Subsurface Characterization of the Pembina-Wabamun Acid-Gas Injection Area

Energy Resources Conservation Board

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1 Introduction

Over the past decade, oil and gas producers in western Canada (Alberta and British Columbia) have been faced with a growing challenge to reduce atmospheric emissions of hydrogen sulphide (H_2S), which is produced from "sour" hydrocarbon pools. Sour oil and gas are hydrocarbons that contain H_2S and carbon dioxide (CO_2), which have to be removed before the produced oil or gas is sent to markets. Since surface desulphurization through the Claus process is uneconomic, and the surface storage of the produced sulphur constitutes a liability, increasingly more operators are turning to acid gas disposal by injection into deep geological formations. Acid gas is a mixture of H_2S and CO_2, with minor traces of hydrocarbons, that is the byproduct of "sweetening" sour hydrocarbons. In addition to providing a cost-effective alternative to sulphur recovery, the deep injection of acid gas reduces emissions of noxious substances into the atmosphere and alleviates the public concern resulting from sour gas production and flaring.

The first acid-gas injection operation was started in 1989 in Alberta. To date, 42 injection sites have been approved in Alberta and British Columbia; their locations are shown in Figure 1. In Alberta, the Oil and Gas Conservation Act requires that operators apply for and obtain approval from the Alberta Energy and Utilities Board (AEUB), the provincial regulatory agency, to dispose of acid gas. Before approving any operation, the AEUB reviews the application to maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety. To adequately address these matters, the AEUB requires that the applicants submit information regarding surface facilities, injection well configurations, characteristics of the injection reservoir or aquifer, and operations. After approval for acid gas injection is granted, the operators have to submit to the regulatory agencies biannual progress reports on the operations.

Although the purpose of the acid-gas injection operations is to dispose of H_2S, significant quantities of CO_2 are being injected at the same time because it is costly to separate the two gases. Actually, more CO_2 than H_2S has been injected to date into deep geological formations in western Canada. In the context of current efforts to reduce anthropogenic emissions of CO_2, these acid-gas injection operations represent an analogue to geological storage of CO_2. The latter is an immediately-available and technologically-feasible means of reducing CO_2 emissions into the atmosphere that is particularly suited for land-locked regions located on sedimentary basins, such as the Alberta Basin in western Canada. Large-scale injection of CO_2 into depleted oil and gas reservoirs and into deep saline aquifers is one of the most promising methods of geological storage of CO_2, and in this respect it is no different from acid-gas injection operations. However, before implementation of greenhouse gas geological storage, a series of questions needs addressing, the most important ones relating to the short- and long-term fate of the injected CO_2. Thus, the study of the acid-gas injection operations in western Canada provides the opportunity to learn about the safety of these operations and about the fate of the injected gases, and represents a unique opportunity to investigate the feasibility of CO_2 geological storage.

Geographically, the acid-gas injection operations in western Canada can be grouped in several clusters (Figure 1). The operations located in the cluster situated southwest of Edmonton in the Brazeau-Pembina area inject acid gas in the Upper Devonian Winterburn and Wabamun groups. At the Brazeau site, acid gas is injected into the Nisku Q Pool in the Winterburn Group, and this operation was the subject of a previous study. At three other sites injection takes place into the overlying Wabamun Group. The fourth site, although approved by AEUB, was never implemented by the operator. The subsurface characterization of the operations in the Pembina area that inject acid gas into the Wabamun Group will help in understanding various issues that relate to the disposal and/or sequestration of acid and greenhouse gases in geological media. The

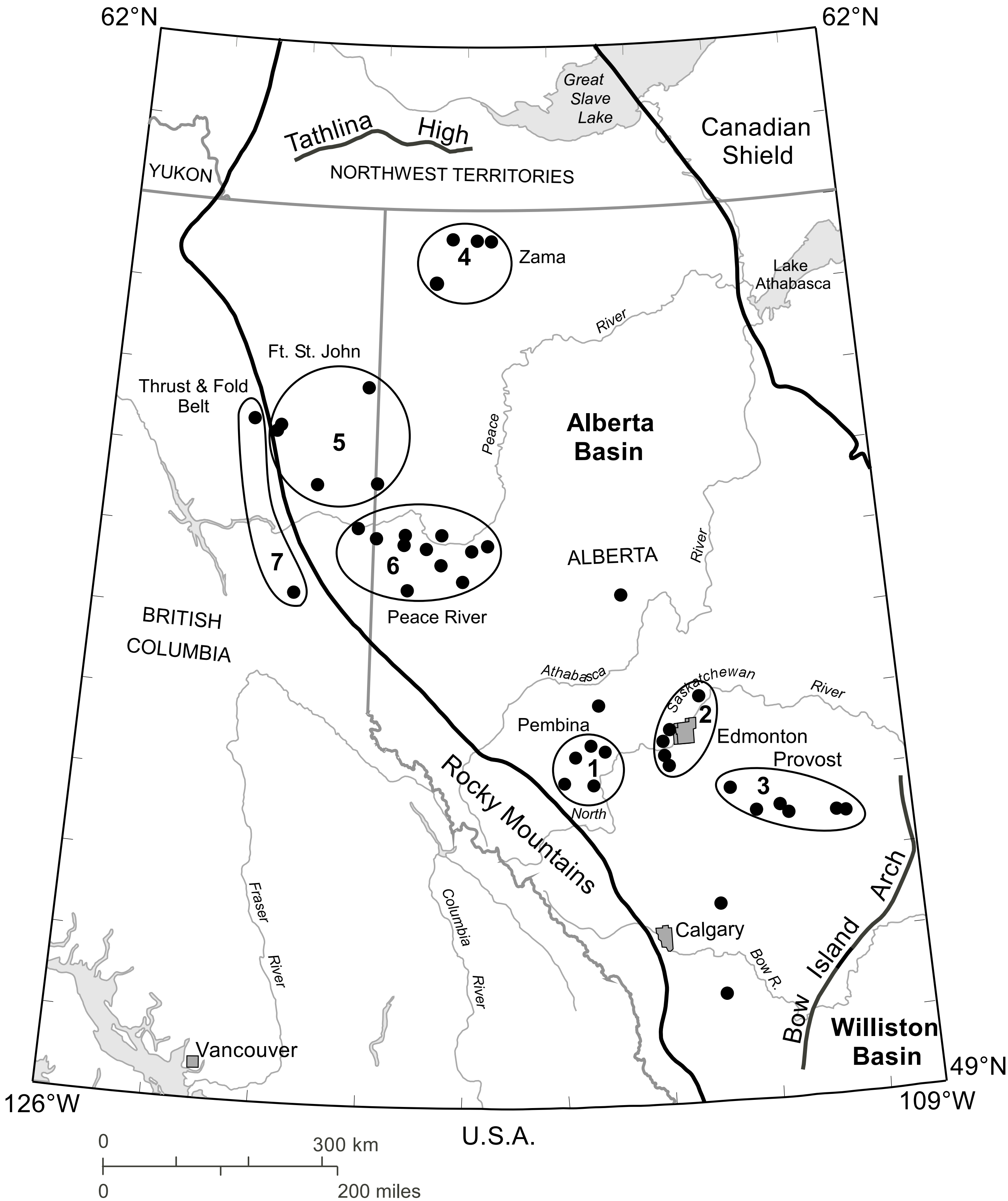


Figure 1. Location of the Pembina-Wabamun cluster of acid-gas injection sites in western Canada at the end of 2002.

characterization is based on reservoir-scale data and information submitted by the operators to the AEUB, on basin-scale work performed at the Alberta Geological Survey (AGS) during the last 15 years, and on specific, local and reservoir-scale work performed by the AGS specifically for this report.

2 Selection of an Acid-Gas Injection Site

In Alberta, applications for acid gas disposal must conform to the specific requirements listed in Chapter 4.2 of Guide 65 that deals with applications for conventional oil and gas reservoirs (AEUB, 2000). The selection of an acid-gas injection site needs to address various considerations that relate to: proximity to sour oil and gas production that is the source of acid gas; confinement of the injected gas; effect of acid gas on the rock matrix; protection of energy, mineral and groundwater resources; equity interests; wellbore integrity and public safety (Keushnig, 1995; Longworth *et al*., 1996). The surface operations and the subsurface aspects of acid gas injection depend on the properties of the H_2S and CO_2 mixture, which include, but are not limited to non-aqueous phase behavior, water content, hydrate formation and the density and viscosity of the acid gas (Carroll & Lui, 1997; Ng *et al*., 1999).

2.1 Acid Gas Properties

The acid gas obtained after the removal of H_2S and CO_2 from the sour gas may also contain 1%-3% hydrocarbon gases, and is saturated with water vapor in the range of 2%. In their pure state, CO_2 and H_2S have similar phase equilibria, but at different pressures and temperatures (Carroll, 1998a). They exhibit the normal vapour/liquid behavior with pressure and temperature (Figure 2), with CO_2 condensing at lower temperatures than H_2S. Methane (CH_4) also exhibits this behavior, but at much lower temperatures. The phase behavior of the acid-gas binary system is represented by a continuous series of two-phase envelopes (separating the liquid and gas phases) located between the unary bounding systems in the pressure-temperature space (Figure 2).

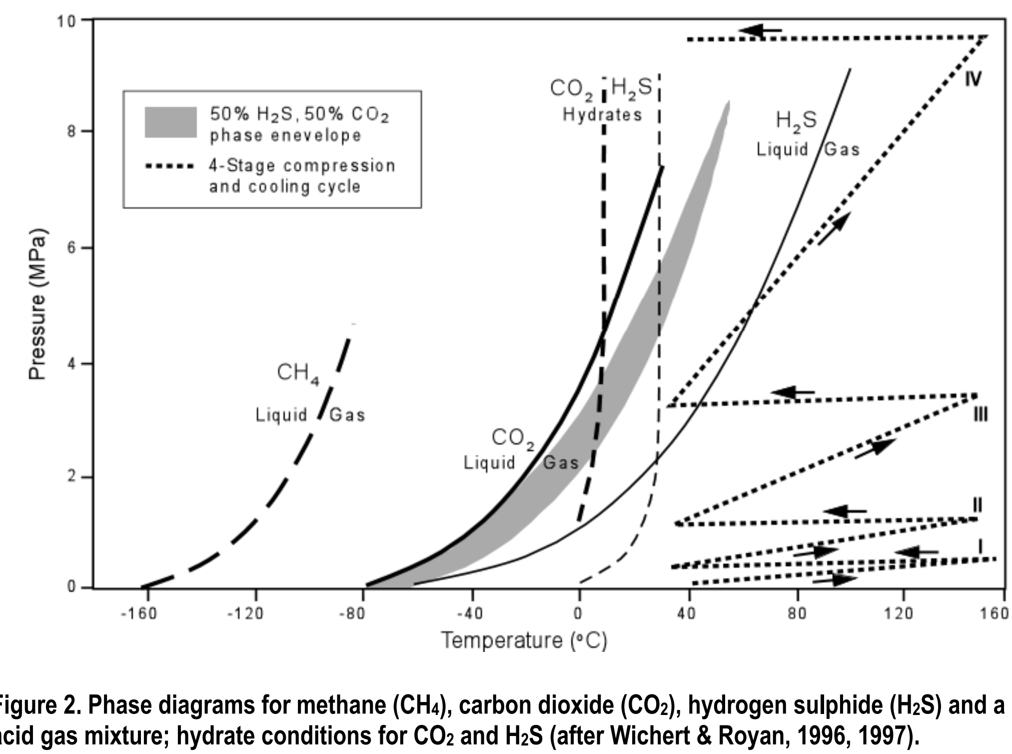


Figure 2. Phase diagrams for methane (CH_4), carbon dioxide (CO_2), hydrogen sulphide (H_2S) and a 50%-50% acid gas mixture; hydrate conditions for CO_2 and H_2S (after Wichert & Royan, 1996, 1997).

If water is present, both CO_2 and H_2S form hydrates at temperatures up to 10°C for CO_2 and more than 30°C for H_2S (Carroll & Lui, 1997). If there is too little water, the water is dissolved in the acid gas and hydrates will generally not form. However, phase diagrams show that hydrates can form without free water being present (Carroll, 1998a,b), thus operating above the hydrate-forming temperature is desirable. Unlike the case of hydrocarbon gases, the solubility of water in both H_2S and CO_2, hence in acid gas, decreases as pressure increases up to 3-8 MPa, depending on temperature, after which it dramatically increases (Figure 3). The solubility minimum reflects the pressure at which the acid gas mixture passes into the dense liquid phase, where the solubility of water can increase substantially with increasing pressure due to the molecular attraction between these polar compounds (Wichert & Royan, 1996, 1997).

The properties of the acid gas mixture are important in facility design and operation because, to optimize storage and minimize risk, the acid gas needs to be injected: (1) in a dense-fluid phase, to increase storage capacity and decrease buoyancy; (2) at bottom-hole pressures greater than the formation pressure, for injectivity; (3) at temperatures generally greater than 35°C to avoid hydrate forming, which could plug the pipelines and well; and (4) with water content lower than the saturation limit, to avoid corrosion.

After separation, the water-saturated acid-gas stream leaves the regeneration unit at 35 to 70 kPa and must be cooled and then compressed for injection to pressures in excess of the subsurface storage formation pressure. Typically, four stages of compression are required to provide the required discharge pressure. By the 4th stage in a cycle, compression will tend to dewater the acid gas up to a maximum pressure between 3 and 5 MPa (Figure 3), if there are no hydrocarbon impurities present. Further compressing the acid gas to higher pressures increases the solubility of water in the acid gas, such that any residual excess water dissolves into the acid gas, and more than counteracts the decrease in solubility due to inter-stage cooling. To avoid pump cavitation, the acid gas must not enter the two-phase region during compression. Once the acid gas is compressed, it is transported through a pipeline to the injection wellhead usually at a short distance from the gas plant. The high pressures after the fourth compression stage stabilize, upon cooling, the high-density liquid-phase of the acid gas, which can have a density of approximately 75% of the density of water, providing the hydrocarbon content is not greater than approximately 2%.

Although a number of safety valves are always installed, both in the well and in the surface facilities to be able to isolate the containment lines for the acid-gas injection system into small volumes, the release of even small volumes of acid gas can be harmful. Consequently, the operators are required to have a detailed emergency response plan (ERP) in case a leak occurs that may impact humans. An emergency planning zone, the EPZ (i.e., area of land which may be impacted by the release of H_2S), is defined around the sour gas facility.

2.2 Criteria for Site Selection

The general location for an acid-gas injection well is often influenced by the proximity to sour oil or gas production facilities that are the source of acid gas. The specific location is based on a general assessment of the regional geology and hydrogeology, which is designed to evaluate the potential for leakage (Longworth *et al*., 1996) and which includes:

1. size of the injection zone, to confirm that it is large enough to volumetrically hold all of the injected acid gas over the lifetime of the project;
2. thickness and extent of the overlying confining layer (caprock), and any stratigraphic traps or fractures that may affect its ability to contain the acid gas;
3. location and extent of the underlying or lateral bounding formations;

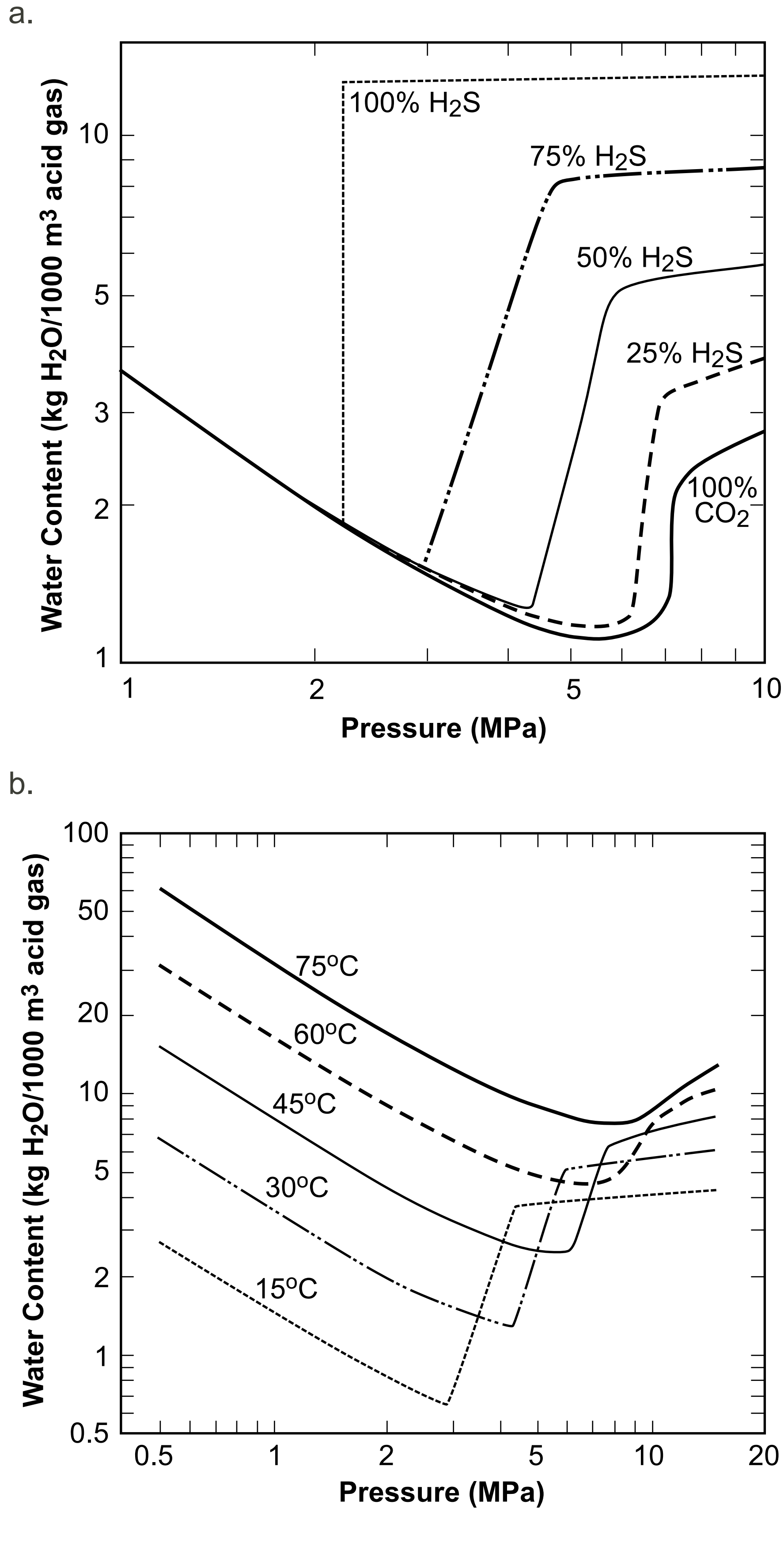


Figure 3. Solubility of water in acid gas as a function of pressure for: a) different acid gas composition (CO_2 and H_2S) at 30°C, and b) different temperatures for an acid gas with a composition of 49% CO_2, 49% H_2S and 2% CH_4 (see also Lock, 1997; Wichert & Royan, 1996, 1997).

4. folding or faulting in the area, and an assessment of seismic (neotectonic) risk;
5. rate and direction of the natural flow system, to assess the potential for migration of the injected acid gas;
6. permeability and heterogeneity of the injection zone;
7. chemical composition of the formation fluids (water for aquifers, oil or gas for reservoirs);
8. formation temperature and pressure;
9. analyses of formation and caprock core (if available); and, finally,
10. a complete and accurate drilling history of offsetting wells within several kilometres of the injection well, to identify any wells or zones that may be impacted by the injected acid gas.

Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short- and long-term fate of the injected acid gas. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface. These potential pathways are of three types: the caprock pore space ("membrane" type), natural and/or induced fractures ("cracks") through the confining strata, and improperly completed and/or abandoned wells ("punctures"). To avoid diffuse gas migration through the caprock pore space, the difference between the pressure at the top of the injection aquifer or reservoir and the pressure in the confining layer must be less than the caprock threshold displacement pressure, which is the pressure needed for the acid gas to overcome the capillarity barrier and displace the water that saturates the caprock pore space. To avoid acid gas migration through fractures, the injection zone must be free of natural fractures, and the injection pressure must be below a certain threshold to ensure that fracturing is not induced. The maximum bottomhole injection pressure is set by regulatory agencies at 90% of the fracturing pressure of the reservoir rock. In the absence of site-specific tests, the pressures are limited by pressure-depth correlations, based on basin-wide statistical data for the Alberta Basin. From this point of view, injection into a depleted oil or gas reservoir has the advantages of injection pressures being low and of wells and pipelines being already in place (Keushnig, 1995).

2.3 Issues

Critical issues are for the most part environmental and safety-related and they directly affect the economics of acid gas injection. Acid gas leaks can result in loss of life or contamination of the bio- and atmosphere. Surface safety is addressed through engineering, installation of safety valves and monitoring systems, and emergency procedures for the case of H_2S leaks. Subsurface issues are of two inter-related categories: the effect of the acid gas on the rock matrix and well cements, and plume containment.

When the acid gas contacts the subsurface formation, it will readily dissolve in the formation water in an aquifer, or connate water in a reservoir, and create weak carbonic and sulphuric acids. This leads to a significant reduction in pH that accelerates water-rock reactions. Depending on mineralogy, rock dissolution or precipitation may occur, affecting the porosity and permeability of the host rock. The fact that both CO_2 and H_2S are dissolving in the formation water leads to some complex reaction paths where carbonates precipitate and dissolve, and pyrite/pyrrhotite precipitates (Gunter *et al*., 2000; Hitchon *et al*., 2001). Dissolution of some of the rock matrix in carbonate strata, or of the carbonates surrounding the sand grains in sandstone units results in lower injection pressures in the short term. A major concern with the injection process is the potential for formation damage and reduced injectivity in the vicinity of the acid gas scheme. The reduction in injectivity could possibly be the result of fines migration, precipitation and scale potential, oil or condensate banking and plugging, asphaltene and elemental sulphur deposition, and hydrate plugging (Bennion *et al*., 1996).

