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**ALBERTA ENERGY AND UTILITIES BOARD**

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## Executive Summary

Sequestration of anthropogenic $CO_2$ in geological media is a potential solution to the release into the atmosphere of $CO_2$, a greenhouse gas. Basically, there are five ways of sequestering $CO_2$ in geological media: 1) through enhanced oil recovery (EOR), 2) storage in depleted oil and gas reservoirs, 3) replacement of methane by $CO_2$ in deep coal beds (ECBMR), 4) injection into deep saline aquifers, and 5) storage in salt caverns. Criteria in assessing the suitability of a sedimentary basin for $CO_2$ sequestration are 1) tectonism and geology, 2) the flow of formation waters, and 3) the existence of storage media (hydrocarbon reservoirs, coal seams, deep aquifers, and salt structures). Because of $CO_2$ properties, identification of the depths of the 31.1ºC isotherm and the 7.38 MPa isobar is essential in establishing if $CO_2$ could be sequestered as a gas, as a liquid, or in a supercritical state.

Alberta's subsurface is tectonically stable. The geology of the undeformed part of the Alberta Basin underlying most of Alberta is very favourable for $CO_2$ sequestration due to its layer-cake structure and the existence of confined regional-scale aquifers, oil and gas reservoirs in various stages of depletion, uneconomic coal seams, and extensive salt beds. There are six regions in Alberta with various degrees of suitability and different characteristics in terms of $CO_2$ sequestration in geological media:

- Northeastern Alberta: generally not suitable; possibly in gas reservoirs and salt caverns
- Eastern Alberta: reasonably suitable; in oil and gas reservoirs and salt caverns
- Southeastern Alberta: suitable; in oil and gas reservoirs and deep aquifers
- Northwestern Alberta: suitable; in oil and gas reservoirs and deep aquifers
- Central Alberta: extremely suitable; in oil and gas reservoirs, deep aquifers, coal seams, and salt beds
- Southwestern Alberta: extremely suitable; in oil and gas reservoirs, deep aquifers, and coal seams

Major $CO_2$ producers in Alberta are found in the northeast (oil-sands plants), in the east (heavy-oil and power plants), in the central part (refineries and power, petrochemical, and cement plants), and in the southwest (power, cement, and gas plants). Future work should identify specific sites and means for sequestering $CO_2$ in the vicinity of major $CO_2$ producers, and characterize these sites in terms of capacity and retention time.

## Acknowledgements

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## 1 Introduction

Human activity since the industrial revolution has increased atmospheric concentrations of gases with a greenhouse effect, such as carbon dioxide ($CO_2$) and methane ($CH_4$), leading to climate warming and weather changes (Bryant, 1997; Jepma and Munasinghe, 1998). There are many uncertainties regarding the impact of human activity on climate, and there may be other mechanisms responsible for the warming of about 0.4-0.6ºC observed for the last century (Bryant, 1997). Nevertheless, there is almost general acceptance that the world cannot wait for definitive answers on this subject, and that preventive and mitigating actions must take place concurrently. Because of its relative abundance compared with the other greenhouse gases, $CO_2$ is by far the most important, being responsible for about 64 per cent of the enhanced "greenhouse effect" (Bryant, 1997). On a sectoral basis, the energy sector contributes the most (45 per cent) to anthropogenic effects on global climate change (Intergovernmental Panel on Climate Change, 1991).

The high use of fossil fuels (supplying 85 per cent of the world's energy needs), foreseen to continue well into the future (Jepma and Munasinghe, 1998), is the major contributor to increased emissions of $CO_2$ into the atmosphere. Thus, a major challenge in mitigating anthropogenic effects on climate change is the reduction of $CO_2$ emissions into the atmosphere. In 1997, the developed countries committed, through the Kyoto Protocol, to reduce by 2012 the amount of $CO_2$ released into the atmosphere to levels 5.2 per cent lower than those of 1990. Canada, a signatory of the Kyoto Protocol, has agreed to reduce her $CO_2$ emissions in 2012 by 6 per cent below the 1990 levels. Canada produced 460 million tonnes (Mt) of anthropogenic $CO_2$ in 1990, which constituted approximately 2 per cent of total global emissions. Of these, Alberta produced 126 Mt, or 27.5 per cent of the Canadian total, which put Alberta in second place in the country after Ontario. At the time the Kyoto Protocol was signed in 1997, the last year for which figures are available, Canada produced 13 per cent more $CO_2$ than in 1990. Alberta's emissions increased by 21 per cent with respect to 1990, putting Alberta ahead of Ontario as the province with most $CO_2$ emissions. This increase in Alberta's emissions is attributed to economic development, mainly in the energy sector (upstream and power generation), which contributes approximately 55 per cent of province's $CO_2$ emissions.

A significant reduction in $CO_2$ emissions must be achieved in the next decade, both nationally and provincially, in order to meet the commitments undertaken in Kyoto. To this end, no single category of mitigation measures is sufficient and many of them are mutually dependent, including both a reduction in greenhouse-gas emissions and the enhancement of greenhouse-gas sinks (Turkenburg, 1997). The overall potential and effect of increased $CO_2$ utilization are negligible, while some mitigation strategies will have a limited impact without major technological breakthroughs and expenditures (Turkenburg, 1997). Thus, to meet mid- to long-term $CO_2$-reduction targets agreed to in the Kyoto Protocol, more costly mitigation approaches need to be considered. Foremost among these are $CO_2$ capture and sequestration, whose costs are comparable to those for nuclear or renewable energy options (Herzog et al., 1997). In this context, **sequestration is the removal of $CO_2$, either directly from anthropogenic sources or from the atmosphere, and disposing of it either permanently or for geologically significant time periods**. The oceans represent possibly the largest potential global sink (Herzog et al., 1997), but ocean disposal involves issues of poorly understood physical and chemical processes, sequestration efficiency, cost, technical feasibility, and environmental impact (Herzog et al., 1997). For a landlocked province like Alberta, ocean disposal is not even an option for reducing $CO_2$ emissions. Biomass fixation of $CO_2$ is an option for mid-term reduction of $CO_2$ emissions, but, in addition to some cost issues, factors of practicality and uncertainty make this an improbable solution at present (Herzog et al., 1997). In addition, biomass $CO_2$ fixation through forest growth depends on climatic conditions and competes with agriculture, fishing, other industries, and land use. This leaves $CO_2$ sequestration in geological media as the best option currently available for the long-term sequestration of $CO_2$ in Alberta. Since fossil fuels and power generation are intrinsically and serendipitously linked with sedimentary basins (Hitchon et al., 1999), geological sequestration has the added advantage of lower overall transportation costs. The technology of deep injection of $CO_2$ and industrial liquid waste is well developed and currently practised, mainly by the energy industry. Depending on the type of $CO_2$ disposal and trapping mechanism, the residence time may be up to several million years (Bachu et al., 1994; Lindeberg and Holloway, 1999). Cost, local environmental issues, and public perception may need to be addressed prior to large-scale implementation of $CO_2$ sequestration in Alberta's subsurface, but these are issues common to all mid- to long-term $CO_2$ sequestration technologies.

## 2 Geological Sinks for $CO_2$

Under normal atmospheric conditions, $CO_2$ is a gas that is thermodynamically very stable and heavier than air. At temperatures greater than 31.1ºC and pressures greater than 7.38 MPa (critical point), $CO_2$ is in a supercritical state (Figure 1). Under these pressure and temperature conditions, $CO_2$ still behaves like a gas by filling all the available volume, but has a "liquid" density that increases, depending on pressure and temperature, from 200 to 900 kg/m$^3$, thus approaching that of water (Holloway and Savage, 1993; Hendriks and Blok, 1993). For conditions below the critical point, $CO_2$ is either a gas or a liquid, depending on temperature and pressure (Figure 1). Carbon dioxide's affinity to coal is almost twice as high as that of methane, a gas abundantly found in coal beds (Figure 2). These thermodynamic properties of $CO_2$ and various other criteria play a role in the selection of appropriate methods and sites for $CO_2$ disposal and sequestration in geological media. Depending on in situ temperature and pressure, $CO_2$ can be stored by various methods, either as a **compressed gas**, as a **liquid,** or in **supercritical state**.

### 2.1 Oil Displacement in Reservoirs

Carbon dioxide is a good **solvent** for organic compounds (Holloway and Savage, 1993) because it reduces oil viscosity and the interfacial tension (capillary pressure). Based on this property, it is currently used worldwide in more than 70 tertiary enhanced oil recovery (EOR) operations to increase oil mobility and to displace up to 40 per cent of the residual oil left in an active reservoir after primary production and water flooding (Blunt et al., 1993). In Alberta, $CO_2$ is used in an EOR operation at Joffre. Use of $CO_2$ in EOR operations actually represents a form of both utilization and sequestration. Because only miscible displacement is possible, EOR applications are limited to light crude oil (25ºAPI or higher). Much of the $CO_2$ will remain stored in the reservoir, but a significant part ultimately breaks through at the producing well, together with the recovered oil, and has to be recirculated back into the system. As a result, the residence time is relatively small (on the order of months to several years). Moreover, the total amount that can

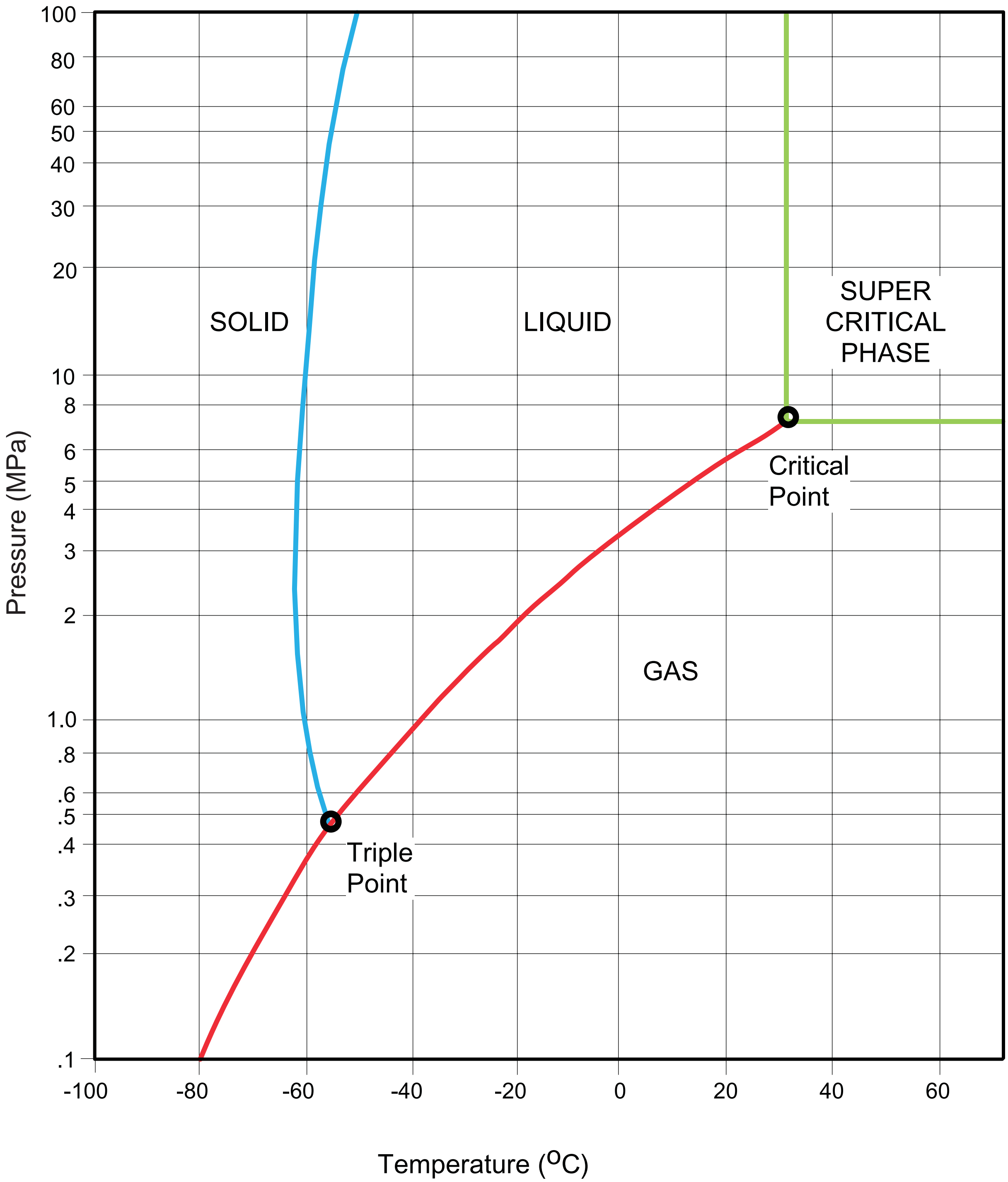



Figure 1: Carbon-dioxide phase diagram.

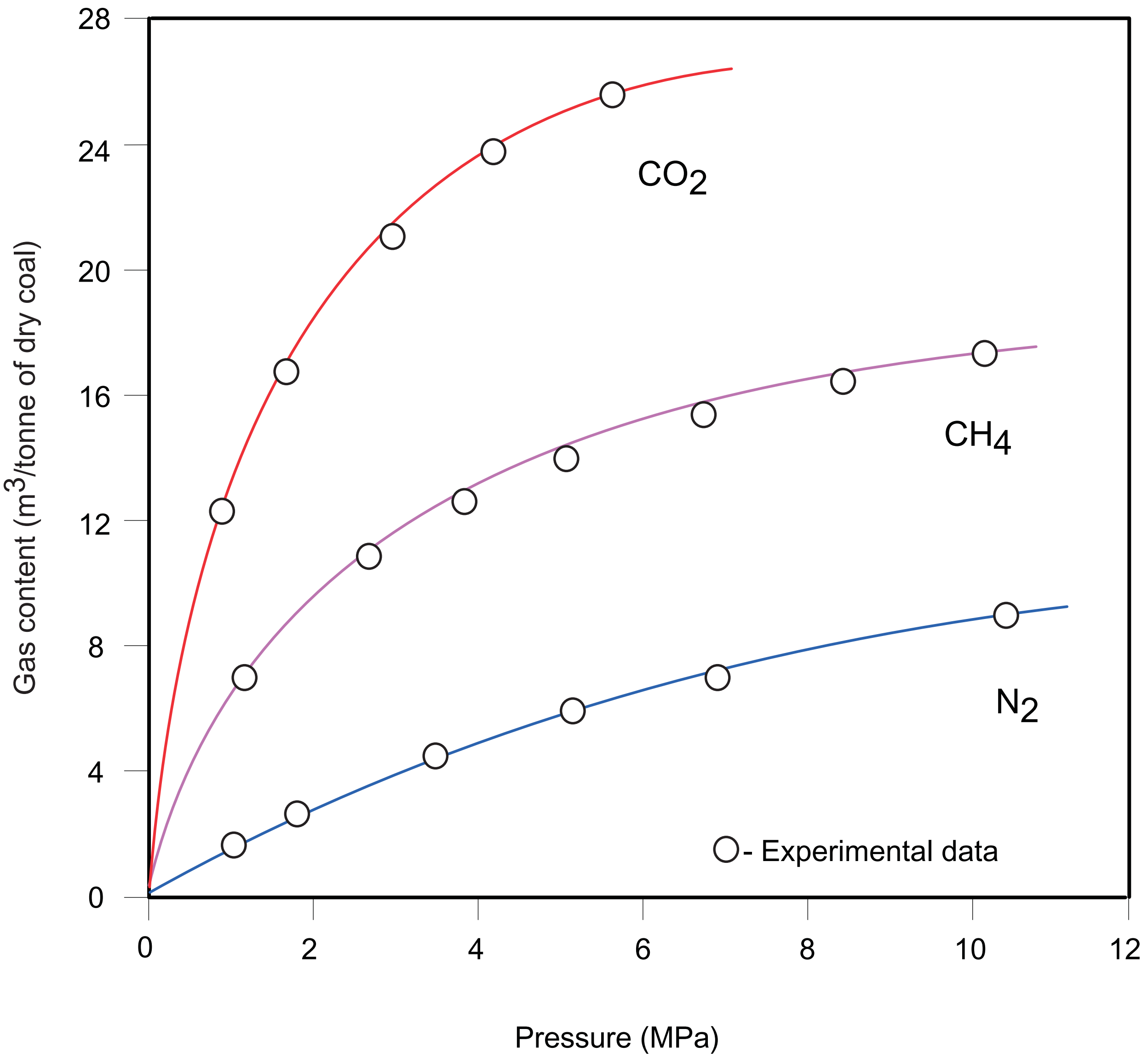



Figure 2: Adsorption isotherms on coal for some gases (*from* Arri et al., 1992).

ultimately be sequestered in EOR operations is very small compared with the magnitude of $CO_2$ sources (International Energy Agency Greenhouse Gas R&D Programme, 1995).

## 2.2 Displacement of Methane and Sequestration in Coal Beds

Injecting $CO_2$ into coal beds that are too deep or uneconomic for coal mining presents a two-fold advantage (Gunter et al., 1997; Stevens et al., 1999). First, $CO_2$ is sequestered by adsorption on the coal matrix. Second, methane is produced; although it is also a greenhouse gas, it can be used instead of coal as a much cleaner fuel, implicitly reducing $CO_2$ emissions. Carbon-dioxide injection into coal beds is already used in the San Juan Basin (Stevens et al., 1999) to enhance methane recovery (enhanced coalbed methane recovery or ECBMR). However, most coal seams have unfavourably low permeability because of complex geological setting (Stevens et al., 1999). Therefore, depending on geological conditions, $CO_2$ sequestration in coal beds has potential for the mid to long term.

## 2.3 Storage in Depleted Hydrocarbon Reservoirs

Hydrocarbon reservoirs in structural and stratigraphic traps have demonstrated good storage and sealing characteristics over geological time; they can therefore be used for $CO_2$ sequestration once a reservoir is no longer exploited ("depleted" or "disused"). The term "depleted" is relative for oil reservoirs, because there is always residual oil in place that could be recovered in the future, depending on technological advances and economic conditions. Thus, there is some reluctance to use abandoned oil reservoirs for $CO_2$ sequestration, so it is more likely that $CO_2$ injection into oil reservoirs will be associated more with EOR than with sequestration per se. This problem does not exist for gas reservoirs, so they are better candidates for $CO_2$ sequestration.

The trapping mechanism (structural, stratigraphic, or lithological) that retained hydrocarbons in the first place should ensure that $CO_2$ does not reach the surface. The proven trap, known reservoir properties, and existing infrastructure make storage of $CO_2$ in depleted hydrocarbon reservoirs a simpler and cheaper option than other forms of $CO_2$ sequestration. Closed, depleted gas reservoirs represent the most straightforward case, as primary recovery usually removes as much as 95 per cent of the original gas in place and $CO_2$ can be used to repressurize the reservoir to its original pressure. Closed, underpressured oil reservoirs that have not been invaded by formation water should also have a large storage capacity. Oil and gas reservoirs in contact with underlying formation water (pressured by the water drive) are invaded by water as the reservoir is depleted. These reservoirs have less potential for $CO_2$ sequestration because the $CO_2$ will have to displace ("push back") the formation water. In this respect, these reservoirs will behave more like aquifers. Increasing the pressure beyond the original reservoir pressure could pose problems of reservoir integrity and safety (van der Meer, 1993).

## 2.4 Storage in Deep Saline Aquifers

Deep aquifers in sedimentary basins contain fossil, high-salinity connate water that is not fit for industrial and agricultural use, or for human consumption. Such aquifers are already used for injection of hazardous and nonhazardous liquid waste. The high pressures encountered in deep aquifers indicate that they can withstand $CO_2$ injection. Some of the injected $CO_2$ will dissolve in the water (up to 29 per cent) and the rest will form a plume that will migrate to the top of the aquifer (Bachu et al., 1994; Law and Bachu, 1996; Gupta et al., 1999). Although the dissolved $CO_2$ will travel at the velocity of formation waters (on the order of cm/a), the $CO_2$ plume will be driven both by the natural hydrodynamic flow and by its buoyancy with respect to water. Thus, the closer the density of injected $CO_2$ to that of water (i.e., at greater depths characterized by higher pressures), the less effect buoyancy will have on the flow of $CO_2$ in aquifers. Carbon dioxide is **hydrodynamically** sequestered in deep aquifers for geological periods of time (Bachu et al., 1994). This is because of 1) slow spreading from the injection well and hydrodynamic dispersion in the aquifer once outside the well's radius of influence (Law and Bachu, 1996), and 2) extremely long residence time due to the very low velocity of formation waters (Bachu et al., 1994). Carbon dioxide could also be permanently sequestered in deep aquifers by **mineral immobilization**, although extremely long periods of time are needed for sequestration through geochemical reactions (Bachu et al., 1994). As is the case for $CO_2$ utilization in EOR and ECBMR operations and sequestration in depleted hydrocarbon reservoirs, the technology for $CO_2$ injection into aquifers and depleted reservoirs is already developed and relatively easy to apply. For example, acid gas (a $CO_2$-$H_2S$ mixture) is injected into deep saline aquifers and depleted hydrocarbon reservoirs in Alberta (Wichert and Royan, 1997).

### 2.5 Storage in Mined Salt Caverns

Storage in mined salt caverns could provide a very long term solution to $CO_2$ sequestration in geological media. The technology has been already developed and applied to the underground storage of petroleum, natural gas, and compressed air (Tek, 1989; Bradley et al., 1991), and to salt mining for public and industrial use. Salt caverns are used in Alberta and Saskatchewan for LPG and gas storage (Crossley, 1998). Currently, single salt caverns are up to 500 000 $m^3$ in volume and can store fluids at pressures up to 80 per cent of the fracturing threshold. Although salt and rock caverns theoretically have a large storage capacity, the associated costs are very high and the environmental problems relating to rock and brine disposal are significant.

## 3 Alberta's Potential for Geological Sequestration of $CO_2$

Several criteria must be considered when analyzing the potential of a sedimentary basin, such as Alberta's, for $CO_2$ sequestration (Bachu and Gunter, 1999):

- geological factors
- hydrodynamic factors
- hydrocarbon potential and basin maturity
- infrastructure and economic factors

Active orogenic belts and cratonic platforms, such as the Canadian Cordillera along Alberta's boundary in the southwest and the Canadian Shield in northeastern Alberta, are not suitable for $CO_2$ sequestration. They do not possess the rock characteristics necessary for $CO_2$ sequestration, either because of rock type (crystalline, fractured) or because of lack of continuous seals and extensive faulting and fracturing. Most of Alberta is located on the foreland Alberta Basin, east of the Rocky Mountains, which sits on a stable Precambrian platform (Figure 3) far from areas of tectonic plate convergence characterized by earthquakes and volcanism, orogenic events, and

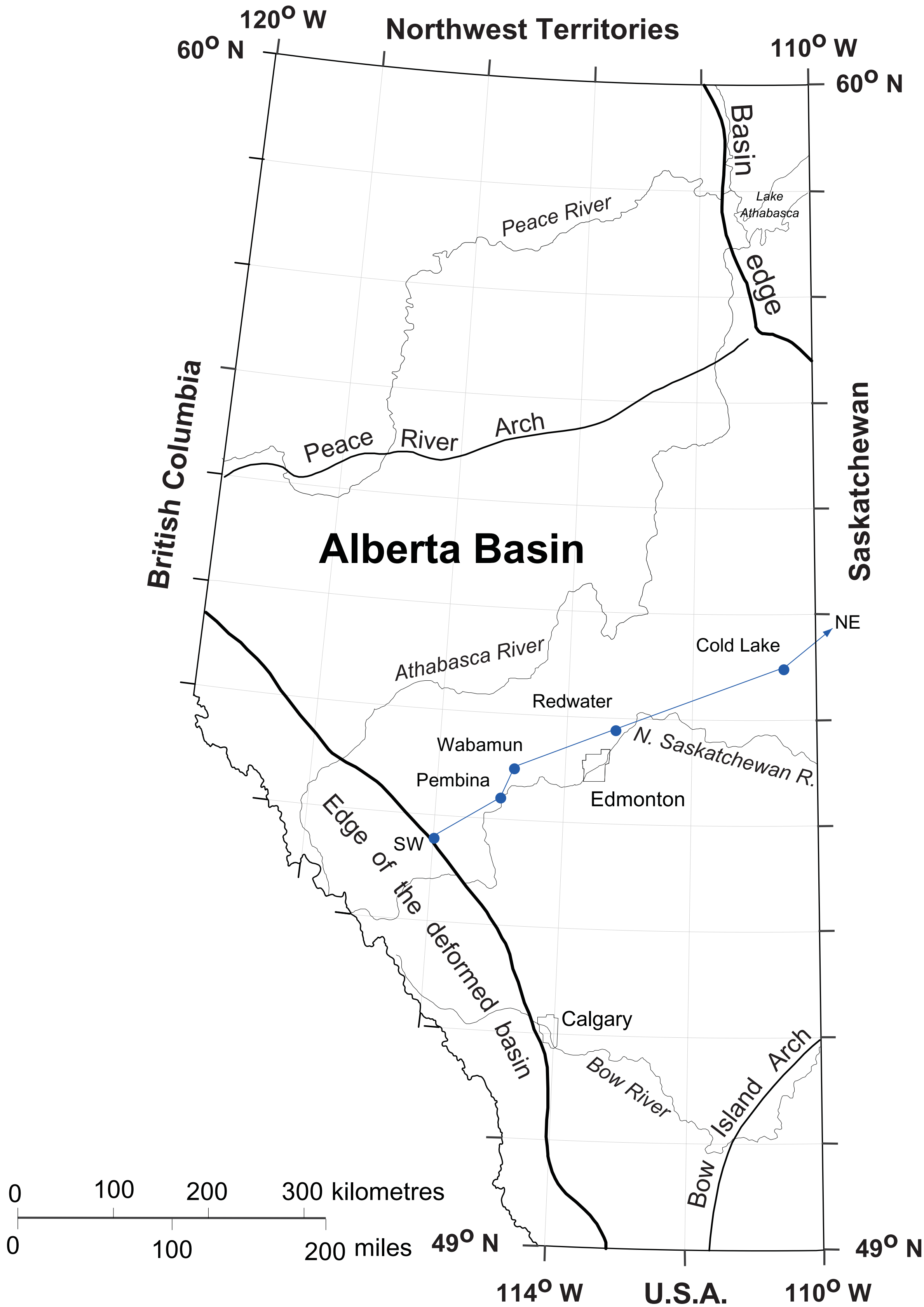



Figure 3: Main tectonic and physiographic features of the Alberta basin in Alberta. Line of cross section refers to Figure 4.

extensive faulting. The sedimentary succession has a layercake-like structure. The Cambrian to Lower Jurassic succession was deposited during the passive-margin stage of basin evolution and consists of mainly carbonate and evaporitic strata, with a few intervening shale beds.

The Upper Jurassic to Tertiary strata consist of a succession of regional-scale thin sandstone and thick shale units deposited during the foreland stage of basin evolution. Due to pre-Cretaceous erosion, successively older Paleozoic strata subcrop from west to east below the Cretaceous Mannville Group, while all Cretaceous strata outcrop beneath a veneer of unconsolidated Quaternary sediments as a result of Tertiary to Recent erosion (Figures 4 to 6). Hydrostratigraphically, the carbonate and sandstone units are aquifers, the shale beds are aquitards, and the evaporitic strata are aquicludes (Figures 4 to 6). The aquifers are separated by the intervening aquitards and aquicludes, except in areas of subcrop along unconformities or where Devonian aquitards are absent above reef buildups (Figure 4).

Alberta is very rich in fossil energy resources and the basin has reached a mature stage of exploration and production. Initial established recoverable oil and gas reserves in Alberta are on the order of 2 and 2.8 trillion $m^3$, respectively, of which approximately 70 per cent and 35 per cent, respectively, has already been produced. All units from the Devonian to the Upper Cretaceous contain gas and oil reservoirs (Figures 5 and 6) that, once depleted, can be used for $CO_2$ sequestration. Some of the oil reservoirs could be used, prior to depletion, in $CO_2$-flood EOR operations to increase oil production. In northeastern Alberta, the Grosmont and Mannville strata contain 266 trillion $m^3$ of unconventional oil-in-place in oil-sand deposits (Figure 5). Oil-sand reservoirs could be used for $CO_2$ sequestration once bitumen is extracted using in situ methods. The Cretaceous Upper Mannville, Belly River, Horseshoe Canyon, and Scollard strata contain coal seams (Figures 5 and 6) at depths that render them uneconomic. These coal seams could be used for coalbed methane production and $CO_2$ sequestration (Gunter et al., 1997); estimates of methane production are on the order of 7 trillion $m^3$. Thus, Alberta meets the conditions of hydrocarbon potential and basin maturity for $CO_2$ sequestration in geological media (Bachu and Gunter, 1999).

