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Subsurface Characterization of the Brazeau Nisku Q Pool Reservoir for Acid Gas Injection

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. 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.

One of the acid-gas injection operations approved by the AEUB is at Brazeau in west-central Alberta, where Keyspan Energy Canada Ltd. has applied for and received approval on November 28, 2002, to dispose of acid gas by injection into the Nisku Q Pool, a depleted gas reservoir. The respective injection well is located at 10-29-47-13-W5 in the western part of the Alberta Basin in carbonates of the Upper Devonian Nisku Formation of the Winterburn Group. In the context of assessing the feasibility of large-scale CO_2 sequestration in geological media, this operation provides a unique opportunity because the baseline in-situ conditions can be established on the basis of regional, local and reservoir-scale data, prior to injection. Subsequent progress reports submitted by the operator, and possibly surface and subsurface monitoring, may provide information regarding the fate and containment of the injected acid gas. Figure 1 presents the location of the Brazeau site and of other acid-gas injection operations in western Canada at the end of 2002.

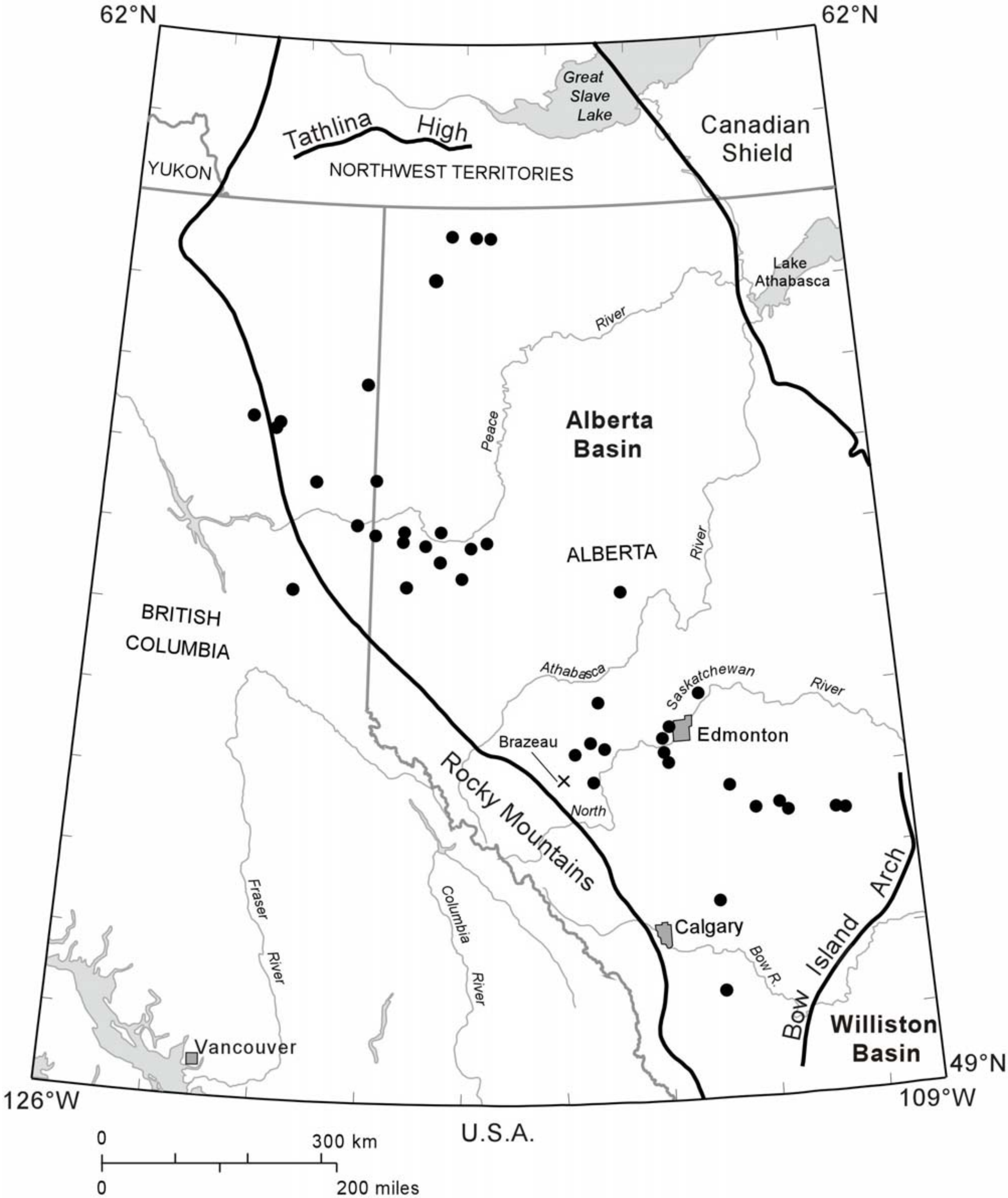

Figure 1. Location of the Brazeau and other acid-gas injection sites in Western Canada at the end of 2002.

The subsurface characterization of the Brazeau Nisku acid-gas injection operation is based on reservoir-scale data and information submitted by Keyspan Energy Canada Ltd. in the application 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).

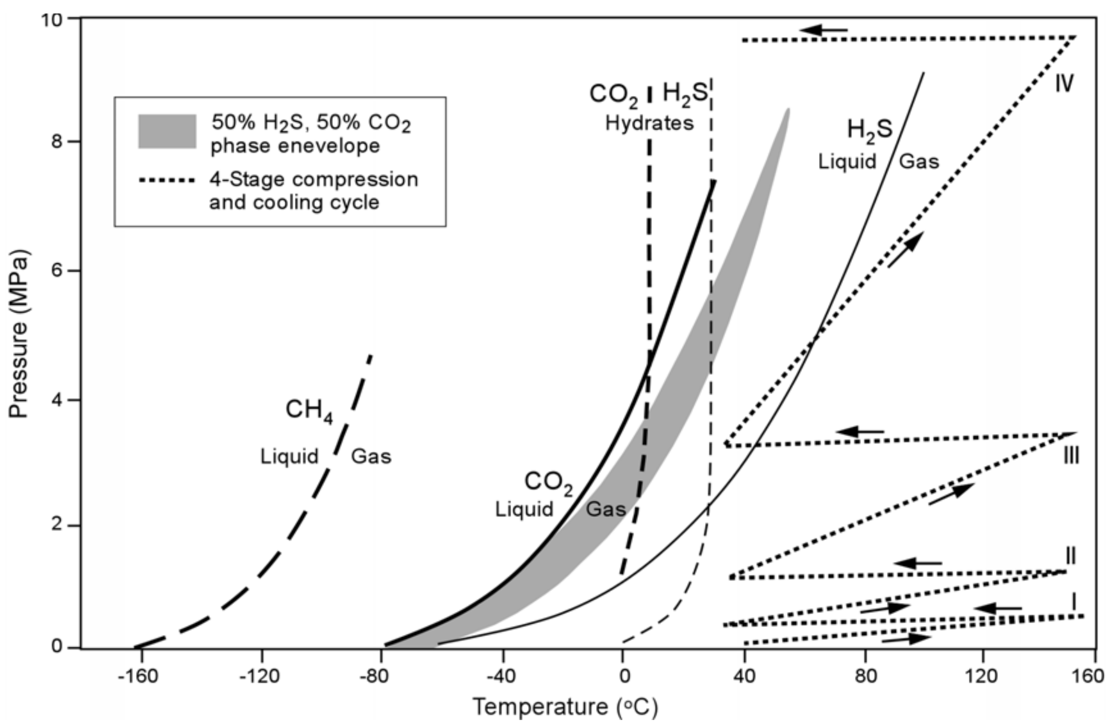

Figure 2. Phase diagrams for methane (CH_4), carbon dioxide (CO_2), hydrogen sulphide (H_2S) and a 50%-50% acid gas mixture; hydrate conditions for CO_2 and H_2S (after Wichert & Royan, 1996, 1997).