Cement compatibility with the acid gas, primarily in the injection well, but also in neighboring wells, is crucial for safety and containment. For example, a non-carbonate and calcium cement blend shattered when tested in an acid gas stream for several weeks (Whatley, 2000). Thus, the compatibility of the acid gas with the cement that bonds the casing to the formation must be tested at a minimum. While the cement for the newly implemented acid-gas operation can be tested and properly selected prior to drilling, the cements in nearby wells are already in place and their condition is largely unknown. Some of these wells could be quite old, with the cement already in some stage of degradation as a result of brine composition. The acid gas, when reaching these wells, may enhance and speed up the cement degradation, leading to possible leaks through the well annulus and/or along casing.

If the acid gas is injected into the originating or other oil or gas pool, the main concern is the impact on further hydrocarbon recovery from the pool and acid gas production at the pump, although the injection operation and enhanced oil recovery may prove successful, like in the case of the Zama X2X pool (Davison *et al*., 1999). If the gas mixture is injected into an aquifer, the degree to which it forms a plume and migrates from the injection well depends on various factors, including pressure and temperature, solubility, interplay between driving forces like buoyancy and aquifer hydrodynamics, and aquifer heterogeneity, which controls gravity override and viscous fingering.

The fate of the injected acid gas in the subsurface is not known, because subsurface monitoring is not currently required and is difficult and expensive. Only the wellhead gas composition, pressure, temperature and rate have to be reported to the AEUB. Thus, a proper understanding of the geology and hydrogeology of the acid-gas injection unit (reservoir or aquifer) is critical in assessing the fate of the injected acid gas and the potential for migration and/or leakage into other units.

3 Basin-Scale Setting of the Pembina-Wabamun Acid-Gas Injection Sites

The Pembina operations for injecting acid gas into the Upper Devonian Wabamun Group are located in the central part of the Alberta Basin, west-southwest of Edmonton (Figure 1). The geology, stratigraphy and hydrostratigraphy of the sedimentary succession are different in the northern part of the Alberta Basin (north of the Peace River arch) from those in the area south of the Peace River arch because of different depositional and erosional conditions and events, with corresponding effects on the flow of formation waters (Bachu, 1999). Consequently, only the southern and central parts of the basin, relevant to the Pembina-Wabamun sites, will be presented in the following. The geology described herein is based on Porter *et al*. (1982), Ricketts (1989) and Mossop & Shetsen (1994) (and references cited therein), and the hydrogeology on Bachu (1999).

3.1 Basin Geology and Hydrostratigraphy

The Alberta Basin sits on a stable Precambrian platform and is bound by the Rocky Mountain Trench to the west and southwest, the Tathlina High to the north and the Canadian Precambrian Shield to the northeast (Figure 1). The Bow Island Arch separates the Alberta and Williston basins to the southeast. The basin was initiated during the late Proterozoic by rifting of the North American craton and consists at the base of a Middle Cambrian to Middle Jurassic passive-margin succession dominated by shallow-water carbonates and evaporites with some intervening shales (Porter *et al*., 1982). From late Jurassic to early Tertiary, accretion of allochthonous terranes to the western margin of the proto North American continent during the Columbian and

Laramide orogenies pushed sedimentary strata eastward, thrusting and folding them in the Rocky Mountain main ranges and in the thrust and fold belt, and creating conditions for foreland-basin development east of the deformation front. Because of lithospheric loading and isostatic flexure, the Precambrian basement tilted westward, with a gentle slope of <4 m/km in the east near the Canadian Shield, becoming steeper westward, up to >20 m/km near the deformation front. In the undeformed part of the basin, progressively older Jurassic to Middle Devonian strata subcrop from west to east at the sub-Cretaceous unconformity, as a result of basement tilting and significant Pre-Cretaceous erosion. Deposition during the foreland stage of basin development was dominated by synorogenic clastics, mainly muds and silts that became shales, derived from the evolving Cordillera. The basin attained maximum thickness and burial during the Laramide orogeny in the Paleocene. Tertiary-to-Recent erosion since then has removed an estimated 2000 to 3800 m of sediments in the southwest (Nurkowski, 1984, Bustin, 1991). The present-day topography of the undeformed part of the basin has a basin-scale trend of decreasing elevations from highs in the 1200 m range in the southwest to lows around 200 m in the north-northeast at Great Slave Lake, which is the lowest topographic point in the basin. As a result of these depositional and erosional processes, the undeformed part of the Alberta Basin comprises a wedge of sedimentary rocks that increases in thickness from zero at the Canadian Shield in the northeast to close to 6000 m in the southwest at the thrust and fold belt. The stratigraphic and hydrostratigraphic nomenclature and delineation for the entire sedimentary succession in the Alberta Basin south of the Peace River Arch are shown in Figure 4.

Hydrostratigraphically, the Precambrian crystalline basement constitutes an aquiclude, except possibly for fault and shear zones that may have been conduits for fluid flow and may still be active today. A thin, diachronous basal quartz sandstone unit and Granite Wash detritus cover the Precambrian basement. As a result of pre-Middle Ordovician erosional beveling and of major pre-Middle Devonian erosion, Cambrian strata are eroded near the Peace River arch. Ordovician strata are present only in the southeast along a narrow band along the basin edge, and Silurian strata are completely absent. The Basal Sandstone unit forms the Basal aquifer, while the shale-dominated Cambrian and Ordovician strata form the Cambrian aquitard system.

A Middle Devonian interbedded succession of low-permeability anhydritic red beds and carbonates, halite and argillaceous carbonates of the Lower Elk Point Group overlies the Cambrian units or Granite Wash detritus, and forms the Elk Point aquitard system. The overlying platform and reefal carbonates of the Upper Elk Point Group Winnipegosis Formation form the Winnipegosis aquifer. This unit is overlain over most of the basin by the thick halite of the Prairie Formation and the shales of the Watt Mountain Formation, which together form the Prairie aquiclude system. Because of the variable lithology of the Prairie Formation in the west, and salt dissolution in the east along the basin edge, this hydrostratigraphic system has aquiclude characteristics where the salt is present, and aquitard characteristics where the salt is absent, or present only in minor quantities.

The Elk Point Group is overlain by the Middle-Upper Devonian Beaverhill Lake Group. The latter can be subdivided into the open marine reefs and carbonates of the Slave Point Formation, which is an aquifer, and the shales and argillaceous carbonates of the Waterways Formation, which form, depending on location and dominant lithology, either an aquitard or an aquifer. The aquifers and aquitards of the Beaverhill Lake Group subcrop at the sub-Cretaceous unconformity, and crop out in the northeast along the Athabasca River and in the Great Slave Lake area.

The Upper Devonian Woodbend Group strata conformably overlie the Beaverhill Lake Group and are the result of renewed marine transgression and deepening within the Alberta Basin, which resulted in the deposition of the thick euxinic shales of the Duvernay and Majeau Lake

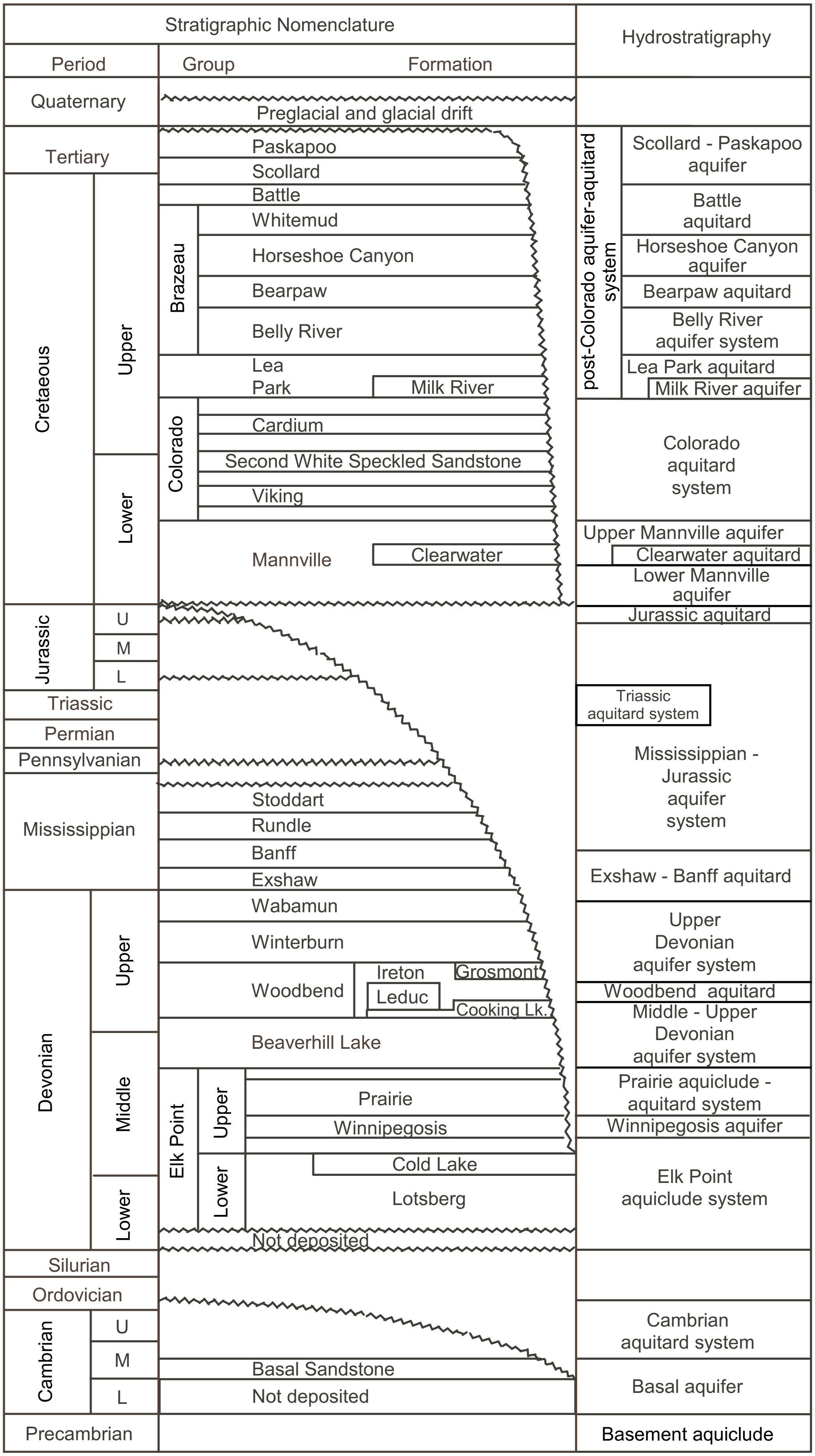


Figure 4. Basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature for the southern and central parts of the Alberta Basin (after Bachu, 1999).

formations. In southern and southeastern Alberta, extensive platform carbonates of the Cooking Lake Formation comprise shallow water equivalents of the Duvernay and Majeau Lake formations. During subsequent drowning of the carbonate platform, shallow water and locally evaporitic carbonate deposition of the Leduc Formation took place. Infilling of the Woodbend basin by shales of the Ireton Formation started at the northeastern margin and progressed into southern Alberta, subsequently terminating younger Leduc reef growth. The Grosmont shelf complex developed over the prograding Ireton in northeastern Alberta. Thick accumulations of Upper Woodbend Group shales filled the entire basin by the close of the Ireton deposition, except for a small portion in central Alberta, which remained unfilled. This part, the Cynthia Basin, was the site of later reef development during overlying Winterburn sedimentation (Burrowes & Krause, 1987).

Hydrostratigraphically, the Cooking Lake and Leduc carbonates form the Cooking Lake aquifer, which, together with the underlying Beaverhill Lake aquifers, form the Middle-Upper Devonian aquifer system. The Ireton, Duvernay and Majeau Lake formations form the Woodbend aquitard. The Grosmont Formation is an aquifer that is included in the overlying Upper Devonian aquifer system as a result of its hydraulic continuity with and influence on the Winterburn and Wabamun aquifers in the area of subcrop in the northeast (Anfort *et al*., 2001). All the units of the Woodbend Group subcrop at the sub-Cretaceous unconformity, while the Grosmont aquifer also crops out along the Peace River at an elevation of approximately 250 m.

The Woodbend Group is overlain by the Winterburn Group. It represents a continuation of Grosmont-type deposition wherein carbonates “piggy-back” on prograding clastics (Watts, 1987). Within this respect, basal Winterburn carbonates of the Nisku Formation formed widespread shelf deposits over most of Alberta. In the north, these were rather silty and argillaceous, but in eastern and southeastern Alberta, and rimming the Cynthia basin, fossiliferous shelf and reef carbonates were widespread. A major marine transgression followed the Nisku sedimentation, which is marked by widespread terrigenous deposits of the Calmar Formation. After a time of non-deposition and/or erosion, shallow shelf sedimentation returned to most of the Alberta Basin and resulted in the carbonates of the Blue Ridge Member. A second major regression occurred at the close of the Winterburn time, resulting in the northwestward thickening wedge of the “Graminia Silt” (Burrowes & Krause, 1987).

The strata of the Wabamun Group conformably overlie the Winterburn Group. They consist mostly of shallow marine carbonates and may reach a thickness of 300 m. In southeastern Alberta, these carbonates interfinger with peritidal evaporites (mainly anhydrite) of the Stettler Formation. Wabamun carbonates consist largely of mud-rich to grainy to pelletal limestones. These change in parts of the basin to fossiliferous carbonates that pinch out into the evaporitic Stettler Formation. A second transgressive episode occurred close to the end of Wabamun time and resulted in the open marine limestones of the Big Valley Formation over most of Alberta. Black-shales of the Exshaw Formation abruptly overlie the Wabamun and straddle the Devonian-Mississippian Boundary.

The widespread platform carbonates interspersed with minor shales of the Winterburn and Wabamun groups subcrop at the sub-Cretaceous unconformity (Figure 5), and, at the basin scale, form the Upper Devonian aquifer system. Reefs of the Leduc Formation breach the Ireton aquitard in places, thus establishing local hydraulic communication between the Middle-Upper Devonian aquifer system and the overlying Upper Devonian aquifer system, including the Grosmont aquifer (Bachu & Underschultz, 1993; Hearn & Rostron, 1997; Rostron & Toth, 1996, 1997; Anfort *et al*., 2001).

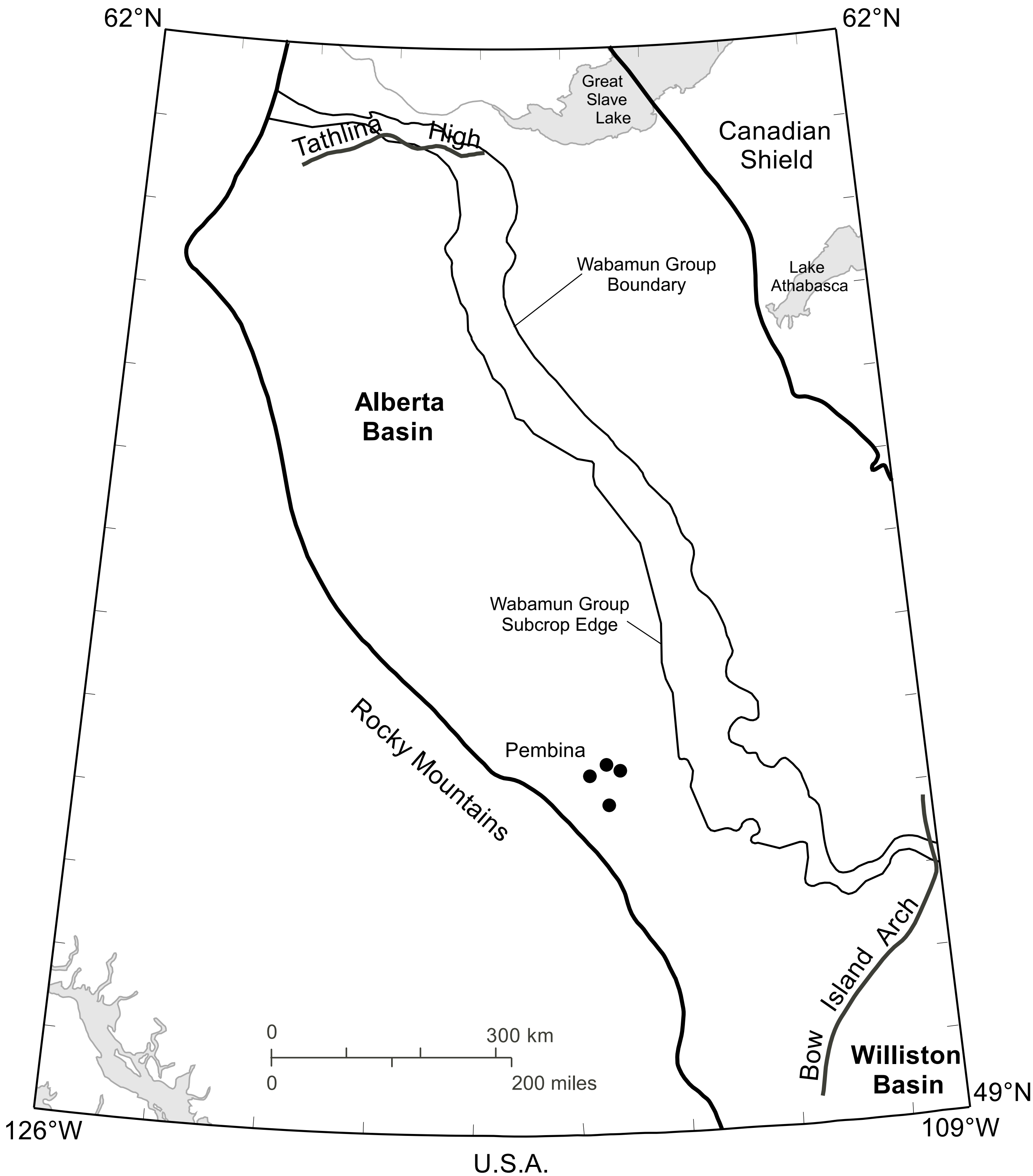


Figure 5. Subcrop of the Wabamun Group at the pre-Cretaceous unconformity in the Alberta Basin. The location of the four acid-gas injection operations in the Pembina area is also shown.

The thin, organic rich, competent shales of the Exshaw Formation were conformably deposited during late Devonian – early Carboniferous, followed by the interbedded shale-to-carbonate succession of the Banff Formation. This trend continued with the deposition of the overlying thick carbonate successions of the Rundle and Stoddart groups (Figure 4). Permian, Triassic and early Jurassic strata are present only in the Peace River Arch area in the northwest near the eastern edge of the thrust and fold belt, and consist of interbedded sandstones, siltstones, carbonates, evaporites and shales. The shales of the Exshaw Formation and the shale-dominated lower part of the Banff Formation form the Exshaw-Banff aquitard. The Triassic shales and evaporites form aquitards and aquicludes that dominate the Triassic succession, which, as a whole, forms an aquitard system. At a regional scale, the entire Upper Banff to Lower Jurassic succession, except for the Triassic, forms the Carboniferous-Jurassic aquifer system in the southern and central parts of the basin.

Late Jurassic siliciclastics were deposited along the western edge of the basin at the beginning of the foreland-stage of basin evolution. They are variably dominated by either sandstones or shales, which form an aquifer or a weak aquitard, depending on location. The overlying Cretaceous strata are divided into several depositional successions. The Mannville Group, the depositional response to the Columbian orogeny, consists of fluvial and estuarine valley-fill sediments, and sheet sands and shales deposited by repeated marine transgressive-regressive events. In the southern part of the basin, the Mannville Group forms at the basin-scale a single sandstone-dominated aquifer, while in the central-to-northern part, the Lower and Upper Mannville aquifers are separated by the intervening shale-dominated Clearwater aquitard. At a local scale, the lithology and therefore, the hydrostratigraphy of the Mannville Group are much more complex, with lateral or vertical discontinuities caused by siliciclastic deposition in a fluvio-deltaic environment.

The Colorado Group was deposited during a lull in tectonic plate convergence when the basin was subject to a widespread marine transgression. Colorado strata consist predominantly of thick shales that form aquitards, within which there are isolated, thin, sandy units that form aquifers. Some of the sandstones, like the Viking and Cardium formations, are laterally extensive. Others are more restricted areally, present only in the south, like the Second White Speckled Sandstone.

Post-Colorado Cretaceous and Tertiary strata were deposited during the Laramide orogeny and the subsequent period of tectonic relaxation, and consist of eastward-thinning nonmarine clastic wedges intercalated with argillaceous sediments. This cyclicity is developed best in the southern and southwestern parts of the basin, where the Milk River, Belly River, Horseshoe Canyon and Scollard-Paskapoo formations form the clastic wedges, and the Lea Park, Bearpaw, Whitemud and Battle formations comprise the intervening shales. In the central and northern parts of the basin many of these cycles are absent due to either non-deposition or erosion. The clastic wedges form aquifers, while the intervening shales form aquitards. A variety of pre-glacial, glacial and post-glacial surficial deposits of Quaternary age overlie the bedrock over the entire basin.

3.2 Basin-Scale Flow of Formation Water

The flow of formation water in the Alberta Basin is quite well understood at the basin scale as a result of work performed over the last three decades by various researchers, starting with the pioneering work of Hitchon (1969a,b) and ending with a comprehensive summary and synthesis of previous work by Bachu (1999). Publications since then (i.e., Anfort *et al*., 2001; Michael *et al*., 2003; and Bachu & Michael, 2003) only confirm and detail the broad understanding of the flow of formation water in the basin. The flow in the deformed part of the basin (the Rocky Mountains and the thrust and fold belt) seems to be driven by topography in local-scale systems. Recharge takes place at the surface throughout the entire system, with discharge as springs, in lakes and along river valleys. In most cases, fresh groundwater of meteoric origin discharges along various faults and thrust sheets, such as the Brazeau, Burnt Timber and McConnell, that separate the flow systems in the Rocky Mountain thrust and fold belt from the flow systems in the undisturbed part of the basin (Wilkinson, 1995; Grasby & Hutcheon, 2001). The flow in the undeformed part of the Alberta Basin (from the eastern edge of the deformation front in the southwest to the edge of the exposed Precambrian Shield in the northeast) is extremely complex due to basin evolution, geology, lithology and hydrostratigraphy.