The geology and hydrostratigraphy of Alberta's subsurface are very favourable for deep injection and sequestration of $CO_2$. The Middle Devonian Elk Point Group contains thick and areally extensive salt beds (Figures 4 to 6) that can be used for $CO_2$ sequestration in salt caverns. Most aquifers are overlain by competent, thick, regionally extensive aquicludes and aquitards such as the Prairie, Ireton, Exshaw-Banff, and Lea Park formations (Figures 4 to 6; Bachu, 1999). The thin Cretaceous aquifers, such as the Viking and Cardium (Figure 5), that are embedded in the thick Colorado Group shale units are completely isolated (Bachu, 1999). All these aquifers can be used, depending on location, for $CO_2$ sequestration. Thus, Alberta's subsurface meets the tectonic and geological criteria for $CO_2$ sequestration (Bachu and Gunter, 1999).

The flow of formation waters in Alberta's subsurface is driven by various mechanisms (Bachu, 1999). Two deep, long-range systems are driven by basin-scale topography, one from a recharge area south of Alberta's border northward to discharge at the Peace River, and the other from a recharge area in northeastern British Columbia across northern Alberta to discharge at Great Slave Lake. Past tectonic compression drives the northeastward flow across Alberta in deep Devonian aquifers. The flow velocity in these systems is on the order of 10 km/Ma. The flow of

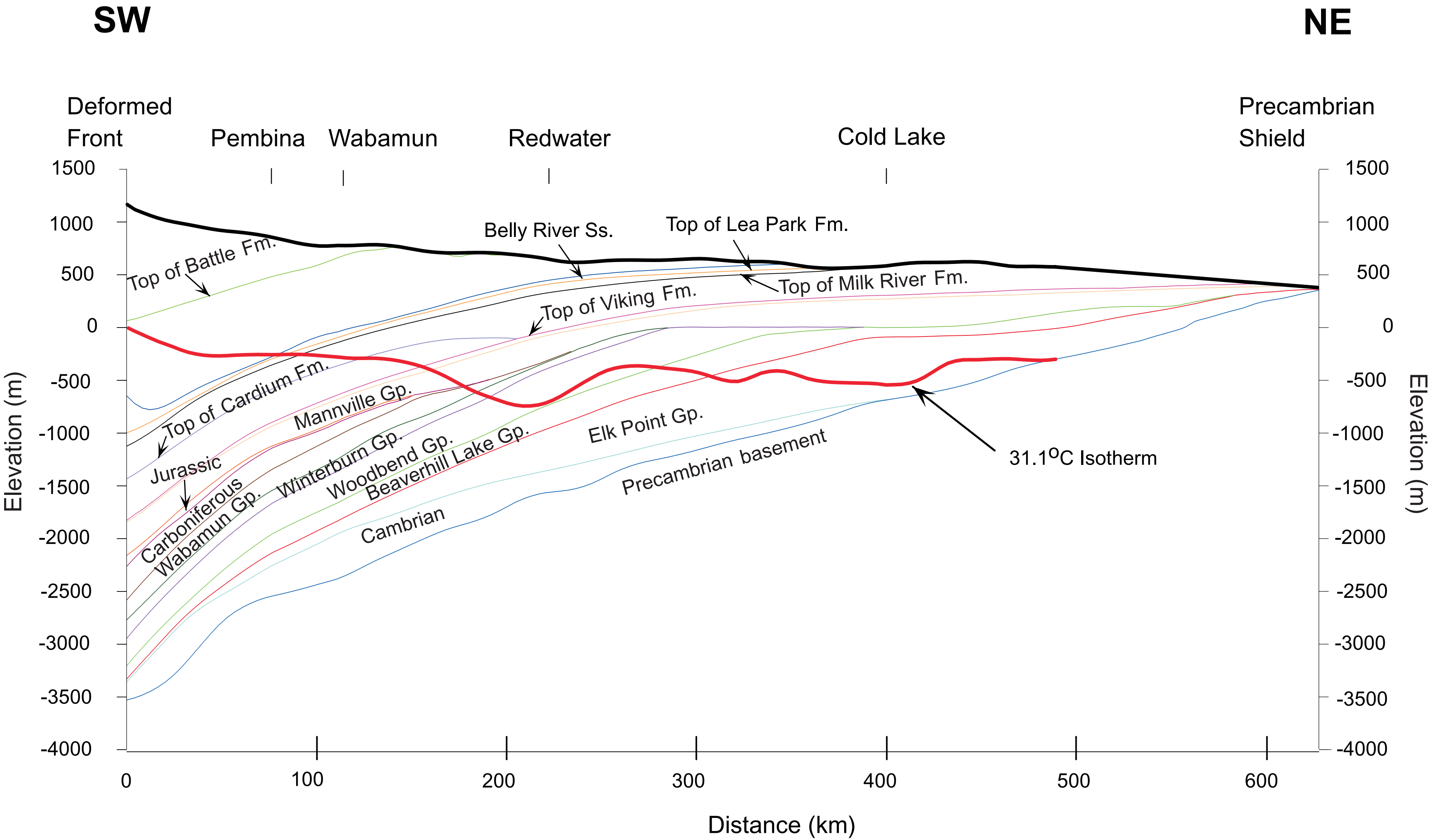



Figure 4: Cross section through the Alberta basin showing the position of the 31.1°C isotherm in relation to various sedimentary units (line of cross section in Figure 3).

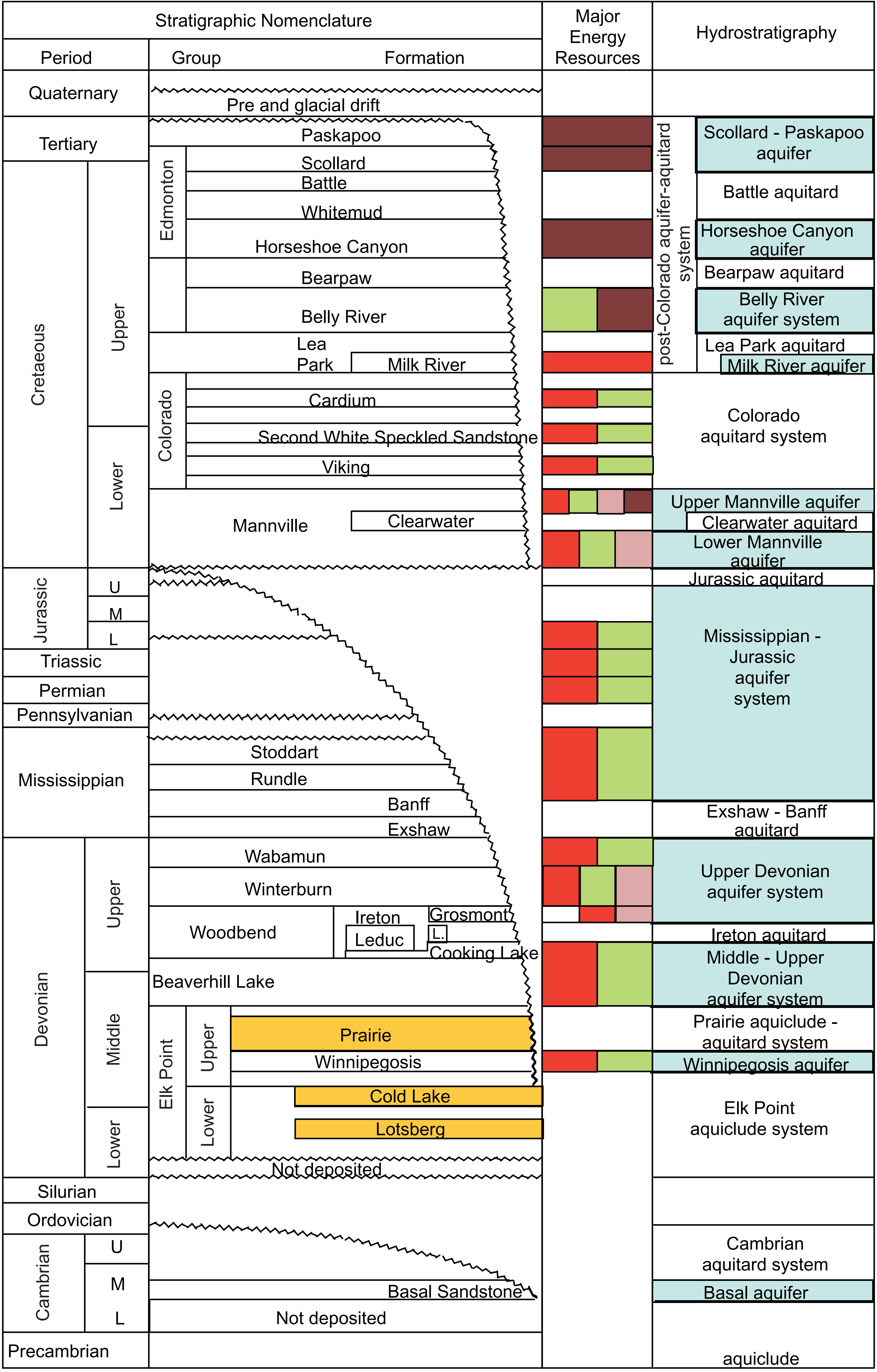



Figure 5: Relevant basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature in the southern and central parts of the Alberta basin ( Legend: gas; oil; heavy oil and oil sands; coal; salt; aquifer ).

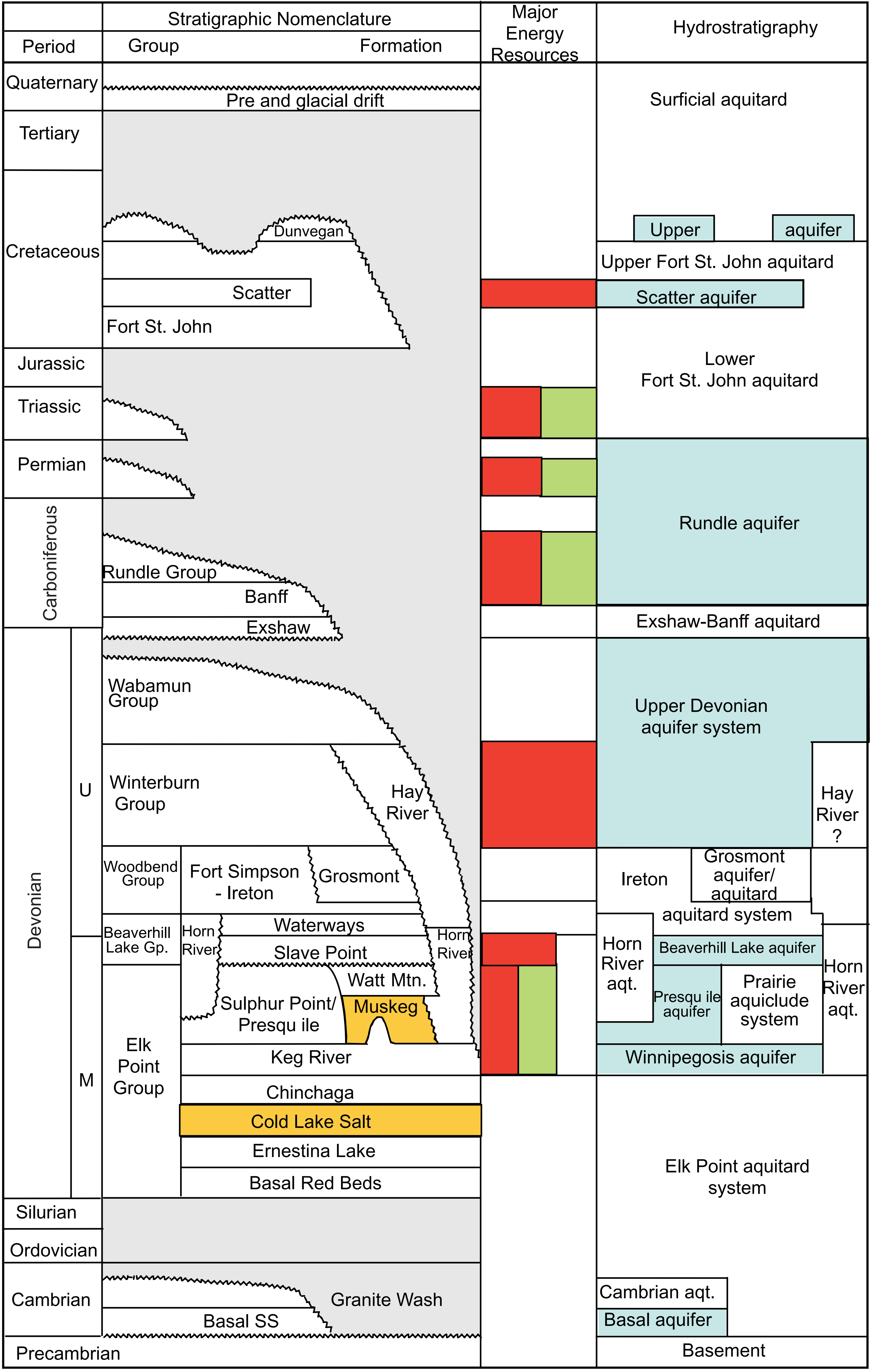



Figure 6: Relevant basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature in the northern part of the Alberta basin ( Legend: gas; oil; heavy oil and oil sands; coal; salt; aquifer ).

formation waters in Cretaceous aquifers in southwestern Alberta is driven inward, downdip by erosional rebound of the thick intervening shale units (Bachu, 1999). Short-range, shallower flow systems are driven by local topography. Cross-formational flow and mixing take place through Devonian reefs and at the sub-Cretaceous unconformity. The salinity of formation waters increases with depth, reaching as much as 350 g/l in the vicinity of salt beds (Bachu, 1995, 1997). The pre-Colorado formation waters are quite saline, ranging from brackish to brines, making them unfit for any use.

Economic considerations in geological sequestration of $CO_2$ deal with the existing or required infrastructure. In mature basins, such as Alberta's, the infrastructure is already in place (access roads, pipelines, and wells) and injection sites are easy to access and inexpensive to develop.

# 4 Carbon-Dioxide Sequestration in EOR, Depleted Oil and Gas Reservoirs, and Deep Saline Aquifers

## 4.1 Determination of Geothermal and Pressure Regimes

Knowledge of the geothermal and pressure regimes in Alberta's subsurface is needed for establishing the depths and areal distributions of the 31.1ºC isotherm and the 7.38 MPa isobar. For depths either below or above both the isotherm and isobar, $CO_2$ is in supercritical state or in gaseous phase, respectively (Figure 1). For depths between the isotherm and isobar, $CO_2$ is in either liquid or gaseous phase, depending on temperature and pressure. Thus, $CO_2$ injection and sequestration strategies depend directly on the geothermal and pressure regimes in the basin, particularly in the case of oil and gas reservoirs and deep saline aquifers.

The geothermal pattern in the Alberta Basin is controlled at the basin scale by multiyear average ground-surface temperatures and by basement heat flow; at the regional scale by the structure and lithology of the sedimentary succession; and only at the local scale by the flow of formation water (Bachu, 1985, 1988; Bachu and Burwash, 1991; Bachu and Cao, 1992). The basement heat flow at the top of the Precambrian has a regional-scale northward trend of increasing values, from less than 40 $mW/m^2$ in the south to values in the 50-60 $mW/m^2$ range in the north, with local values reaching 70-80 $mW/m^2$ (Bachu, 1993). Multiyear average ground-surface temperatures vary from 7ºC in the south to less than 5ºC in the north and along the thrust and fold belt (Bachu and Burwash, 1991). The resulting geothermal gradients, calculated on the basis of bottom-hole temperatures measured and collected by the energy industry, vary from less than 20ºC/km in the south to more than 50ºC/km in the north (Bachu, 1993). Accordingly, the depth to the 31.1ºC isotherm varies along a SW-NE line (Figure 7) in Alberta from more than 1200-1400 m in the south to less than 800 m in the north (Figure 7). Because of local anomalies in basement heat flow and variations in lithology (Bachu, 1993), the depth to the 31.1ºC isotherm deviates locally from the basin-scale south to north trend of decreasing depth (Figure 7). The most significant feature of the position of the 31.1ºC isotherm is that, where the basin is shallow in the northeast, it is found below the Precambrian crystalline basement (Figure 7). This is better portrayed on Figure 8, which presents the thickness of the sedimentary strata below this isotherm. The significance of the position of the 31.1ºC isotherm is that

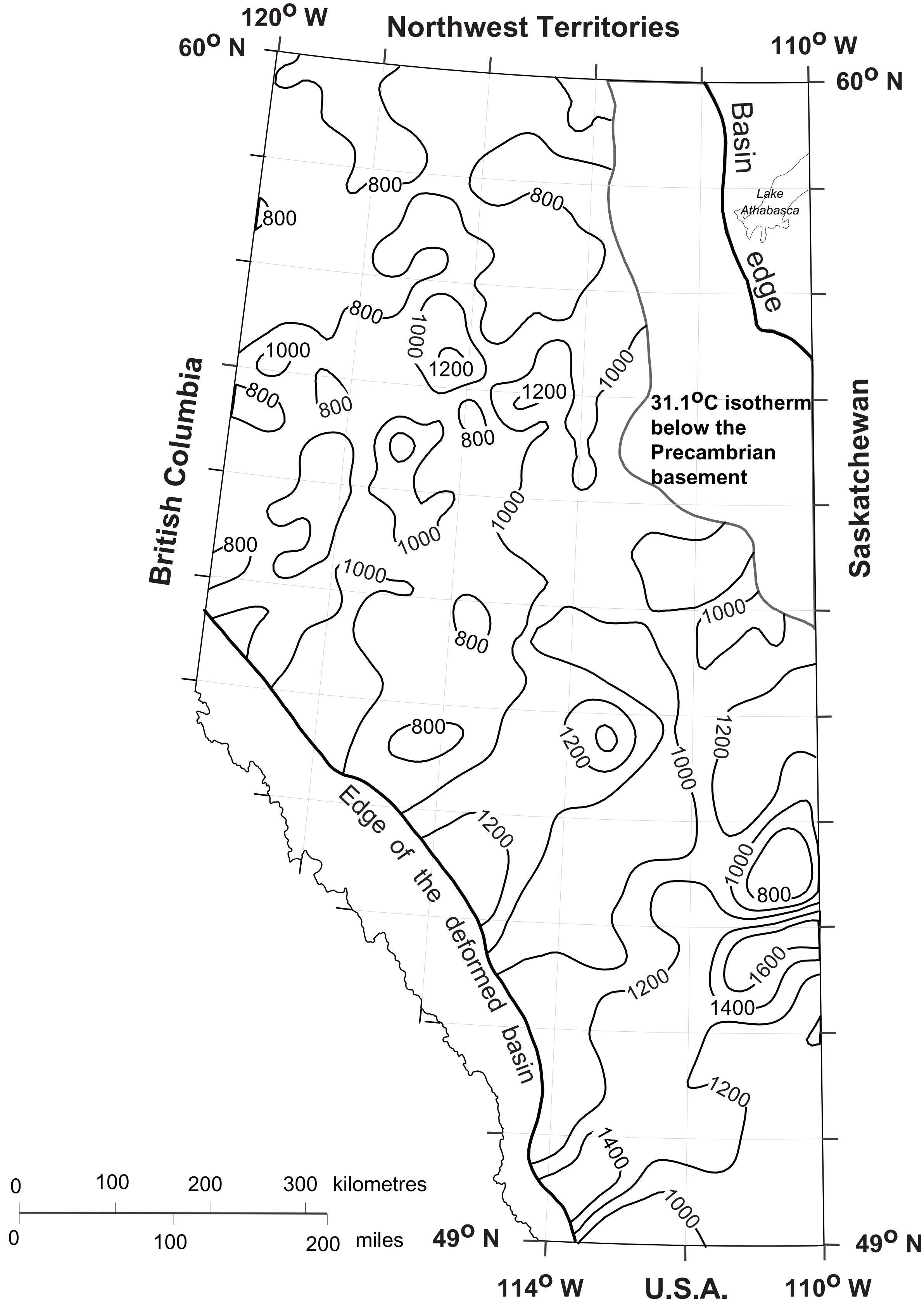



Figure 7: Depth (m) to the 31.1°C isotherm in Alberta.

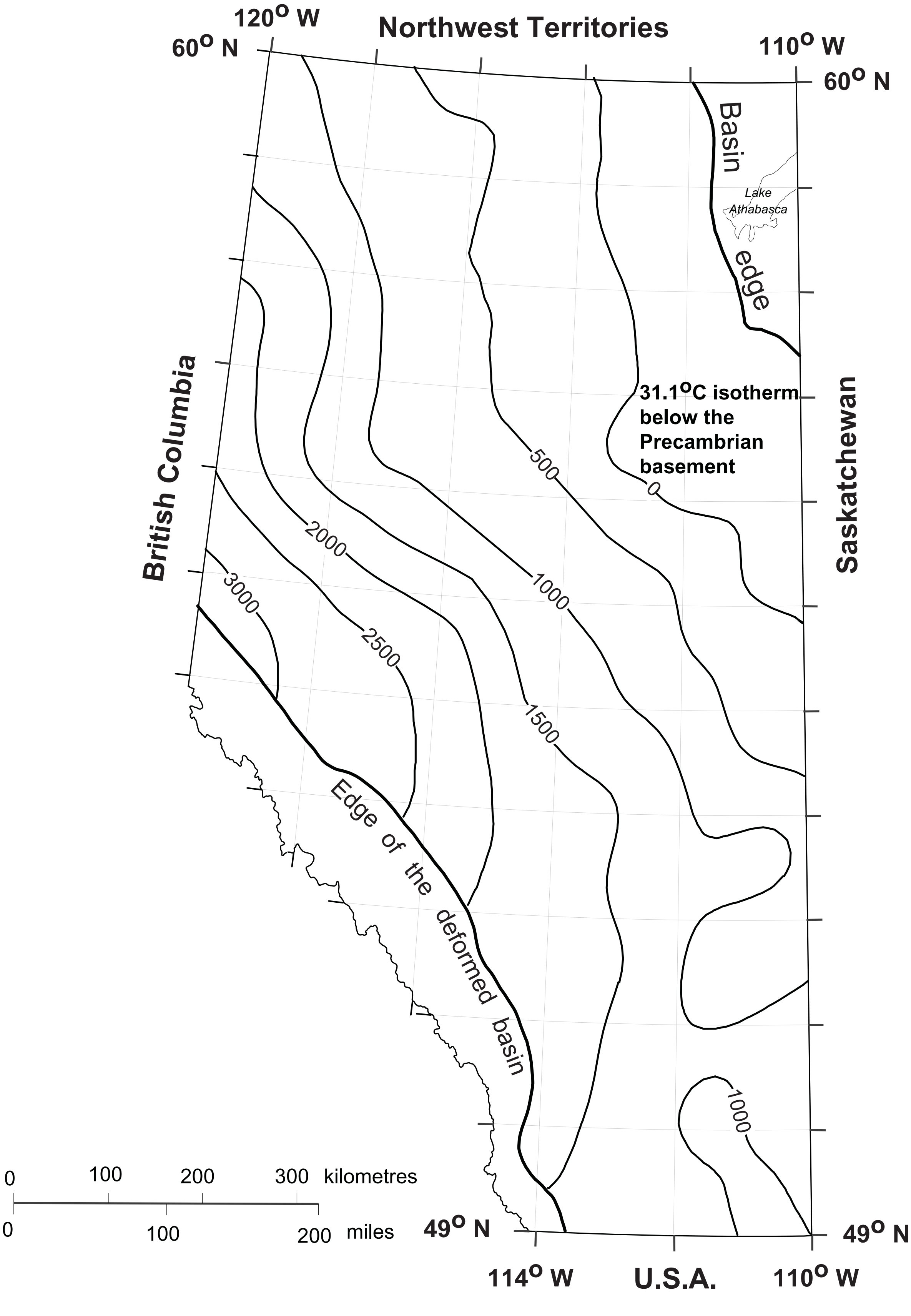



Figure 8: Isopachs (m) of the sedimentary succession below the 31.1$^{O}$C isotherm in Alberta.

1) the drilling depth for $CO_2$ sequestration in the supercritical state is significantly greater in southern and central Alberta than in the northern part; and
2) in the northeast (Athabasca area), $CO_2$ cannot attain the supercritical state within the shallow sedimentary succession.

As mentioned previously, the physical state of the injected $CO_2$ depends on the in situ temperature and pressure. Because terrestrial heat flows, mainly vertically, by conduction through the sedimentary succession, the temperature at any location in the basin can be estimated from surface temperature, geothermal gradient, and depth (Bachu, 1985). The pressure distribution is more difficult to assess because of 1) the presence of aquitards, which separate the various aquifers in the sedimentary succession; 2) salinity variations; 3) the lateral flow in dipping aquifers; and 4) the various flow-driving mechanisms in the basin, such as topography, buoyancy, and erosional rebound (Bachu, 1999). Thus, unlike temperature, which varies continuously through the sedimentary succession, the pressure distribution needs to be established individually, aquifer by aquifer. If the injected $CO_2$ is lighter than formation fluids, particularly water, it will segregate at the top of the aquifer or reservoir and will tend to override the flow (Law and Bachu, 1996). Thus, in order to establish the physical state of the injected $CO_2$, it is necessary to determine the pressure distribution at the top of each aquifer and/or reservoir.

Formation pressure is commonly measured by the energy industry during exploration and production. For thin aquifers or reservoirs, the measured pressure represents an acceptable approximation of the pressure at the top of the formation, particularly in the case of gas reservoirs. However, in the case of thick aquifers, the pressure at the top of the aquifer or reservoir may be considerably less than the measured pressure, depending on the position of the tested interval. For these cases, the pressure at the top of the formation can be calculated using the relation:

$$p_t = p_m - (z_m - z_t)\, \rho_f\, g \qquad (1)$$

where p is pressure, z is elevation, $\rho_f$ is fluid density, g is the gravitational constant, and the subscripts t and m refer to the aquifer/reservoir top and measurement point, respectively. The density of formation waters can be calculated from in situ salinity, temperature, and pressure (Rowe and Chou, 1970). For gas, an average density of 1.3 kg/m$^3$ was used in the calculations. Structure tops were constructed for 27 major units in the sedimentary succession in Alberta that provided the elevation ($z_t$) of the respective aquifer or reservoir top. The salinity distribution in each unit was mapped using a database of 123 958 formation water analyses, collected by industry, that passed rigorous checking and culling (Hitchon and Brulotte, 1994). Pressure measurements ($p_m$) from 101 917 water and gas drillstem tests were used to calculate first the water density ($\rho_f$), and subsequently the distribution of pressure ($p_t$) at the top of aquifers and reservoirs in the sedimentary succession. As a result of this massive data-processing effort, pressure and temperature distributions were determined for 23 units in the sedimentary succession in Alberta, and the positions of the 31.1ºC isotherm and the 7.38 MPa isobar were individually established in each unit.

## 4.2 Carbon-Dioxide Sequestration in Hydrocarbon Reservoirs

Analysis of the suitability of the major units in the sedimentary succession in Alberta for $CO_2$ sequestration in oil and gas reservoirs and in deep saline aquifers is presented, in ascending order, from the crystalline Precambrian basement to the surface. The units in the succession are shown in Figures 5 and 6. Pressures and temperatures for the deeper units are high, and decrease for the shallower units. As a result of basin dip from the northeast to the southwest, the positions of the 31.1ºC isotherm and the 7.38 MPa isobar shift westward as successive units are located higher up in the sedimentary succession, until they disappear from the basin. As expected, the 31.1ºC isotherm and the 7.38 MPa isobar generally run approximately parallel to the deformation front in all the units, with local deviations from this trend caused by basement heat-flow anomalies and by underpressuring. East of both the isotherm and isobar in any particular unit, the injected $CO_2$ will be a gas or a liquid, depending on temperature and pressure (most probably a gas). West of them, the injected $CO_2$ will be in supercritical state. In regions between the two where the 31.1ºC isotherm is located west of the 7.38 MPa isobar, the injected $CO_2$ will be in liquid phase. In regions where the isotherm is located east of the isobar, the injected $CO_2$ will be in gaseous phase.

Pressures in the **Cambrian** and **Ordovician** are everywhere greater than 7.38 MPa. Temperatures are greater than 31.1ºC everywhere except in the northeast corner, near Lloydminster and Cold Lake (Figures 9 and 10). There are no oil or gas reservoirs in the Cambrian and Ordovician.

Major oil and gas fields are present in carbonate and sandstone reservoirs in the **Elk Point Group** in northwestern Alberta (Figure 11). These occur in Keg River pinnacle reefs in the Rainbow, Zama, and Sheikilie basins in the northwestern corner of Alberta, and in Granite Wash, Keg River, and Gilwood (Watt Mountain Formation) sandstone units deposited around the Peace River Arch landmass in the southern part of northwestern Alberta. Carbon dioxide can be sequestered in supercritical state in all the carbonate and sandstone oil and gas reservoirs of the Elk Point Group except the Red Earth field (Figure 11). In the latter, $CO_2$ can be sequestered in both supercritical and liquid states, depending on specific in situ conditions, because the oil reservoirs are at some depth from the top of the Elk Point Group.