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 and 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 that 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

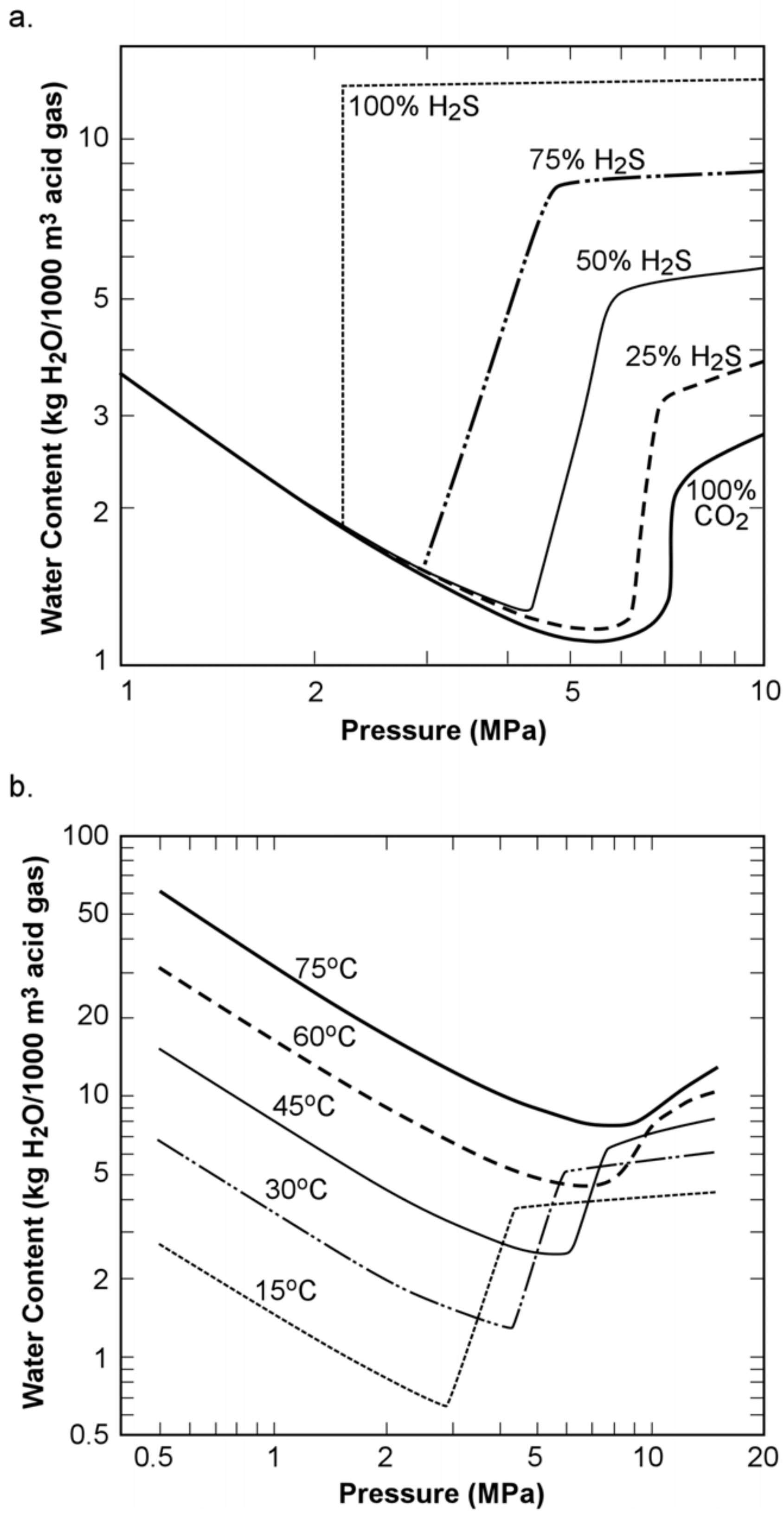

Figure 3. Solubility of water in acid gas as a function of pressure for: a) different acid gas composition (CO_2 and H_2S) at 30ºC, and b) different temperatures for an acid gas with a composition of 49% CO_2, 49% H_2S and 2% CH_4 (see also Lock, 1997; Wichert & Royan, 1996, 1997).

that may affect its ability to contain the acid gas;
3. location and extent of the underlying or lateral bounding formations;
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 well-head 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 Brazeau Acid-Gas Injection Site

The Brazeau operation for injecting acid gas into the Nisku Q pool is located in the central part of the Alberta Basin, west-southwest of Edmonton (Figure 1). The Nisku Q Pool is a depleted carbonate gas reservoir in the Nisku Formation of the Upper Devonian Winterburn Group. 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 Brazeau site, 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 bounded 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 Cambrian 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 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