Topography-Driven Flow

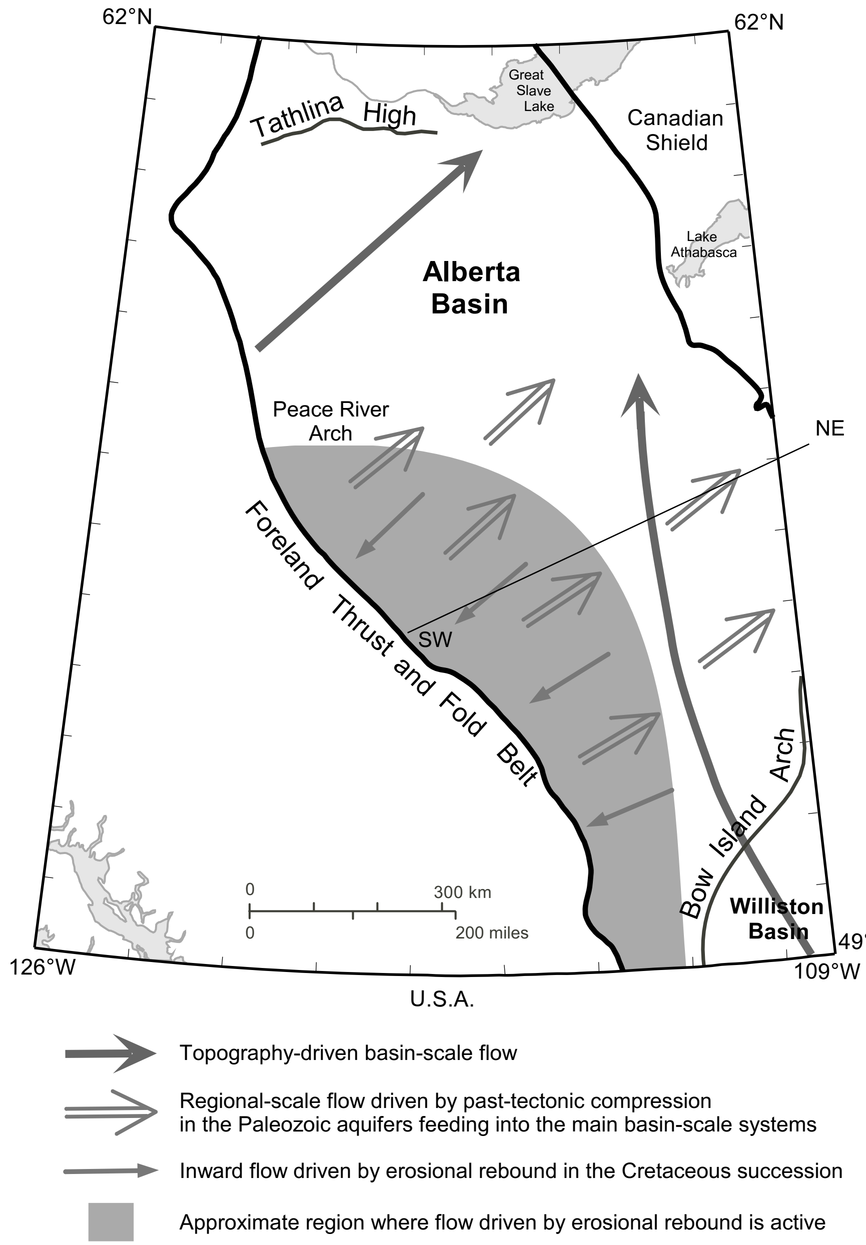
The flow of formation water is driven by topography in local, intermediate, regional and basin scale systems, from regions of recharge at high elevations to regions of discharge at low elevations. A basin-scale flow system in the southern and central parts of the basin is recharged with fresh meteoric water in the south where Devonian, Carboniferous and Cretaceous aquifers crop out at high elevation in Montana. Water flows northward and discharges at outcrop of the Grosmont aquifer along the Peace River (Figure 6). The aquifers in this flow system are the Upper Devonian and Carboniferous-Jurassic in the region of respective subcrop at the sub-Cretaceous unconformity, the Grosmont, and the Lower Mannville. They all are in hydraulic contact in southeastern and central Alberta due to the absence of intervening aquitards as a result of pre-Cretaceous erosion (Figures 4-6). In this basin-scale flow system, low hydraulic heads corresponding to discharge areas propagate far upstream, inducing widespread sub-hydrostatic pressures, as a result of high aquifer permeability downstream (Anfort *et al*., 2001).

An intermediate-scale flow system driven by topography is present in the Athabasca region, where meteoric water recharges at relatively high elevations in the Birch and Pelican mountains, penetrates down to the Slave Point (Beaverhill Lake Group) aquifer and discharges at low-elevation outcrop along the Athabasca, Peace and Hay rivers (Bachu & Underschultz, 1993; Bachu, 1999). All aquifers and aquitards in the Upper Devonian to Jurassic succession are absent in this area due to pre-Cretaceous erosion (Figures 4 and 5). The Slave Point and Winnipegosis aquifers in northeastern Alberta are in an intermediate position between regional-scale flow in the western part of the basin, and local-scale flow systems close to the basin's eastern edge (Hitchon *et al*., 1990; Bachu & Underschultz, 1993).

Local-scale flow systems are present throughout the entire basin in the shallower strata. Fresh meteoric water is driven from local topographic highs, such as Swan Hills, Cypress Hills and Pelican Mountains, to the nearest topographic lows, usually a river valley. Such local flow systems were identified in the Upper Cretaceous – Tertiary strata in the south, southwest and west (Toth & Corbet, 1986; Michael & Bachu, 2002a, Bachu & Michael, 2003), and in the Red Earth and Athabasca regions (Toth, 1978; Bachu & Underschultz, 1993).

Flow Driven by Erosional and/or Post-Glacial Rebound

During sediment loading, water flows vertically in compacting sand-shale successions, out of overpressured shaly aquitards into the adjacent sandstone aquifers (expulsion), then laterally in the sandstones, outward toward the basin edges. Directions of water movement are reversed during erosional unloading, with transient effects lasting for long periods of time in rocks characterized by very low hydraulic diffusivity. Significant underpressuring in shales drives the flow of formation waters in the intervening aquifers laterally inward from the permeable basin edges, and vertically into the rebounding shaly aquitards ("suction"). This type of flow is present at both local and large scales in the southern and southwestern part of the Alberta Basin in the siliciclastic Mannville, Viking, Second White Speckled Sandstone, Belly River and Horseshoe a.



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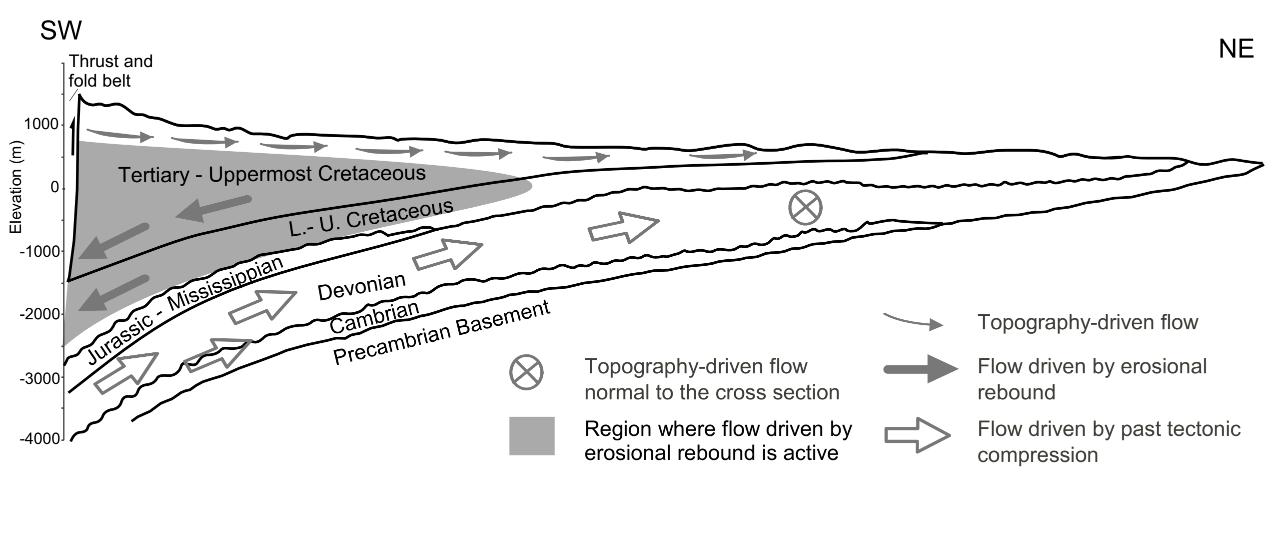

Figure 6. Diagrammatic representation of flow systems in the Alberta Basin: a) in plan view, and b) in cross-section (after Bachu, 1999).

Canyon aquifers in the Cretaceous succession (Figures 5 and 6) (Toth & Corbet, 1986; Parks & Toth, 1993; Bachu & Undershultz, 1995; Anfort *et al*., 2001; Michael & Bachu, 2002a). The flow is driven by erosional and post-glacial rebound in the thick intervening shales of the Colorado Group, and Lea Park, Bearpaw and Battle formations, as a result of up to 3800 m of sediments having been eroded in the area since the peak of the Laramide orogeny some 60 My BP (Nurkowski, 1984; Bustin, 1991) and since the retreat of 2 km thick Laurentide ice sheets since the Pleistocene. The flow in these Cretaceous aquifers is in a transient state, driven inward from the aquifers' eastern boundary to the west-southwest, downdip toward the thrust and fold belt. The aquifers are severely underpressured in places, with corresponding hydraulic heads being less than 200 m close to the thrust and fold belt (Bachu *et al*., 2002; Bachu & Michael, 2003). These hydraulic heads are lower than the lowest topographic elevation in the basin at Great Slave Lake more than 1500 km away in the northeast.

Tectonic Compression

Unlike compaction and erosion, which create vertical stresses in the fluid-saturated sedimentary succession, tectonic compression during orogenic events creates lateral stresses and pressure pulses that lead to water expulsion from the overridden and thrusted rocks into the foreland basin. These pressure pulses dissipate over several million years, depending on the hydraulic diffusivity of the sedimentary succession (Deming & Nunn, 1991). In the deep part of the Alberta Basin in the southwest, the flow of formation waters in the Middle-Upper Devonian, Upper Devonian and Mississippian-Jurassic aquifer systems (Figures 4 and 6) is northeastward updip until it reaches the sub-Cretaceous unconformity, where it joins the northward basin-scale gravity-driven flow system (Hitchon *et al*., 1990; Bachu & Underschultz, 1993, 1995; Rostron & Toth, 1997; Anfort *et al*., 2001). In the deeper Basal and Winnipegosis aquifers the flow of formation waters is also northeastward updip to their respective northeastern boundary (Hitchon *et al*., 1990; Bachu & Underschultz, 1993). The salinity of formation waters in these aquifers generally increases southwestward downdip. (Hitchon *et al*., 1990; Bachu & Underschultz, 1993, 1995; Rostron & Toth, 1997; Anfort *et al*., 2001; Michael & Bachu, 2002a,b; Michael *et al*., 2003). Up to their respective eastern erosional or depositional boundary, all of these aquifers are separated by intervening strong aquitards or aquicludes. Direct freshwater meteoric recharge from the surface of these aquifers in either the deformed or the undeformed parts of the basin in the southwest is not possible or very unlikely for a variety of reasons (Bachu, 1999; Michael & Bachu, 2002a,b; Bachu *et al*., 2002; Michael *et al*., 2003). Based on the high salinity of formation waters in the deep Paleozoic aquifers in the southwestern part of the basin, and because of the lack of an identified recharge source and mechanism, Bachu (1995) postulated that the flow in these aquifers is driven by past tectonic compression (Figure 6). This hypothesis is supported by isotopic analyses of formation waters and late-stage cements in both the deformed and undeformed parts of the basin (Nesbitt & Muehlenbachs, 1993; Machel *et al*., 1996; Buschkuehle & Machel, 2002).

Hydrocarbon Generation

During the process of hydrocarbon generation, the phase change of solid kerogen that fills the pore space into fluid hydrocarbons leads to volumetric expansion and generation of internal stresses that create overpressures capable of driving flow. However, the overpressures caused by active hydrocarbon generation can be maintained only if the respective reservoirs are well sealed by very low permeability rocks. Overpressured reservoirs are present in Cretaceous strata in the deep parts of the Alberta Basin (e.g., Masters, 1984). Most of the overpressuring attributed to hydrocarbon generation occurs in the southwest, in the deep basin near the thrust and fold belt in the Cretaceous Mannville, Viking and Cardium strata (Figure 5) associated with low-permeability (tight) rocks and seals (Bachu & Underschultz, 1995; Anfort *et al*., 2001; Michael & Bachu, 2002a). The high pressures are caused by present-day or recent (last few million years) hydrocarbon generation in strata that still contain organic matter capable of yielding thermally generated hydrocarbons, but which have very low permeability that impedes pressure dissipation. The rock succession in the Cretaceous deep basin is generally gas or oil saturated, and discrete hydrocarbon-water contacts generally are not present. In the absence of contact between the overpressured reservoirs and formation water in aquifers, hydrocarbon generation is not an effective flow-driving mechanism.

Buoyancy

The flow of formation water is driven in the gravitational field by hydraulic gradients and by density differences (buoyancy). Generally, Paleozoic waters are more saline than Mesozoic waters (Hitchon, 1969a,b; Bachu, 1999; Anfort *et al*., 2001; Michael & Bachu, 2002a,b; Michael *et al*., 2003). The increase in salinity is mild in Cretaceous strata, rather abrupt at the sub-Cretaceous unconformity, and steep in Paleozoic strata, particularly in the vicinity of evaporitic beds (Bachu, 1999). In southern Alberta, water salinity in Upper Devonian and Carboniferous aquifers is lower than in the central and northern parts of the basin and comparable with water salinity in Mesozoic aquifers, as a result of meteoric water recharge at outcrop in Montana (Anfort *et al*., 2001). The existence of high-salinity connate waters in the Paleozoic strata shows that the basin has not been flushed yet of the original waters existing in the basin at the time of deposition. Thus, buoyancy, rather than generating or enhancing the flow of formation waters in the Alberta Basin, retards it, to the point of stagnation or sluggishness in some places. A zone of mixing between high-salinity Paleozoic connate waters and freshwater of meteoric origin is present in the Lower Mannville aquifer in the south-central part of the basin, in the region where Devonian aquifers subcrop at the sub-Cretaceous unconformity (Bachu, 1995; Rostron & Toth, 1997; Anfort *et al*., 2001).

Cross-Formational Flow

Generally there is little cross-formational flow in the Alberta Basin because of its “layer-cake” structure, where strong aquitards and aquicludes separate the major aquifers and aquifer systems in the sedimentary succession. Cross-formational flow takes place over large areas only where aquitards are weak. Such cases are the Clearwater and Watt Mountain aquitards in the northeast in the Athabasca area (Bachu & Underschultz, 1993), and the Calmar aquitard in the Upper Devonian aquifer system (Rostron & Toth, 1997; Anfort *et al*., 2001). Localized, direct cross-formational “pipe” flow between aquifers takes place across Devonian aquitards and aquicludes only in places where Winnipegosis and Leduc reefs breach through the intervening shaly aquitards. Such “pipes” were identified between the carbonate platforms of the Woodbend Group and the Winterburn Group in the Cheddarville and Bashaw areas, and along the Rimbey-Meadowbrook reef trend (Bachu & Underschultz, 1993; Wilkinson, 1995; Rostron & Toth, 1996, 1997; Anfort *et al*, 2001). Reefs of the Leduc Formation create a path for direct hydraulic communication across the Ireton aquitard between the underlying and overlying Cooking Lake-Leduc and Upper Devonian aquifer systems. Otherwise, mixing of formation waters from different aquifers, and consequently of fresh meteoric and connate waters, takes place at the sub-Cretaceous unconformity in the area where various Devonian-to-Carboniferous strata subcrop (Figure 4) (Hitchon *et al*., 1990: Bachu & Underschultz, 1993, 1995; Rostron & Toth, 1997; Anfort *et al*., 2001).

4 Regional-Scale Setting of the Pembina-Wabamun Acid-Gas Injection Sites

Because hydrogeological data for the Wabamun Group are scarce in the Pembina area, a regional scale study area was defined between 52.5°N to 54°N and 117°W to 113.5°W (Figure 7), to better understand the flow of formation waters and hydrogeology around the acid-gas injection sites.

4.1 Geology of the Wabamun Group in West-Central Alberta

The Upper Devonian Wabamun Group extends from southern Alberta to northern Alberta and British-Columbia (Figure 7) and marks a reflooding of the Alberta Basin following the Winterburn cycle of basin fill. At the initiation of the cycle, the underlying Winterburn succession had infilled almost all of the preexisting topography throughout most of Alberta. Therefore the Wabamun Group is preserved as a rather monotonous package of low-angle mud-dominated carbonate ramp sediments (Figures 7 and 8). The infilling of the basin took place from the northwest, resulting in the deposition of basinal shales followed by thick limestone sequences in northern Alberta. The Wabamun Group becomes increasingly dolomitic and eventually anhydritic in southeastern Alberta and southwest Saskatchewan (Figures 7; Stoakes, 1992). Due to this transitional sedimentation pattern, the Wabamun Group has been sub-divided mainly into two formations across the basin: the Big Valley Formation and the Stettler Formation (Figure 9), whereby the Big Valley Formation is a calcitic unit and the underlying Stettler Formation becomes increasingly dolomitic to the south. The Stettler Formation can be further subdivided into members as indicated in Figure 9.

In the Pembina study area the Wabamun is represented mainly by a thick limestone succession with a few dolomitized areas. The depth to the top of the Wabamun Group in the regional-study area ranges between more than 4000 m in the southwest along the deformation front to less than 1100 m in the northeast (Figure 10a) with an average thickness of 200 m in most of the area except for the very eastern border where it approaches the sub-Cretaceous unconformity and has been eroded to around 30 m. The top of the Wabamun Group dips southwestward with a slope that varies between 15m/ km in the northeast and 20m/km near the deformation front, from above – 400m in the northeast to less than -2600 m in the southwest (Figure 10b).

The Wabamun Group in the regional-scale study area consists of dolomitic limestones and calcareous dolomites, with the limestones predominating in the upper part of the formation and dolomites in the middle and lower parts. Appreciable interbedded anhydrite occurs, which forms a prominent zone near the base of the formation in some areas (e.g. the Leduc field just west of Edmonton). In the Stettler area and southeastward (southeast study area), halite may be interbedded with these anhydrites. In a trend further to the south, interbedded anhydrite and dolomite occur in both the upper and lower portion of the group, with the variably porous Crossfield Member dolomites occurring in between. In the northwestern part of the study area the Wabamun is wholly limestone. Brecciation, secondary anhydrite and calcite veining are common. At the upper contact with the Exshaw Formation the limestone may be highly pyritic.

The Wabamun Group is underlain by siliciclastics and carbonates of the Graminia–Blueridge succession of the Winterburn Group, which reach a thickness of about 30 m in the study area. The injection zone is overlain by several metres of the tight shales of the Exshaw Formation, and the shaly carbonates of the Banff Formation, with an aggregate thickness of 200 m on average.

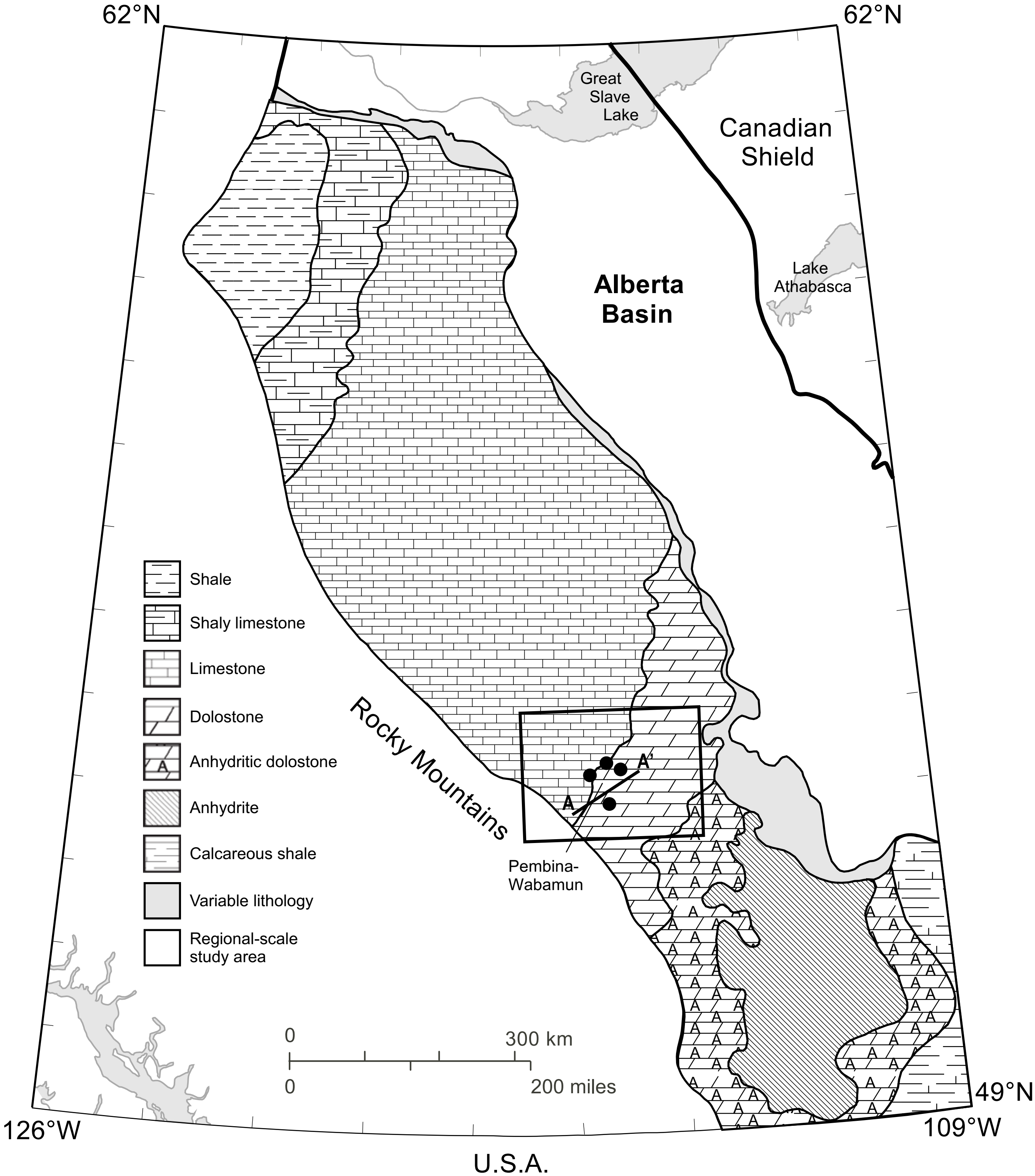

Figure 7. Lithofacies distribution of the Wabamun Group in the Alberta Basin (after Stoakes, 1992). Line of cross-section refers to Figure 8. The Pembina-Wabamun acid-gas injection sites and the regional-scale study area are also shown.