Almost all oil and gas pools in the **Beaverhill Lake Group**, such as Swan Hills and Kaybob, are located west of the 31.1ºC isotherm and 7.38 MPa isobar, mainly in reefs around the Peace River Arch (Figure 12). Thus, $CO_2$ can be sequestered in supercritical state in these oil and gas pools.

Most of the oil and gas pools in the **Woodbend Group**, found in Leduc reefs along the Rimbey-Meadowbrook trend and around the Peace River Arch, are located west of the 31.1ºC isotherm and 7.38 MPa isobar (Figure 13). Carbon dioxide can be sequestered in supercritical state in these reservoirs and as a gas in fields such as Redwater, at the northern tip of the Rimbey-Meadowbrook trend, and Liege, along the subcrop area.

As with the Woodbend Group, oil and gas pools in the overlying **Winterburn** and **Wabamun** groups are located mainly west of the 31.1ºC isotherm and 7.38 MPa isobar (Figures 14 and 15). Pools, mainly gas, in the subcrop areas are located east of the isotherm and isobar (e.g., Calling

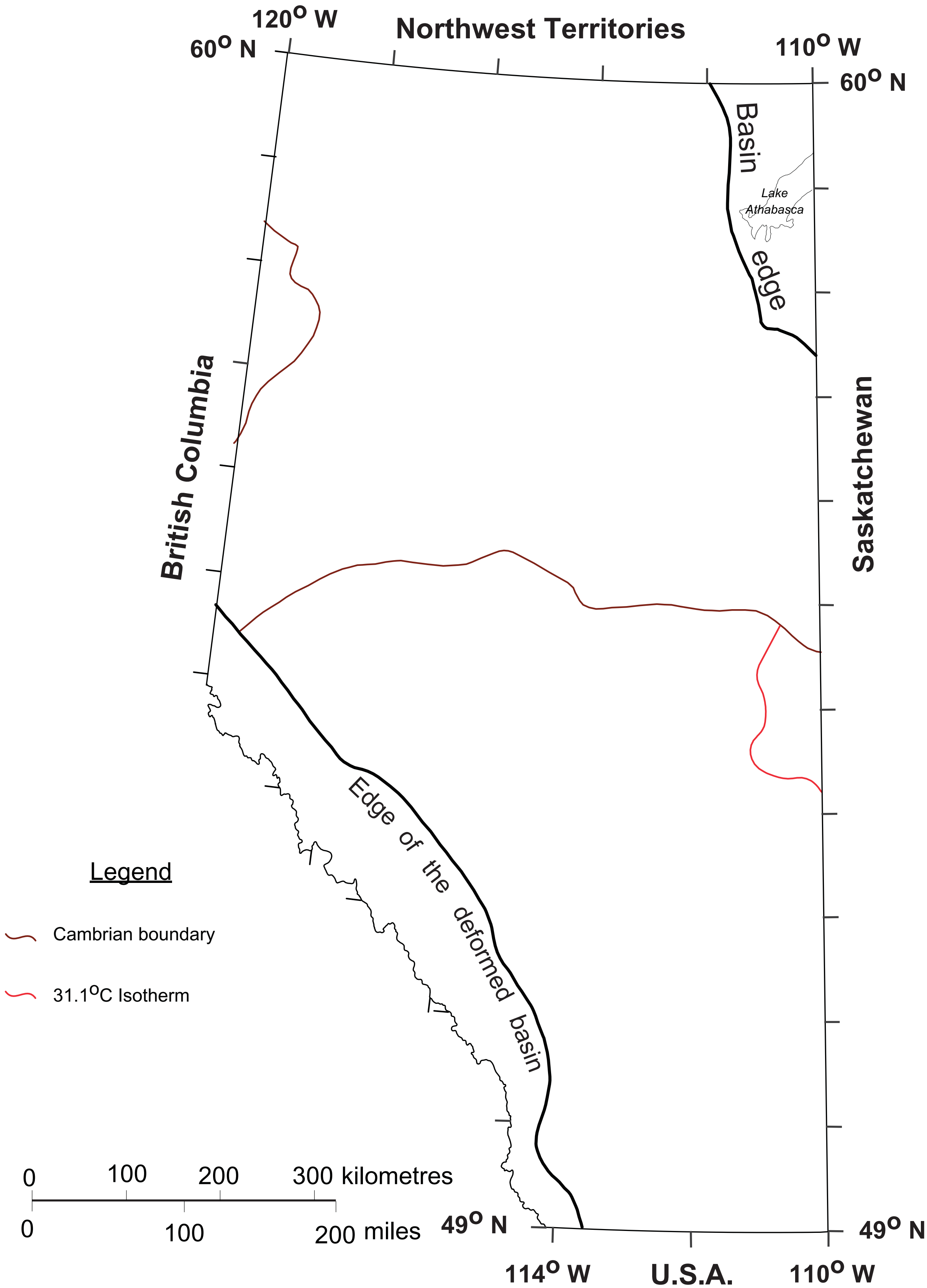



Figure 9: Position of the 31.1°C isotherm at the top of the Cambrian.

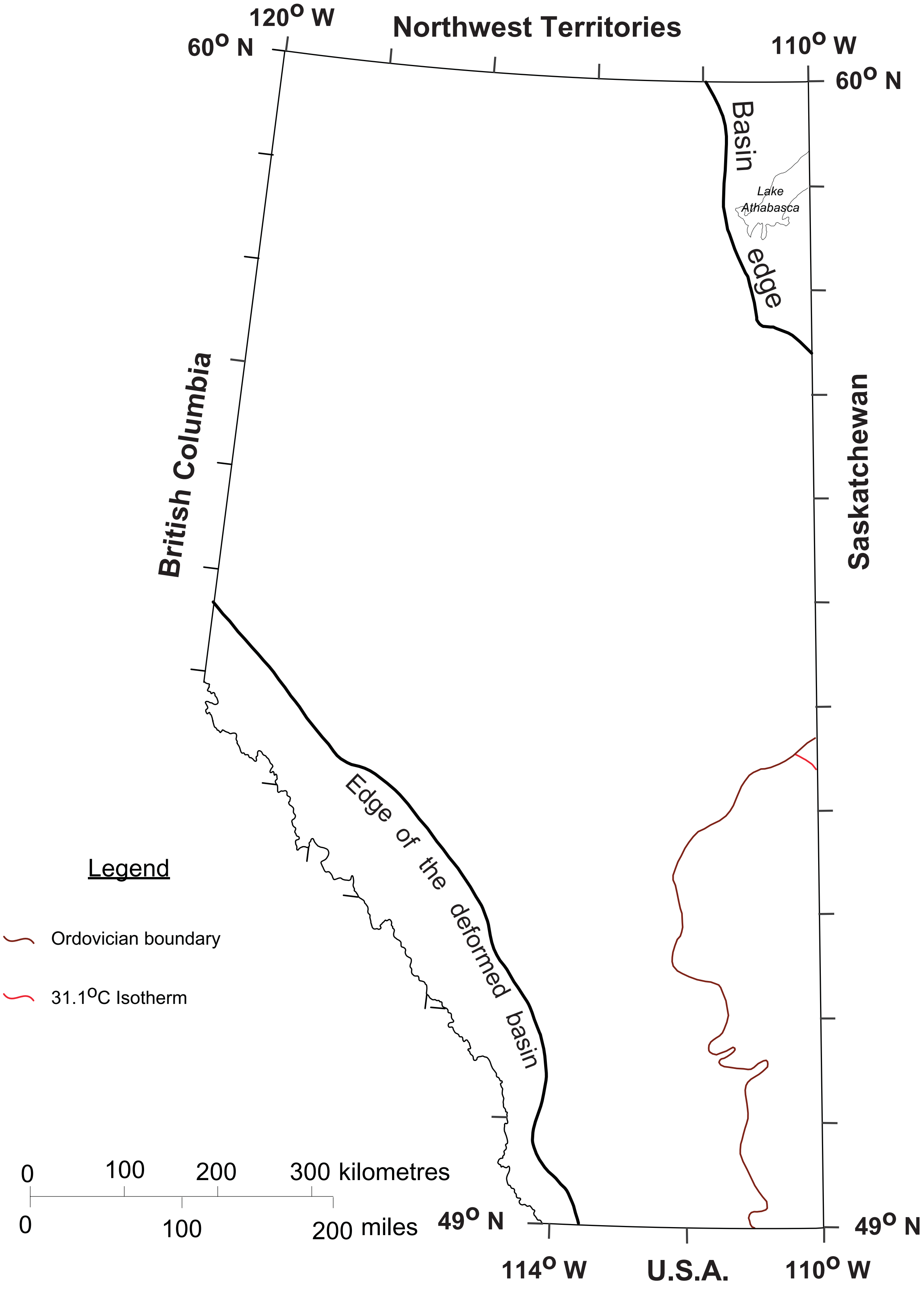



Figure 10: Position of the 31.1$^{O}$C isotherm at the top of the Ordovician.

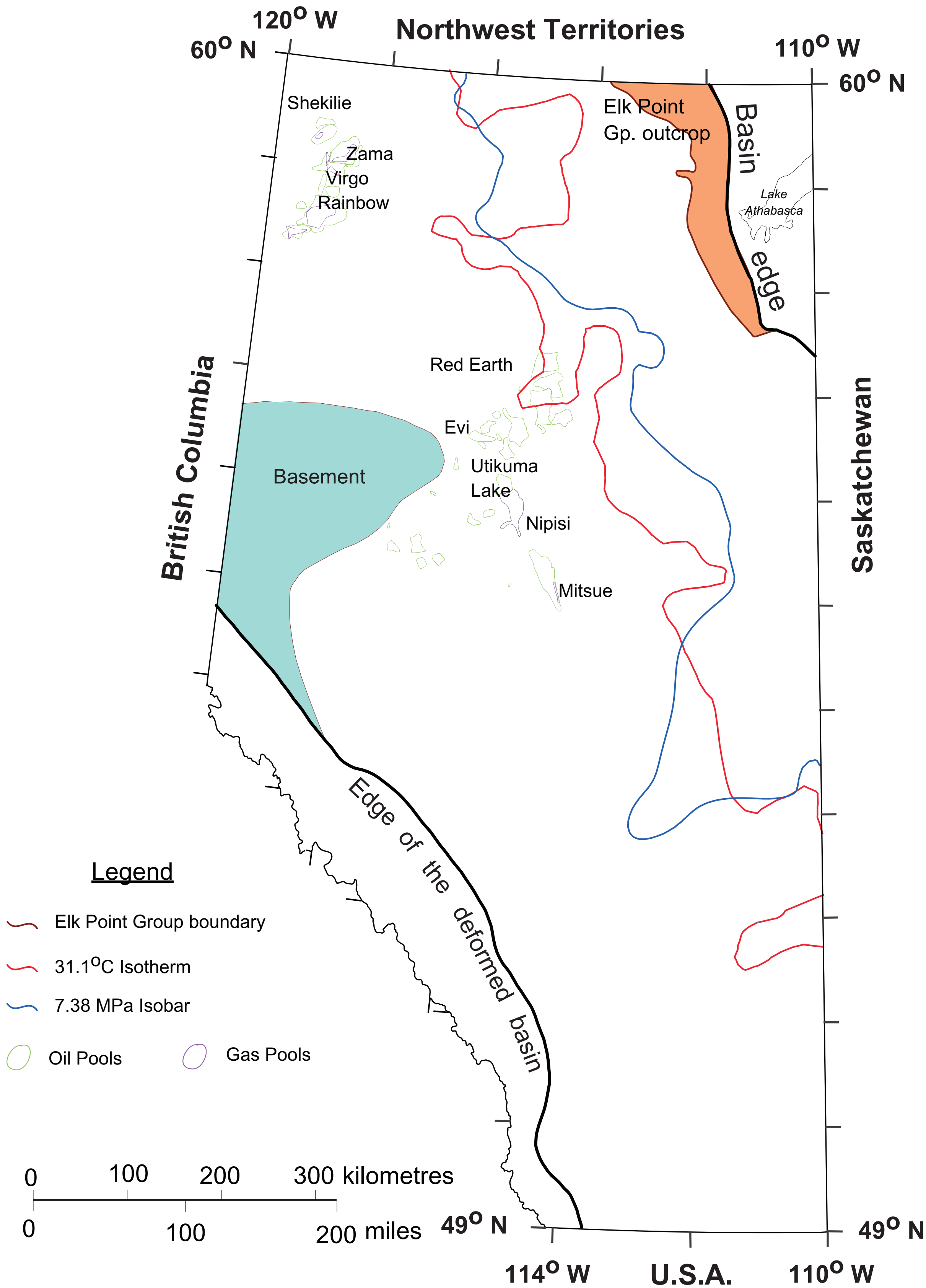



Figure 11: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Elk Point

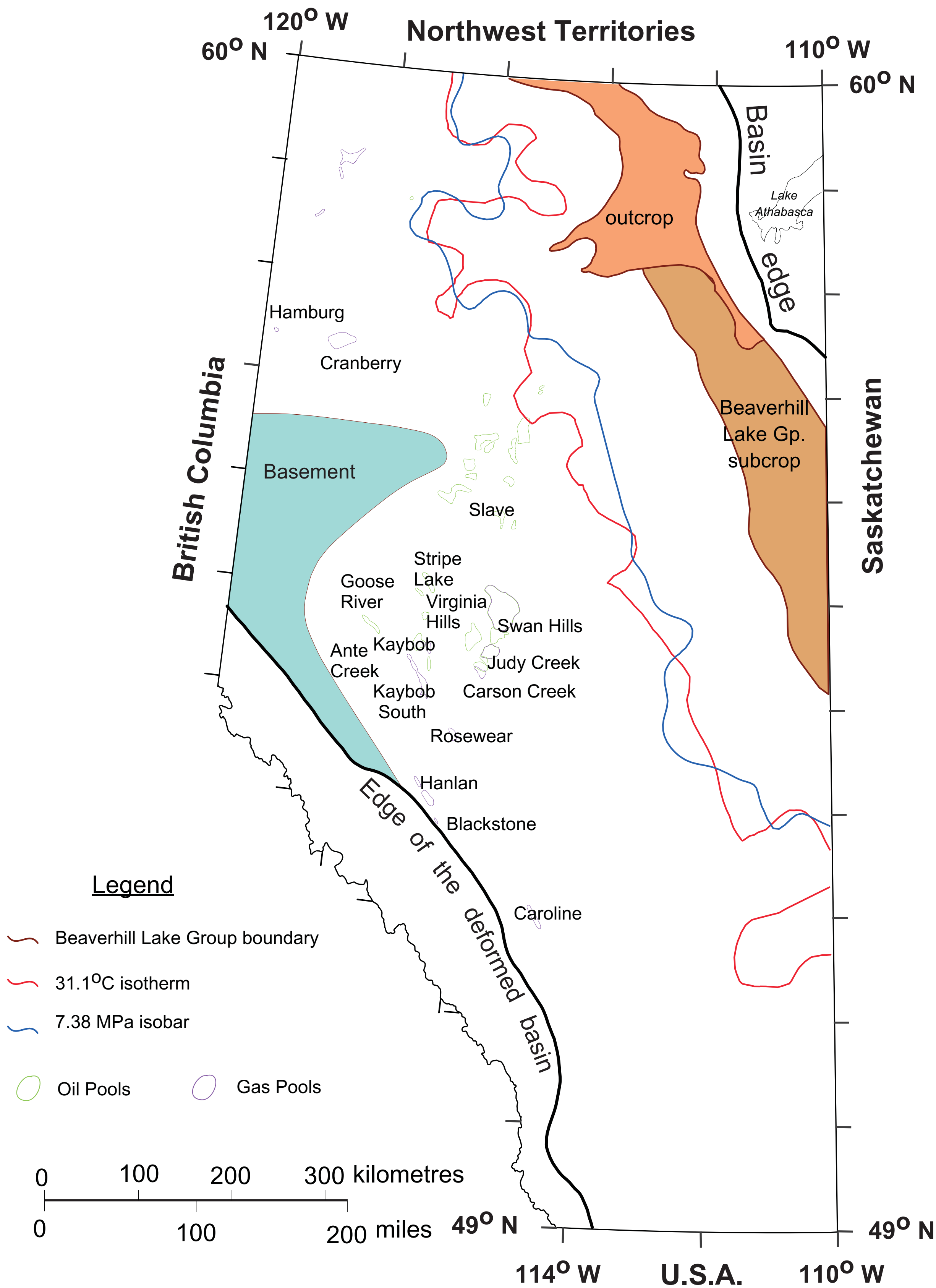



Figure 12: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Beaverhill Lake Group.

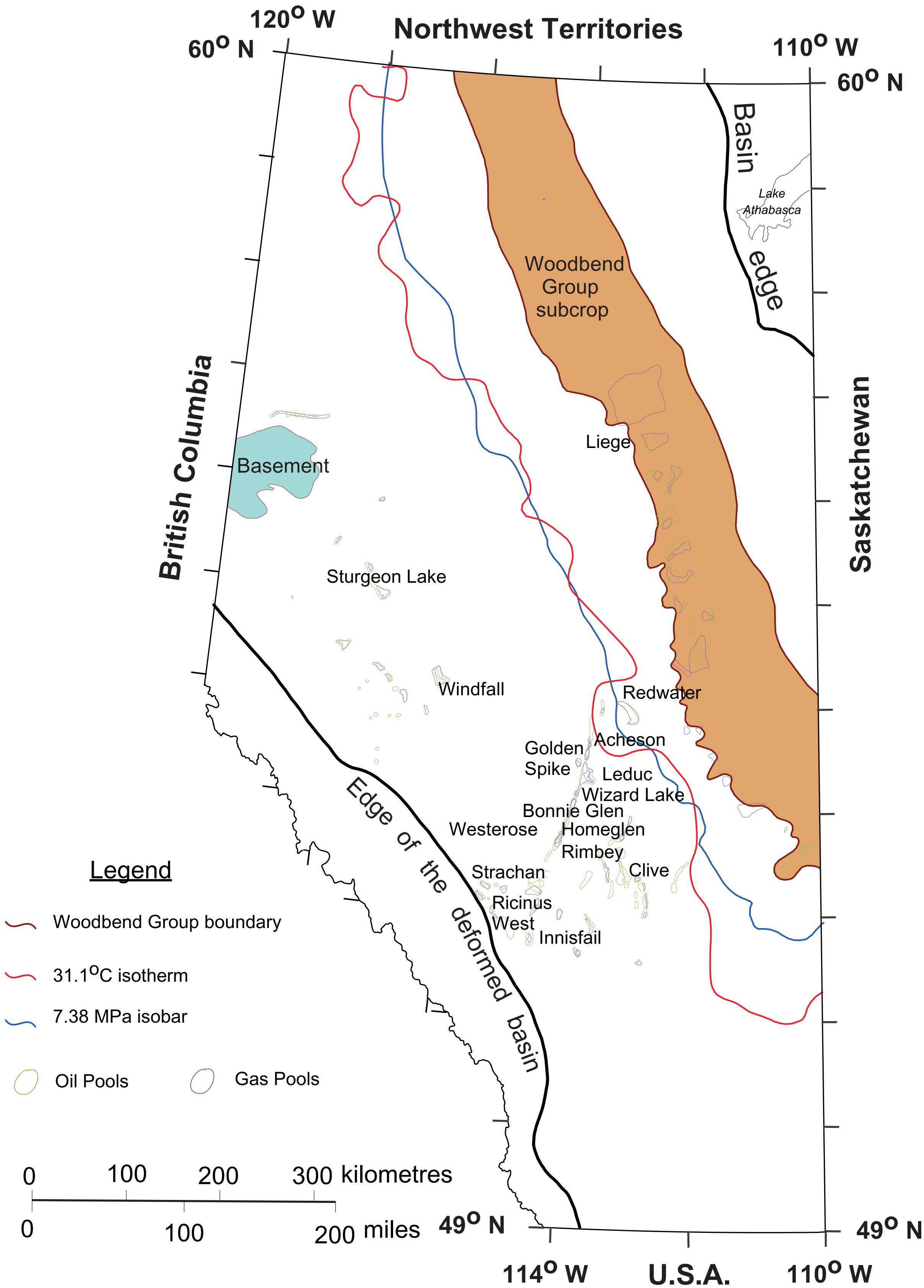



Figure 13: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Woodbend Group.

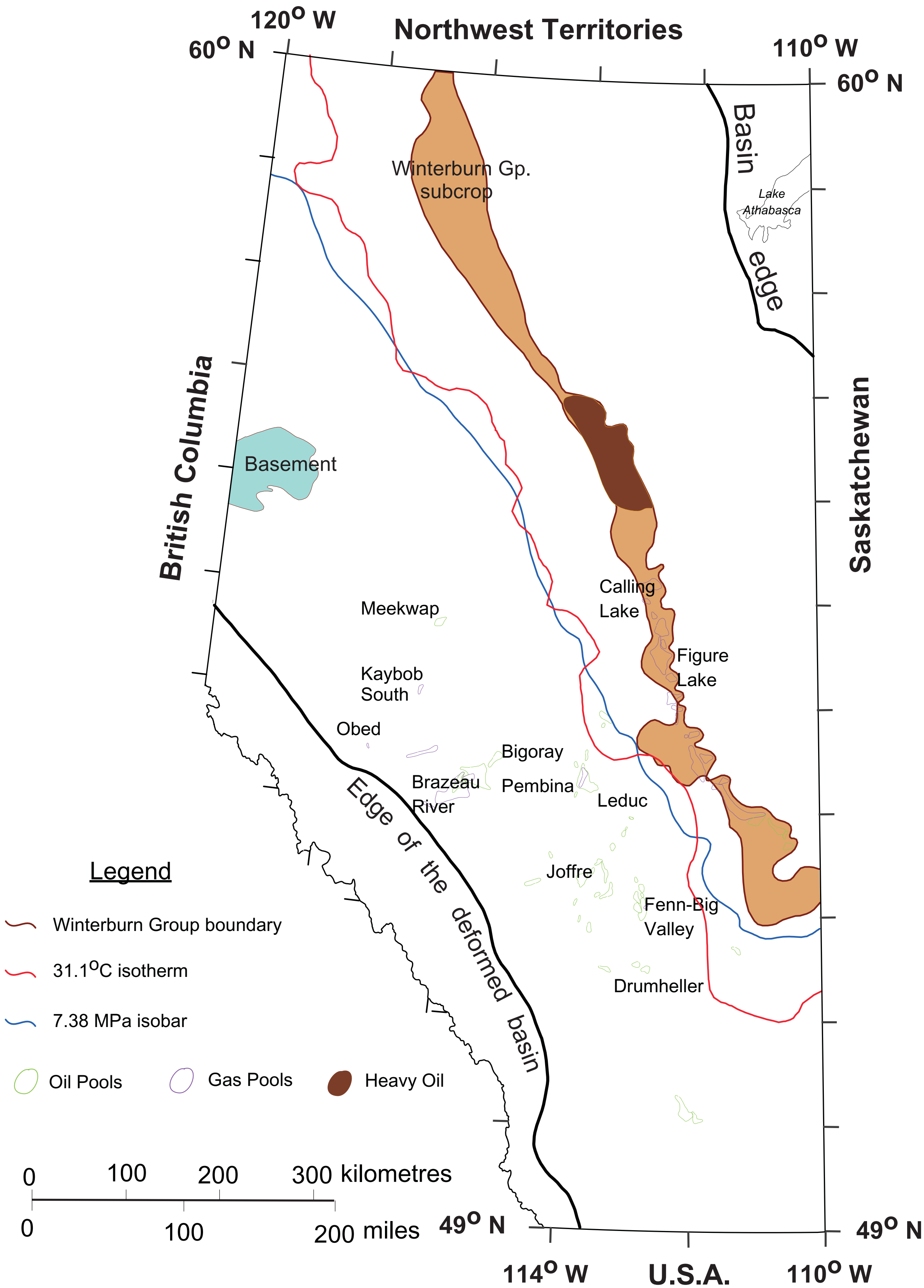



Figure 14: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Winterburn Group.

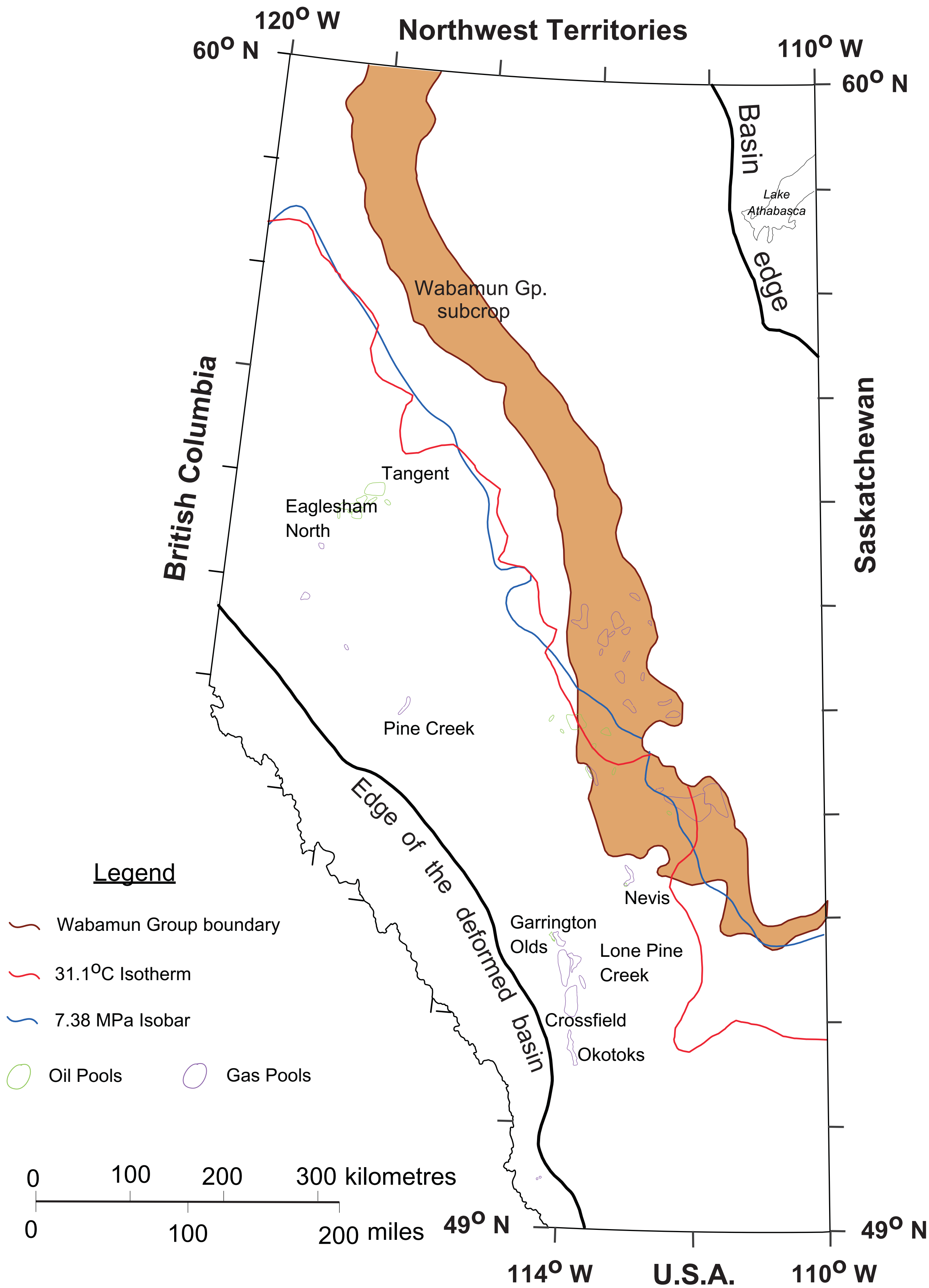



Figure 15: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Wabamun Group.

Lake). Thus, $CO_2$ can be sequestered in supercritical state in oil and gas pools in the uneroded part of these carbonate-dominated groups, and in gaseous phase in oil and gas pools in subcrop areas.

The oil and gas fields in the **Carboniferous** along the edge of the deformed basin (Rocky Mountain Foothills), such as Harmattan and Crossfields, are located west of the 31.1ºC isotherm and 7.38 MPa isobar (Figure 16). Thus, $CO_2$ can be sequestered in supercritical state in these reservoirs.

Both **Permian** and **Triassic** strata are present only in the northwest (Figures 17 and 18). Except for a few gas pools in the Triassic, $CO_2$ can be sequestered in supercritical state in oil and gas reservoirs.