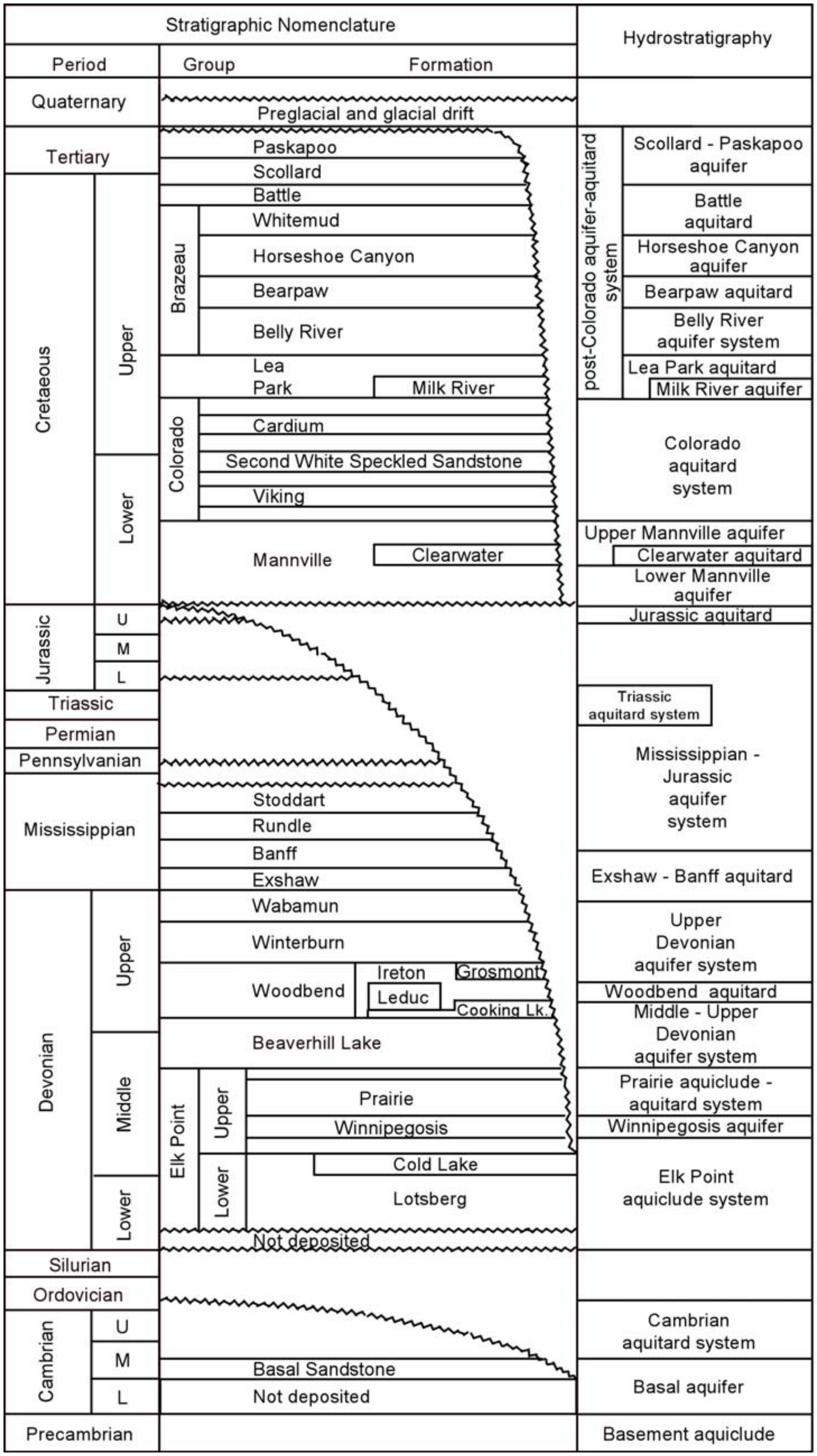

Figure 4. Basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature for the southern and central parts of the Alberta basin (after Bachu, 1999).

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 and 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 and 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).