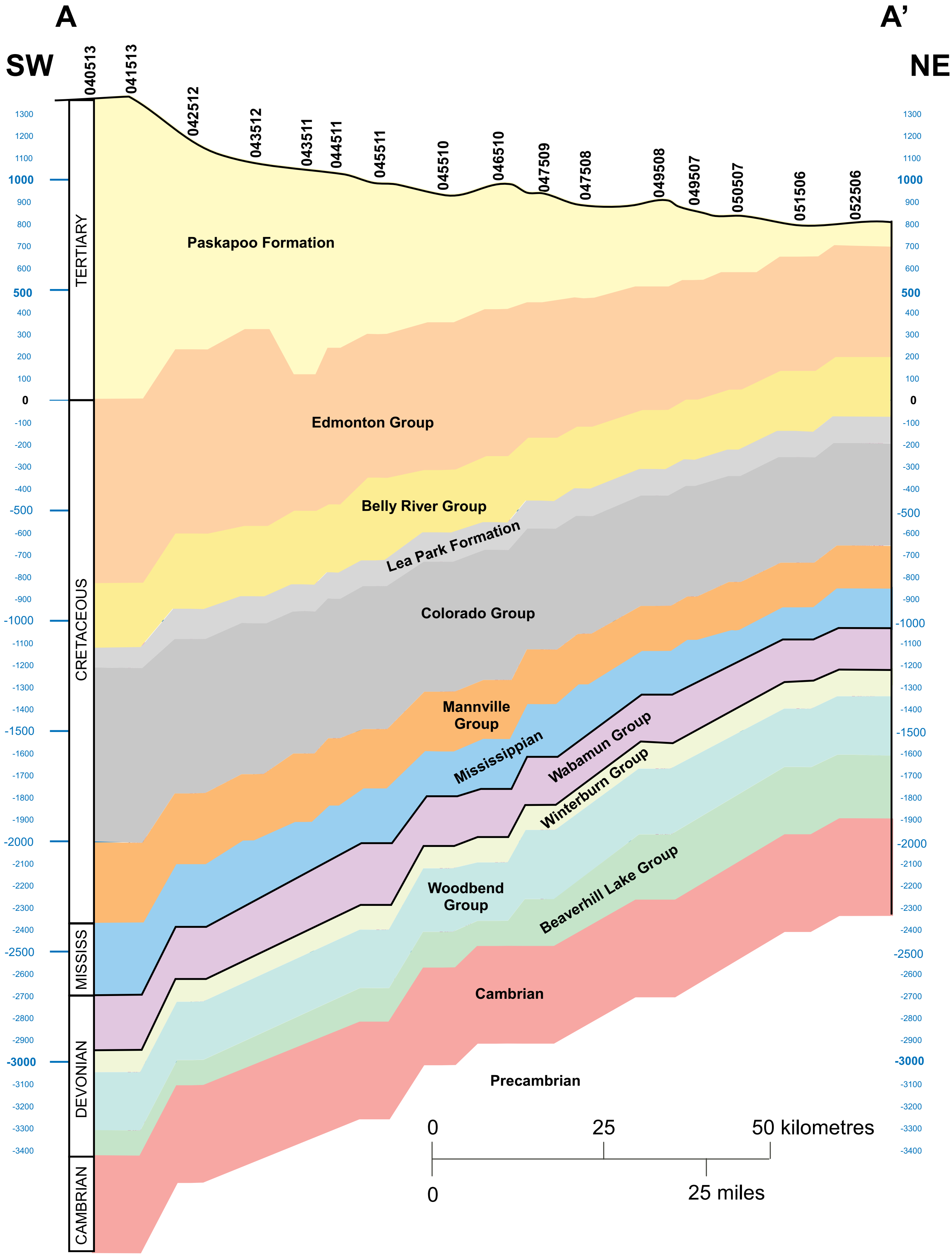

Figure 8. Structural cross-section through the study area showing the position of the Wabamun Group. Line of cross-section is shown in Figure 7. Elevation in metres above sea level. Location numbers at the top are well locations in DLS coordinates (township, meridian, and range).

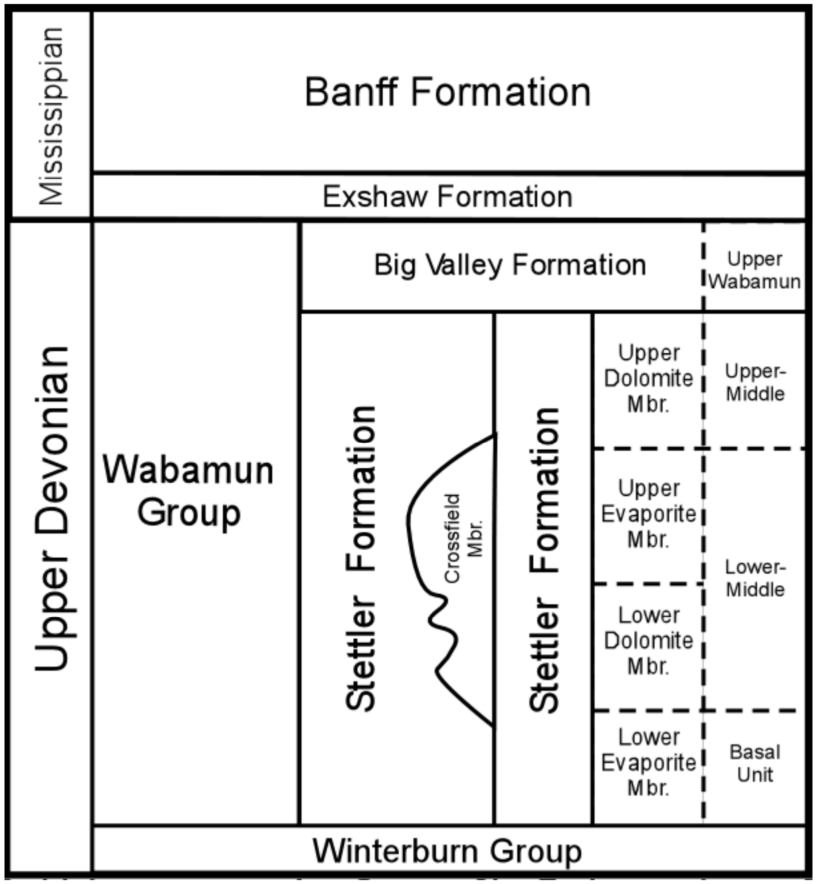

Figure 9. Stratigraphic nomenclature of the Upper Devonian Wabamun Group in west-central Alberta (modified from compilation by Stoakes, 1992).

4.2 Hydrogeology of the Wabamun Group in West-Central Alberta

From a hydrostratigraphic point of view, the limestones and dolostones of the Wabamun Group form an aquifer, the dolostones having the higher permeability. Only at the southern boundary of the study area increasing amounts of anhydrite result in a successive decrease in permeability. Consequently, the Wabamun Group has aquitard characteristics southeast of the regional-scale study area (Rostron & Toth, 1997).

The Wabamun aquifer is confined at its base by siliciclastics and carbonates of the underlying Calmar and Graminia formations of the Winterburn Group. Locally, the Graminia Formation may act as an aquifer and provide hydraulic communication with the platform and reef carbonates of the Nisku Formation that form an aquifer in the lower Winterburn Group. The Mississippian shales of the Exshaw and Lower Banff formations form an aquitard at the top of the Wabamun Group, separating it from the Mississippian aquifer system. The Mississippian is eroded in the northeastern corner of the regional-scale study area, where the Wabamun aquifer subcrops against, and is in direct hydraulic communication with, the Cretaceous Mannville aquifer system.

Hydrochemical analyses of formation waters and drillstem tests were used to interpret the flow of brines in the Wabamun aquifer in the regional study area. The data used in this study are in the public domain and were available from the Alberta Energy and Utilities Board (AEUB). The data

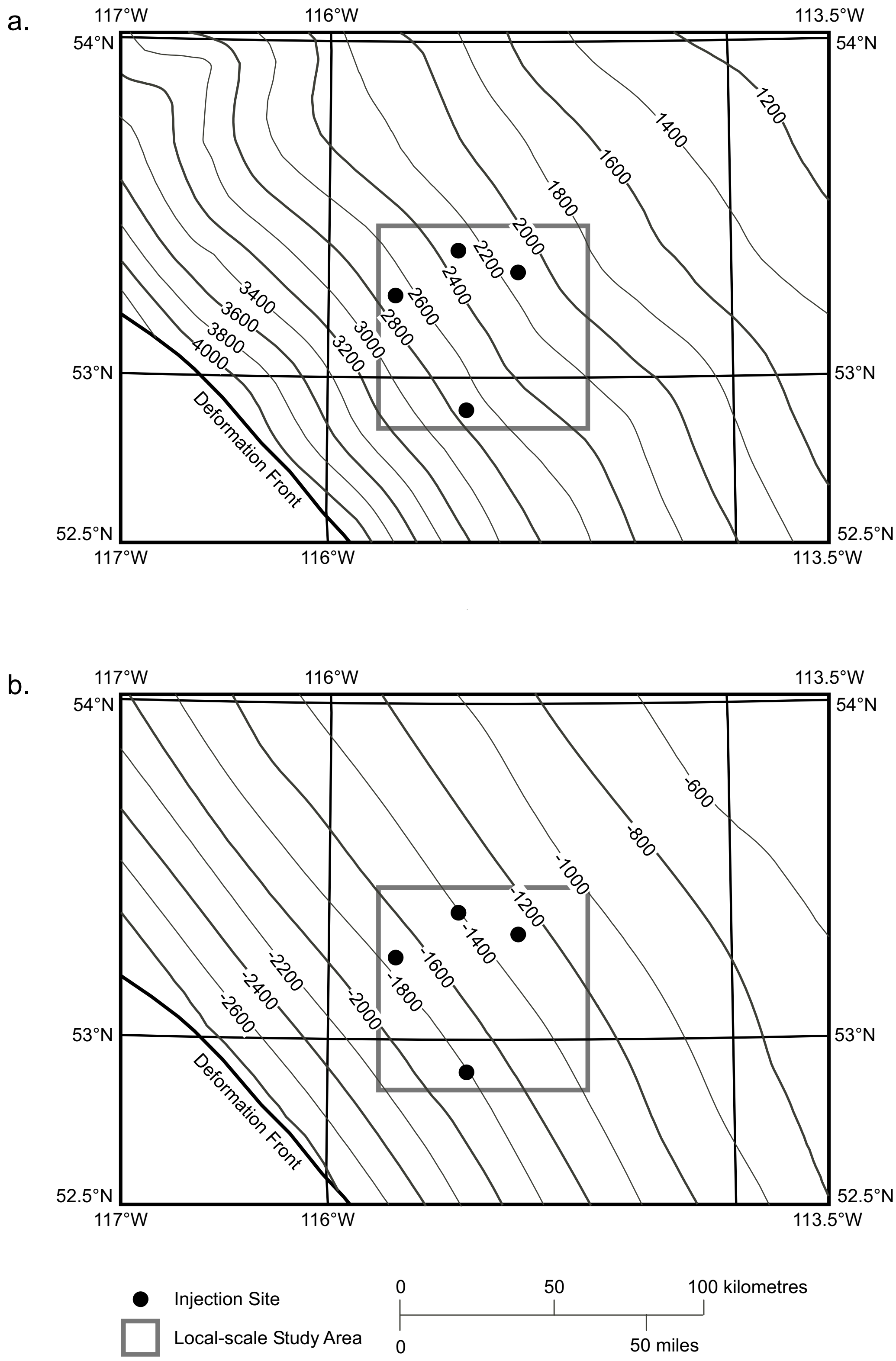

Figure 10. Top of the Wabamun Group in the regional-scale study area: a) depth, and b) elevation. Contours in metres. Location of the local-scale study area is also shown.

were culled for erroneous analyses and tests, including production influence, and processed according to the methods presented by Hitchon and Brulotte (1994), Hitchon (1996) and Michael and Bachu (2002a).

Chemistry of Formation Waters

The Upper Devonian formation waters in west-central Alberta are of Na-Cl and Na-Ca-Cl types in the shallow and deep parts, respectively (Spencer, 1987; Adams & Bachu, 2002; Michael *et al*., 2003). In the regional-scale study area, water salinity in the Wabamun aquifer varies between less than 100 g/l in the northeast corner of the study area where the Wabamun subcrops against the Mannville Group, and greater than 180 g/l in the northwest near the deformation front (Figure 11a). In the Pembina area, the salinity is approximately 120 g/l. Significantly lower salinity of formation water in the overlying Mississippian aquifer, ranging from less than 40 g/l to 120 g/l (Figure 12a), indicates that the Exshaw-Lower Banff aquitard is an effective barrier to cross-formational flow. The salinity of formation water in the underlying Winterburn Group is in the same range as the salinity in the Wabamun Group in the northern half of the study area; however, in the southeastern half the salinity is significantly higher, reaching more than 200 g/l (Figure 13a). The differences in salinity between the Wabamun and Winterburn aquifers in the south suggest that the intervening Calmar and Graminia aquitards prevent cross-formational mixing of formation waters. Only in the northeast, where salinities are in a similar range, the possibility of cross-formational flow is likely.

Flow of Formation Waters

The analysis of the flow of formation waters is based on distributions of hydraulic heads in the Wabamun Group (Figure 11b). These hydraulic heads were calculated with a reference density of 1050 kg/m^3 in order to minimize the errors in representing and interpreting the flow of variable density water in the vicinity of the acid-gas injection sites (Bachu & Michael, 2002). The reference density, calculated for in-situ conditions according to the algorithm of Batzle and Wang (1992), corresponds to brine density at conditions characteristic of the acid-gas injection sites. Hydraulic heads were calculated according to:

$$H = \frac{p}{\rho_o g} + z \qquad (1)$$

where z (m) is the elevation of the pressure recorder, p (Pa) is pressure, ρ_o (kg/m^3) is the reference density and g is the gravitational constant (9.81 m/s^2).

In general, the distributions of hydraulic heads in the Winterburn and Wabamun aquifers in the regional-scale study areas are similar to each other and both are quite different than that in the Mississippian aquifer (Figures 11b, 12b and 13b). Hydraulic heads decrease in both Wabamun and Winterburn aquifers from greater than 700 m in the northwest and greater than 500 m in the southeast, to less than 350 m in the northeast (Figures 11b and 13b). Hydraulic-head gradients are high in the western half and in the southeast, where hydraulic-head values decrease to 400 m over a relatively short distance. However, gradients are comparably low in the central and northeastern portions of the study area, where hydraulic heads decrease northeastward from approximately 400 m to 300 m over a distance of 300 km.

Flow inferred from the hydraulic head distributions in the Wabamun and Winterburn aquifers generally shows the potential for updip flow, eastward in the northern half, and north to

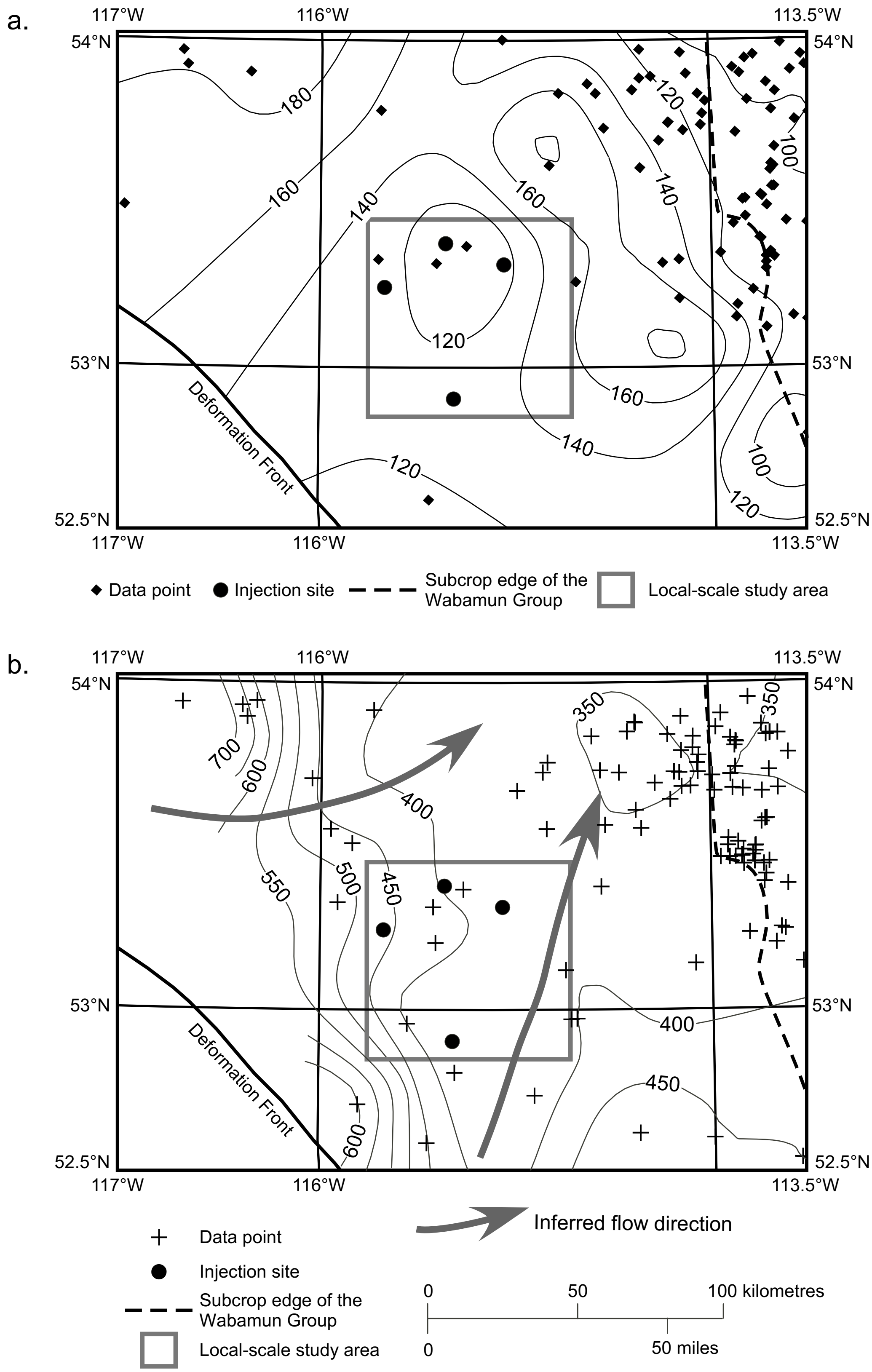

Figure 11. Hydrogeological characteristics of the Wabamun aquifer in the regional-scale study area: a) salinity of formation waters (g/l), and b) distribution of hydraulic heads (m).

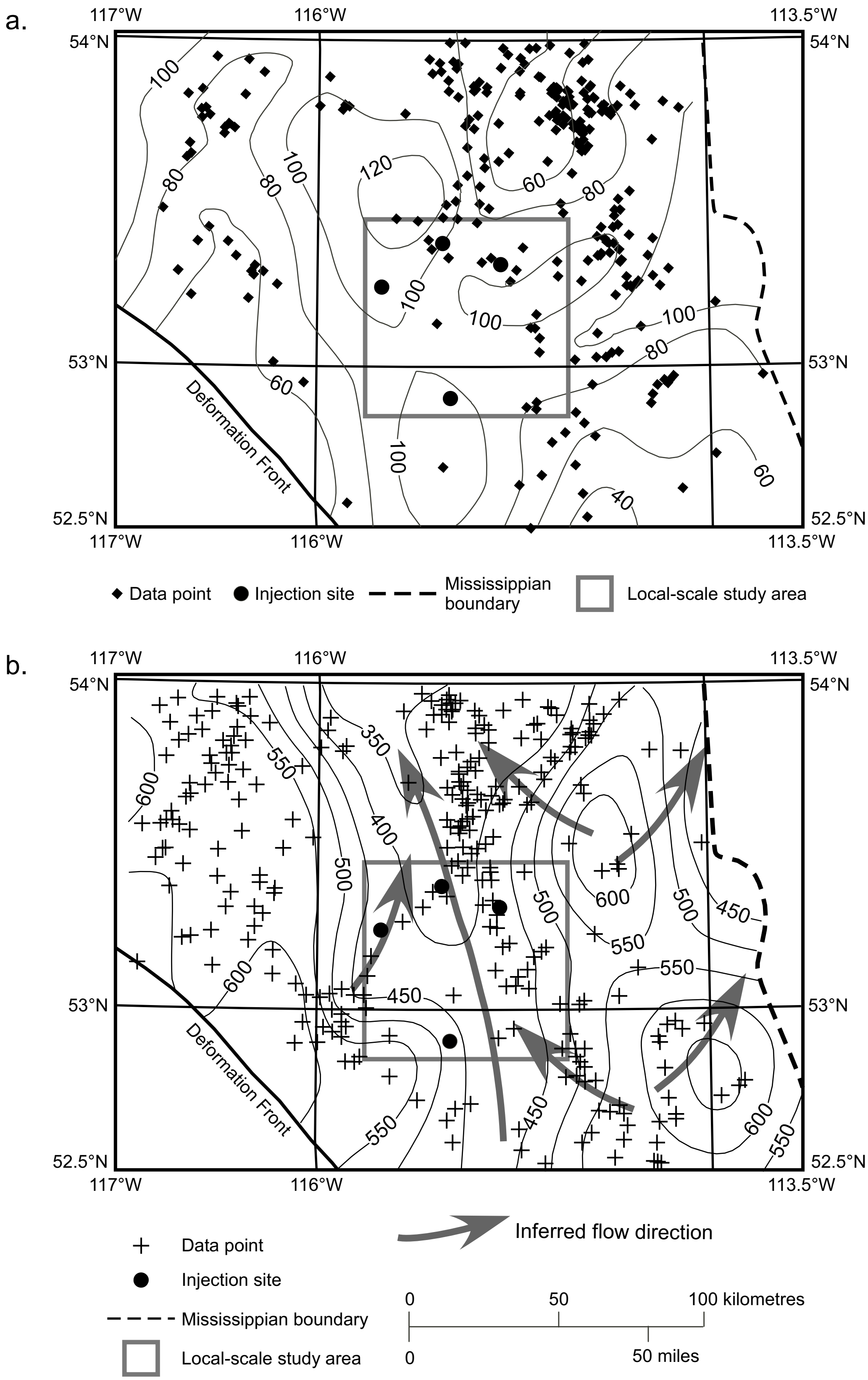

Figure 12. Hydrogeological characteristics of the Mississippian aquifer in the regional-scale study area: a) salinity of formation waters (g/l), and b) distributions of hydraulic heads (m).