As with the Carboniferous, $CO_2$ can be sequestered in **Jurassic** strata in supercritical state in oil and gas reservoirs along the edge of the deformed basin in the southwest, and in liquid phase in the southeast (Figure 19).

Carbon dioxide can be sequestered in supercritical state in oil and gas reservoirs, such as Elmworth, Gilby, and Sylvan Lake, in the southwestern part of the siliciclastic **Lower Mannville Formation**, along the edge of the deformed basin (Figure 20). In the southeastern part, $CO_2$ can be sequestered as a liquid in oil and gas reservoirs such as Cessford, Bantry, and Grand Forks (Figure 20). In the eastern part of the formation, $CO_2$ can be sequestered as a gas in oil and gas reservoirs such as Provost. Depleted bitumen reservoirs in the Cold Lake, Athabasca, and Peace River areas could store $CO_2$ in gaseous phase (Figure 20). The overlying **Upper Mannville Formation** has very similar characteristics, with respect to $CO_2$ sequestration, as the Lower Mannville Formation (Figure 21).

The **Viking Formation,** separated from the Mannville Group by the very thin shale of the Joli Fou Formation, presents a similar pattern with respect to $CO_2$ sequestration (Figure 22). Namely, $CO_2$ could be sequestered in supercritical state in oil and gas reservoirs such as Crystal and Gilby in the southwest, and as a gas in central and eastern Alberta (e.g., at Provost, Beaverhill Lake, and Cessford). In the southeast, $CO_2$ can be sequestered as a gas, unlike in the Mannville Group (Figure 22), because of low pressures characteristic of the underpressured Viking Formation.

Almost all oil and gas reservoirs in the sandstone **Cardium Formation** are located west of the 31.1ºC isotherm and 7.38 MPa isobar (Figure 23). Thus, $CO_2$ can be sequestered in supercritical state in these reservoirs.

The sandstone **Dunvegan Formation** is found in northwestern Alberta (Figure 24), where it outcrops along the Peace River. Only in the southern part of this formation are oil and gas pools, such as Simonette, at temperatures and pressures greater than 31.1ºC and 7.38 MPa, respectively (Figure 24). Carbon dioxide can be sequestered in these reservoirs in supercritical state. Carbon dioxide sequestration in the north-northwestern part of this unit is not recommended because it is too close to outcrop, and $CO_2$ will most likely be in gaseous phase. Thus, the buoyancy of the gas may lead to its early escape at formation outcrop.

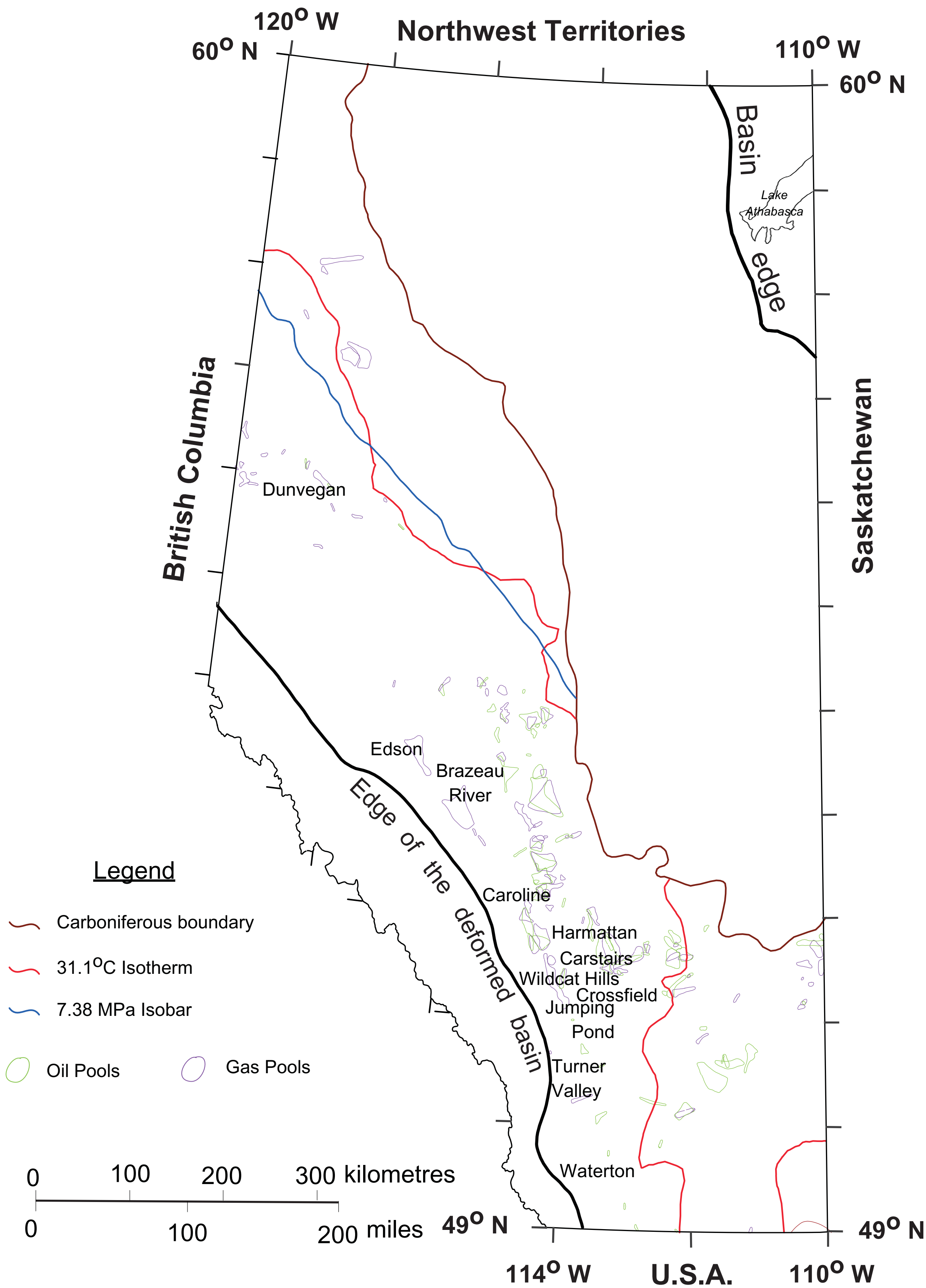



Figure 16: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Carboniferous.

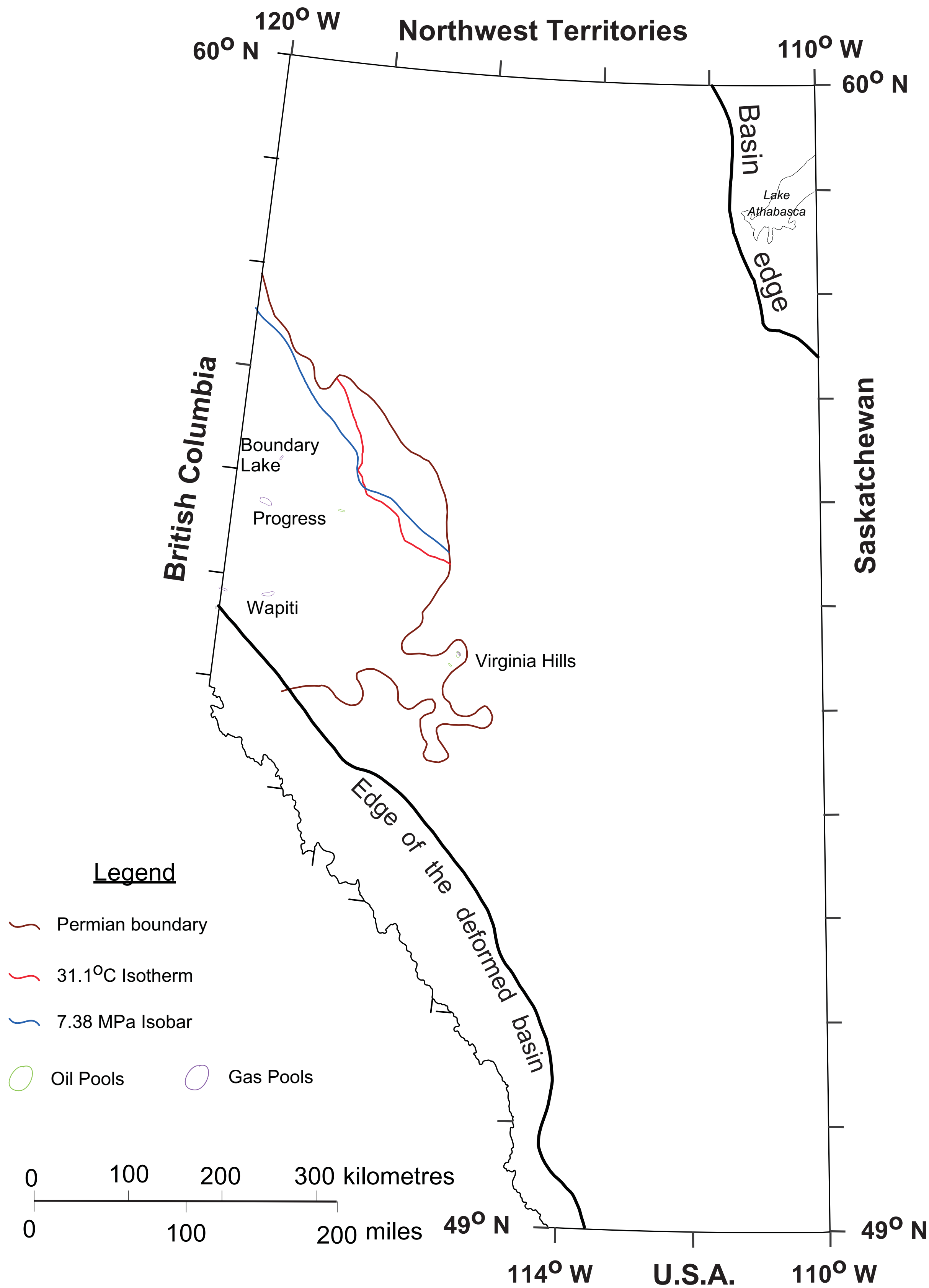



Figure 17: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Permian.

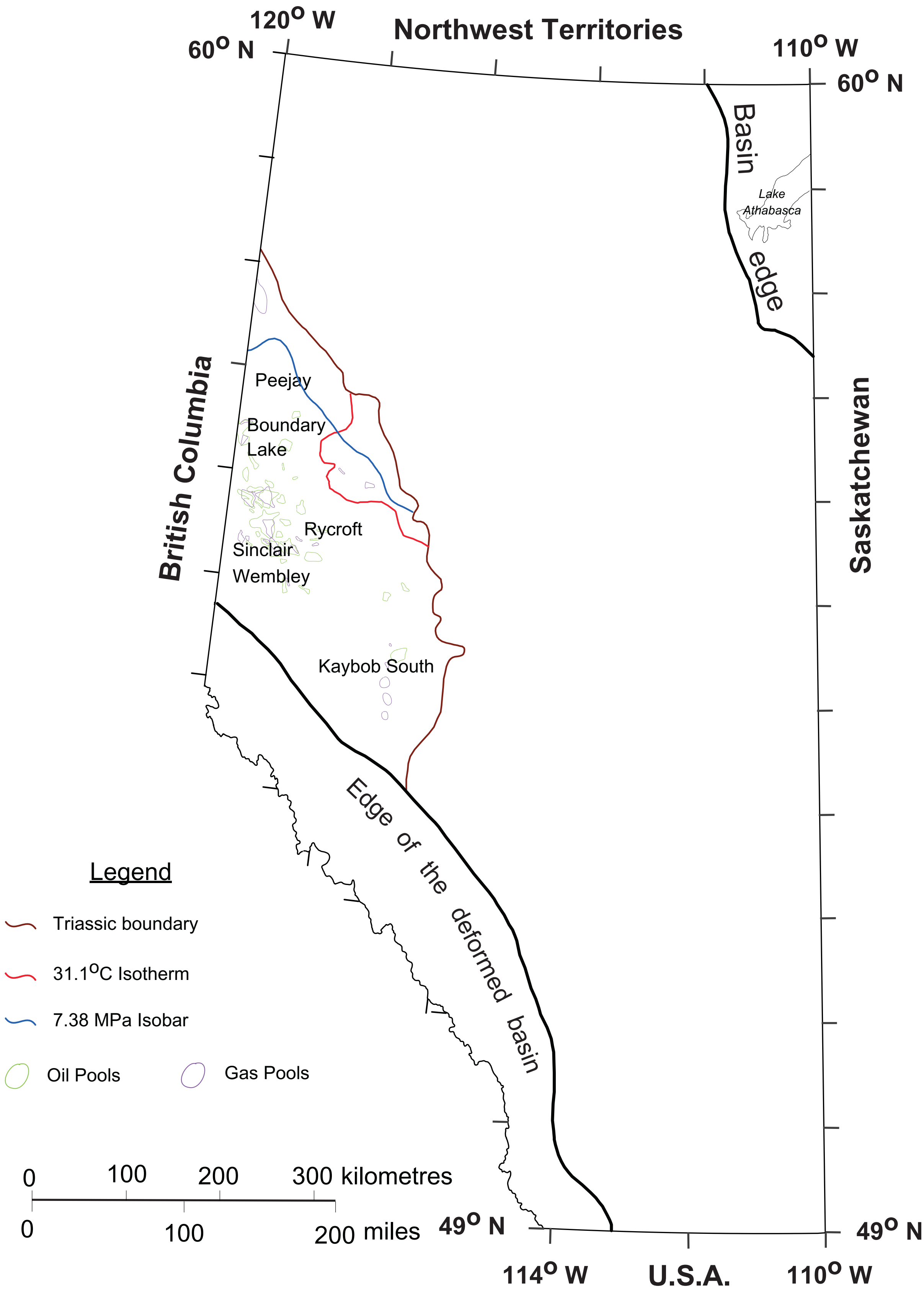



Figure 18: Position of the 31.1$^{O}$C isotherm and the 7.38 MPa isobar at the top of the Triassic.

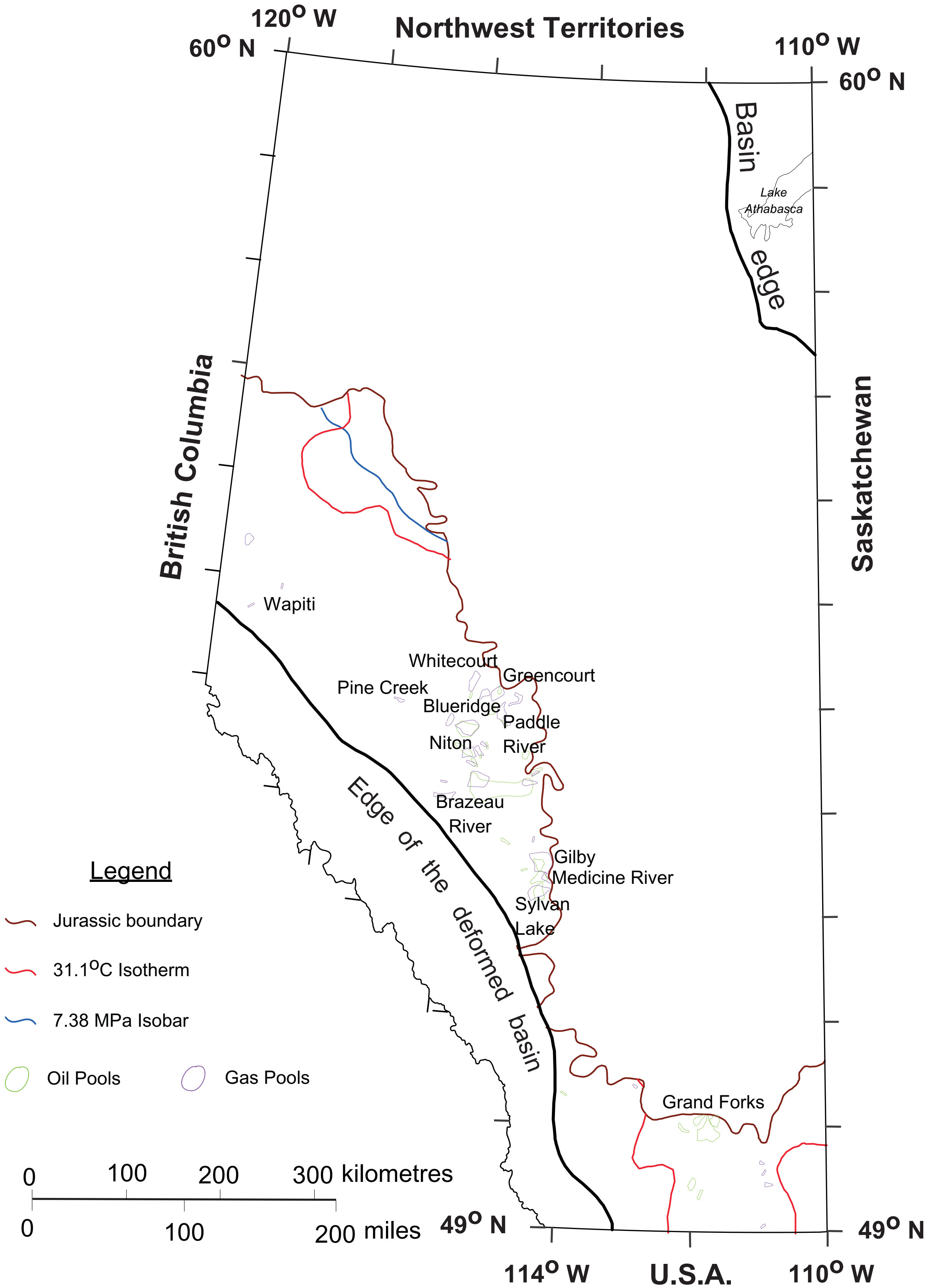



Figure 19: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Jurassic.

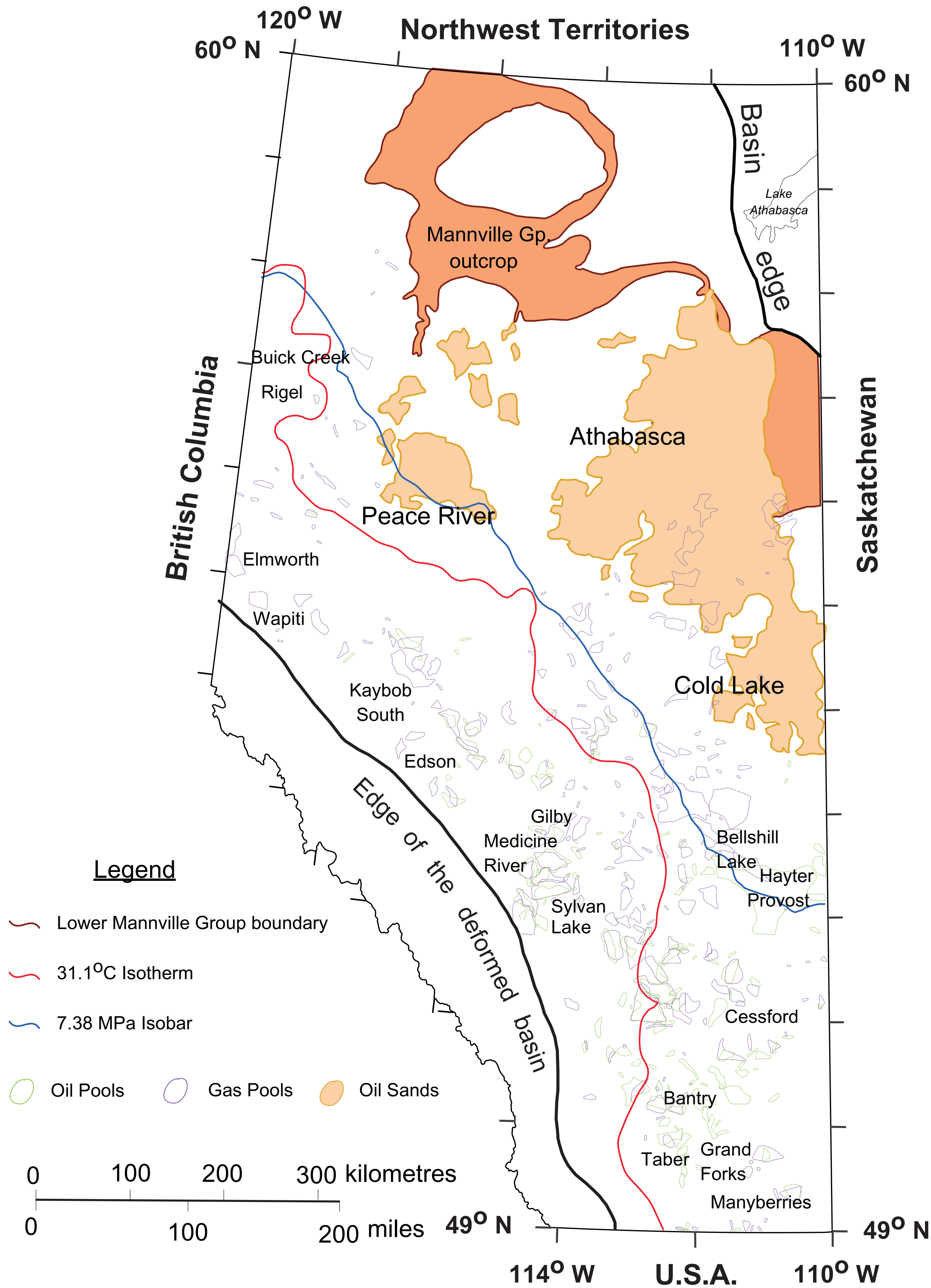



Figure 20: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Lower Mannville Group.

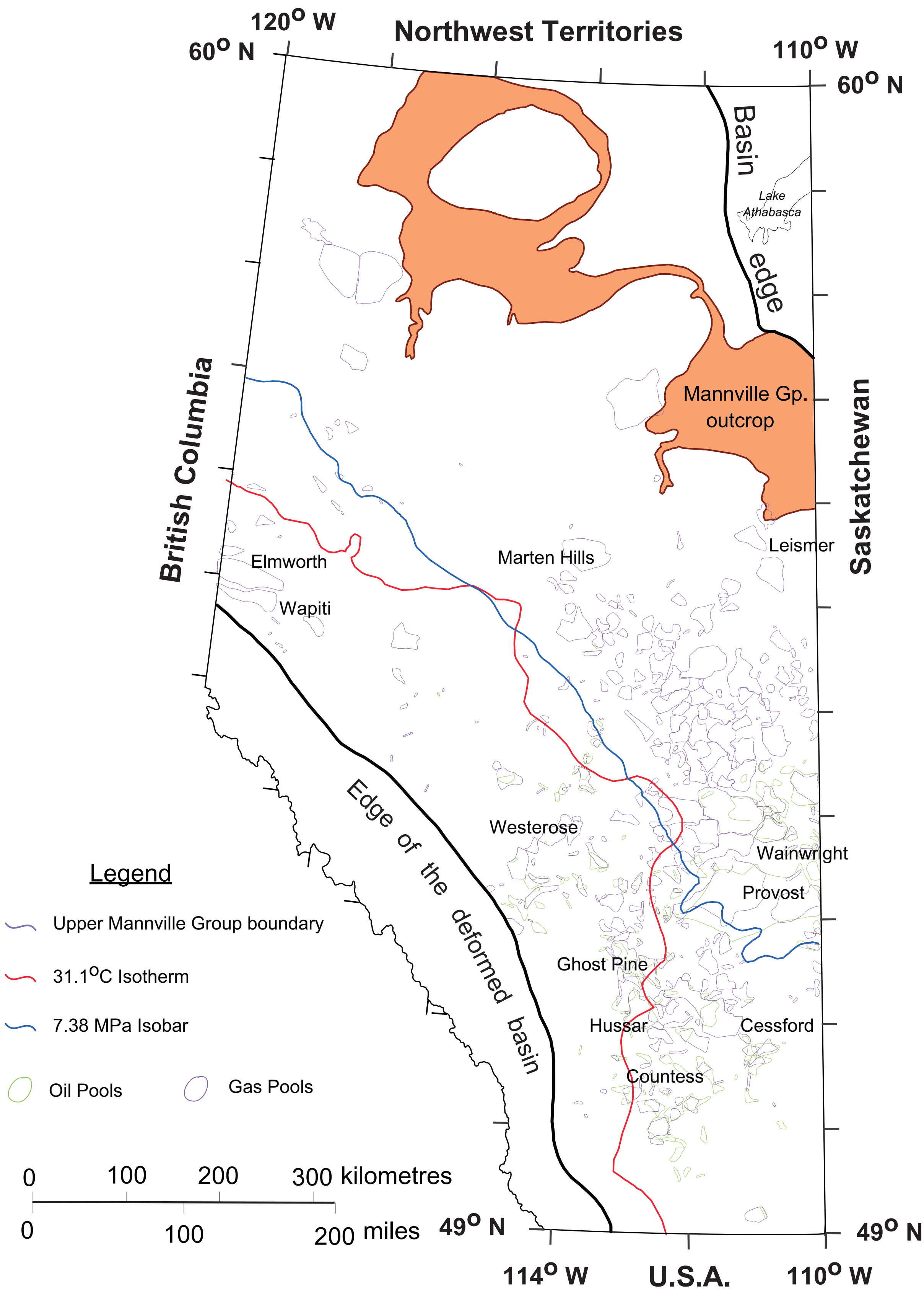



Figure 21: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Upper Mannville Group.

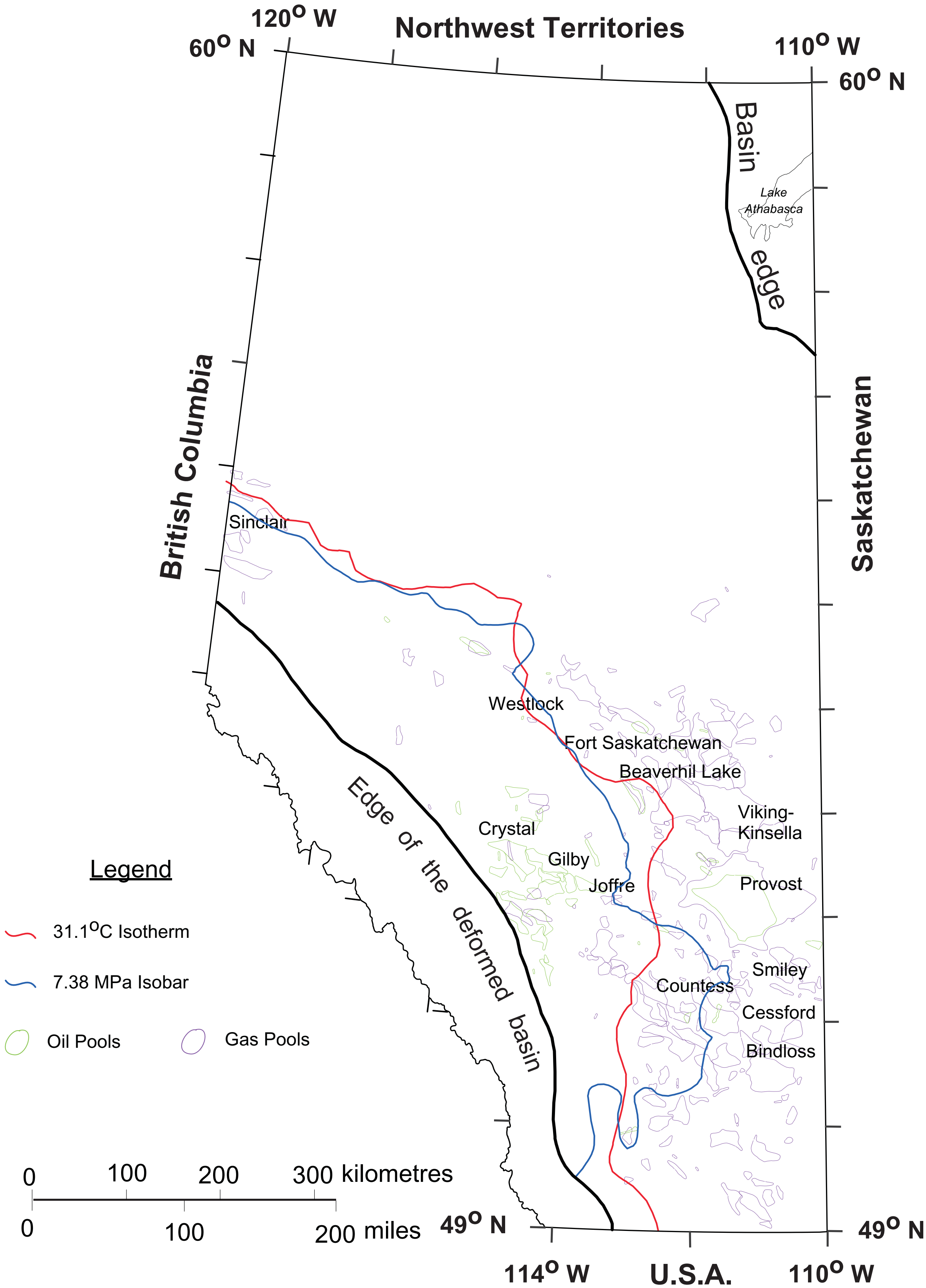



Figure 22: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Viking Formation.