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 5). 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

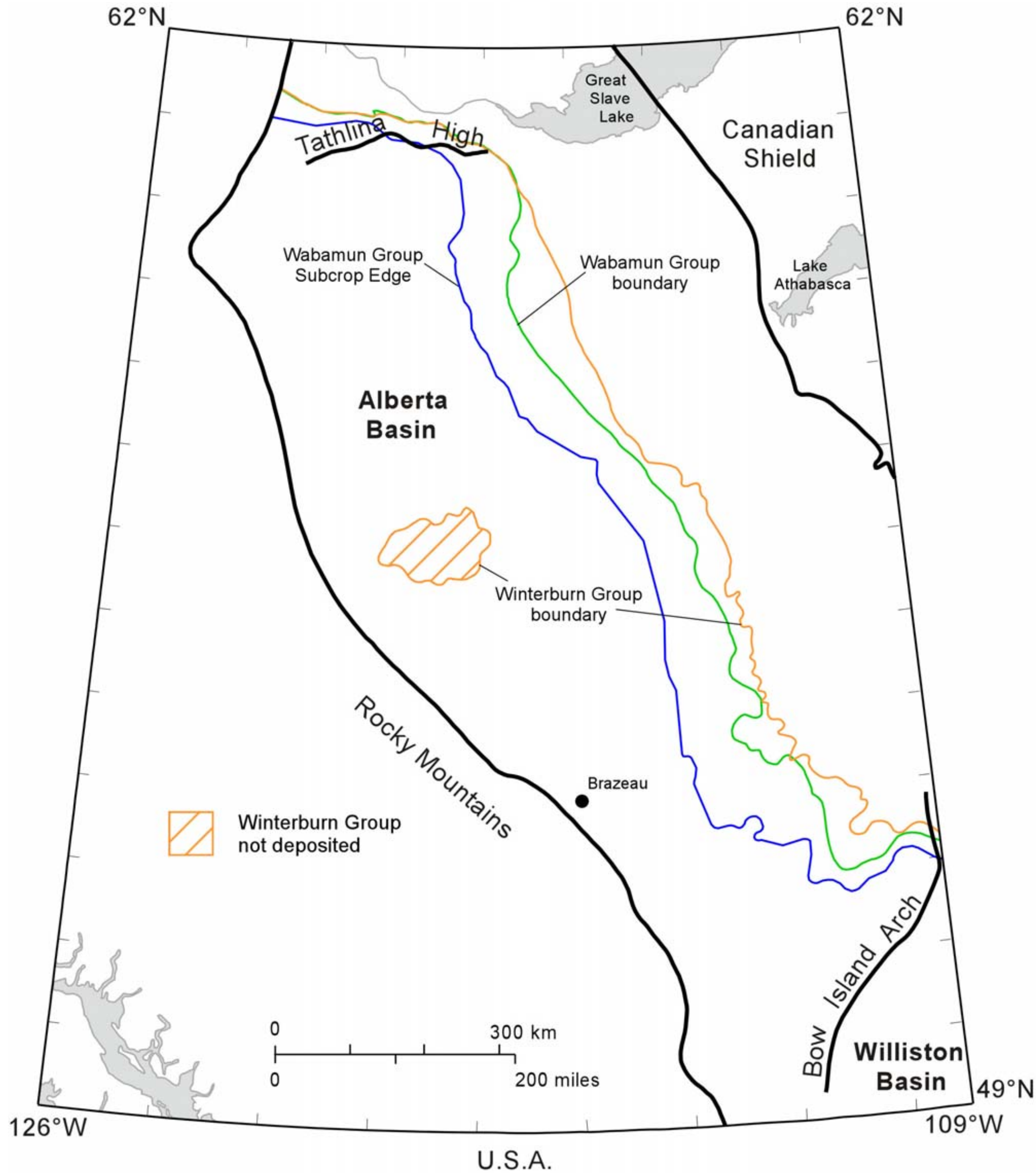

Figure 5. Subcrop of the Winterburn and Wabamun groups at the pre-Cretaceous unconformity in the Alberta Basin.

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 systems 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 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