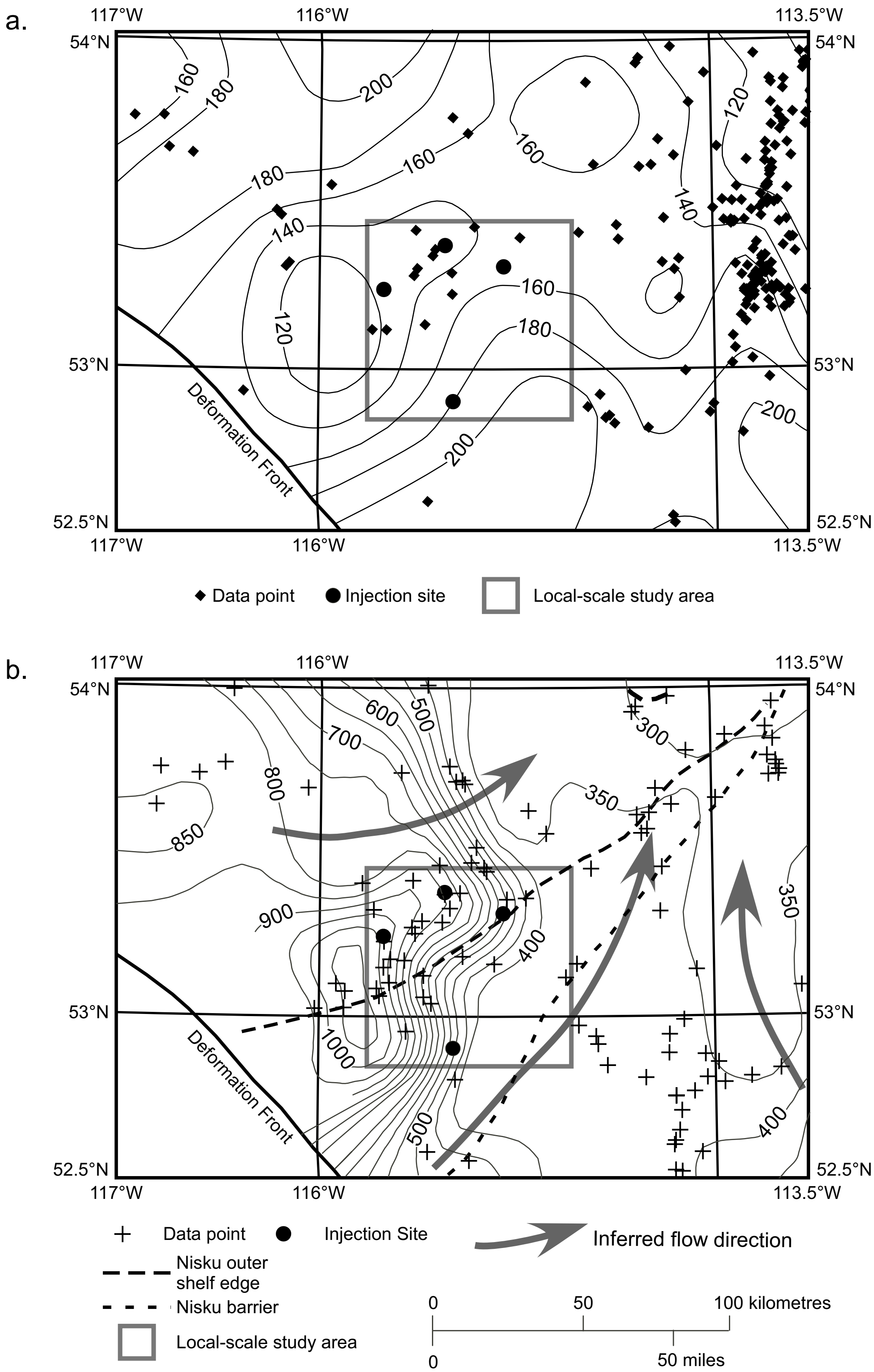

Figure 13. Hydrogeological characteristics of the Winterburn aquifer in the regional-scale study area: a) salinity of formation waters (g/l), and b) distributions of hydraulic heads (m).

northeastward in the southern part of the study area, suggesting that, on a regional scale, both aquifers are controlled by similar flow-driving mechanisms. The flow in the southern part of the regional-scale study area appears to be directed along the facies change from limestone to dolostone in the Wabamun aquifer and along the trend of the Nisku shelf edge in the Winterburn aquifer. The main difference in hydraulic head distributions between the Wabamun and Winterburn aquifer is a north-south trend (approximately 200 km long along 115.5^{o}W) of rapidly decreasing hydraulic heads (from 1000 m to 400 m) in the Winterburn Group aquifer over a relatively short distance of approximately 50 km, a feature that is absent in the Wabamun aquifer (Figures 11b and 13b). This zone of high hydraulic gradients indicates the existence of a region of low permeability in the underlying Winterburn aquifer. The hydraulic gradient in the Wabamun aquifer in this region, although not as high as in the Winterburn aquifer, is similarly higher than the gradient in the central and northeastern portions of the study area, suggesting that the limestones in the Wabamun aquifer have a lower permeability than the dolostones. The Pembina acid-gas injection sites are located in the transition zone from relatively low-permeability limestone to higher-permeability dolostone along the western margin of the north-northeastwardly directed regional flow system.

The hydraulic head distribution in the Mississippian aquifer shows a completely different flow pattern from those in the underlying Wabamun and Winterburn aquifers (Figure 12b). Generally, flow is directed northwestward in the western and central parts of the study area, and only in the east flow is updip, towards the Mississippian erosional edge. The contrast between flow patterns in the Mississippian and Wabamun aquifers indicates that the intervening Exshaw-Lower Banff interval is an effective aquitard. Conversely, similar distributions of hydraulic heads in the Wabamun and Winterburn aquifers suggest that the intervening Graminia and Calmar formations form, at least locally, a relatively weak aquitard.

Based on the relatively high salinity of formation waters, and because of the lack of an identified recharge source and flow-driving mechanism for meteoric water, Bachu (1995) postulated that the flow in the Wabamun and Winterburn aquifers is driven by past tectonic compression (Figure 6). This hypothesis is supported by isotopic analyses of formation waters and late-stage cements in both the deformed and undeformed parts of the basin (Nesbitt & Muehlenbachs, 1993; Machel *et al*., 1996; Buschkuehle & Machel, 2002).

5 Local-Scale Setting of the Pembina-Wabamun Acid-Gas Injection Sites

The geological and hydrogeological characteristics of the Wabamun Group are described at a local scale (defined as Twp. 45-51, Rge. 6-12 W 5th Mer.), to better understand the containment of the injected acid gas, and to examine the potential for gas migration and/or leakage from the Wabamun Group. The geology in this area is only moderately well understood, because there are no hydrocarbon reservoirs within the Wabamun Group in the study area and, as a result, not many wells have been cored. The four injection sites are located within the boundaries of the Pembina Field about 20 to 40 km apart; their locations are 14-22-49-12W5, 02-11-51-10W5, 11-14-50-8W5, and 06-25-45-10W5 (Figure 14).

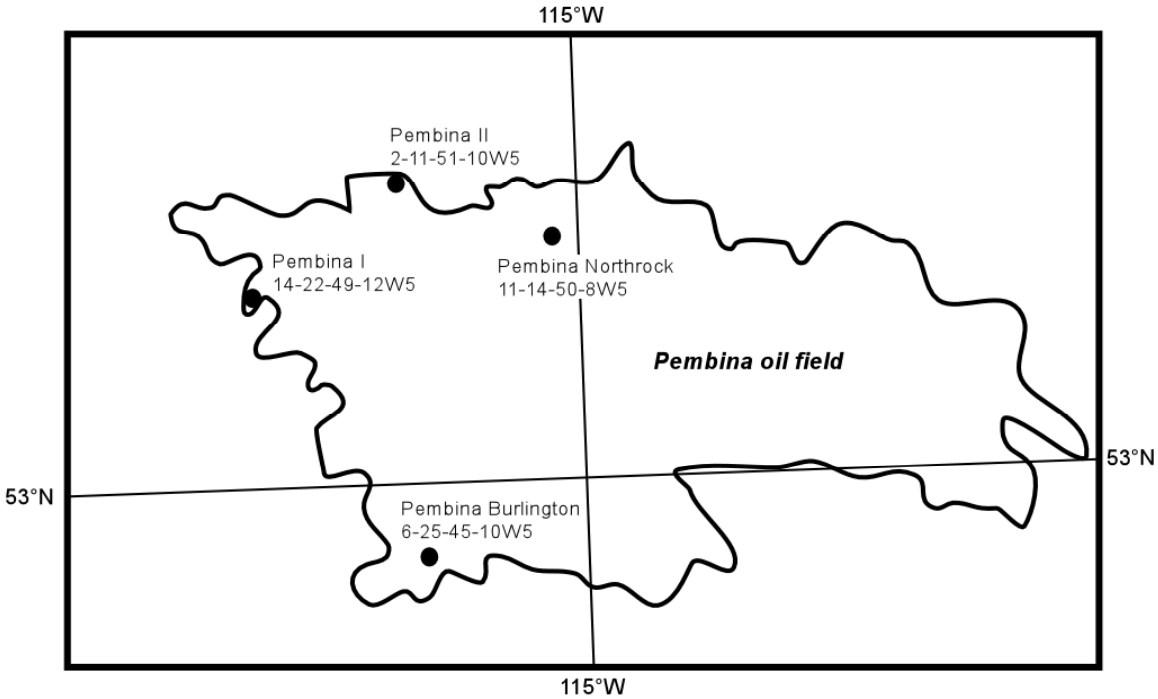

Figure 14. Location of the acid-gas injection sites in relation to the Pembina oil field.

5.1 Geology of the Wabamun Group

In the local-scale study area, the Wabamun Group constitutes a thick, homogenous sequence of shallow marine carbonates, which have been deposited on a large, semi-restricted shelf (Halbertsma, 1994). The Wabamun carbonates lie at depths of about 2700 m (-1700 to -1800 m elevation) in the southwest and rise updip, northeastward, towards 2000 m (-1100 to -1200 m elevations) (Figure 15). The Wabamun Group has a uniform thickness of 200 to 220 m in the injection areas and thins slightly to 180 m towards the northeast as a result of erosion (Figure 16). There are no known faults in the area.

5.2 Lithology and Mineralogy of the Graminia-Wabamun-Banff/Exshaw Interval

To understand the fate of the acid gas injected into the Wabamun Group in the Pembina area there is need for a description not only of the rocks of the Wabamun Group, but also of the underlying and overlying confining strata. Thus, the following presents the entire sedimentary succession from the underlying Graminia Formation of the Winterburn Group to the Wabamun Group, which in turn is overlain by the Exshaw and Banff formations of the Mississippian Period.

Blue Ridge Member (Graminia Formation, Winterburn Group)

The Blue Ridge is the lower member of the Graminia Formation. It overlies a thin silty unit assigned to the Calmar Formation and is overlain by another silt unit designated the Graminia silt. The Blue Ridge Member is composed of burrowed, nodular, silty dolomite and fine siltstones, with occasional thin shale partings. Fauna is generally scarce and confined to scattered brachiopods and crinoids.

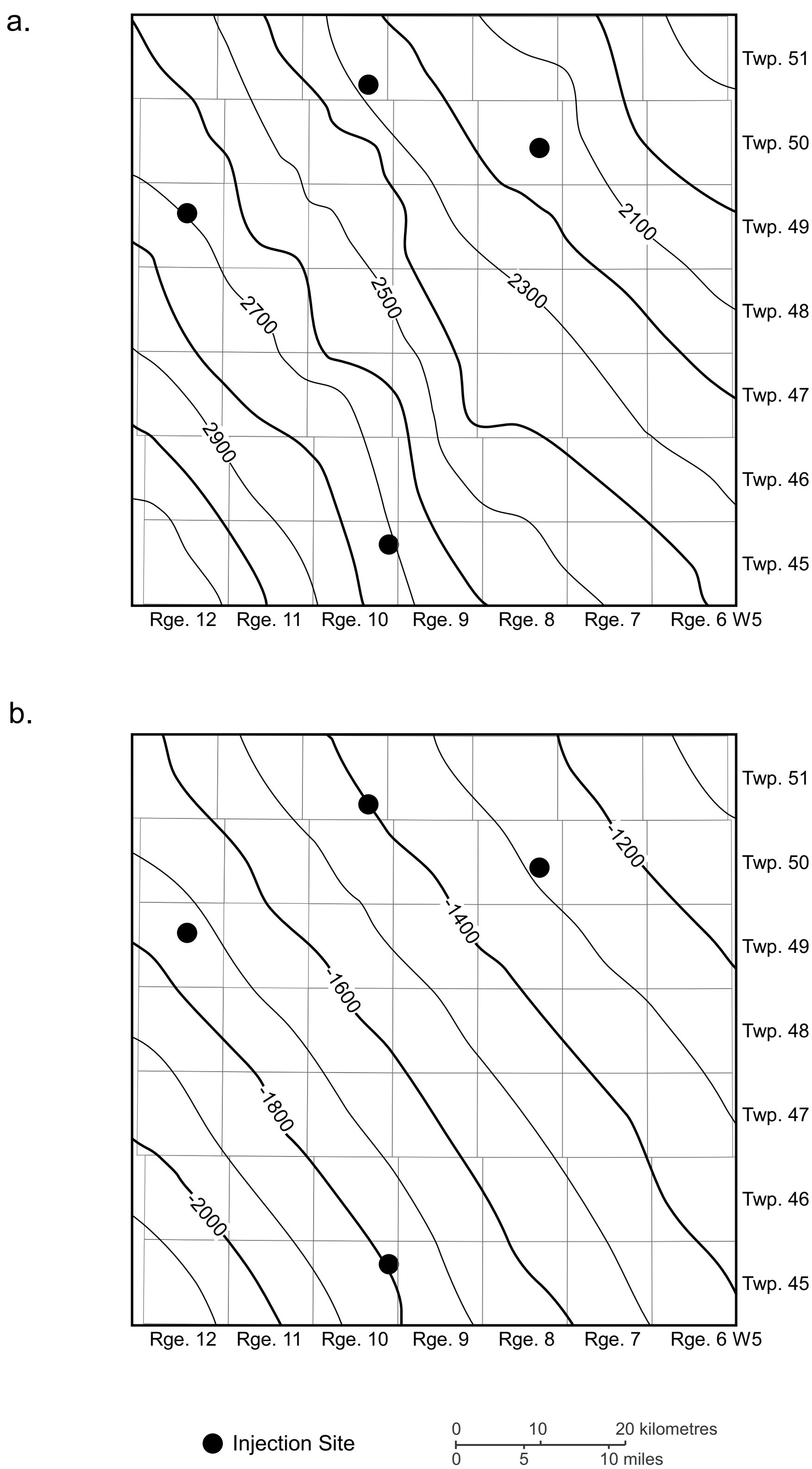

Figure 15. Top of the Wabamun Group in the local-scale study area: a) depth, and b) elevation. Contours in metres.

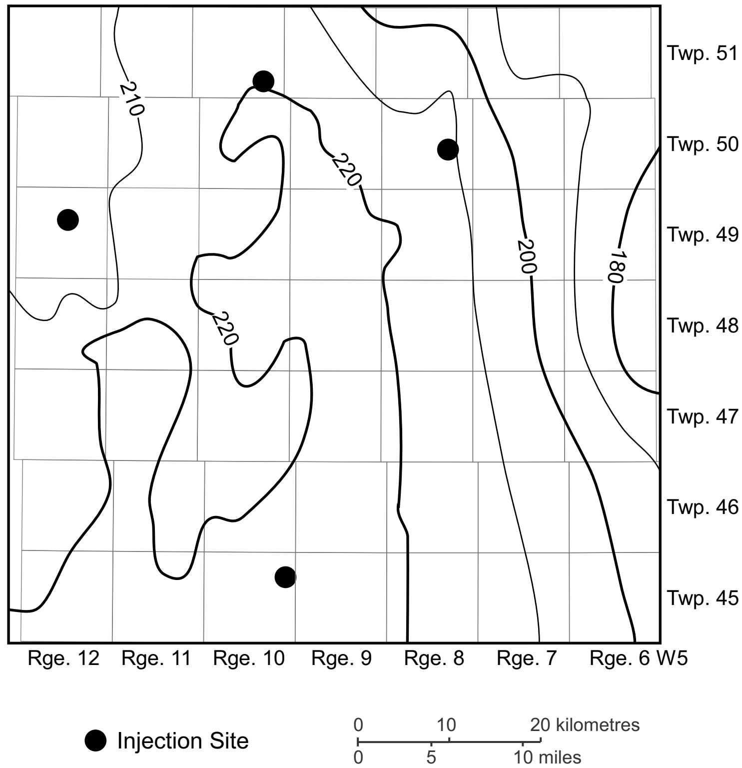

Figure 16. Isopach of the Wabamun Group in the local-scale study area. Contours in metres.

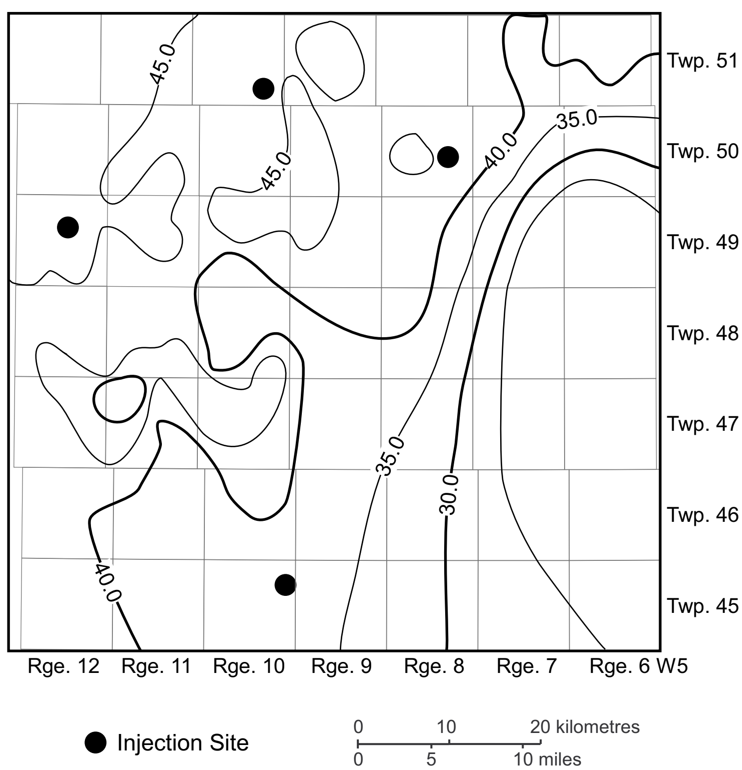

Figure 17. Isopach of the Graminia Formation of the Winterburn Group in the local-scale study area. Contours in metres.

Graminia Silt (Graminia Formation, Winterburn Group)

The Graminia Formation consists predominantly of anhydrite, with subordinate siltstone and silty dolomite and buff, crystalline, silty dolomite. It commonly consists of an upper and lower silty zone separated by a carbonate (Blue Ridge Member). The Blue Ridge-Graminia interval is about 30 m to 45 m thick in the local study area and thins due to erosion towards the east (Figure 17).

Wabamun Group

The Wabamun Group in the Pembina area is a thick sequence of grey to dark grey, shallow marine, massive to burrow mottled, platform carbonates. The sediments usually consist of limestone with minor amounts of dolomite and they are generally tight. Eight to six thin, laterally continuous, dolomitized intervals occur in the Wabamun Group in the study area, which range in thickness from 2 to 14 m; these intervals form the major injection units. In more detail, the Wabamun Group can be subdivided into four unofficial units, which consist from top to bottom of a tight argillaceous limestone, an upper anhydrite, a middle dolomite of reservoir quality, and a lower anhydrite unit. The porous portion of the Wabamun Group commonly is the thickest member. It is the middle dolomite section, which is primarily dolomite with minor layers of limestone. It contains about 25 to 50 m of reservoir quality rock, with porosity reaching up to 20% in some intervals.

Thin-section point-counting analyses, XRD and XRF analyses from core samples were used to determine the mineralogical composition of the Wabamun Group carbonates in the study area (Table 1). The XRF analyses do not measure carbon content, which constitutes the balance to 100%. The rocks consist of 90% calcite, 5-9% dolomite, and the remainder being other minor compounds like clay or ferroan minerals. This composition may vary locally due to different degrees of dolomitization and recrystallization. These diagenetic processes also resulted in a highly variable distribution of porosity and permeability, which is mainly confined to the middle dolomite member. The porosity is mainly inter-crystalline porosity with minor amounts of vuggy porosity.