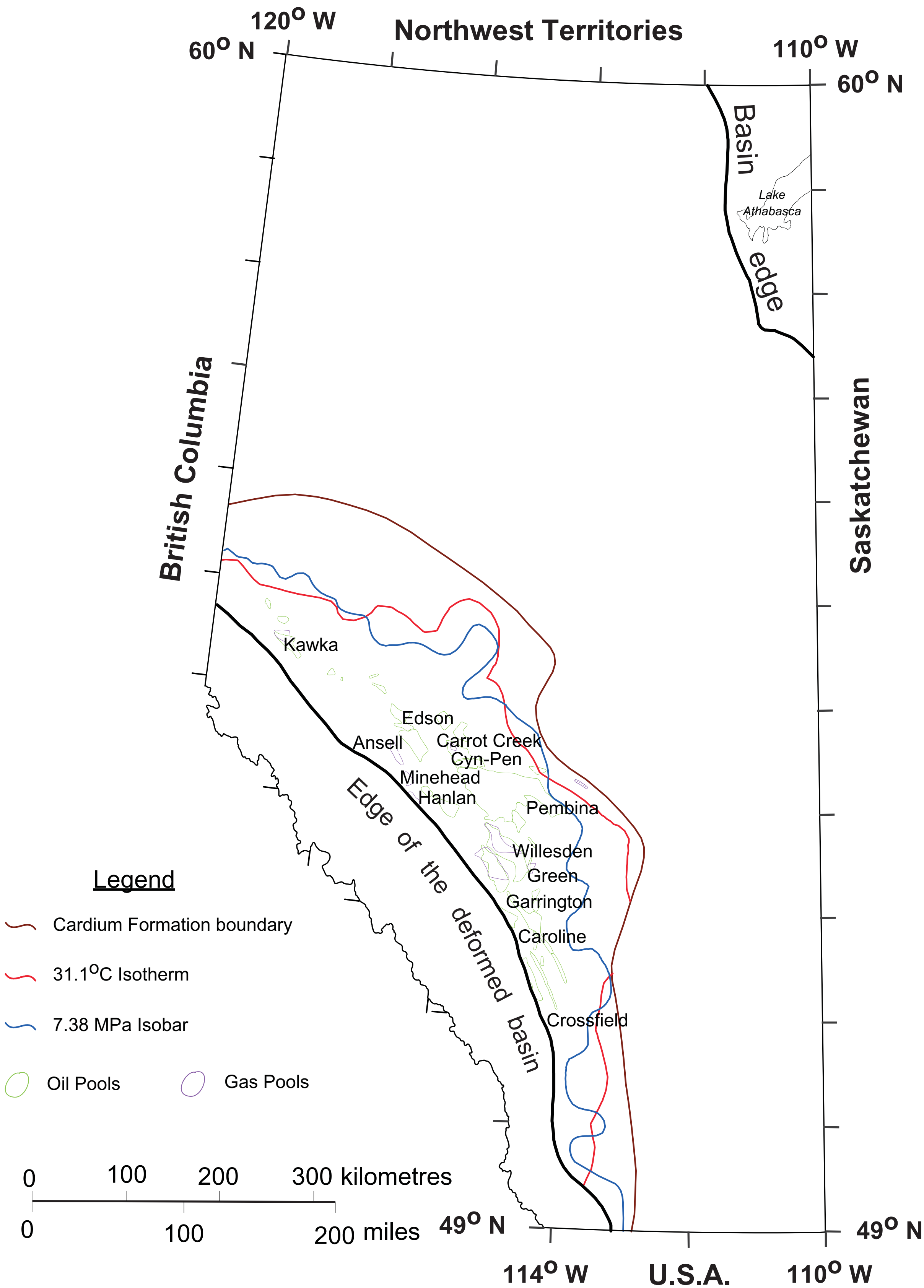



Figure 23: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Cardium Formation.

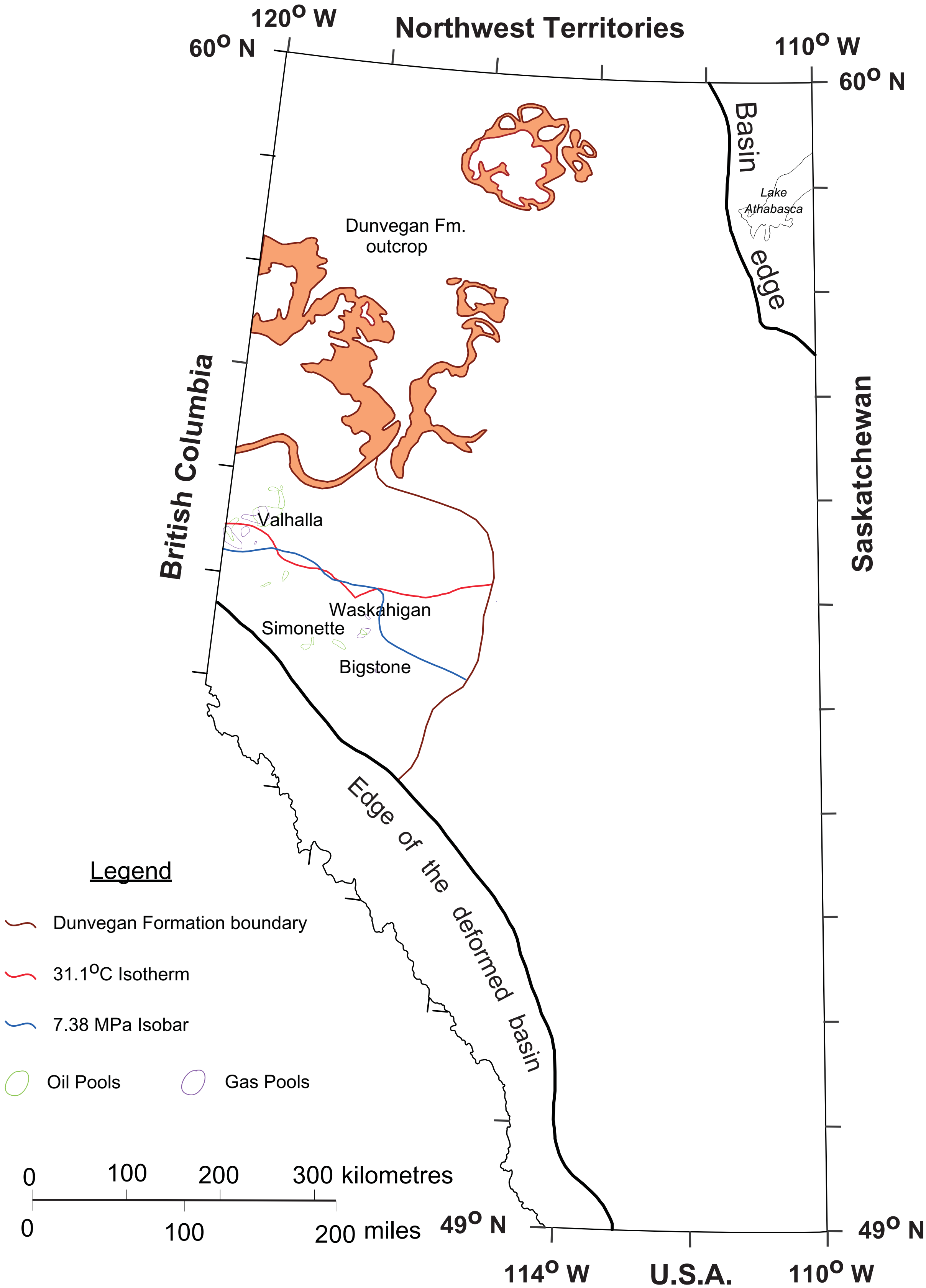



Figure 24: Position of the 31.1$^{o}$C isotherm and the 7.38 MPa isobar at the top of the Dunvegan Formation.

Most gas fields in the sandstone **Milk River Formation**, such as the giant Medicine Hat field, are located east of both the 31.1ºC isotherm and 7.38 MPa isobar (Figure 25). Carbon dioxide could probably be sequestered as a gas in these gas fields.

In the Lower **Belly River Formation (sandstone),** $CO_2$ can be sequestered in supercritical state in oil reservoirs, such as Brazeau River, that are located west of both the 31.1ºC isotherm and 7.38 MPa isobar (Figure 26). In oil pools located east of the 7.38 MPa isobar, such as Ferrybank Creek, $CO_2$ will be in gaseous phase. Higher up in the **Belly River Formation**, pressures are lower than 7.38 MPa and temperatures are less than 31.1ºC almost everywhere (Figure 27). There are no hydrocarbon reservoirs in the shallower, overlying **Horseshoe Canyon, Scollard,** and **Paskapoo** formations.

### 4.3 Carbon-Dioxide Sequestration in Aquifers

The flow of formation waters in Alberta's subsurface 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. Injection of $CO_2$ in local flow systems is not recommended because these are shallow, have a relatively short travel time, and have temperatures and pressures at which $CO_2$ is in gaseous phase. Under these conditions, $CO_2$ will most likely rise to the top of the aquifers, migrate updip and may escape at outcrop back into the atmosphere. In addition, the injected $CO_2$ may contaminate shallow groundwater resources. Thus, $CO_2$ sequestration in aquifers is not recommended for any Cretaceous aquifers (**Mannville Group**) in northeastern Alberta. For similar reasons, sequestration of $CO_2$ is not recommended in the **Belly River**, **Horseshoe Canyon, Scollard,** and **Paskapoo** formations in southwestern Alberta, and in the **Milk River** aquifer in southern Alberta (Figure 5).

Sequestration of $CO_2$ by injection into intermediate flow systems is not recommended either, because these systems are located at shallow to intermediate depths and $CO_2$ will most likely be unstable (change phase from liquid or supercritical to gas) and may easily override and escape into local flow systems. Such is the case with the Devonian aquifers (Figure 6) in northern and northeastern Alberta (Bachu, 1997, 1999).

Regional-scale flow systems are primary targets for $CO_2$ sequestration in aquifers. In northern Alberta, the flow is driven by topography from recharge in the west, at the edge of the deformed basin, to discharge under a thin Quaternary cover in the northeast, along the Precambrian Shield (Figures 28 and 29A; Bachu, 1997). Sequestration of $CO_2$ is possible in **Devonian** and **Carboniferous** aquifers in northwestern Alberta, where it will be in supercritical state (west of both the 31.1ºC isotherm and the 7.38 isobar, Figures 11 to 16).

The other basin-scale flow system in Alberta is from recharge in the south, at the outcrop of Devonian and Carboniferous aquifers in Montana, to discharge at the outcrop of the Grosmont aquifer along the Peace River (Figure 28; Bachu, 1999). Because this flow system is shallower than the others and runs in eastern Alberta along the pre-Cretaceous unconformity (Figures 28 and 29b), $CO_2$ injection into the aquifers forming this system is possible, although not optimal. The main reason is that Devonian regional sealing aquitards are absent due to pre-Cretaceous erosion, thus creating communication paths between various aquifers along the unconformity and

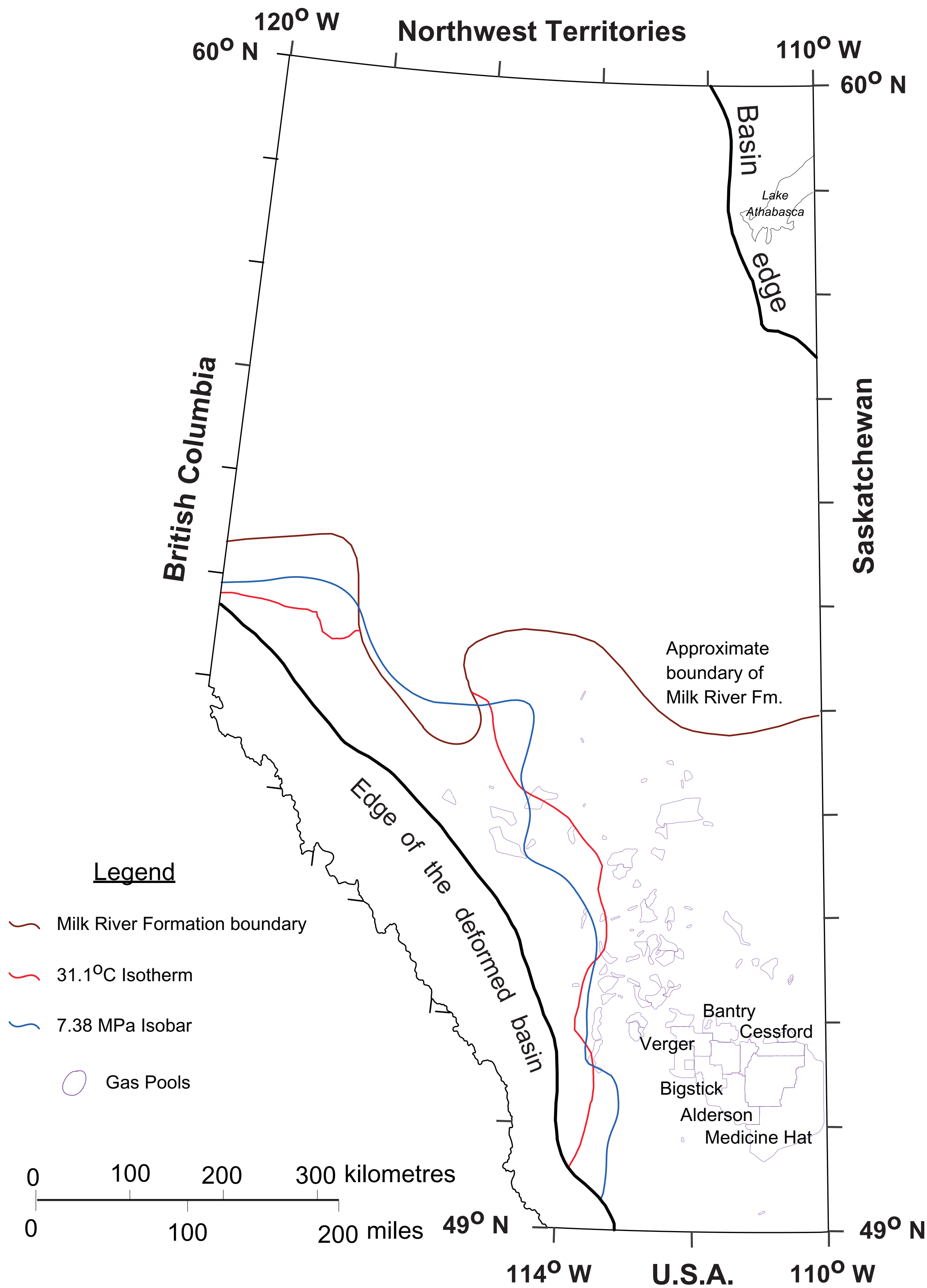



Figure 25: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Milk River Formation.

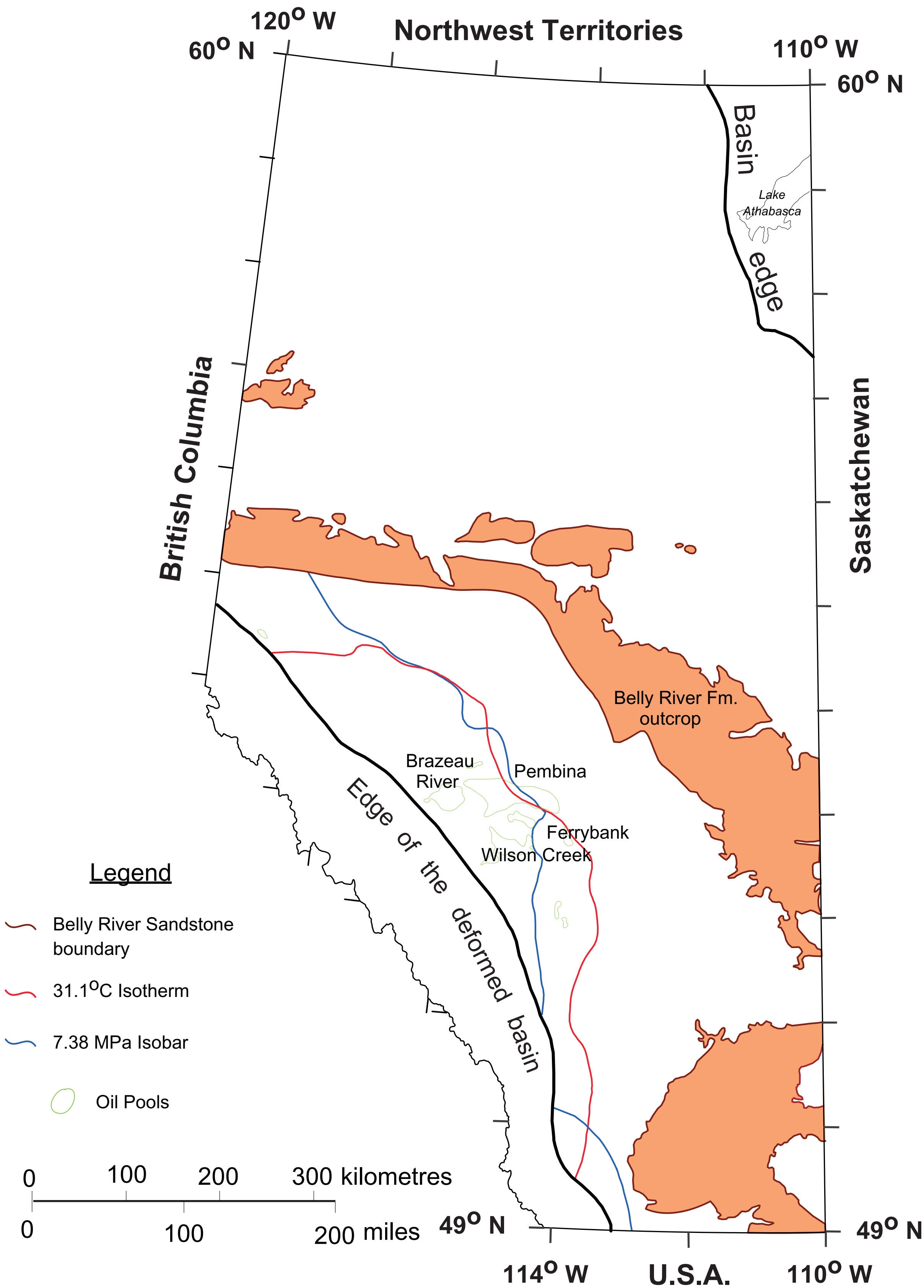



Figure 26: Position of the 31.1°C isotherm and the 7.38 MPa isobar at the top of the Belly River Sandstone.

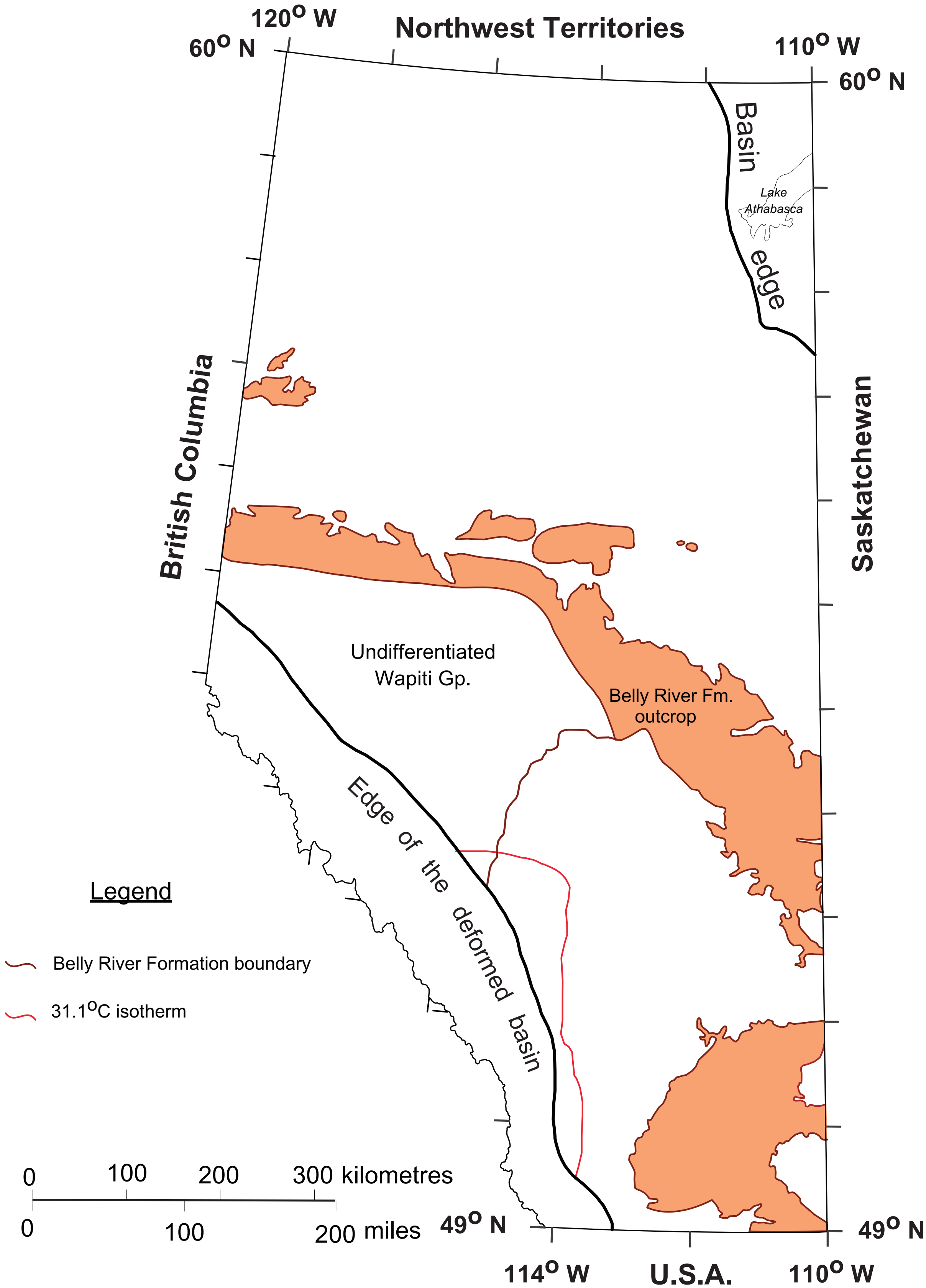



Figure 27: Position of the 31.1$^{O}$C isotherm at the top of the Belly River Formation.

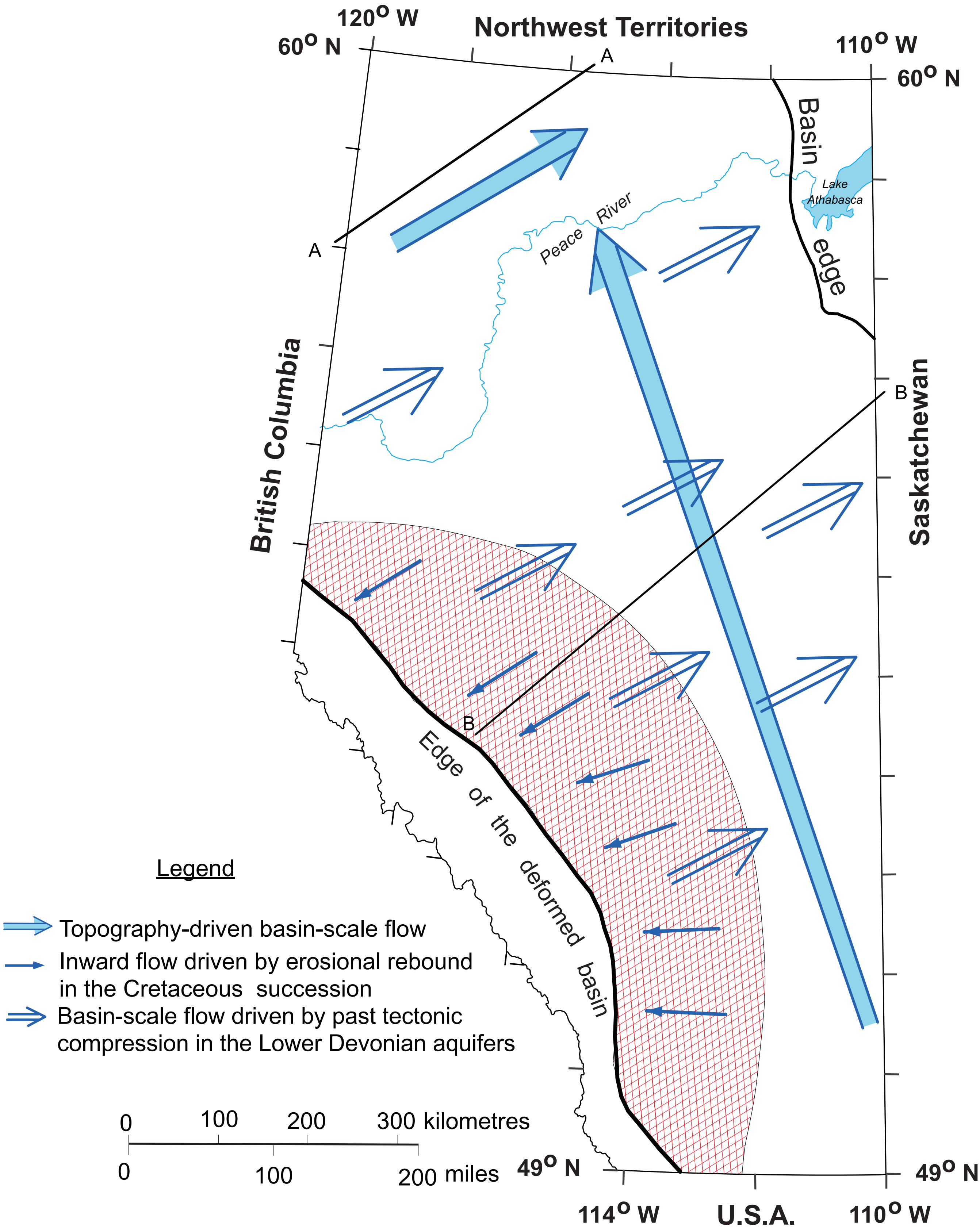



Figure 28: Plan-view diagrammatic representation of the flow systems and pattern in Alberta's subsurface. Lines of cross sections refer to Figure 29.

