measured hydraulic gradients and published shale permeabilities. These non-zero flow rates demonstrate that the Joli Fou aquitard is not an impermeable seal.

In west-central Alberta, aquitard thicknesses play a key role in fluid migration. Regional-scale lateral up dip flow systems are generally found when thick overlying aquitards are present. Conversely, flow tends to become vertically ascending where overlying aquitards are reduced in thickness due to depositional facies changes, erosion, or non-deposition. This provides a mechanism for formation fluids to migrate cross-formationally across aquitards.

6.1.3 Influence on Hydrocarbon Trapping

The influence of cross-formational flow on hydrocarbon trapping in the study area is most pronounced in the UDHG. Trapping in both the Leduc and Nisku formations is related to the thickness of the Ireton aquitard. Correlations between shale thickness and hydrocarbon pools reveal: 1) with less that six metres of Ireton aquitard there are no pools in the Leduc Formation; 2) in areas with greater than six metres of Ireton aquitard present, trapping occurs in the Leduc Formation, but the traps are not filled to their spill points and there is upward leakage of hydrocarbons; 3) one group of hydrocarbon pools in the Nisku Formation is located directly over breaches in the Ireton aquitard; 4) a second group of hydrocarbon pools in the Nisku Formation is located up dip less than five kilometres from direct breaches in the Ireton aquitard; these pools are presumably filled by short distance lateral migration after cross-formational migration or by migration through the Ireton aquitard; 5) a third group of pools in the Nisku Formation is located down dip of direct breaches; these pools are either sourced by unknown breaches farther down dip, or by cross-formational migration through the Ireton aquitard.

In the Rimbey-Meadowbrook reef trend, hydrocarbon trapping conditions contrast those in the Bashaw reef complex. Leduc Formation pools have substantially larger hydrocarbon columns and are generally filled to their spill points because the Ireton aquitard above the reefs in the main part of this trend is at least 35 metres thick. Migration and trapping generally follow Gussow's theory of differential entrapment, although better match between observed fluid distributions and those predicted by the original model could be obtained if the hydraulic properties of the cap-rock were included in the migration analysis.

Hydrocarbons must have migrated across the Ireton aquitard in the Rimbey-Meadowbrook reef trend because Nisku Formation pools above Leduc Formation reefs in the Rimbey-Meadowbrook reef trend contain Duvernay-Formation sourced hydrocarbons. Thus, hydrocarbons must be able to traverse in excess of 35 metres of Ireton aquitard in at least some locations, or more likely there are unfound breaches in the Ireton aquitard to the south of the study area.

Finally, the observations of migration and trapping from the Bashaw reef complex the concept of vertical migration through shales may be applied to explore for other hydrocarbon traps above Leduc Formation reefs. One place could be the Rimbey-Meadowbrook reef trend.

6.2 THESES

The scientific contributions of this work can be stated as follows:

1) The subsurface flow field in the Devonian to Lower Cretaceous strata of west-central Alberta consists of two large-scale flow domains: the Paleozoic and Jurassic-Lower Cretaceous domains.

2) Cross-formational fluid flow occurs within the Western Canada Sedimentary Basin. In west-central Alberta, flow occurs across three of the basin-wide aquitards present in the subsurface (Ireton, Wabamun, and Joli Fou aquitards).

3) The Ireton aquitard is not an impermeable seal to fluid flow as postulated by Hunt (1990), Powley (1990), and Bradley and Powley (1994). In numerous places in west-central Alberta, the Ireton aquitard is thin or absent, creating preferential pathways for cross-formational migration of water, oil, and gas.

4) Hydrocarbons and saline waters are leaking upward from the Leduc Formation in the Rimbey-Meadowbrook and Bashaw reef trends. Exploration in the Nisku Formation should be conducted above the Rimbey-Meadowbrook reef trend.

5) The model of differential entrapment of hydrocarbons (Gussow, 1954) can better fit the observed distribution of hydrocarbons in the Rimbey-Meadowbrook reef trend if the hydraulic properties of the cap-rocks are included in the model.

6) Hydrocarbon trapping in the Nisku and Leduc formations (Bashaw and Rimbey-Meadowbrook reef trends) is controlled primarily by the thickness of the Ireton aquitard.

7) A large saline plume exists in the Mannville Group aquifer. The plume is caused by upward cross-formational flow of Devonian formation fluids into the Mannville Group.

8) The Joli Fou aquitard is not a regional barrier to fluid flow as postulated by Creaney and Allan (1990, 1992), Creaney et al. (1994), and Bradley and Powley (1994). This aquitard is absent from the southwestern part of the study area and thus cannot provide a resistance to fluid flow. Where the shale is present in the northeast, flow rates of 5.7×10^{-4} to 1.3×10^{-3} metres/year occur across it.

9) The model of sealed compartments of Hunt (1990), Powley (1990), and Bradley and Powley (1994) does not apply to the Western Canadian Sedimentary Basin.

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