Banff and Exshaw Formations (Mississippian)

The Wabamun Group disconformably underlies the Mississippian-aged Exshaw and Banff formations, which consist of 180 m to 200 m tight limestones and bituminous shales (Figure 18). The Exshaw Formation consists of a lower, shale-dominated member (~ 9 m) that is gradationally overlain by an upper member (~37 m) comprised of siltstone and silty limestone (Macqueen & Sandberg, 1970; Richards & Higgins, 1988). Conodonts are locally common within calcareous concretions of the black shale member and indicate that the Devonian-Carboniferous boundary actually lies within that unit in some places (Macqueen & Sandberg, 1970; Richards & Higgins, 1988). The lower member consists of anomalously radioactive, brownish black, sparsely fossiliferous shale. A thin (10 cm) phosphatic, pyritic to sphaleritic, basal sandstone to conglomerate bed is locally present. Bentonite and tuff beds are commonly present in the shale member (Macdonald, 1987). The upper member is composed of a grey shale grading up into siltstone, sandstone, silty limestone and skeletal to ooid lime grainstone and packstone. The Exshaw Formation is generally disconformably overlain by the Banff Formation and/or grades laterally into that unit.

Na2O	wt%	0.11	Ni	ppm	5
MgO	wt%	0.22	Cu	ppm	8
Al2O3	wt%	0.11	Zn	ppm	<LD
SiO2	wt%	1.28	Ga	ppm	<LD
P2O5	wt%	0	As	ppm	<LD
S	ppm	981	Rb	ppm	0.5
Cl	ppm	1495	Sr	ppm	151.1
K2O	wt%	0.04	Y	ppm	<LD
CaO	wt%	71.2	Zr	ppm	1.5
Sc	ppm	32	Nb	ppm	<LD
TiO2	wt%	<LD	Ba	ppm	<LD
V	ppm	9	Ce	ppm	<LD
Cr	ppm	<LD	Pb	ppm	9
MnO	wt%	0.01	Th	ppm	<LD
Fe2O3T	wt%	0.04	U	ppm	<LD
			total	wt%	73.45%

Table 1. X-ray flourescence analysis of matrix rock from the Wabamun Group in well 14-29-48-6W5 at 2154 m depth.

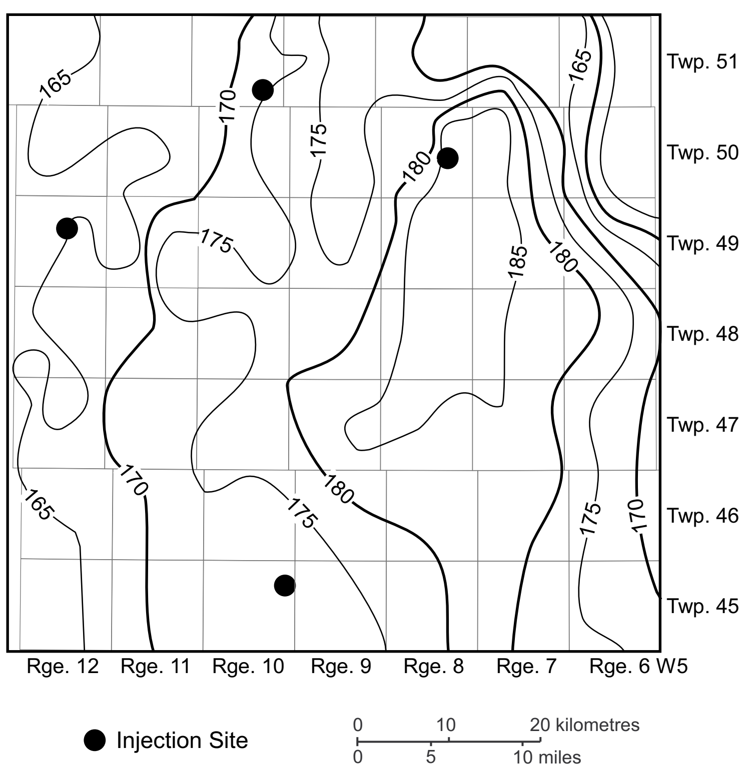

Figure 18. Isopach of the Mississippian, Banff and Exshaw formations in the local-scale study area. Contours in metres.

In general, the Banff Formation comprises a lower succession of shale and marlstone grading upward and eastward into spiculite, bedded chert and carbonates that pass into interbedded sandstone, siltstone, and shale.

The Banff-Exshaw interval has a thickness of 170 to 180 m (Figure 18) in the study area and forms an effective seal on top of the Wabamun Group carbonates.

The downhole geology from the Mississippian caprock through the Wabamun injection strata into the underlying Winterburn Group is shown in Figures 19 to 21 for three of the four injection sites.

5.3 Rock Properties of the Wabamun Group

Rock properties relevant to the flow of formation fluids and injected acid gas are porosity and permeability. Only six wells with core analyses from the Wabamun Group strata exist in the local-scale study area. The core-scale porosity values were upscaled to the well scale using the weighted arithmetic average. Permeability values were upscaled to the well scale using a power–law average with a power of ω=0.8 (Desbarats & Bachu, 1994). The well-scale porosity and permeability values are shown in Table 2. However, core analyses are sparse in the Wabamun Group because it is not a reservoir unit in the Pembina area and it has not been cored over its entire interval. Actually, all available measurements are from the lowermost, tighter part of the Wabamun Group, at the contact to the underlying Winterburn Group; hence the porosity and permeability measurements are not representative for the entire Wabamun Group in the study area. Consequently, the porosity and permeability values are relatively low, ranging from 0.4% to 5% for porosity, 0.01 to 6.3 mD for horizontal permeability, and 0.03 to 0.7 mD for vertical permeability. The well-scale porosity and permeability values can be scaled up to the formation scale using the geometric average of well-scale values (Dagan, 1989), leading to values of 1.9% for porosity and 0.2 mD for horizontal permeability. Similar results from core analyses were obtained for the Wabamun Group in the Brazeau area, west-southwest of the Pembina local-scale study area, where values range from 0.4% to 7.7% for porosity, 0.09 to 3.8 mD for horizontal permeability, and 0.02 to 3.5 for vertical permeability (Bachu *et al*., 2003). Unfortunately, as mentioned previously, these values are representative for the lower, tighter part of the Wabamun Group strata, but not for the interval used for acid gas injection.

Well Location	Porosity (%)	Horizontal Permeability (mD)	Vertical Permeability (mD)
00/03-32-047-11W5-0	2.4	0.01	-
00/09-22-050-10W5-0	1.1	0.59	-
00/15-28-050-10W5-0	3.7	1.12	0.03
00/05-09-051-09W5-0	4.9	6.30	0.67
00/14-02-051-10W5-0	0.4	0.10	0.03
00/03-32-047-11W5-0	2.4	0.01	-

Table 2. Well-scale porosity and permeability values obtained from core-scale measurements in core plugs from the Wabamun Group in the local-scale study area.

Sufficient data from DSTs were not available to calculate permeability on a larger scale than those values derived from core analyses. However, the analyses of injectivity tests from the various injection sites show permeability values in the 100 mD range for the reservoir scale. Although the Wabamun Group is characterized as a regional aquifer, generally its permeability is

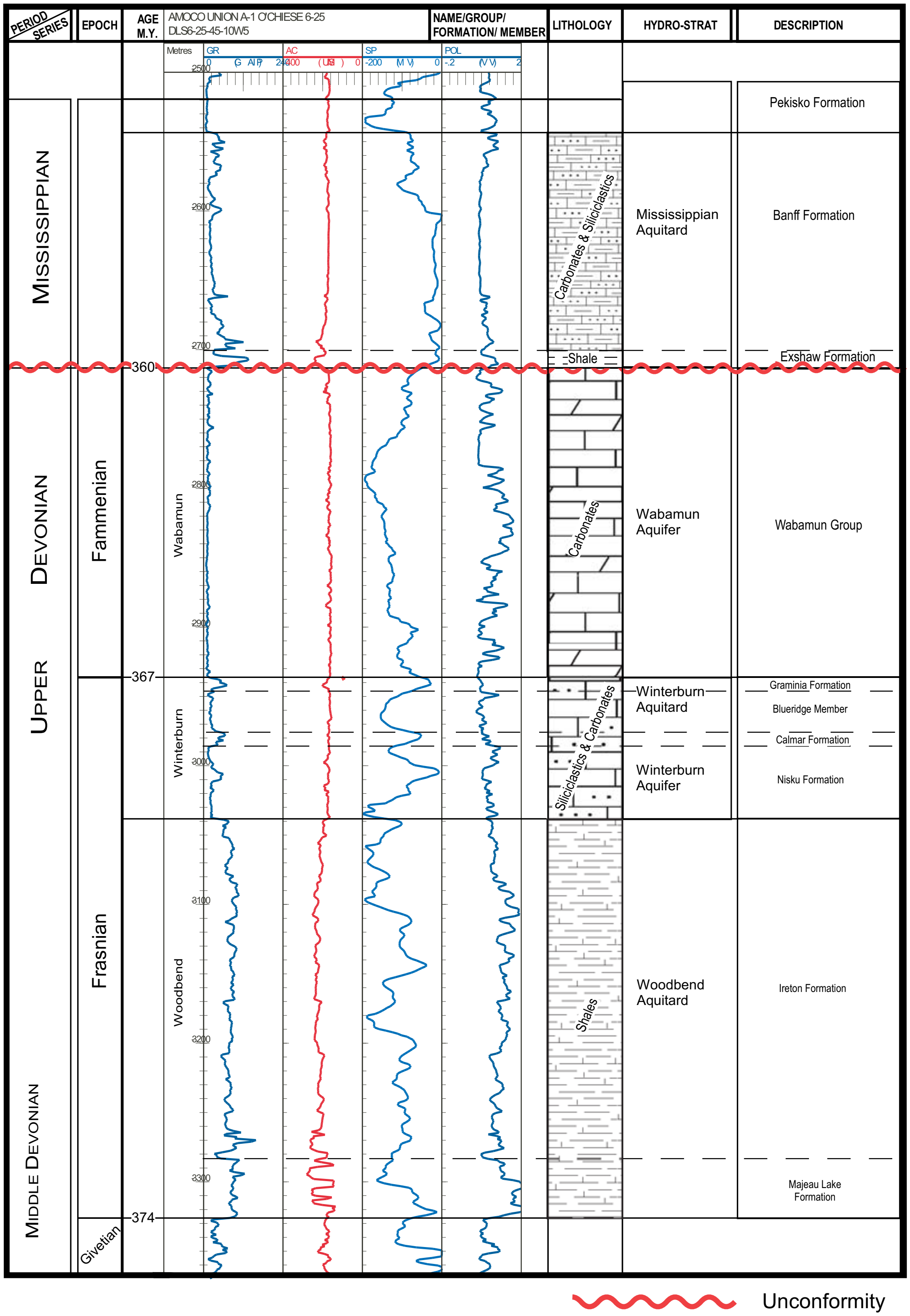

Figure 19. Downhole stratigraphic model for the injection location at Pembina Burlington in well 06-25-45-10W5.

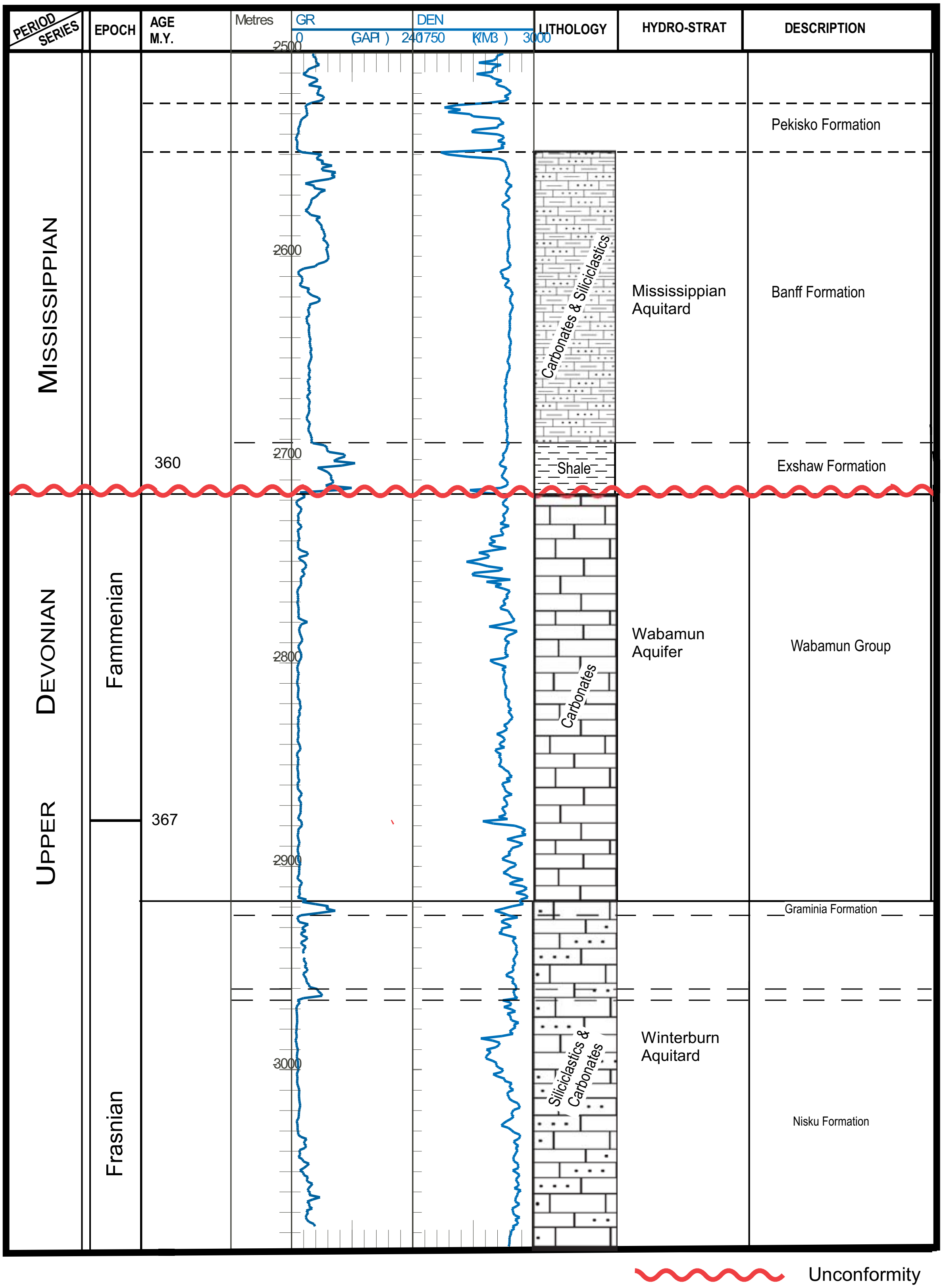

Figure 20. Downhole stratigraphic model for the injection location at Pembina I in well 14-22-49-12W5.

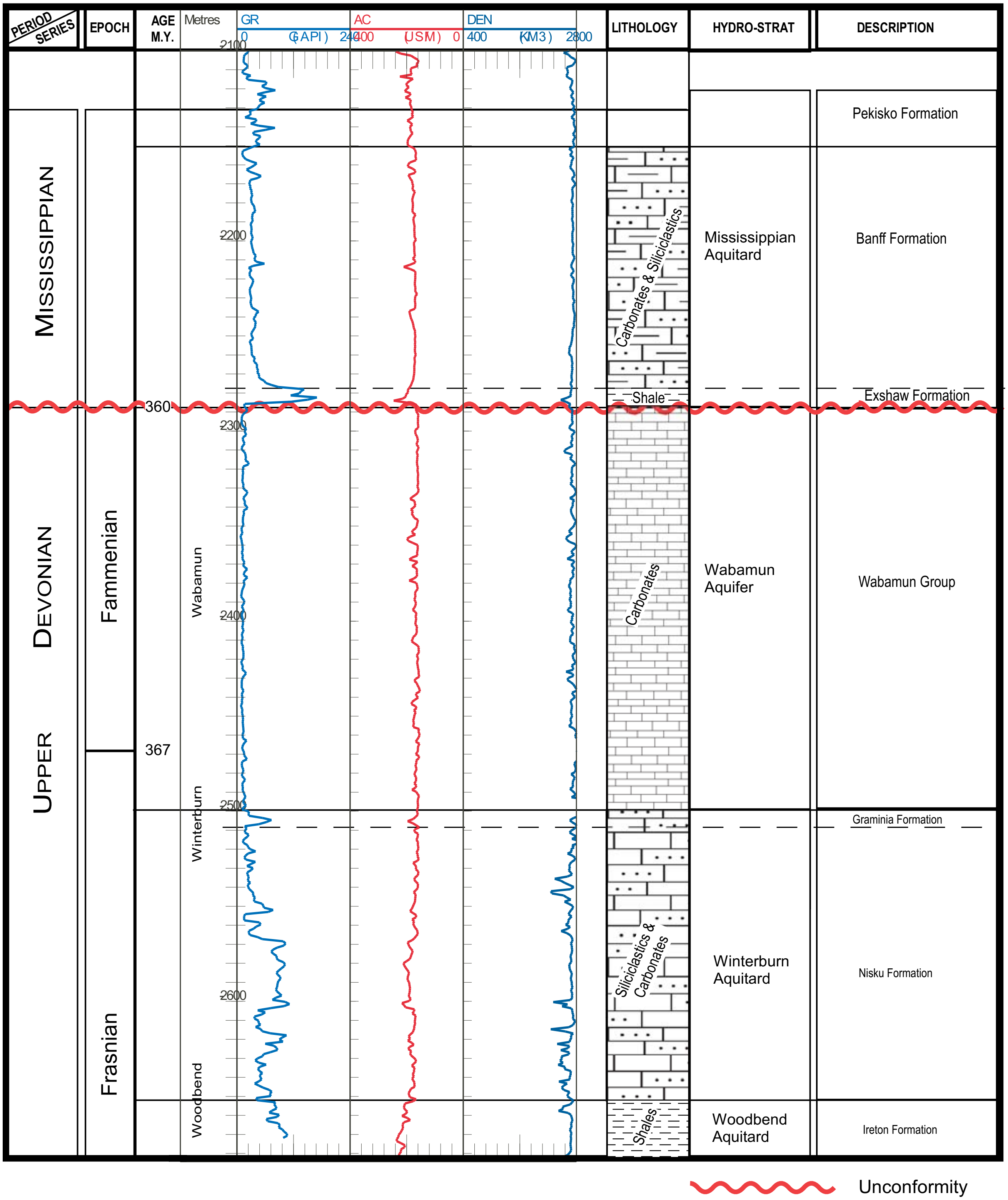

Figure 21. Downhole stratigraphic model for the injection location at Pembina II in well 02-11-51-10W5.

relatively low, and areas of high porosity and permeability occur only locally and are not well connected.

5.4 Chemistry of Formation Water in the Wabamun Group

The major constituents of the Wabamun Formation water are sodium and chloride, and in lesser concentrations calcium, magnesium, bicarbonate and sulfate (Figure 22). Formation water salinity in the local-scale study area ranges between 86 g/l in the north and 165 g/l in the east (Figure 23a). The higher salinity values in the eastern part of the study area are probably due to the increasing amount of evaporites found towards the southeast in the Wabamun Group. The bicarbonate and sulfate concentrations are variable, ranging from 0.35 to 2.6 g/l and 0.01 to 1.5 g/l, respectively (Table 3), and no geographical trend can be observed (Figure 23a). The salinity in the vicinity of acid-gas injection sites Pembina-Wabamun I and Pembina-Wabamun II is around 130 g/l and 90 g/l, respectively. There are no chemical analyses of formation water in the Wabamun Group close to the Pembina-Burlington and Pembina-Northrock sites, however interpolation between the surrounding wells suggests a salinity of formation water between 120 and 150 g/l (Figures 11a and 23a). The in-situ density of formation water in the Wabamun Group in the local-scale study area was estimated to be 1050 kg/m^3 using the methods presented in Adams and Bachu (2002).

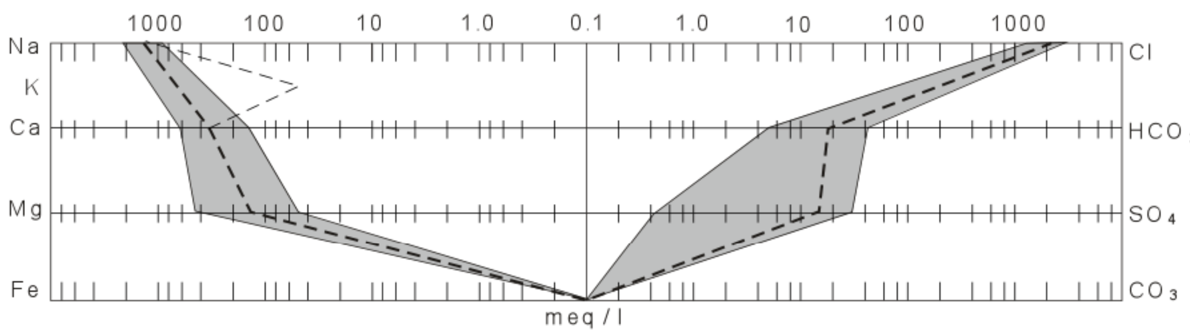

Figure 22. Stiff diagram of Wabamun Formation waters in the local-scale study area. The thick dashed line represents the average major ion composition of formation waters, whereas the grey shading shows the range in concentrations. The thin dashed line shows the concentration of potassium (K).

5.5 Pressure Regime in the Wabamun Group

Only five DSTs were performed in the Wabamun Group in the local-scale study area. Corresponding hydraulic heads, calculated with a representative density of 1050 kg/m^3 according to the method presented by Bachu and Michael (2002), vary in a very narrow range of 377 to 390 m, except for a single value of 456 m off-centre towards the northwest (Figure 23b).

The recorded pressures are plotted versus depth and elevation in Figure 24. Pressures in the Wabamun aquifer plot along a linear trend approximately 5000 kPa less than pressures within a hydrostatic water column in hydraulic continuity with the ground surface, indicating underpressured conditions (Figure 24a). The overlying Mississippian aquifer, which at greater depth is similarly underpressured, becomes increasingly less underpressured updip as it becomes shallower. Pressures in the underlying Nisku aquifer are significantly higher than those in the Wabamun aquifer.