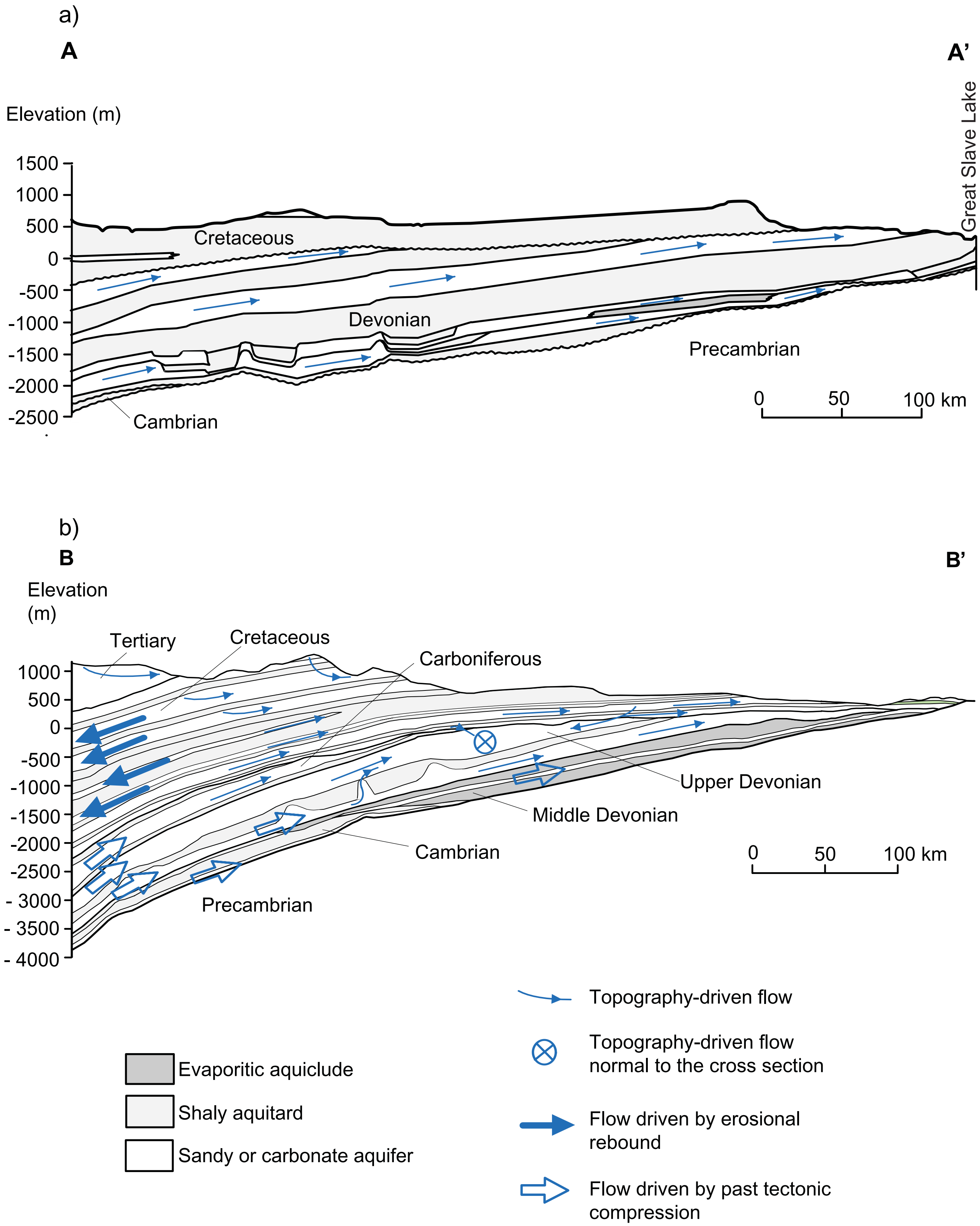



Figure 29: Diagrammatic representation in cross section of the flow systems and flow pattern in Alberta's subsurface: **a)** in the northern part, and **b)** in the south-central part. The locations of the hydrostratigraphic cross-sections are shown in Figure 28.

allowing the upward flow of $CO_2$. In addition, because of pressures and temperatures less or slightly greater than 7.38 MPa and 31.1ºC, respectively (Figures 11 to 16, and 19), $CO_2$ will be either a gas or a liquid significantly lighter than formation waters. It will override at the top of the aquifers and flow updip to the east-northeast, driven by buoyancy, rather than to the north along the system flow path. However, $CO_2$ will be trapped by the thick, competent, regional-scale Clearwater and Colorado aquitards.

Flow driven by erosional rebound is present in Cretaceous strata in the southwestern part of Alberta (Bachu, 1999), in the sandstone-dominated **Mannville, Viking, Second White Speckled Sandstone,** and **Cardium** aquifers (Figures 5, 28, and 29b). The flow in these aquifers is driven inward, downdip to the west-southwest, toward the edge of the deformed basin. These aquifers, which are severely underpressured (Bachu, 1999), are primary targets for $CO_2$ sequestration in southwestern Alberta. Because of their depth, $CO_2$ will be in supercritical state in these formations (Figures 20 to 23). The thick intervening shale beds of the Colorado Group form regional-scale confining aquitards that combine with the downdip flow of formation waters to form a powerful hydrodynamic trap for the injected $CO_2$.

In the deep part of the Alberta Basin in the southwestern part of the province, the flow of formation waters in the **Cambrian Basal Sandstone, Winnipegosis, Middle** and **Upper Devonian,** and **Mississippian-Jurassic** aquifers and aquifer systems (Figure 5) is updip northeastward (Figures 28 and 29b), assumed to be driven by past tectonic compression (Bachu, 1999). Up to their respective eastern erosional or depositional boundaries, all these aquifers are separated from recharge areas by intervening strong aquitards or aquicludes, and by the overlying underpressured and overpressured aquifers in the Cretaceous sedimentary succession (Bachu, 1999). These aquifers are also primary targets for $CO_2$ sequestration because of good confinement and very long retention time. Carbon dioxide injected into these aquifers in the southwest will be in supercritical state (Figures 9 to 16).

## 5 Carbon-Dioxide Sequestration in Coal Beds

In the Alberta plains, coal seams of variable thickness, maturity, and quality (Smith et al., 1994) occur in Lower Cretaceous (Upper Mannville), Upper Cretaceous (Belly River, Horseshoe Canyon, Scollard), and Tertiary (Scollard, Paskapoo) strata (Figure 5). Coal seams are up to 6 m in thickness and have a gas content that varies between 2 and 15 $m^3$/t (Dawson, 1995). The erosional (outcrop) boundaries of the coal-bearing Belly River, Horseshoe Canyon, and Scollard formations are shown in Figure 30. The coal beds vary in rank with depth from lignitic to bituminous (Figure 31). The Upper Mannville coal beds are generally thin and mature, and reach depths greater than 3000 m in the western part of the basin, close to the thrust and fold belt, where temperatures and pressures are higher than 31.1ºC and 7.38 MPa, respectively (Figure 21). Carbon dioxide can be injected into Upper Mannville coal beds in this area in supercritical state, although the behaviour of supercritical $CO_2$ in coal is not well known. In southeastern Alberta (south of approximately 51.5ºN), where temperatures are less than 31.1ºC and pressures are greater than 7.38 MPa (Figure 21), $CO_2$ can be injected as a liquid. In east-central Alberta, where Upper Mannville strata are shallower and in situ temperatures are less than 31.1ºC and pressures are less than 7.38 MPa (Figure 21), $CO_2$ can be injected mostly as a gas. Significant coal deposits are found in the Upper Cretaceous Belly River, Horseshoe Canyon, and Scollard formations. The

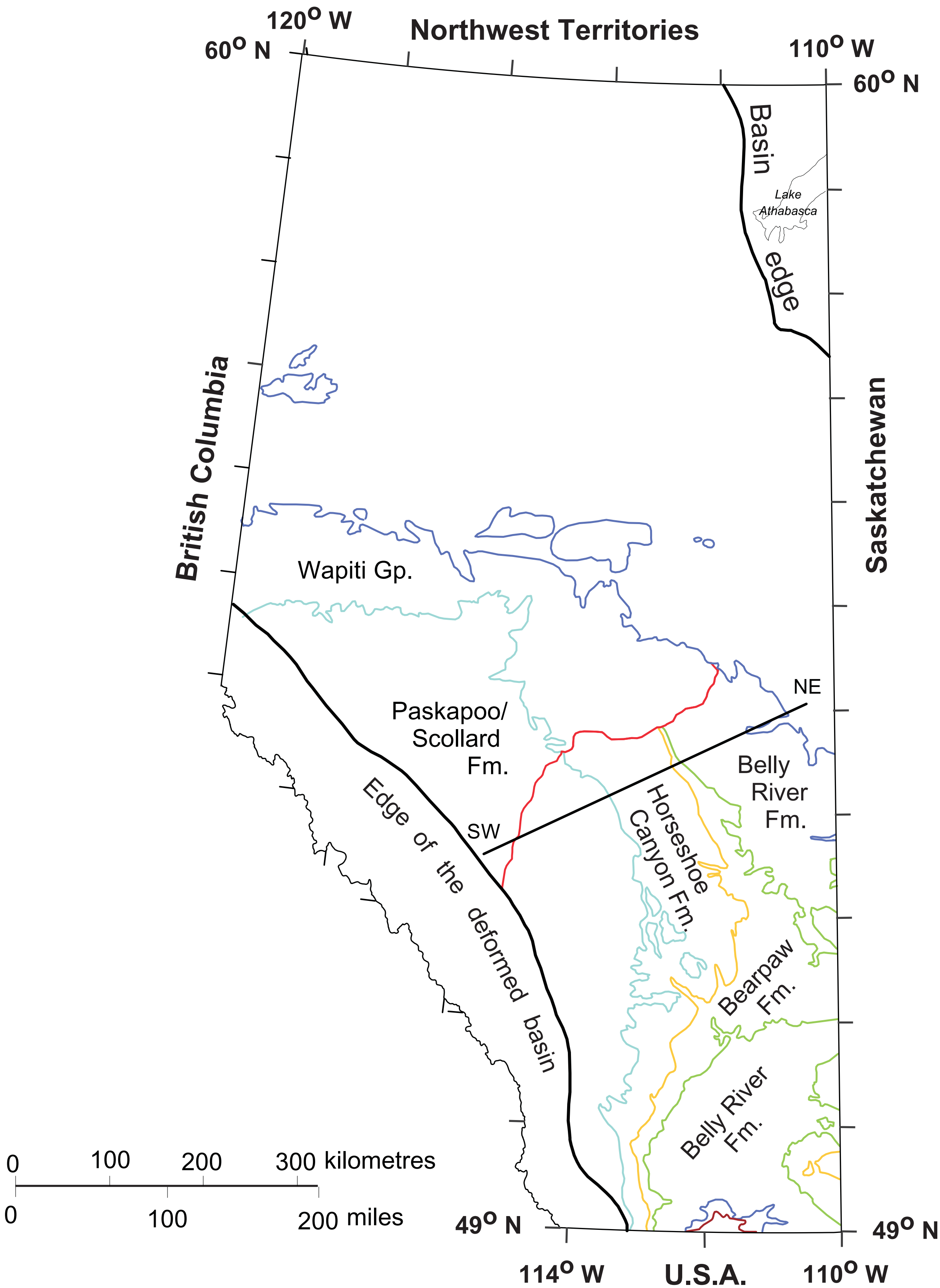



Figure 30: Outcrop boundaries of Upper Cretaceous and Tertiary coal-bearing strata in Alberta. Line of the cross section SW-NE refers to Figure 31.

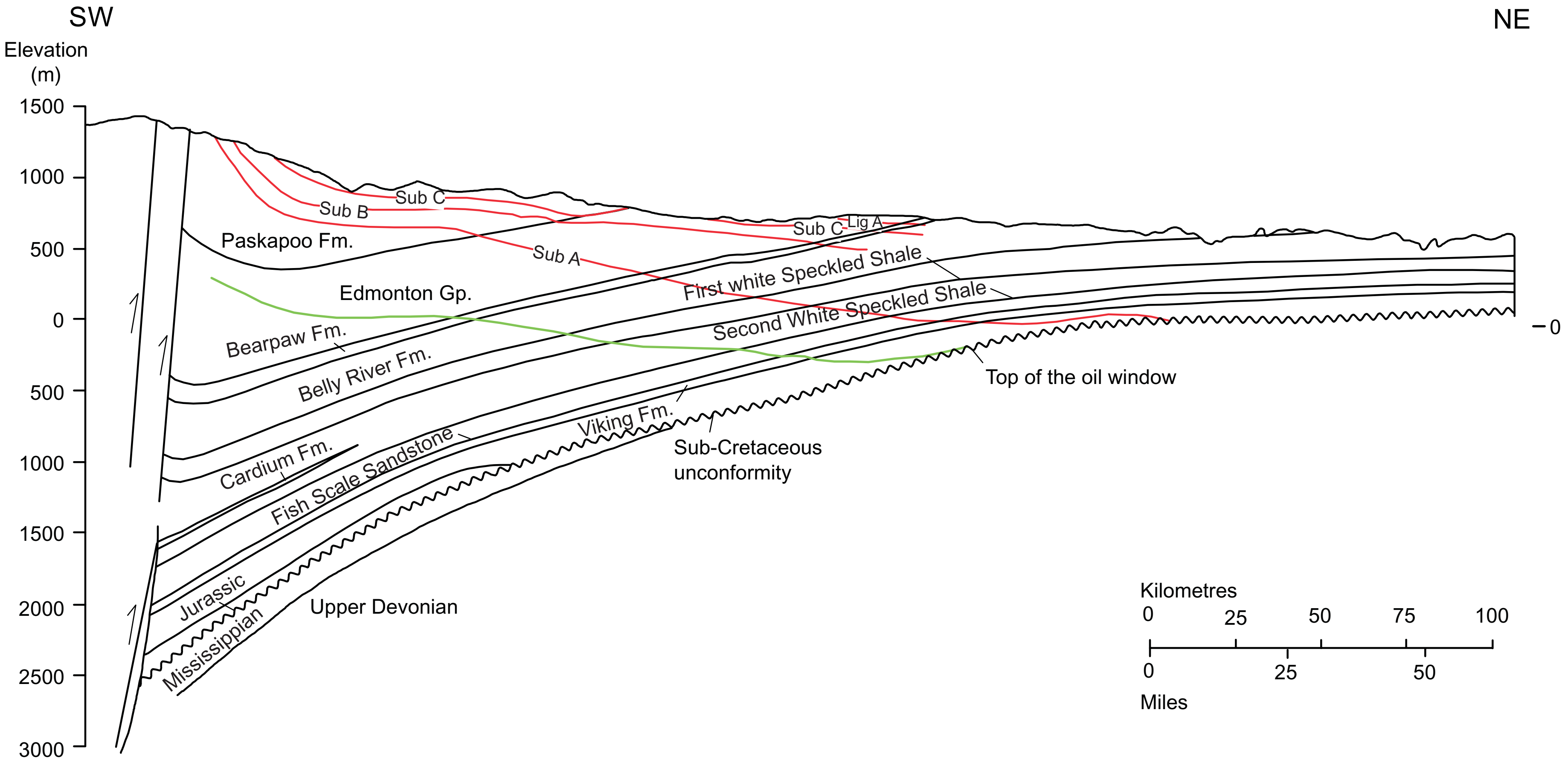



Figure 31: Coal maturity (red) in Cretaceous strata above the oil window (green) along a dip cross-section (SW-NE in Figure 30) in southern Alberta (after Bustin, 1991).

intervening Bearpaw Formation is absent in the west-central part of the Alberta Basin and the entire succession is known as the Wapiti Group (Figure 27). Except for the extreme southwestern part of the Belly River Formation, temperatures in the Upper Cretaceous to Tertiary coal-bearing strata in Alberta are less than 31.1ºC (Figure 27) and pressures are less than 7.38 MPa. Thus, $CO_2$ can be injected into these strata in either liquid or gas phase, depending on pressure.

Large volumes of coal in Alberta are deemed as either uneconomic for thermal or metallurgical purposes, or outright unmineable because of their depth. However, they may contain significant coalbed methane resources. Total coalbed methane resources in the Mannville strata are estimated to be on the order of 4.5 trillion $m^3$ (Langenberg et al., 1997), while the Ardley coal zone (Wapiti Group) may contain 2.8 trillion $m^3$. These coal zones can therefore be used for coal-bed methane production and $CO_2$ sequestration (Gunter et al., 1997). Preliminary estimates show that Alberta's coal beds have the potential for sequestering 8.6 trillion t (Gt) of $CO_2$ (Stevens et al., 1999).

## 5.1 Coal Permeability

Geological and reservoir conditions must be favourable for the application of $CO_2$ sequestration in enhanced coalbed methane recovery ($CO_2$-ECBMR) technology, because most coal deposits have unfavourably low permeability (Stevens et al., 1999). Reservoir temperature and pressure control the $CO_2$ state, and coal-gas content controls the $CO_2$ adsorption capacity and methane production. However, the most important parameter in $CO_2$-ECBMR is coal permeability, because it controls $CO_2$ injectivity. Currently there are no permeability measurements of coal seams in Alberta because 1) the oil and gas industry has no interest in testing coal seams, since methane is not being produced from coal beds; and 2) the coal-mining industry has no such need. However, if no tests are available, coal permeability can sometimes be inferred from the stress regime of the coal-bearing strata. Laboratory measurements and field tests on coal samples from depths of 66 to 702 m in the Sydney Basin of Australia (Enever, 1995; Bustin, 1997) indicate a strong dependency of coal permeability on effective stress (Figure 32), in addition to the dependency on coal composition and fracturing (Bustin, 1997). Laboratory measurements indicate lower permeability than the in situ tests (Figure 32), this being attributed to scale effects relating to testing on small plugs that have less fracture interconnectivity than the in situ coal seams (Bustin, 1997). The coal samples with a well-developed fracture set have higher permeabilities than those that contain significant authigenic mineralization (Bustin, 1997). The dependency of permeability of the two groups of coal samples on the effective stress ($\sigma_3$ - $P_o$) can be described by the following empirical relations, developed on the basis of the laboratory measurements on coal samples collected by Bustin (1997) in the Sydney Basin.

For low-permeability, poor-quality coal,

$$\log k = 6.896 - 3.1625(\sigma_3 - P_o) \qquad (R^2 = 0.9899) \qquad (2)$$

and for high-permeability, good-quality coal,

$$\log k = 3 - 5.5981(\sigma_3 - P_o) \qquad (R^2 = 0.9994) \qquad (3)$$

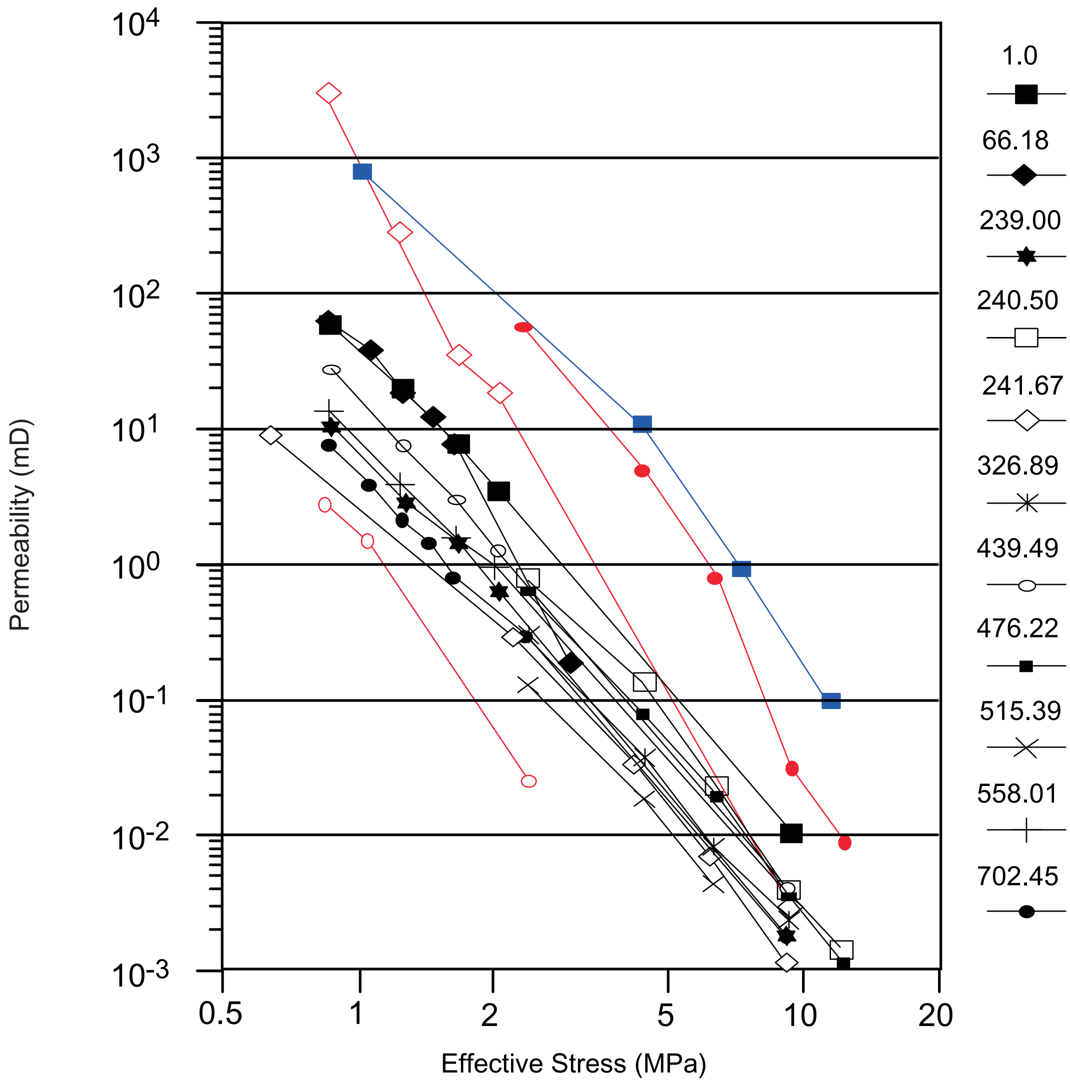



Figure 32: Variability of coal permeability with effective stress in the Sydney basin, Australia based on: **a)** laboratory measurements on poor-quality coals (black), **b)** laboratory measurements on good-quality coals (red), and **c)** field tests (blue).

where k is permeability (mD[1]), $\sigma_3$ is the smallest principal stress (MPa), and $P_o$ is pore pressure (MPa). Figure 32 also indicates that coal permeability, as measured in the laboratory, depends not only on the effective stress to which the sample was subjected, but also on the depth from which the sample originated. For the same effective stress, the permeability of deeper coal beds is less than that of shallower ones. In the field, particularly in the plains, one of the principal stresses is approximately vertical (denoted by $S_V$). Generally, the minimum stress in sedimentary basins is one of the horizontal principal stresses; therefore, the smallest principal stress ($\sigma_3$) measured in laboratory becomes the smaller horizontal stress ($S_{Hmin}$). As with the laboratory data, Enever's (1995) in situ data (Figure 32) for the Sydney Basin can be approximated by the following empirical relation:

$$\log k = 3.4 - 0.4(S_{Hmin} - P_o) \qquad (4)$$

A similar dependency of coal permeability on the in situ effective stress was found by Enever et al. (1994) for coal seams 300 to 750 m deep in the Bowen Basin, Australia (Figure 33a):

$$\log k = 6.221 - 0.84465(S_{Hmin} - P_o) \quad (R^2 = 0.8407) \qquad (5)$$

The same study (Enever et al., 1994) showed that, for the same depth, the minimum horizontal stress, $S_{Hmin}$, is lower by approximately 40 per cent in coal seams than in the adjacent siliciclastic sedimentary rocks (Figure 33b). These studies indicate that the smallest principal stress $S_{Hmin}$ appears to be the major control on coal seam permeability. Sparks et al. (1995) have shown a similar dependency of coal permeability on minimum effective stress ($S_{Hmin}$ - $P_o$) for the Black Warrior Basin in Alabama, where methane is commercially produced from coal beds (Figure 34). This dependency can be approximated by the following relation:

$$\log k = 0.93 - 0.0793(S_{Hmin} - P_o) \quad (R^2 = 0.85) \qquad (6)$$

which shows a milder decrease of permeability with minimum effective stress than for the Australian basins.

## 5.2 Stress Distribution in Upper Cretaceous to Tertiary Strata

The dependence of coal permeability on stress indicates that the coal seams in areas characterized by lower stresses probably have higher permeability, and therefore higher $CO_2$ injectivity, than those in areas subjected to higher stresses. Thus, coal seams in these lower stress areas would be a prime target for $CO_2$ sequestration and methane production. The distribution of the vertical stress ($S_V$), which is controlled by the weight of the overburden, was calculated for the Upper Cretaceous to Tertiary coal-bearing strata in Alberta on the basis of density logs in 13 wells that reach the base of the sedimentary succession. Figures 35 and 36 show the areal distribution of the vertical stress ($S_V$) at depths of 500 and 1000 m, respectively. The magnitude of $S_V$ increases generally to the southwest, running subparallel to the Mesozoic deformation front of the basin, probably as a result of greater burial in the southwest at the peak of the Tertiary

[1] The millidarcy (mD) is not an accepted SI unit. It has been retained here because of its long-standing and widespread use in the oil industry. For those who wish to convert to the appropriate SI unit, the conversion factor is 1 mD = $9.869233 \times 10^{-15}$ $m^2$.

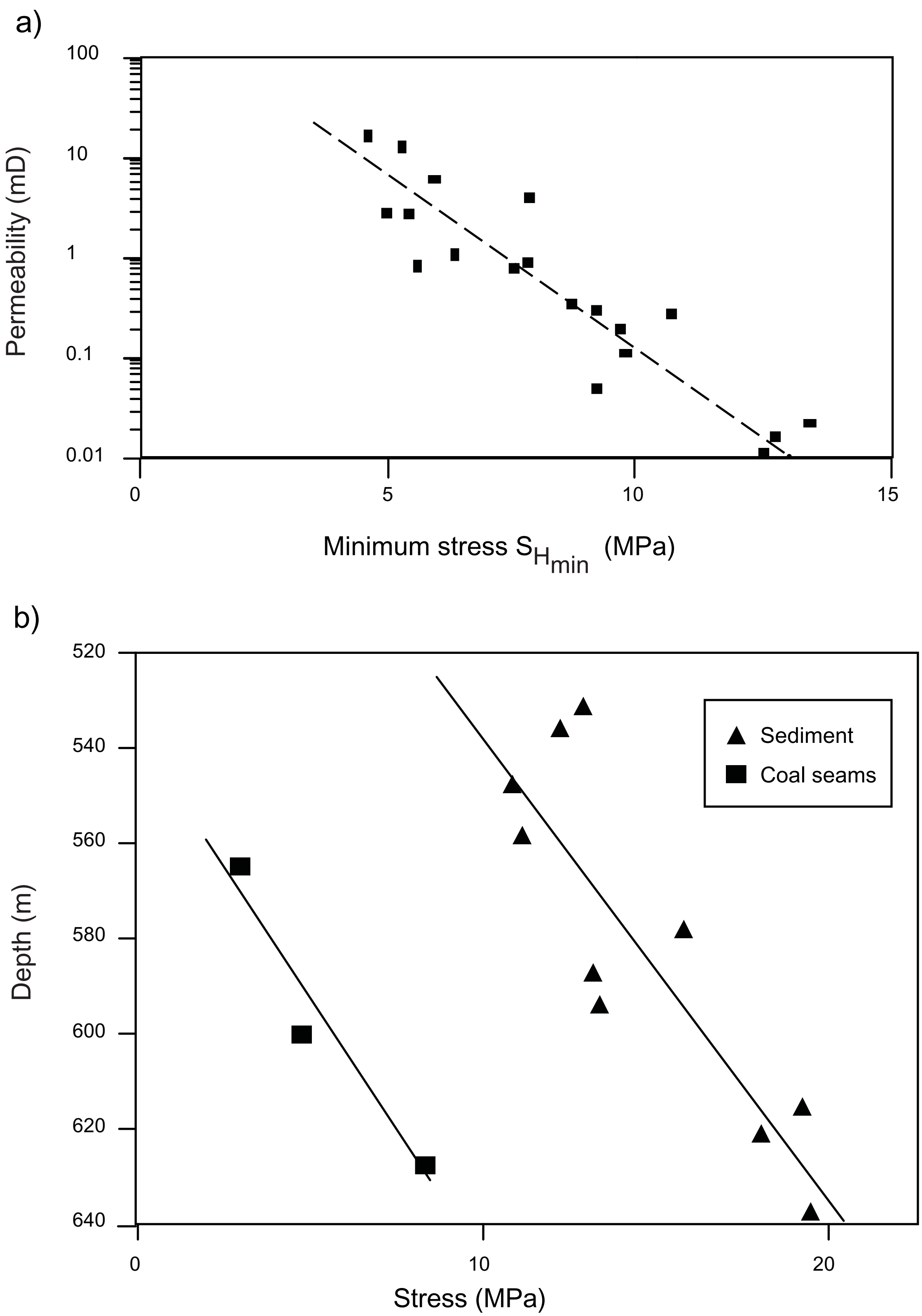



Figure 33: Relationships between coal permeability and stress in the Bowen basin, Australia: **a)** permeability and minimum stress $S_{H_{min}}$, and **b)** stress and depth for coal beds and adjacent sediments.

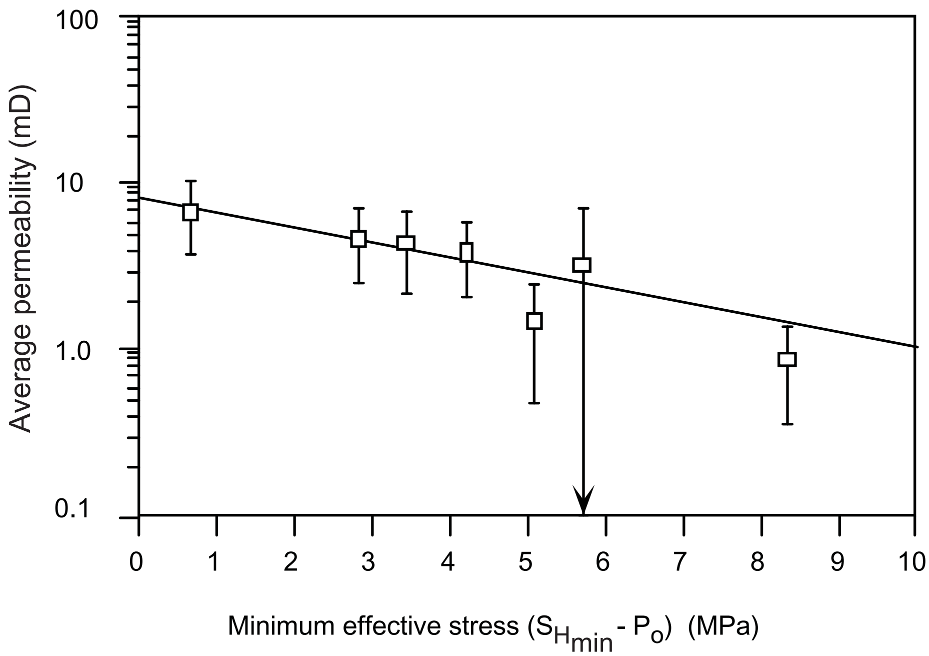



Figure 34: Variability of coal permeability with effective minimum stress ($S_{H_{min}}$ - $P_o$) in the Black Warrior Basin, Alabama.