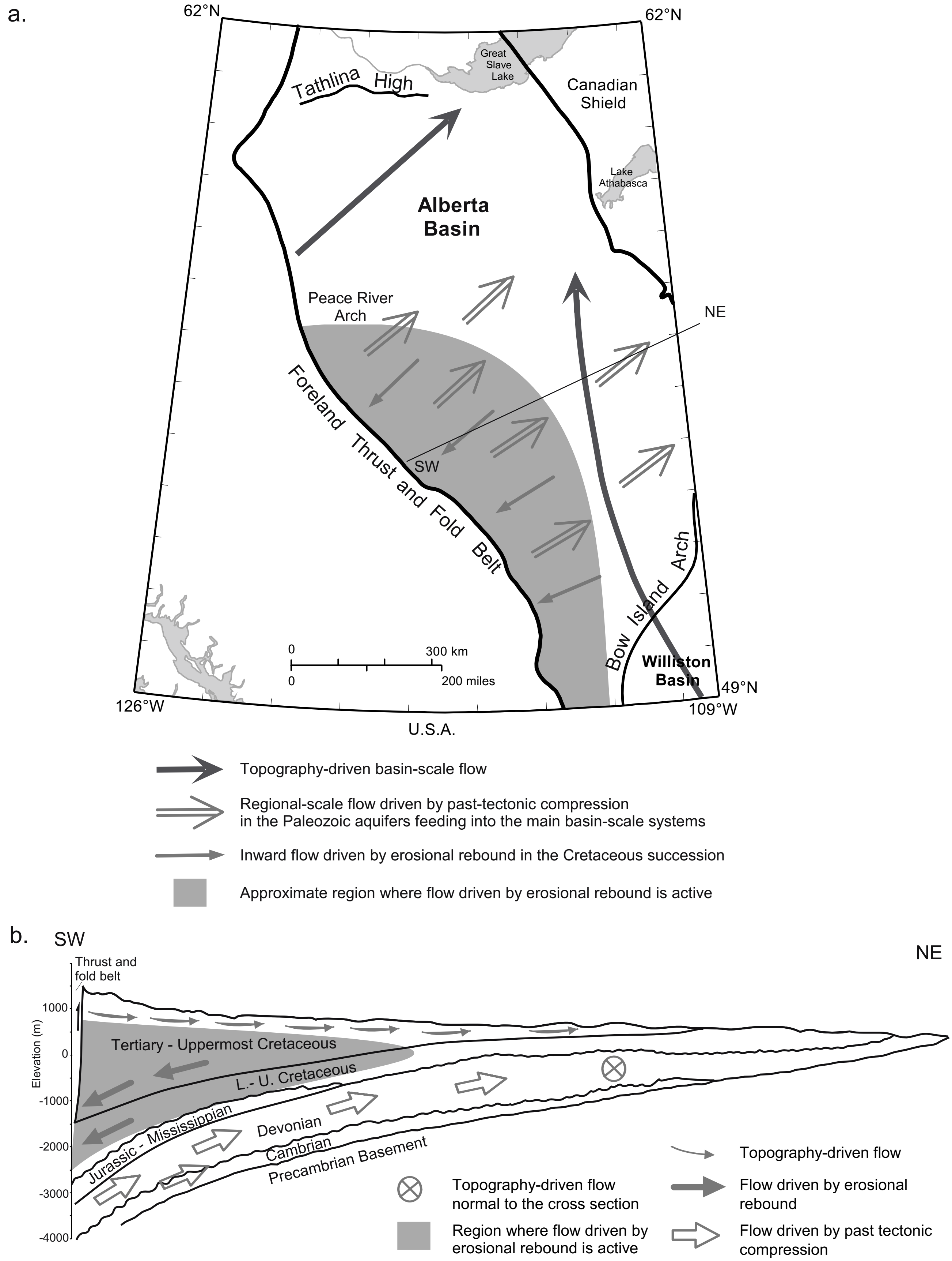

Figure 6. Diagrammatic representation of flow systems in the Alberta basin: a) in plan view, and b) in cross-section (after Bachu, 1999).

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 overriden 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 and Nunn, 1991). In the deep part of the Alberta Basin in the southwest, the flow of formation waters in the Slave Point aquifer and in the Upper Devonian and Carboniferous-Jurassic aquifer systems (Figure 5) 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 Cambrian 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 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 Brazeau Acid-Gas Injection Site

The Upper Devonian Winterburn Group extends from southern Alberta to northern Alberta and British Columbia (Figure 7). The Winterburn is basically divided into two geographical domains: first the Shale Basin in central Alberta, which is bordered by the Meekwap shelf to the north and northeast, the Pembina-Brazeau shelf to the south, and a less continuous shelf system in the “Deep Basin” to the west that presumably connected to an open seaway; the second part is the Shale Basin north and northwest to Peace River Arch landmass, and is not further discussed herein (Stoakes, 1992) (Figure 7).