Well location	Sample Date	Depth (mKB)		Cations (mg/l)				Anions (mg/l)			TDS	Density	Density T	pH	pH T
		from	to	Na	K	Ca	Mg	Cl	HCO3	SO4	(mg/l)	(g/m3)	(^{o}C)		(^{o}C)
02/14-29-048-06W5-0		2224	2263	50110		10615	2207	101486	375	1052	165845	1.017	16	7.7	
		2185	2195	45995		10224	1872	93189	380	1083	152965	1.111	16	8.6	
00/14-20-050-12W5-0	29-Apr-77	2908	2932	46924		3115	695	78900	452	1027	131113	1.092	16	6.8	24
00/02-20-050-10W5-0	08-May-78	2582	2591	32594		8689	1118	68300	1037	12	111750	1.08	16	7.3	22
00/14-28-050-10W5-0	28-Nov-83	2601	2603	31500	2150	3208	668	54253	2006	843	94628	1.0755	15.4	8.6	
	28-Nov-83	2601	2603	34000	2740	3412	741	59613	2324	722	103552	1.0818	15.4	8.6	
00/01-28-048-12W5-0	25-Mar-83	2995	2997	31030	2111	13170	5900	83900	2635	494	139240	1.099	25	7.2	25
00/14-04-051-09W5-0	09-Mar-87	2239	2260	25180	1918	4324	1074	52000	351	1535	86382	1.055	25	7.7	23
	12-Mar-87	2260	2281	41530	3553	9830	2175	93800	481	1444	152813	1.103	25	7.0	23
00/13-26-051-09W5-0	13-Jan-86	2216	2239	45450	4494	11200	2284	102100	817	479	166820	1.110	25	7.0	22
02/14-12-048-06W5-0	06-Apr-89	2146	2183	45235	2496	10410	3156	100000	805	605	162707	1.111	25	6.4	21

Table 3. Chemical analyses of formation water from the Wabamun Group in the local-scale study area. The location of sample wells and salinity (TDS) values are shown in Figure 23a.

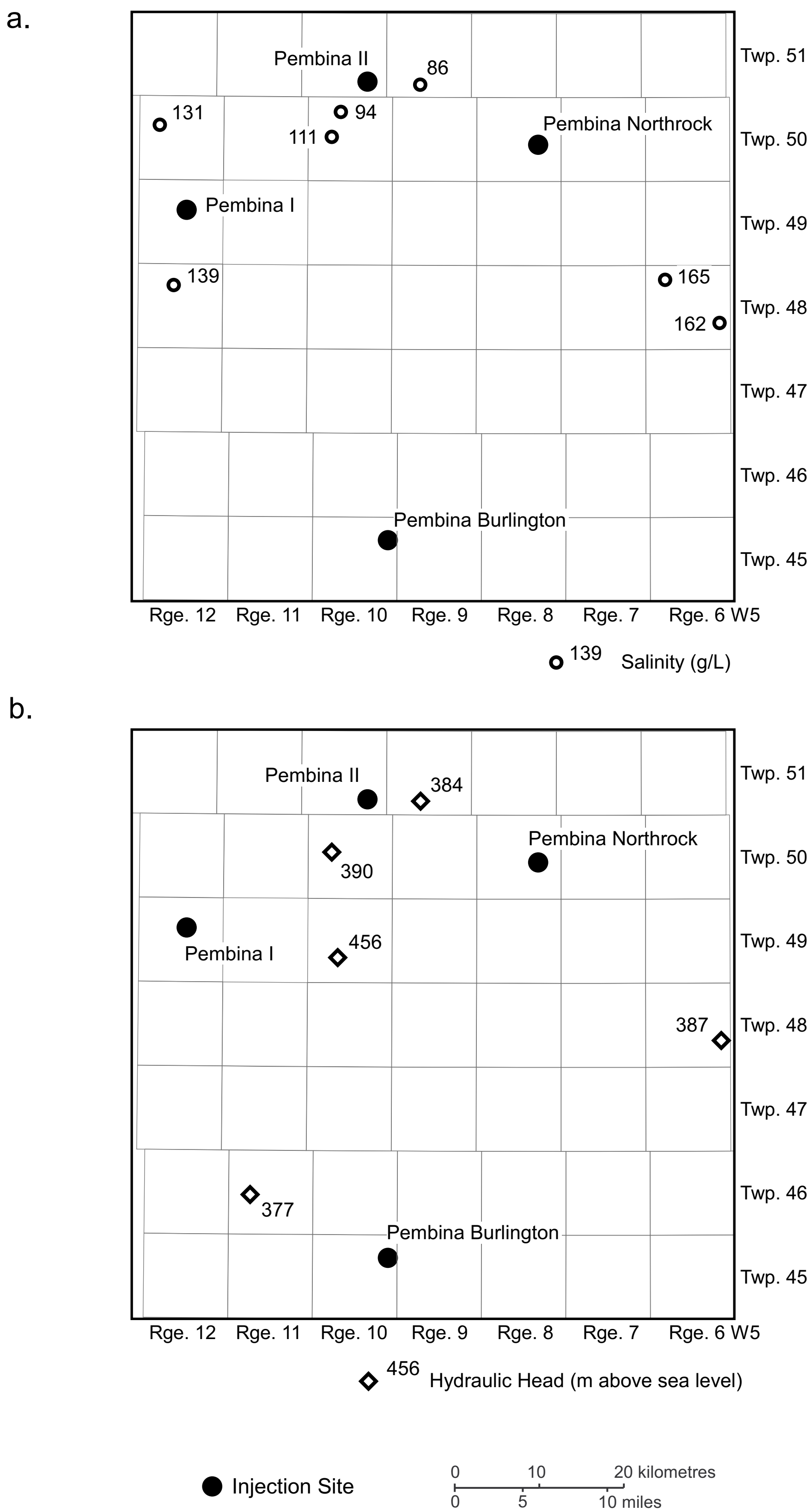

Figure 23. Hydrogeological characteristics of the Wabamun aquifer in the local-scale study area: a) salinity of formation water (g/l), and b) hydraulic heads (m; calculated with a reference density of 1050 kg/m^3).

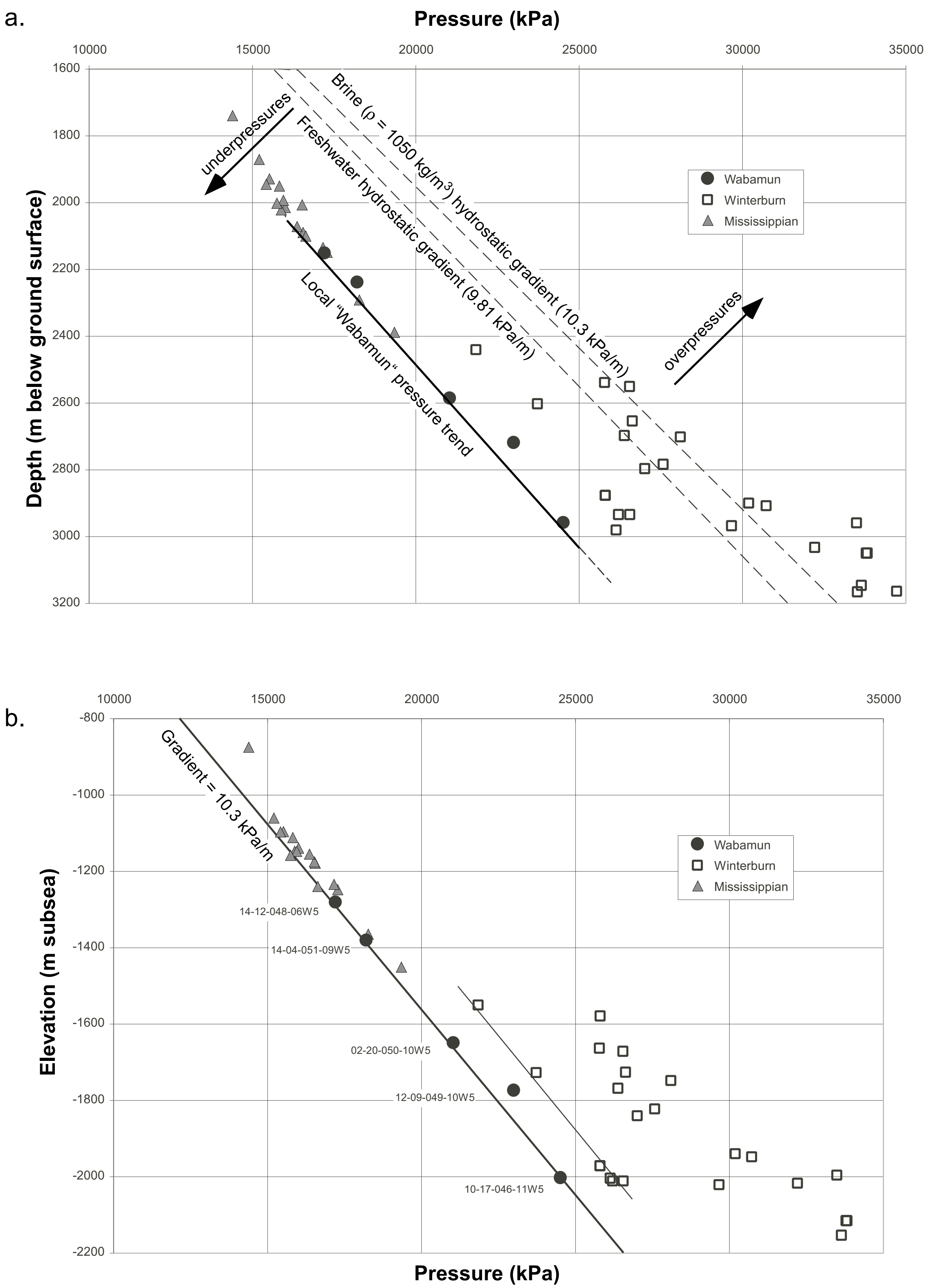

Figure 24. Variation of pressure with: a) depth and b) elevation, in the Wabamun Group and adjacent formations in the local-scale study area. The area shaded in grey represents the range of pressures in a hydraulically continuous, static column of water with a density range of 1000 to 1050 g/l (0 kPa at ground surface).

On the pressure-elevation plot (Figure 24b), data points from the Wabamun aquifer follow a linear trend with a slope of 10.3 kPa/m, which is representative of the pressure distribution in a static column of water with a density of 1050 kg/m^3. Only the pressure measurement from the 12-09-049-10W5 well falls above this static gradient line. This "higher" pressure translates into the hydraulic head value of 456 m, which is higher than the surrounding head values (Figure 23b).

5.6 Flow of Formation Water in the Wabamun Group

The pressure regime and hydraulic head distribution in the Wabamun aquifer suggest that flow conditions in the Pembina area are close to static. Only the elevated hydraulic head value in the 12-09-049-10W5 well suggests formation water flow into the Pembina area, with three possibilities for origin and cause: a) lateral flow from the west, where values of hydraulic heads are higher than 450 (Figure 11b), b) vertical upward leakage from the Winterburn aquifer, and c) downward leakage from the Mississippian aquifer. The latter hypothesis can be easily discarded because hydraulic heads in the Mississippian aquifer are lower than those in the Wabamun aquifer in the Pembina area. Pressures and hydraulic heads in the underlying Winterburn Group (Figures 24b and 13b, respectively) are higher than those in the Wabamun Group (Figures 24b and 11b), so that the potential for upwards cross-formational flow exists, at least locally. However, the offset of pressure data from the Wabamun and Nisku aquifers in the pressure-depth and pressure-elevation plots (Figure 24) indicates that, on a larger scale, there is no vertical hydraulic continuity between the two aquifers in the Pembina area and that the intervening Calmar and Graminia formations form an effective aquitard. It is more likely that the elevated hydraulic head value was measured in a lower-permeability limestone interval of the Wabamun Group. As discussed in the regional-scale hydrogeological analysis, the facies boundary from limestone to higher-permeability dolostone runs through the Pembina area, forming a lateral flow barrier and thereby causing the drop in hydraulic head values (Figure 11b). However, a definitive assessment is not possible because this interpretation of the flow and its causes hinges on a single data point, the quality of which could not be validated with sufficient certainty.

Pressures from the Wabamun and overlying Mississippian plot along a similar trend in the pressure-depth and pressure-elevation plots, which may suggest a continuous Wabamun-Mississippian aquifer system. However, the intervening Exshaw-Lower Banff interval forms a thick, competent aquitard (more than 150 m in thickness). Therefore, it is more likely that, rather than being in hydraulic communication, both aquifers are controlled by the same boundary conditions along their subcrop at the sub-Cretaceous unconformity. The northward regional-scale flow system in the Upper Devonian-Cretaceous Mannville aquifer system in central-eastern Alberta affects pressures and flow in both the Mississippian and the Wabamun aquifers along their respective subcrop areas in the center and east of the local-scale study area, respectively. Previous studies have established convergence in central Alberta of Paleozoic flow systems (Michael & Bachu, 2002b, Michael *et al*., 2003) and the flow system in the Upper Devonian-Mannville aquifer system along the sub-Cretaceous unconformity (Bachu, 1995; Rostron & Toth, 1997; Anfort *et al*., 2001).

Mixing of formation waters from various aquifers in their subcrop region at the sub-Cretaceous unconformity region creates a plume of high salinity brine in the Mannville aquifer and, conversely, dilutes brines in the Paleozoic aquifers. Although the Wabamun aquifer connects with the Mannville aquifer east of the local-scale Pembina area, and clearly updip flow of Wabamun brines contributed in the past to the high-salinity plume in the Mannville, at present flow conditions inferred from pressure and hydraulic head distributions appear rather stagnant in the area of the acid-gas injection sites. The high salinity values (160 g/l) in the east (Figure 23a) also show that significant dilution with less saline Mannville waters, like it is observed further east along the Wabamun subcrop edge (Figure 11a), has not occurred in the Pembina area. These hydrogeological conditions are similar to those in the deep formations of the Williston basin in Saskatchewan and North Dakota, where the negative buoyancy of high-salinity formation waters cancels out the topographic drive and leads to quasi-stagnant flow (Bachu & Hitchon, 1996).

5.7 Stress Regime and Geomechanical Properties

Knowledge of the stress regime at the injection sites is important for establishing the potential for hydraulic rock fracturing as a result of injection, and for setting limits for operational parameters. Given its tensorial nature, the stress regime in any structure, including the Earth, is defined by the magnitude and orientation of the three principal stresses, which are orthogonal to each other. In the case of consolidated rocks, the fracturing threshold is greater than the smallest principal stress, σ_3, but less than the other two principal stresses, σ_1 and σ_2. If fracturing is induced, fractures will develop in a plane and direction perpendicular to the trajectory of the smallest principal stress. Basin-scale studies of the stress regime in the Alberta basin suggest that, in most of the basin, the smallest principal stress, σ_3, is horizontal (Bell & Babcock, 1986; Bell *et al.*, 1994; Bell & Bachu, 2003). Due to the orthogonality of the stress tensor, this means that the smallest stress is the minimum horizontal stress (σ_3=S_{Hmin}). Rock fracturing occurs at pressures P_b that are greater than the minimum horizontal stress and that can be estimated using the equation:

$$P_b = 3S_{H\min} - S_{H\max} + P_0 + T_0 \qquad (2)$$

where S_{Hmax} is the maximum horizontal principal stress, P_0 is the pressure of the fluid in the pore space, and T_0 is tectonic stress. In the case of injection, the fluid pressure at the well is the bottom hole injection pressure. This equation demonstrates that the fracturing pressure is related to the effective stress (stress less fluid pressure), beside the tensile strength of the rock.

The minimum horizontal stress, S_{Hmin}, can be evaluated using a variety of tests. The most accurate method for estimating the magnitude of the S_{Hmin}, is through micro-fracture testing, but mini-fracturing, leak-off tests and Fracture Breakdown Pressure tests are also used (Bell, 2003; Bell & Bachu, 2003). The maximum horizontal stress cannot be directly measured, but it can be calculated according to the relation:

$$S_{H\max} = \frac{\upsilon}{1-\upsilon}(S_V - P_0) \qquad (3)$$

where S_V is the vertical stress and υ is Poisson's ratio, which is determined through laboratory tests on rock samples. The magnitude of S_V at any depth coincides with the pressure exerted by the rocks above that point (weight of the overburden), and can be calculated by integrating the values recorded in density logs. Unfortunately there are no methods for estimating the tectonic stress, T_0, hence it is not possible to estimate the rock fracturing pressure. However, previous studies have shown that in the study area the S_{Hmax} is less than S_V (Bell & Babcock, 1986; Bell *et al.*, 1994). Thus, estimation of S_{Hmin} and S_V in a well provides loose lower and upper bounds for the fracturing pressure in that well.

If fractures occur, they will develop in a direction perpendicular to the plane of the minimum horizontal stress, hence the need to know the principal directions of the stress field. Horizontal stress orientations can be determined from breakouts, which are spalled cavities that occur on opposite walls of a borehole (Bell, 2003). They form because the well distorts and locally amplifies the far-field stresses, producing shear fracturing on the borehole wall. If the horizontal principal stresses are not equal, the wall rock of a quasi-vertical well is anisotropically squeezed. Caving occurs preferentially aligned with the axis of the smaller S_{Hmin}. More detailed description of the methods used for estimating stress magnitude, gradient and orientation are found in Bell (2003) and Bachu and Bell (2003).

Because no testing was performed in the injection wells themselves, density logs and tests from adjacent wells in the local-scale study area were used in the analysis of the stress regime in the rocks of the Wabamun Group in the Pembina area. Micro-frac, mini-frac and leak-off tests from wells in the Wabamun Group in the regional-scale study area were used to estimate the gradient of the minimum horizontal stress, ∇S_{Hmin}. These gradients were then mapped, to infer the value of the gradient at the acid-gas injection sites. The S_{Hmin} at each injection site was then back calculated on the basis of stress gradient and depth (Bell, 2003; Bachu & Bell, 2003). Orientations of the S_{Hmin} were determined from wells with breakouts in the Wabamun Group in the local-scale study area. The results are presented in Figure 25.

Vertical stresses at the top of the Wabamun Group in the acid-gas injection wells vary from 50.8 MPa to 65.6 MPa (Figure 25a) and reflect the southwestward dipping of the Wabamun Group strata. Because in some cases the injection interval is deeper than the top of the Wabamun Group, vertical stresses, S_V, at the top of the injection interval vary between 51.5 MPa and 67.4 MPa (Figure 25a). The gradient of the vertical stress, calculated for the injection wells and for the other two wells with data higher up in the sedimentary succession, varies between 22.6 kPa/m and 24.2 kPa/m (Figure 25a), reflecting variations in rock density. Minimum horizontal stresses, S_{Hmin}, in the four injection intervals vary between 36.0 MPa and 47.9 MPa (Figure 25b), reflecting variations in both injection depth and in stress distribution. The implication of these results is that the rock fracturing threshold in each well is between S_{Hmin} and S_V, but generally closer to S_{Hmin}.

If the bottom hole injection pressure (BHIP) reaches the S_{Hmin} value, pre-existing fractures, if present, may open up. If no fractures are present, and there is no indication that there are any (except maybe around the well bore), the pressure has to increase beyond S_{Hmin} to overcome the tensile strength of the rocks, at which time the rocks will fracture. However, fractures may be limited to reservoir rocks only and may not propagate into the caprock. In order to avoid reservoir fracturing, the maximum BHIP should, at all times, remain less than the S_{Hmin}. For safety reasons, AEUB regulations require that the maximum BHIP be less than 90% of the fracturing threshold. Thus, the maximum BHIP approved by AEUB for these injection operations is significantly less than the minimum horizontal stress S_{Hmin}.

The direction of the minimum horizontal stress varies between 127.4^o and 148.8^o, in a general southeast-northwest direction (Figure 25b). This means that fractures will form and propagate in a vertical plane in a southwest-northeast direction (47°-59°), basically perpendicular to the Rocky Mountain deformation front and along the direction of the tectonic stress induced by the Laramide orogeny and by the collision of the Pacific and Juan de Fuca tectonic plates with the North American continent. This preferential fracturing direction was observed previously in coal mines in Alberta (Campbell, 1979), and was similarly determined for overlying Cretaceous rocks in southern and central Alberta (Bell & Bachu, 2003).

Knowledge of the geomechanical properties of rocks in formations affected by acid gas injection is an essential part of the subsurface characterization of any injection site, including the acid-gas injection operations in the Pembina area. These properties, in combination with the stress regime, play an important role in evaluating the safety of the operation and avoiding rock fracturing and acid gas leakage into overlying formations. Two parameters are essential to understanding the rock mechanics of an injection site: Young's modulus and Poisson's ratio. Unfortunately there are

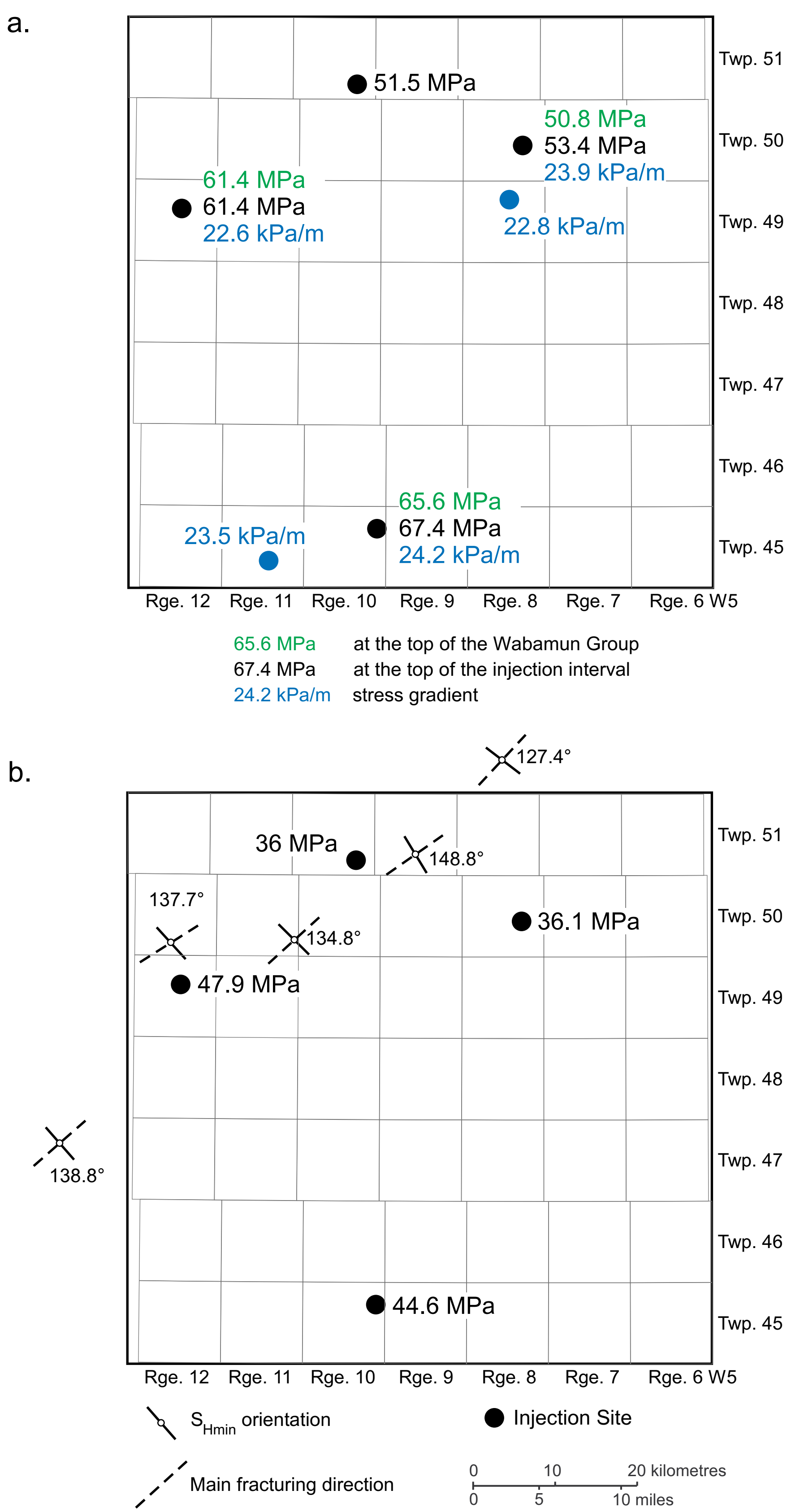

Figure 25. Characteristics of the stress regime in the Wabamun Group in the local-scale study area: a) vertical stresses, S_V, and their gradient, and b) minimum horizontal stresses, S_{Hmin}, and their orientation.

no publicly available values for these parameters for carbonate rocks in the Alberta Basin, and very few values for other geomechanical properties that can be used to derive the parameters of interest (Miller & Stewart, 1990; Allen & Roberts, 1992; Chalaturnyk, 1996). Four of them are for deep Mississippian rocks in west-central Alberta just outside the regional-scale study area, and one is for shallow Middle Devonian rocks in northeastern Alberta (Table 4). For the caprock, which formed by the Exshaw Formation shales, representative values could be derived for only one case of Jurassic Fernie Group shales (Table 4), based on data from Miller and Stewart (1990).