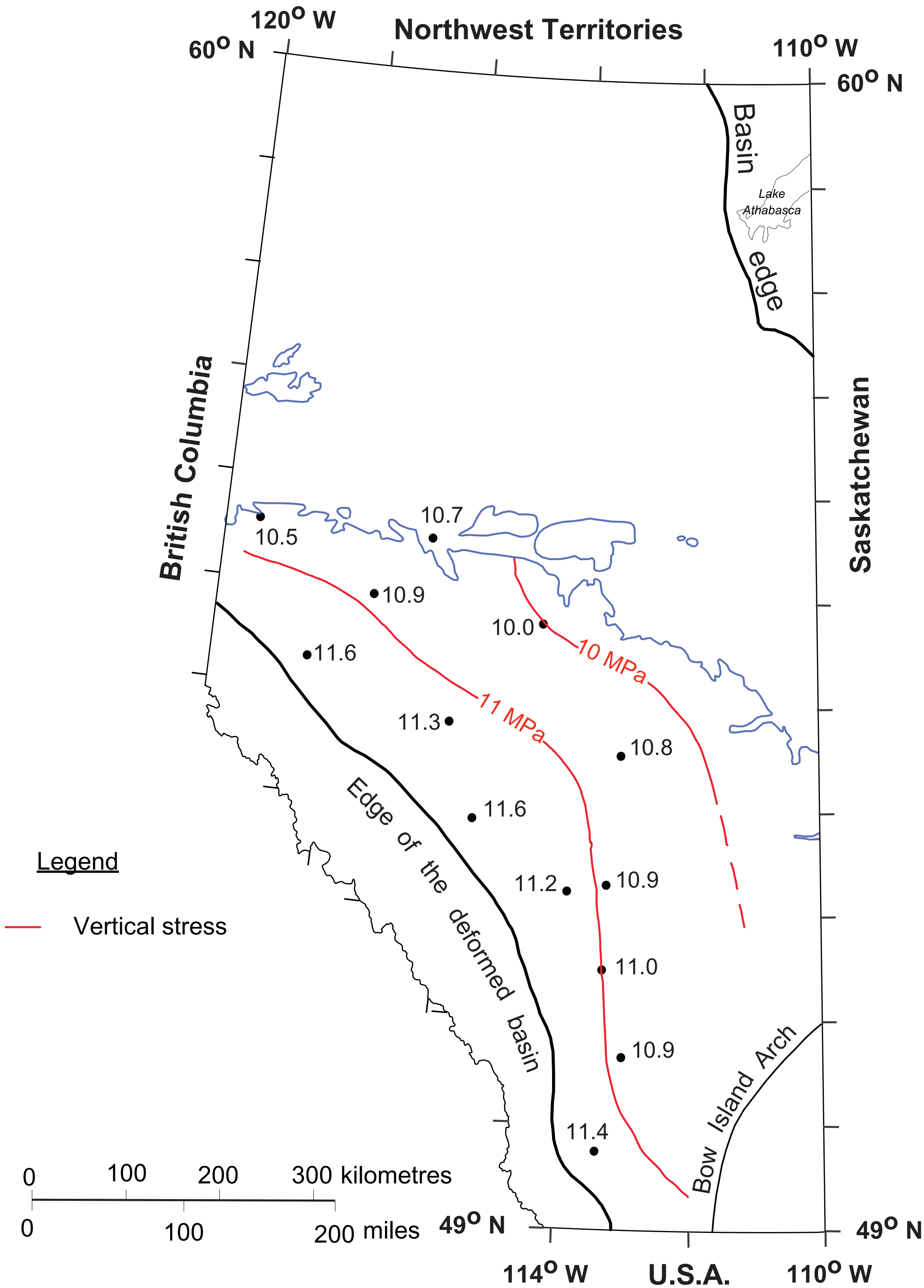



Figure 35: Distribution of vertical-stress magnitude $S_V$ in Upper Cretaceous to Tertiary strata in Alberta at 500 m depth.

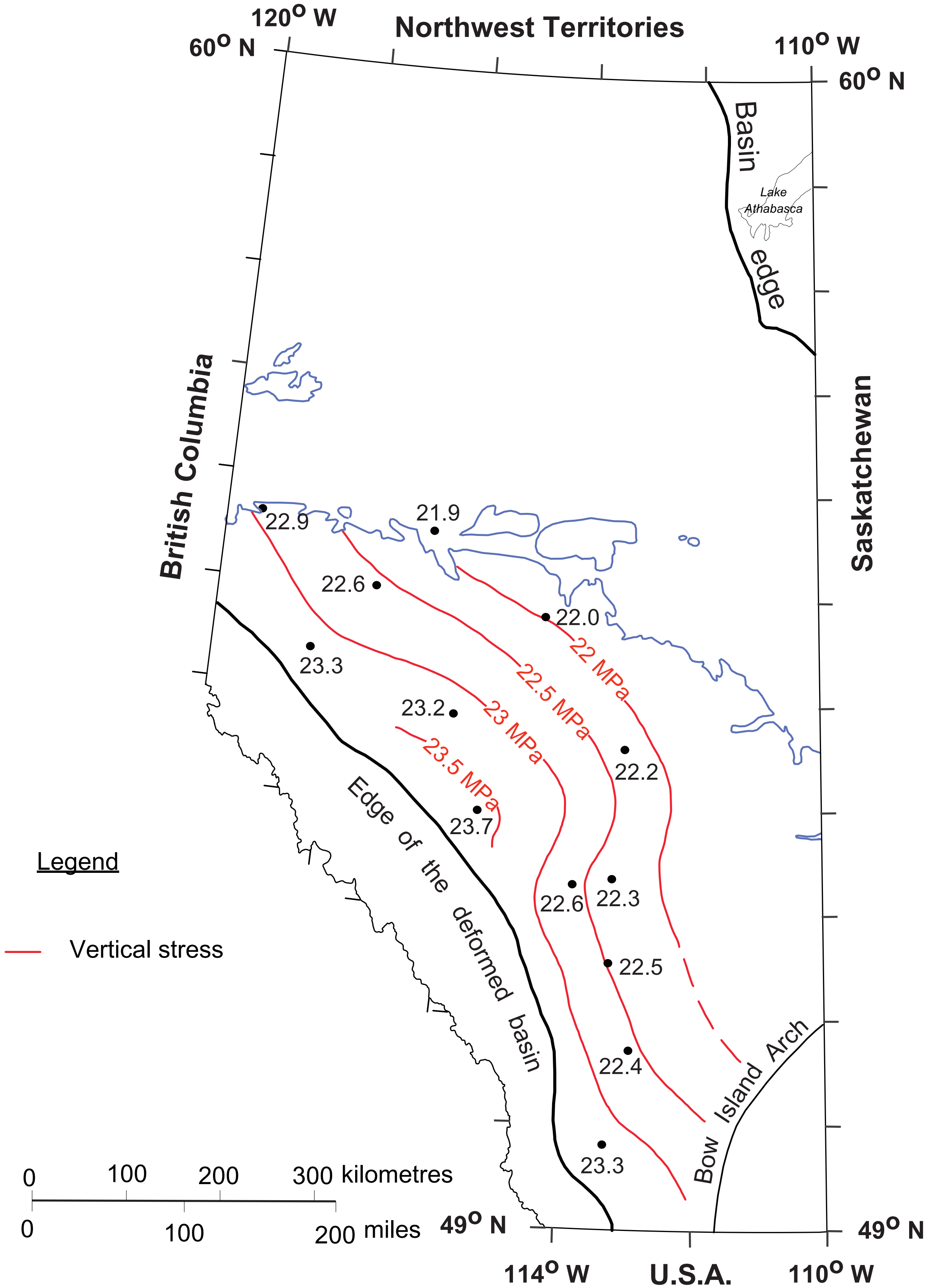



Figure 36: Distribution of vertical stress-magnitude $S_V$ in Upper Cretaceous to Tertiary strata in Alberta at 1000 m depth.

Laramide orogeny (Nurkowski, 1984; Bustin, 1991) and greater lateral (tectonic) compression of rocks closer to the overthrust belt (Bell and McLellan, 1995).

Previous regional-scale work (Bell et al., 1994) suggests that the minimum horizontal stress ($S_{Hmin}$) is the smallest of the three principal stresses in the Alberta Basin. No stress measurements have been conducted, to date, specifically for Alberta's coal seams. However, $S_{Hmin}$ can be estimated by using data from hydraulic fracture tests in oil and gas reservoirs in the adjacent sandstone strata. The distribution of $S_{Hmin}$ was calculated on the basis of 1) fracture-closing pressures in 42 micro- and minifracture tests, and 2) fracture-opening pressures in 29 leak-off tests and 57 fracture-breakdown pressures recorded during massive reservoir fracturing. Cases yielding a calculated stress gradient of less than 12.5 kPa/m were not considered because they represent closure pressure recorded in depleted reservoirs, or are simply records of fluids injected into the pore space with no fracturing taking place. Similarly, a few cases with a calculated stress gradient greater than 30 kPa/m were not used in the analysis because they probably reflect unusually high rock tensile strength rather than elevated stress magnitude. Shallow leak-off tests at depths less than 500 m were also not considered because they are not representative (Dahlberg and Bell, 1993). Closure pressures from micro- and minifracture tests record reliable stress magnitude. The stress gradients obtained from leak-off tests and fracture-breakdown pressures were normalized (adjusted) by a few per cent down to the stress values from micro- and minifracture tests by bringing their respective averages to the average value obtained from the latter. Minimum horizontal stresses ($S_{Hmin}$) at 1000 m depth, obtained from the stress gradients, were compared with the distribution of the vertical stress ($S_V$) at the same depth (Figure 36). In only 5 cases out of 128 was $S_{Hmin}$ greater than $S_V$. Three cases corresponded to abnormally high fracture-breakdown pressures that were probably caused by local high rock resistance to fracturing (high tensile strength), and were therefore rejected. Another case was due to a questionable leak-off test, and it was also rejected. The last case was found in an area where many other wells showed $S_{Hmin}$ less than $S_V$, and was considered a local anomaly.

Figure 37 presents the regional-scale distribution of the minimum horizontal stress gradient ($S_{Hmin}$/depth) in the Upper Cretaceous to Tertiary strata. It shows that $S_{Hmin}$ is indeed the minimum principal stress (i.e., compare $S_V$ in Figure 36 with $S_{Hmin}$ at 1000 m depth, which has the same numerical value as the stress gradient in Figure 37). Except for small, localized areas along the deformation front, $S_{Hmin}$ is relatively high ($S_{Hmin}$ gradient greater than 18 kPa/m) in the northwest and southeast, and along the Rocky Mountain Foothills (Figure 37). In these areas, the coal permeability is most likely to be quite low and therefore unfavourable for $CO_2$ injection. A low-stress region ($S_{Hmin}$ gradient less than 16 kPa/m) trends northwest-southeast, subparallel to the deformation front, from Twp 32 Rge 21 W4M to Twp 64 Rge 27 W5M. Coal permeability is likely to be higher in this region. The stress gradient reaches values as low as 12-13 kPa/m in two areas, one centred around Twp 36 Rge 24 W4M and the other around Twp 49 Rge 8 W5M (Figure 37). From the point of view of $CO_2$ injectivity, these two areas are probably the best target areas for $CO_2$ sequestration in coal beds. However, other site-specific conditions, such as coal depth, thickness, quality, and gas content (Stevens et al., 1999), should be considered when selecting a particular site for $CO_2$ sequestration in coal beds.

Data from 30 previous wells (Bell et al., 1994) and 5 new ones were used to identify the trajectories of the horizontal stresses ($S_{Hmax}$ and $S_{Hmin}$) in Cretaceous strata on the basis of

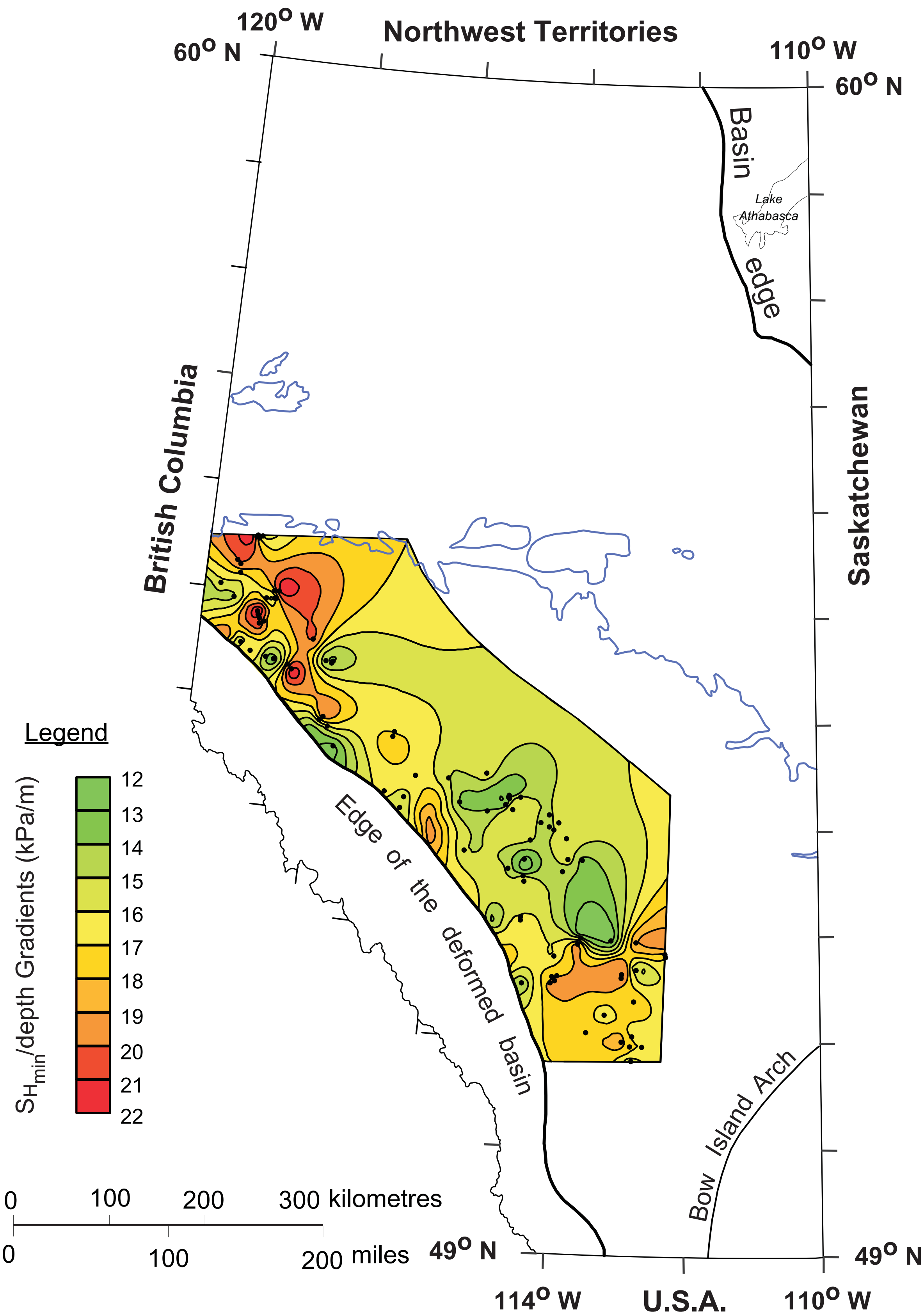



Figure 37: Distribution of the gradient of the minimum horizontal stress $S_{Hmin}$ in Upper Cretaceous to Tertiary strata in Alberta.

breakouts. The data were augmented with an additional 5 determinations from overcoring, well connectivity, anelastic strain recovery, differential strain analysis, and microseismic monitoring. Figure 38 presents the stress trajectories for the Upper Cretaceous strata in Alberta. The maximum horizontal stress ($S_{Hmax}$) is oriented in a southwest-northeast direction, almost perpendicular to the Rocky Mountain deformation front, suggesting that tectonic compression is the most likely cause of the horizontal stress regime in the Alberta Basin. The minimum horizontal stress ($S_{Hmin}$) has a trajectory that is subparallel to the deformation front. Based on information on coal-mine drive orientations in 133 townships in Alberta, Campbell (1979) identified that the coal-face cleats (major vertical fracture systems) are also oriented in a southwest-northeast direction, closely aligned with the present-day trajectory of the maximum horizontal stress ($S_{Hmax}$; *see* Figure 38). The coal-butt cleats (minor fractures) are oriented perpendicular to the face cleats, along the trajectory of the minimum horizontal stress ($S_{Hmin}$). The direction of horizontal stress trajectories and of coal-face and coal-butt cleats are important for designing the well pattern for a $CO_2$-ECBMR operation because the open fractures, usually aligned within 20º of the $S_{Hmax}$ axis (Figure 38) will tend to remain open during injection and allow the flow of $CO_2$ and methane.

## 6 Carbon-Dioxide Sequestration in Salt Caverns

Four major salt-bearing units, deposited in a restricted marine environment during the Middle Devonian, are present in the Alberta Basin. These units are, in ascending order the Lower and Upper Lotsberg salts, the Cold Lake Formation, and the Prairie Formation, all in the Elk Point Group. Their areal distributions and positions in the stratigraphic succession are shown in Figures 39, 5, and 6, respectively. The Lotsberg and Cold Lake salts are separated by red beds and argillaceous carbonate rocks (Figure 5). The Prairie salt and Muskeg anhydrite are underlain by the Winnipegosis and Keg River carbonate rocks, and overlain by the shale beds of the Watt Mountain Formation (Figures 5 and 6). Salt is mined from these units at various locations in Alberta for domestic and petrochemical use, and salt caverns are presently used for the storage of liquid petroleum products (Figure 40).

The Lower and Upper Lotsberg salts are found in east-central Alberta in an area defined approximately by Edmonton, Lloydminster, Cold Lake, and Athabasca River south of Fort McMurray. The salt in these units is of very high purity (greater than 90 per cent). The Lower Lotsberg salt is found at depths ranging from 2100 m in the west to 1100 m in the east (Figure 41), and varies in thickness from 0 m at its depositional edge to 60 m at the depocentre of the evaporitic basin near Cold Lake (Figure 42). The thickness of the intervening red beds between the Lower and Upper Lotsberg salts varies between approximately 30 and 65 m. The Upper Lotsberg salt is found at depths ranging from 2100 m in the west to 500 m in the northeast (Figure 43). It varies in thickness from 0 m at the depositional and erosional edge to more than 150 m in the east near Cold Lake (Figure 44). The total vertical stress induced by the weight of the overburden varies between greater than 48 MPa at 2100 m depth and greater than 11 MPa at the extreme northeast corner of the Upper Lotsberg salt. The 31.1ºC isotherm crosses the tops of the Lower and Upper Lotsberg salts in their eastern parts (Figures 42 to 44). Temperatures in these units west of this isotherm are higher than that of the $CO_2$ supercritical point. East of this isotherm, $CO_2$ reaches its supercritical state at varying depths below the formation top(s). Thus,

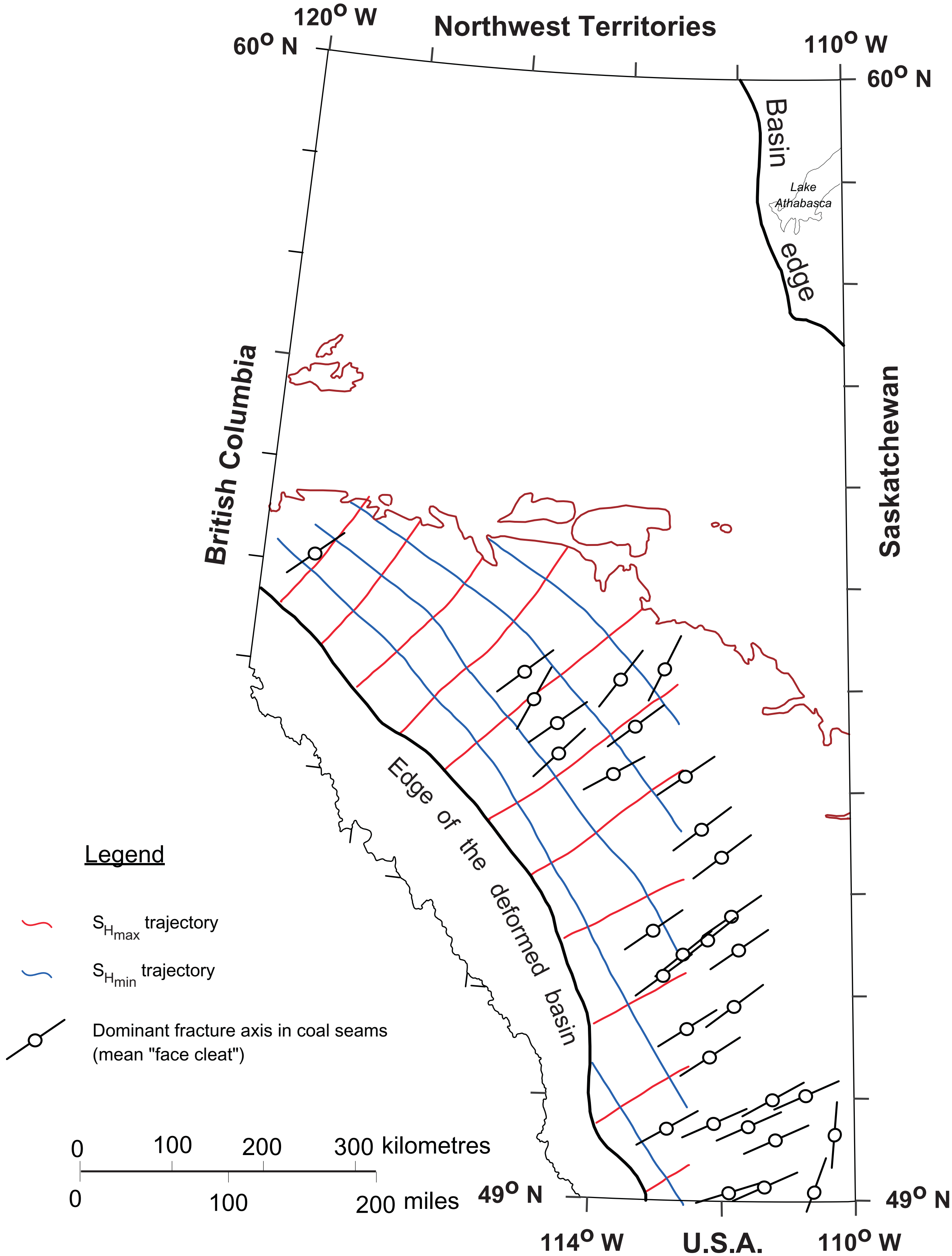



Figure 38: Trajectories of the main horizontal stresses $S_{Hmax}$ and $S_{Hmin}$ in Cretaceous strata in Alberta, and direction of coal-face cleats as observed in coal mines.

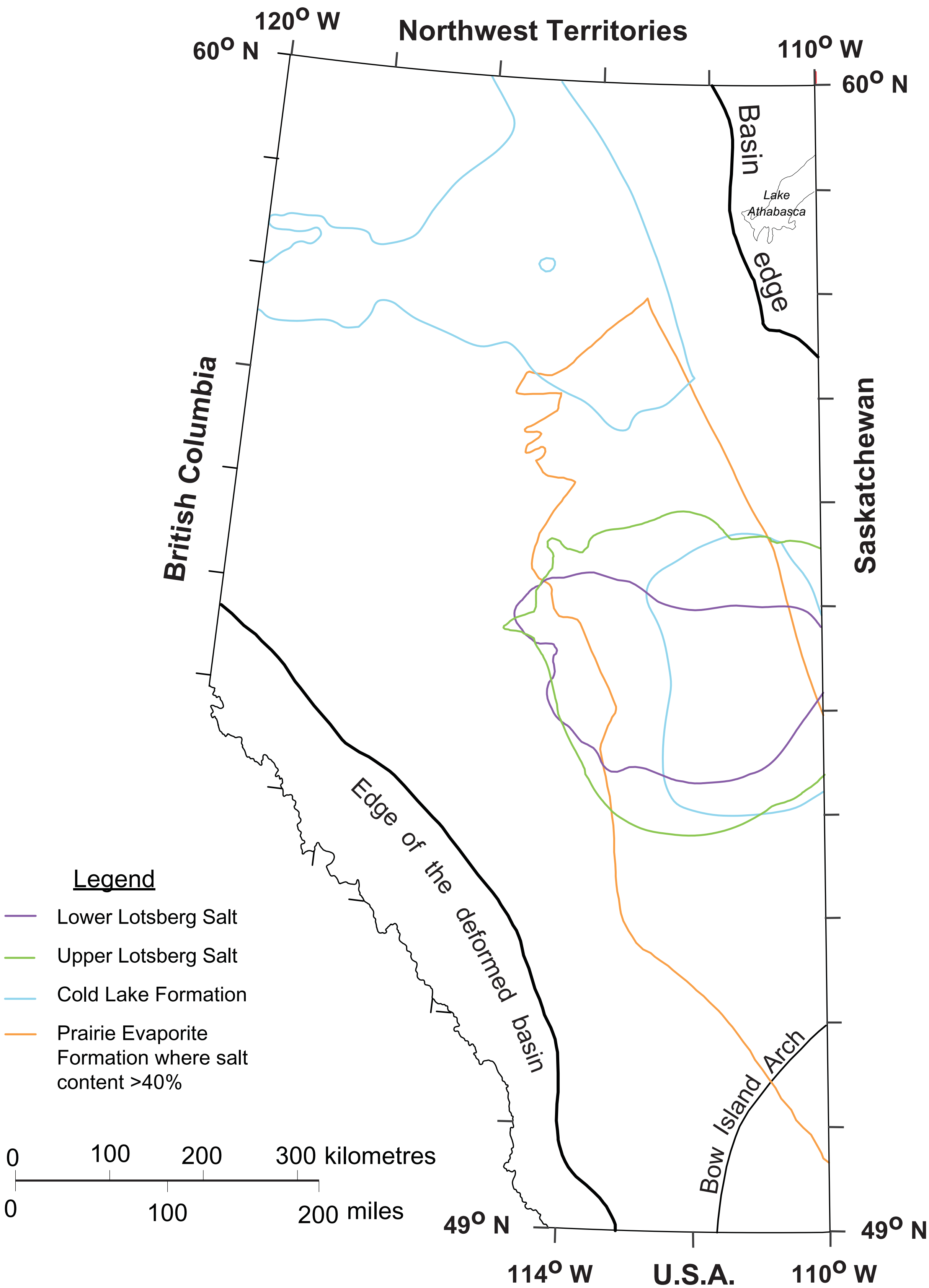



Figure 39: Distribution of Elk Point Group halite units in Alberta.