The Wabamun Group, which similarly extends from southern Alberta to northern Alberta and British Columbia (Figure 8), 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 practically all of the

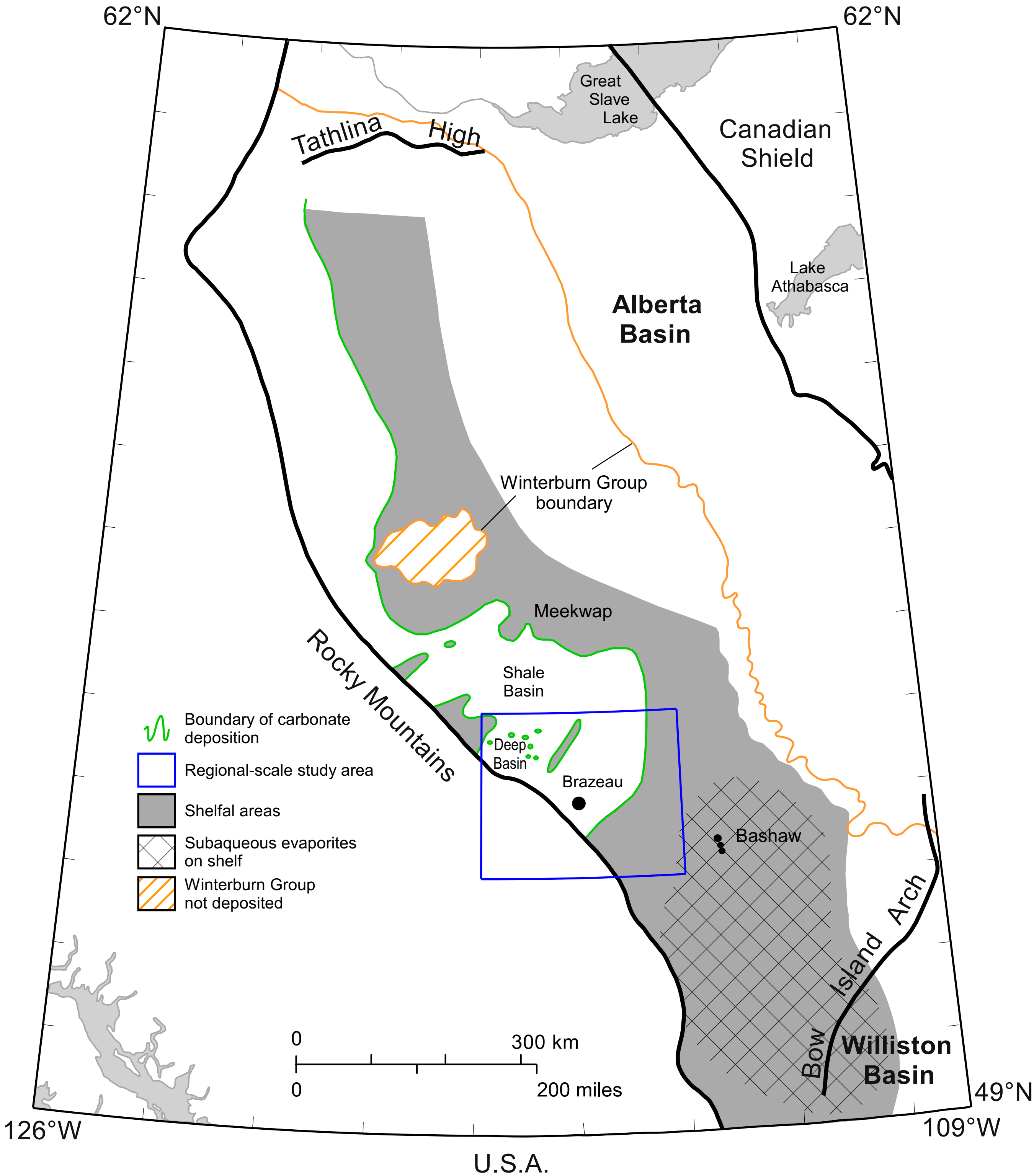

Figure 7. Configuration of the Alberta Basin and paleogeography during Winterburn time (after Stoakes, 1992). A more detailed setting of the Brazeau acid-gas injection site at the edge of the Nisku carbonate platform is shown diagrammatically in Figure 9, and at regional and local scales in Figures 11 and 14, respectively.