Young's modulus is defined as the amount of strain (deformation) caused by a given stress, and is a function of the stiffness of the material. Young's modulus is used as an indication of the possible width of fractures. A high Young's modulus correlates to a narrower fracture width. In general, typical Young's modulus values for rock range from 20 to 82.5 GPa (Jumikis, 1983; Haas, 1989). The values for Mississippian rocks range from 55 GPa to 73.5 GPa, compared with a value of 27.9 GPa for the Jurassic shale (Table 4).

Poisson's ratio is defined as the ratio of the strain perpendicular to an applied stress, to the strain along the direction of that stress. It is a measure of the deformation perpendicular to and along the stress being applied to the rock, and indicates the plasticity of the rock. The rock plasticity, expressed by Poisson's ratio, and $S_{Hmin,}$ have a significant effect in determining the rock fracture threshold (see equations 2 and 3). A formation with high S_{Hmin} and Poisson's ratio likely would be an effective barrier to fracture propagation. In general, values for Poisson's ratio for limestone range from 0.27 to 0.3, and for shales from 0.2 to 0.4 (Lambe & Whitman, 1951; Haas, 1989). For carbonate rocks in the Alberta Basin values range from 0.28 to 0.32, while the single value for shales is 0.3 (Table 4).

Rock Age	Rock Type	Well Location	Average Depth (m)	Poisson's Ratio	Young's Modulus (GPa)
Mississippian	Limestone	Calgary, AB.	2700	0.28	55.0
Mississippian	Limestone	15-18-039-3W5	2195	0.30	73.5
Mississippian	Limestone	9-5-039-3W5	2185	0.31	64.0
Mississippian	Limestone/ Dolostone	9-5-039-3W5	2175	0.26	56.7
Middle Devonian	Limestone	31-092-12W5	261	0.32	-
Jurassic	Shale	9-13-039-3W5	2179	0.30	27.9

Table 4. Geomechanical properties of rocks of interest from the Alberta Basin (derived based on data from Miller & Stewart, 1990; Allen & Roberts, 1992; Chalaturnyk, 1996).

5.8 Site Specific Characteristics of the Acid Gas Operations

The site-specific characteristics of the acid-gas injection operations in the Wabamun Group in the Pembina area are summarized in Table 5. The information contained therein has been compiled from the applications submitted by operators to AEUB in the process of obtaining approval for these operations, and from other sources. It is worth noting that the operators indicate site-specific porosity and permeability values in the range of 6% to 20%, and 35 to 137 mD (Table 5), which are significantly higher than the values obtained from other wells (Table 2).

	Operation Description	Pembina-Wabamun I	Pembina-Wabamun Northrock	Pembina-Wabamun Burlington	Pembina-Wabamun II
Injection Operations	Gas Plant	Chevron West Pembina	Amoco Lobstick	O'Chiese Gas Plant	Chevron Bigoray
	Current Operator	Enerpro Midstream Inc.	Northrock Resources Ltd.	Burlington Resources Canada Energy Ltd.	Enerpro Midstream Inc.
	Approval Date	2/23/1994	1/21/2000	5/11/2000	6/7/2000
	Status	active	not implemented	active	active
	Location (DLS)	14-22-049-12W5/02	11-14-050-08W5/00	06-25-045-10W5/00	02-11-051-10W5/02
	Latitude (N)	53.24688	53.3181	52.90618	53.38374
	Longitude (W)	-115.6746	-114.98	-115.3226	-115.28
	KB Elevation (m AMSL)	966.3	850.0	915.4	879.3
	Depth of Injection Interval (m)	2,715-2,918	2,222-2,228	2,781-2,847	2,285-2,503
	Average Injection Depth (m)	2,817	2,225	2,814	2,394
Reservoir Geology	Injection Formation Name	Wabamun Group	Wabamun Group	Wabamun Group	Wabamun Group
	Injection Formation Lithology	Limestone	Limestone	Dolostone	Limestone
	Injection Formation Thickness (m)	203	6	66	218
	Net Pay (m)	10	8	60	10
	Caprock Formation	Exshaw/Banff Formations	Exshaw/Banff Formations	Exshaw/Banff Formations	Exshaw/Banff Formations
	Caprock Formation Lithology	Shale/Limestone	Shale/Limestone	Shale/Limestone	Shale/Limestone
	Caprock Thickness (m)	130	190	168	130
	Underlying Formation	Graminia Formation	Blueridge Member	Wabamun-Winterburn Group	Graminia Formation
	Underlying Formation Lithology	Siltstone	Dolomitic shale	Limestone	Argillaceous/Silty carbonate
	Underlying Thickness (m)	10	50	90	7
Rock Properties	Porosity (fraction)	0.06	0.20	0.09	0.08
	Permeability (md)	75	122	137	35
	S_V (MPa)	61.4	53.4	67.4	51.5
	S_{HMIN} (MPa)	47.9	36.1	44.6	36.0
Reservoir Properties	Original Formation Pressure (kPa)	27,000	17,762	24,680	20,244
	Formation Temperature (°C)	100	69	103	70
	Reservoir Volume (1000 m^3)	569.3	107	306.9	320
Formation Water	TDS Calculated (mg/L)	152,813	115,000	125,000	86,382
	Na (mg/L)	41,530	ND	ND	25,180
	Ca (mg/L)	9,830	ND	ND	4,324
	HCO_3 (mg/L)	481	ND	ND	351
Licensed Injection Operations	Injected Gas - CO_2 (mole fraction)	0.15	0.65	0.45	0.7919
	Injected Gas - H_2S (mole fraction)	0.75	0.35	0.55	0.1997
	Maximun Approved WHIP (kPa)	12,000	10,500	10,500	13,000
	Maximum Approved Injection Rate (1000 m^3/d)	30	16	28	34
	Total Approved Injection Volume (10^6 m^3)	63,000	38,000	109,000	124,100
	Life Time (years)		15		10
	EPZ (km)	5.30	2.40		6.20

Table 5. Characteristics of the acid-gas injection operations in the Wabamun Group in the Pembina area (status at the end of 2002).

6 Discussion

Based on the hydrogeological analysis of the injection sites at local, regional and basin scales presented in the preceding chapters, the potential for acid gas migration and/or leakage from the Wabamun aquifer in the Pembina area can be qualitatively assessed. Migration is defined here as flow along bedding within the same formation (aquifer), and leakage is defined as upward flow to overlying formations and possibly to the surface. Both will be considered in the context of the natural hydrogeological setting and of man-made features, such as wells and induced fractures.

6.1 Acid Gas Migration

The injected gas will migrate upwards from well perforations towards the top of the Wabamun aquifer because the acid gas is lighter than the formation water, and it will accumulate as a plume at the top of the aquifer. Since the flow of formation water in the Wabamun aquifer is extremely slow, almost stagnant, the hydrodynamic drive for acid gas migration is negligible, and the flow of the injected acid gas will be driven by buoyancy updip to the northwest. Acid gas cannot migrate into overlying Mississippian aquifers because of the overlying confining shales of the Exshaw and Banff formations.

The specific discharge, **q**, (or Darcy velocity) of the flow of acid gas in a sloping aquifer can be written with respect to a reference density ρ_0 as (Bachu, 1995):

$$q = -\frac{k\rho_0 g}{\mu_g}\left(\nabla H_0 + \frac{\Delta\rho}{\rho_0}\nabla E\right)$$

where k is permeability, g is the gravitational constant, μ_g is gas viscosity, $\Delta\rho$ is the density difference between the acid gas and the reference density, ∇H_0 is the hydrodynamic drive, and ∇E is the slope of the aquifer. If the reference density is the density of formation water in the Wabamun aquifer (ρ_0=1050 kg/m^3), then ∇H_0 becomes the hydrodynamic drive of the flow of formation water in the Wabamun aquifer, which is negligible (quasi stagnant flow). In this case, the above relation becomes:

$$q = \frac{k(\rho_b - \rho_g)g}{\mu_g}\nabla E$$

where ρ_b and ρ_g are the densities of the brine and acid gas, respectively. The density and viscosity of the acid gas at in situ conditions in the Wabamun Group in the Pembina area are estimated to be approximately 600 kg/m^3 and 0.054 MPa·s, respectively. An order-of-magnitude analysis shows that, once outside the cone of influence created around the injection well by the bottom-hole injection pressure, the Darcy velocity of the updip migrating acid gas is on the order of 0.1 to 1 m per year, depending on permeability. This means that it will take an extremely long time, on the order of tens to hundreds of thousand of years, for the acid gas to migrate updip in the Wabamun aquifer and reach the subcrop region at the sub-Cretaceous unconformity (Figures

5, 10 and 12). The migration direction will be to the northeast. There the acid gas will meet the northward basin-scale flow system driven by topography from northern Montana to northeastern Alberta (Figure 6a) (Bachu, 1999; Anfort *et al*., 2001).

If the acid gas reaches the subcrop area at the pre-Cretaceous unconformity, it will migrate upward into the Lower Mannville aquifer, and then it will flow to the north-northeast, unless caught in stratigraphic and/or structural traps. The flow will be the resultant of updip, northeastward buoyancy and draining to the north-northwest by the Grosmont drain that controls the flow of formation water in Upper Devonian and Lower Mannville strata in northeastern Alberta (Bachu, 1999; Barson *et al*., 2001).

In the absence of numerical modeling, the time scale of the flow process along the path described previously can be only estimated to be of the order of thousands to millions of years. It is highly improbable that such a flow path would be ever completed, because the amount of acid gas that will be injected during the lifetime of the operation will be much smaller than the volume traps that would be encountered along the path. Also, the acid gas will disperse and dissolve in formation water, such that an acid gas plume would disappear along a basin-scale flow path (McPherson & Cole, 2000). Most likely the injected acid gas will be contained within the Wabamun Group if the injection operations are run within the terms of the respective applications and approvals.

6.2 Acid Gas Leakage

Upward leakage of the acid gas may occur through weak aquitards and natural faults and/or fractures, and through induced fractures and/or improperly completed and/or abandoned wells. There are no known faults and fractures in the Pembina area. Leakage through the overlying aquitards is very unlikely, practically impossible to happen, because the Wabamun Group is capped by the thick, tight and competent shales of the Exshaw and Banff formations, which have been shown in many regional-scale studies to separate the flow systems in Devonian and Mississippian aquifers (e.g., Bachu, 1995; Rostron & Toth, 1997; Michael & Bachu, 2002b; Michael *et al*., 2003). Continuing higher up in the sedimentary succession, the Jurassic Fernie aquitard isolates the Mississippian aquifers from Jurassic and Lower Cretaceous (Lower Mannville) aquifers (Figure 4). Further up, the thick Colorado shales and embedded sandy aquifers form, respectively, a physical barrier and a hydrodynamic barrier as a result of erosional rebound in shales (Bachu, 1999; Michael & Bachu, 2002a). These aquifers behave like sinks for any contained or passing fluids. Similar physical barriers (shaly aquitards) and hydrodynamic barriers (hydraulic sinks) are encountered in the overlying Upper Cretaceous strata of the Belly River and Edmonton groups (Figure 4) (Bachu & Michael, 2003). The barriers to vertical leakage of the acid gas in the natural system exist not only at the site and local scales in the Pembina area, but also at the regional and even basin scales.

Leakage of the injected acid gas through fractures induced in the caprock as a result of injection into the Wabamun Group would be possible if the caprock is fractured or weakened by geomechanical and/or geochemical processes. However, even if the immediate caprock layer may have been weakened, the large thickness of the shaly Exshaw and Banff formations (Figure 18) ensures that no leakage through this aquitard will occur. Further leakage higher up is very unlikely to happen because of the overlying succession of aquitards and hydrodynamic sinks described in the preceding paragraph.

While leakage of acid gas through the natural system is very unlikely to happen, leakage through wells is a very distinct possibility, now or in the future. Figure 26 shows the current distribution

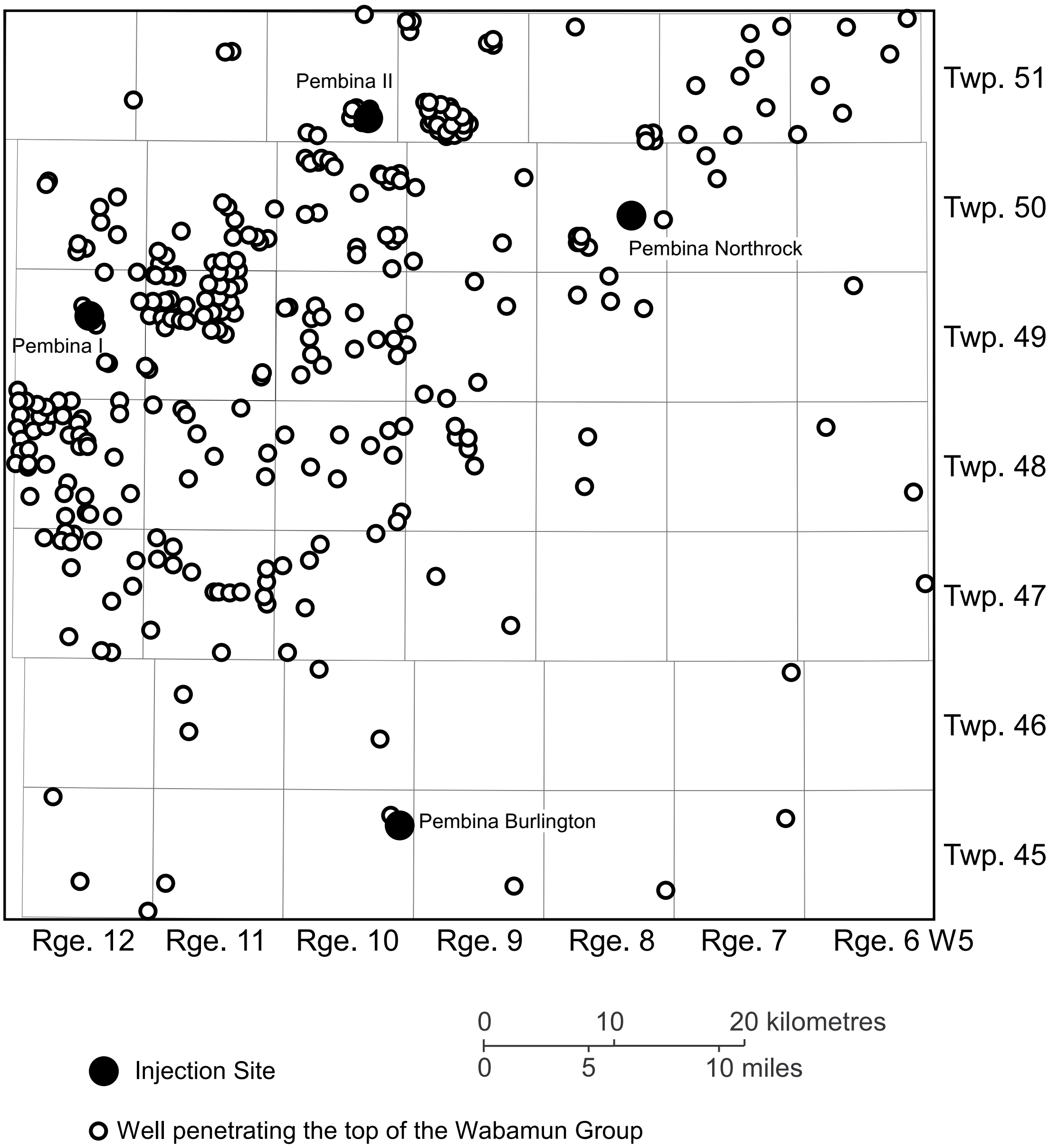

Figure 26. Current distribution of wells that penetrate the Wabamun Group in the local-scale study area.

of wells that penetrate the Wabamun Group in the local-scale study area. The density of wells that penetrate the top of the Wabamun Group is quite high along the updip migration path from the Pembina I and Pembina II acid-gas injection wells, and much less updip from the Pembina Burlington well. The quality of completion and/or abandonment for these wells is not well known at present, and is beyond the scope of this study. Notwithstanding that it may never be known, even in the best-scenario case that the cement and tubing quality are good at present in every well, they will most probably degrade at some point in the future as a result of reactions with formation brine and/or acid gas. Primarily the well cements, but also the steel tubing, will ultimately degrade, potentially creating flow pathways. The leakage may not necessarily occur all along the well up to the surface as leaking acid gas may stop at more competent cements in the well and at plugs.

Poor-quality completion in existing or future wells may provide a pathway for upward leakage from the injection reservoir or from any place that an acid gas plume may reach in the future. However, time scale and magnitude of the degradation cannot be assessed with the current data, knowledge and methods.

7 Conclusions

The experience gained since the start of the first acid-gas injection operation in Canada in 1989 shows that, from an engineering point of view, acid gas disposal is a well-established technology. Close to 1.5 Mt CO_2 and 1 Mt H_2S have been successfully injected to date into deep hydrocarbon reservoirs and saline aquifers in Alberta and British Columbia. A major issue that has not been addressed is the containment and long-term fate of the injected acid gas. Although no incidents of long-range migration or leakage have been detected and reported to date, this issue should be considered by both operators and regulatory agencies.

Injection of acid gas into the Wabamun Group in the Pembina area of west-central Alberta is taking place since 1994. To date, close to 40 million m^3, or 60 kt acid gas have been injected into this aquifer.

If only the natural setting is considered, including geology and flow of formation waters, the basin- to local-scale hydrogeological analysis indicates that injecting acid gas into the Wabamun Group in the Pembina area is basically a safe operation with no potential for acid gas migration to shallower strata, potable groundwater and the surface. Although the Wabamun Group is characterized as a regional aquifer, the average permeability in the Pembina area is relatively low, and intervals of high porosity and permeability occur only locally and are not well connected. There are many physical and hydrodynamic barriers to acid gas migration from the injection zone into other strata, and the flow process, if it will ever happen, would take an extremely long time, on a geological time scale. Any acid gas plume would disperse and dissolve in formation water during flow on such large time and spatial scales.

Based on available data, it seems that there is no potential for acid gas leakage through fractures. However, the possibility for upward leakage of acid gas exists along wells that were improperly completed and/or abandoned, or along wells whose cement and/or tubing has degraded or may degrade in the future as a result of chemical reactions with formation brine and/or acid gas.

These conclusions are based on a qualitative hydrogeological analysis in the sense that the geological and hydrogeological data were interpreted within the framework of the most current knowledge about the Alberta basin and its contained fluids. No quantitative analysis based on numerical modeling was performed because, to the best knowledge of the authors, no such models are available. Predictive numerical models of acid gas injection and flow, if not already in existence, should be developed and used to validate the qualitative hydrogeological analysis presented in this report. Geochemical and geomechanical effects on reservoir rock and caprock should be assessed to confirm integrity. The potential for, and risk of, leakage through existing wells should be better assessed. In addition, a monitoring program would support and provide feedback to the analysis and modeling, and greatly enhance the confidence in the safety of the operation.

Extension of this type of analysis to other current and future disposal sites will lower risk and increase the public trust in the potential and safety of geological sequestration of acid and greenhouse gases. Ideally, a thorough program for predicting the long-term fate of the injected acid gas should contain the following major components:

- a hydrogeological analysis of the injection site at various scales, from site-specific to regional, to provide the context, understanding and necessary data for a qualitative assessment;
- numerical modeling for predicting possible migration and/or leakage paths and corresponding time scales for the injected acid gas;
- monitoring of the acid gas plume, to validate and update the numerical model;
- continuous updating of the hydrogeological and numerical models as new data is acquired.

Currently there are no adequate numerical models that could properly simulate the fate of the acid gas injected in deep geological formations. Also, monitoring programs are expensive, and, in the absence of forward-simulating models, may not provide the necessary information. However, the hydrogeological analysis, the first step for understanding the fate of the acid gas, can be easily implemented for all acid-gas injection sites, particularly in the case of basins with a wealth of data such as the Alberta Basin.

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