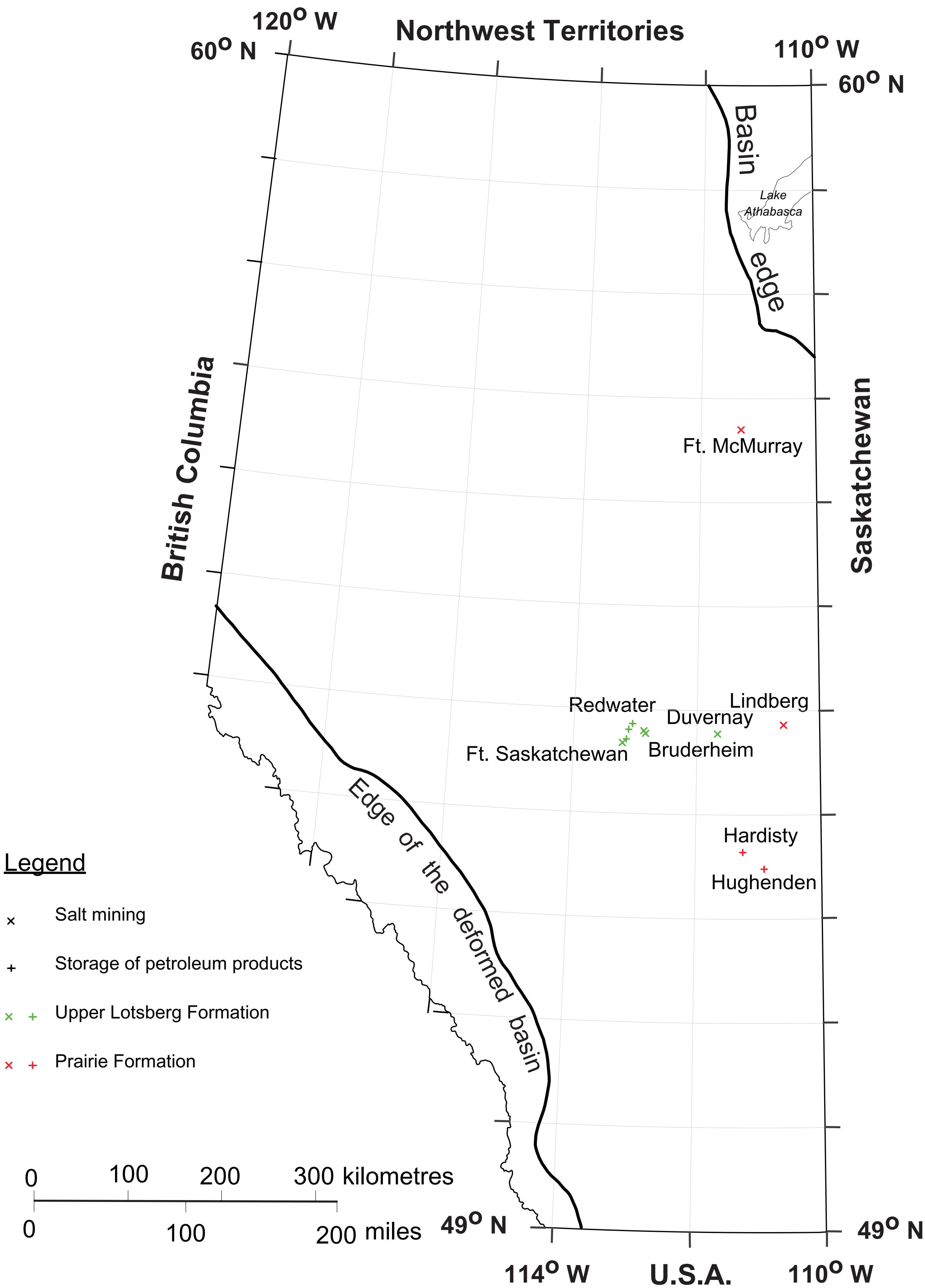



Figure 40: Location of salt caverns in Alberta.

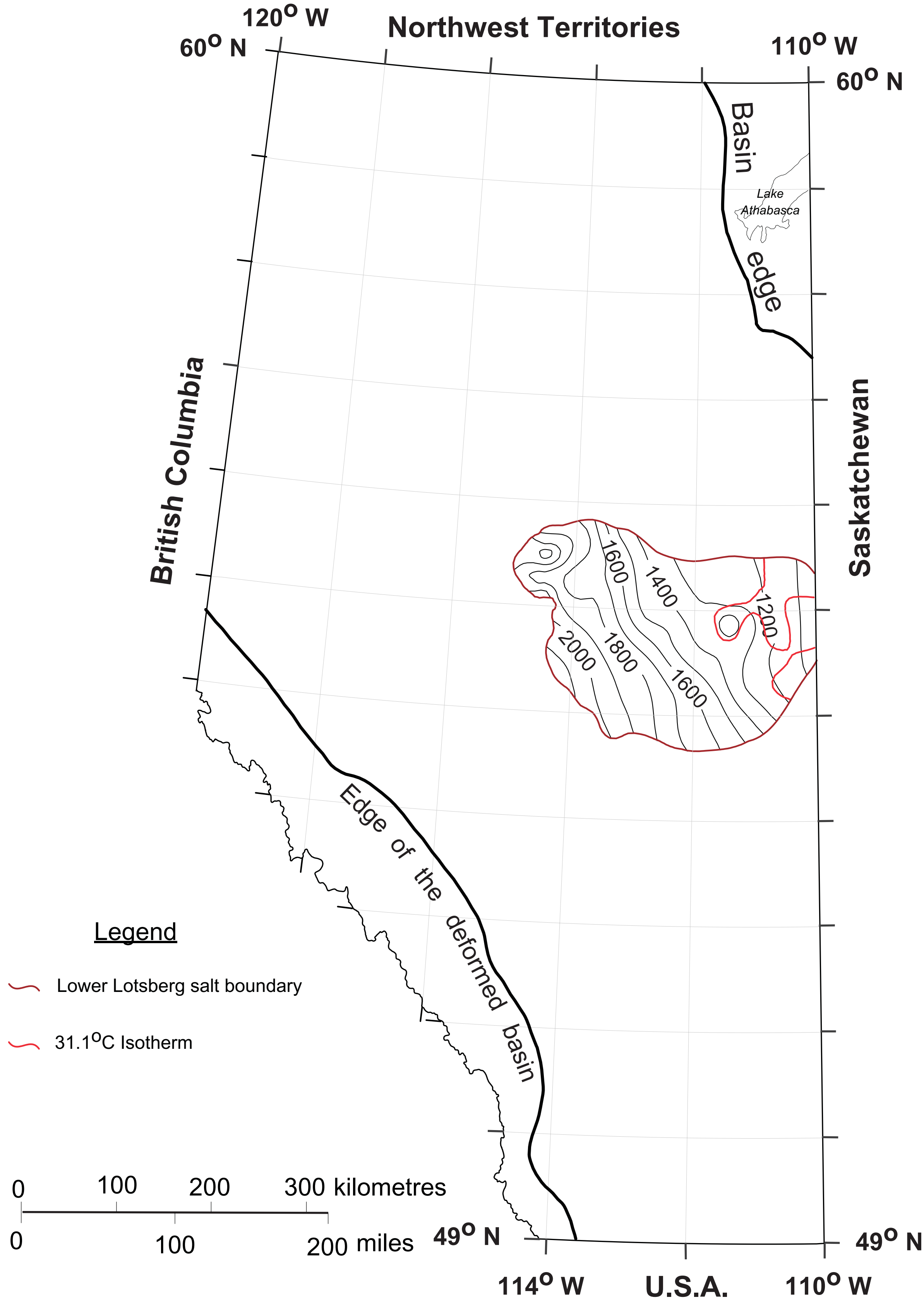



Figure 41: Depth (m) to the Lower Lotsberg salt.

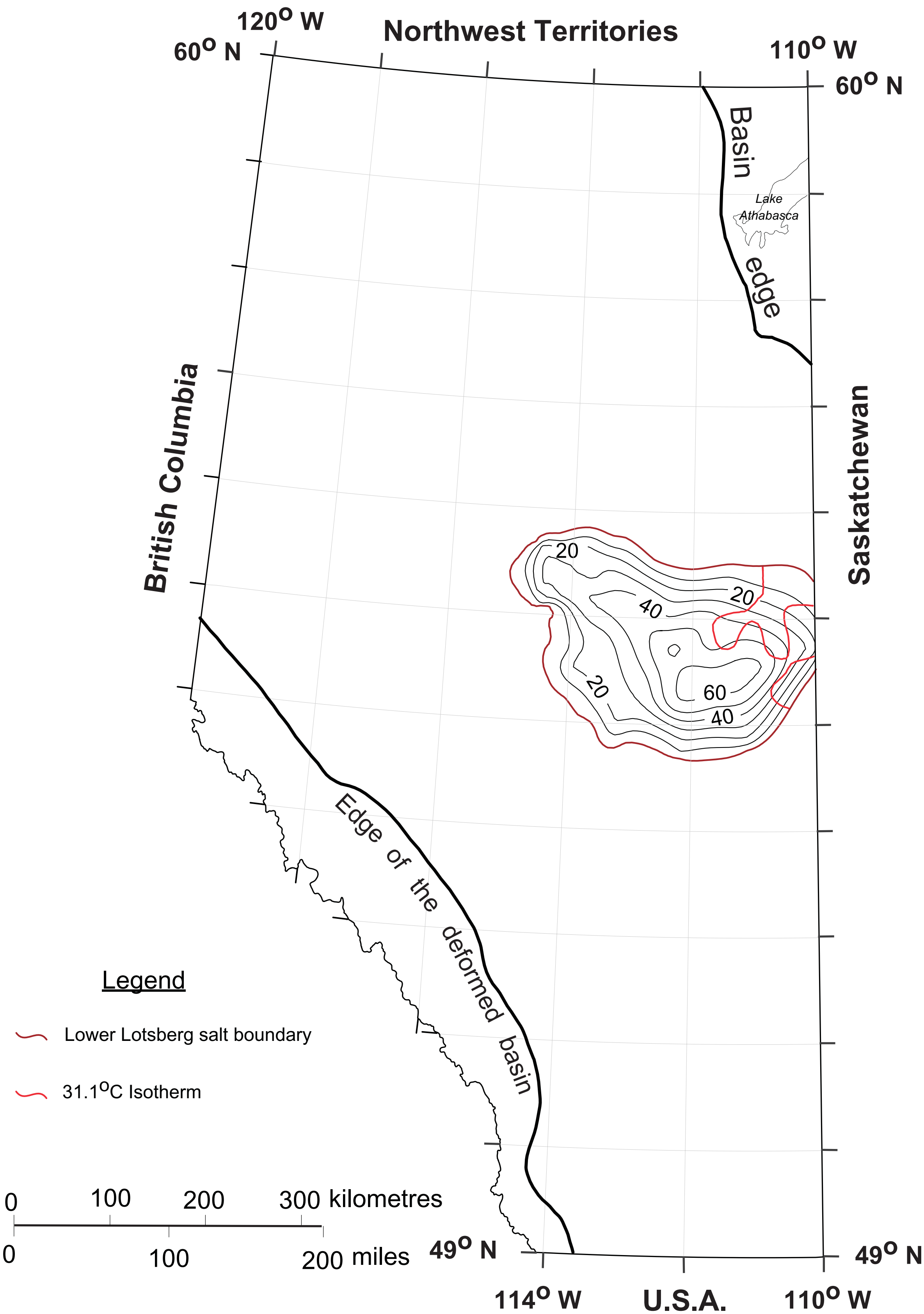



Figure 42: Isopachs (m) of the Lower Lotsberg salt.

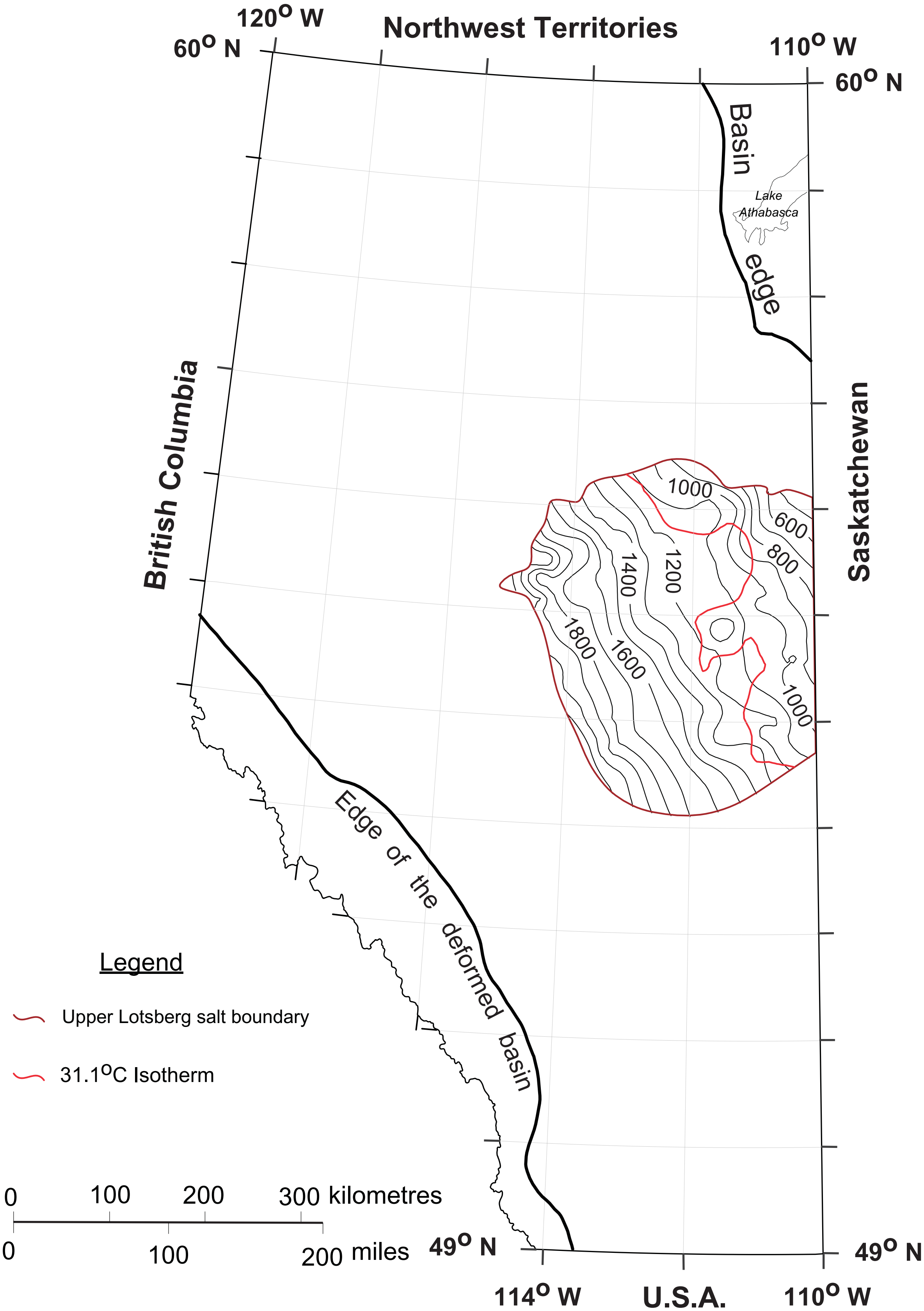



Figure 43: Depth (m) to the Upper Lotsberg salt.

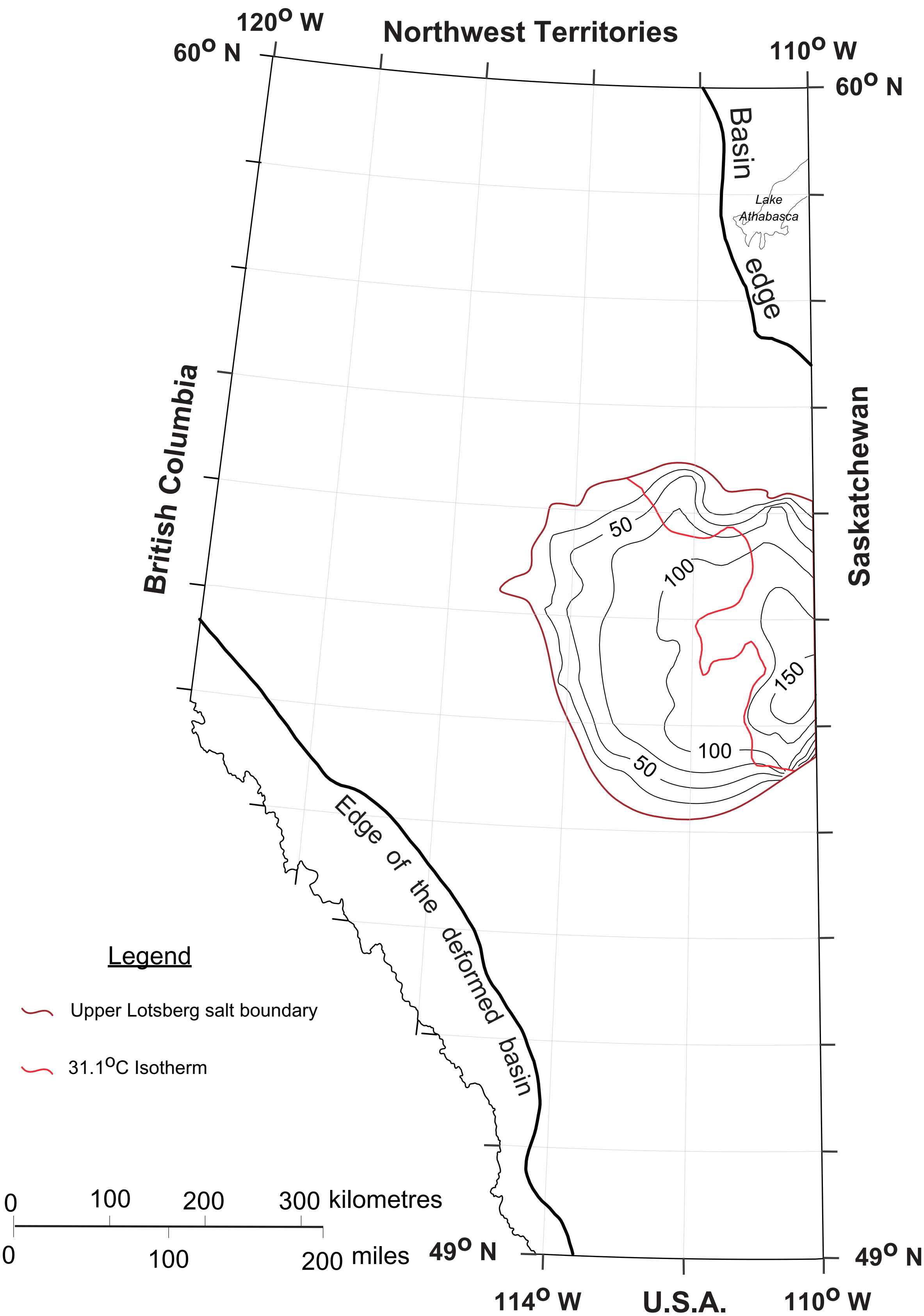



Figure 44: Isopachs (m) of the Upper Lotsberg salt.

$CO_2$ can be sequestered in the supercritical and liquid states in caverns mined in these units, at pressures significantly below the fracturing threshold of the salt beds (Figure 1).

The Cold Lake Formation is found in east-central Alberta along the Saskatchewan border and in northern Alberta (Figure 39). In east-central Alberta, it lies east-northeast of Edmonton, extending from south of Cold Lake to south of Fort McMurray, at depths ranging from 1600 m in the southwest to less than 600 m in the northeast (Figure 45). The thickness of the formation in this area varies between 0 m at the depositional and erosional edge to 60 m near Cold Lake (Figure 46). In northern Alberta, the Cold Lake Formation could be defined only up to the boundary of the Wood Buffalo National Park because of lack of data resulting from the absence of drilling in the park. Depth to the top of the formation ranges from 2300 m in the west at the British Columbia border to 700 m in the east at the park boundary (Figure 45). Its thickness in this area varies from 0 m at the depositional and erosional edge to greater than 80 m in places near the park boundary (Figure 46). The total vertical stress induced by the weight of the overburden varies in the southern part between approximately 37 MPa in the southwest and 13 MPa in the northeast, and in the northern part between 53 MPa in the west and 15 MPa in the east. The 31.1ºC isotherm crosses the top of the Cold Lake Formation along its centre in the southern part, and along its eastern boundary in the northern part (Figures 44 and 45). Thus, $CO_2$ can be sequestered in the supercritical and liquid states in caverns mined in the Cold Lake Formation, at pressures below the fracturing threshold of the salt.

The Prairie Formation is found throughout most of the Alberta Basin. During basin history, fresh meteoric water dissolved and carried away the salt along the eastern boundary of this formation, forming a southeast-trending salt-dissolution edge and a salt escarpment along the eastern boundary (Figure 47). Unlike the Lotsberg and Cold Lake formations, the salt content and purity in this formation are highly variable, decreasing westward from greater than 90 per cent along the dissolution edge to less than 20 per cent along the depositional edge. Depth to the top of the Prairie Formation in the area where the salt content is between 40 and 90 per cent ranges from 2200 m in the southwest to greater than 200 m in the northeast (Figure 47). Thickness of the formation in the same area varies from less than 25 m in the south-southwest, where the salt content is low, to greater than 275 m in the north near the salt-dissolution edge. North of this area, the halite (salt) of the Prairie Formation changes into the anhydrite of the Muskeg Formation (Figures 5 and 6). Anhydrite is not a good medium for $CO_2$ sequestration because of its extremely low solubility, which precludes solution mining of storage caverns. The thickness of the Prairie Formation decreases rapidly to zero along the salt escarpment. The total vertical stress induced by the weight of the overburden varies from greater than 50 MPa in the south-southwest, to approximately 11 MPa in the northeast at the salt-dissolution edge, and to approximately 5 MPa at its shallowest depth at the formation boundary in the northeast. Approximately the eastern third of Prairie Formation top is found at temperatures less than 31.1ºC, although this is the area where the formation attains its greatest thickness (Figures 47 and 48). Thus, $CO_2$ can be sequestered in the supercritical and liquid states in caverns mined in the Prairie Formation west of the salt-dissolution edge, at pressures below the fracturing threshold of the salt.

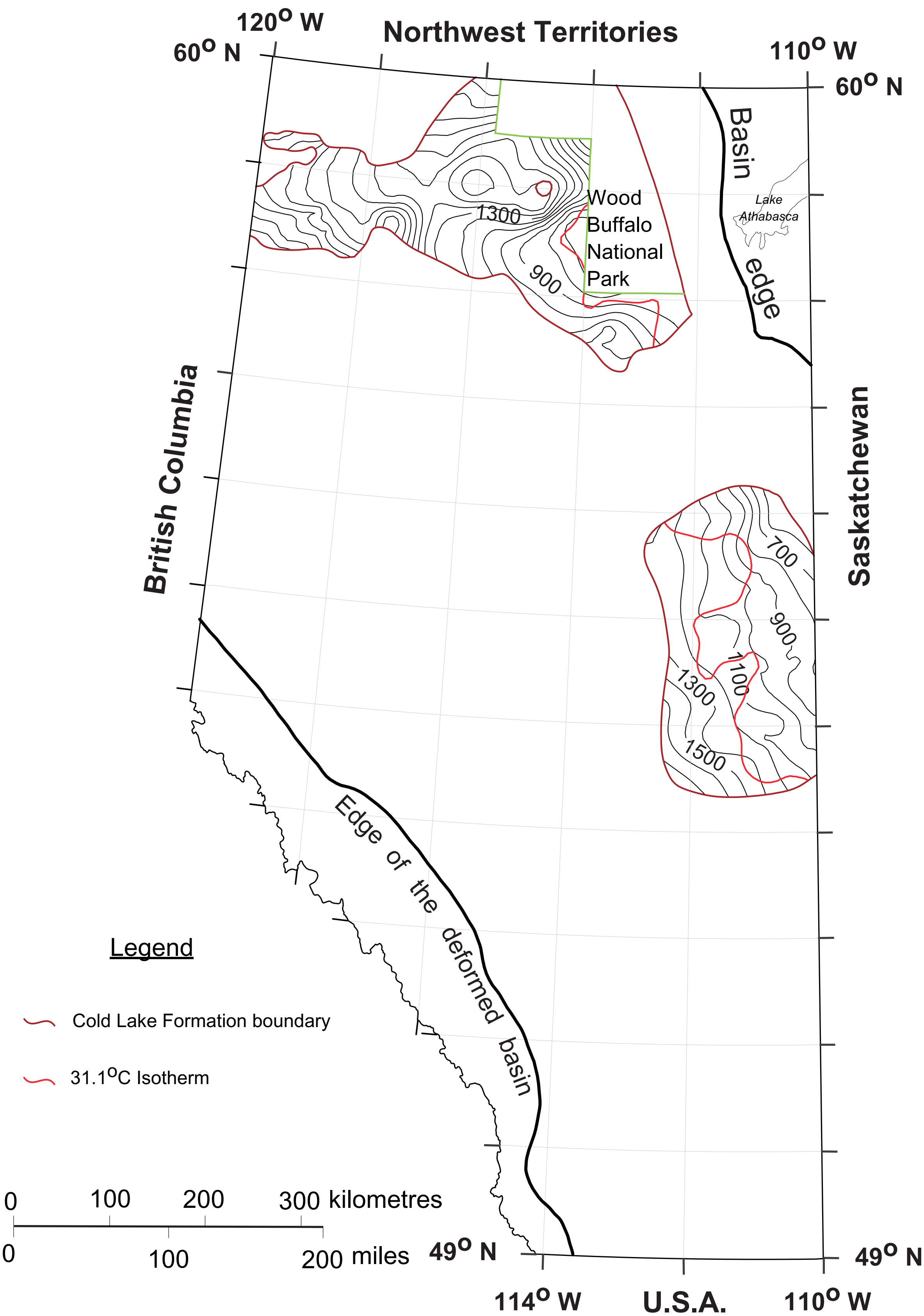



Figure 45: Depth (m) to the Cold Lake Formation.

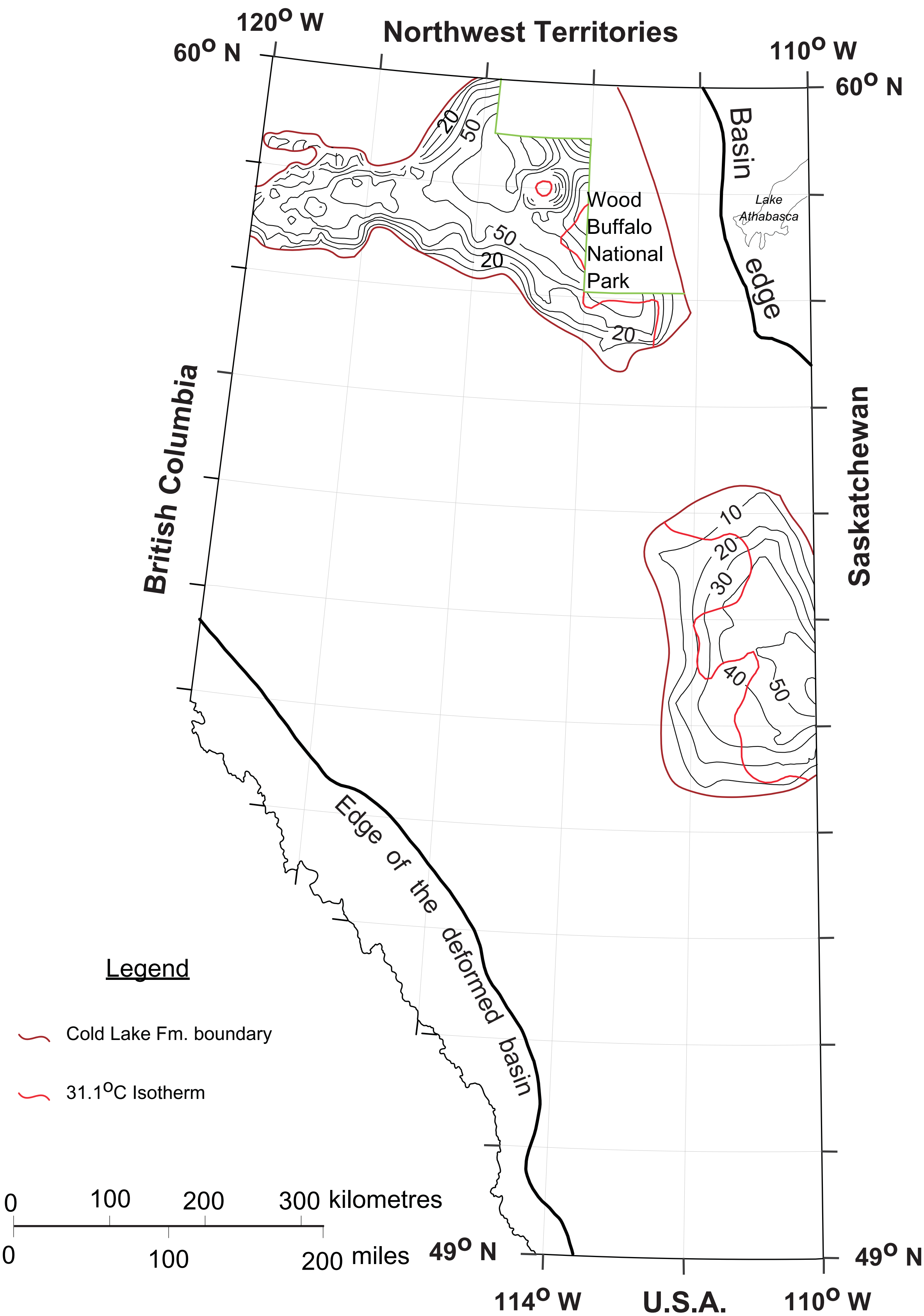



Figure 46: Isopachs (m) of the Cold Lake Formation.

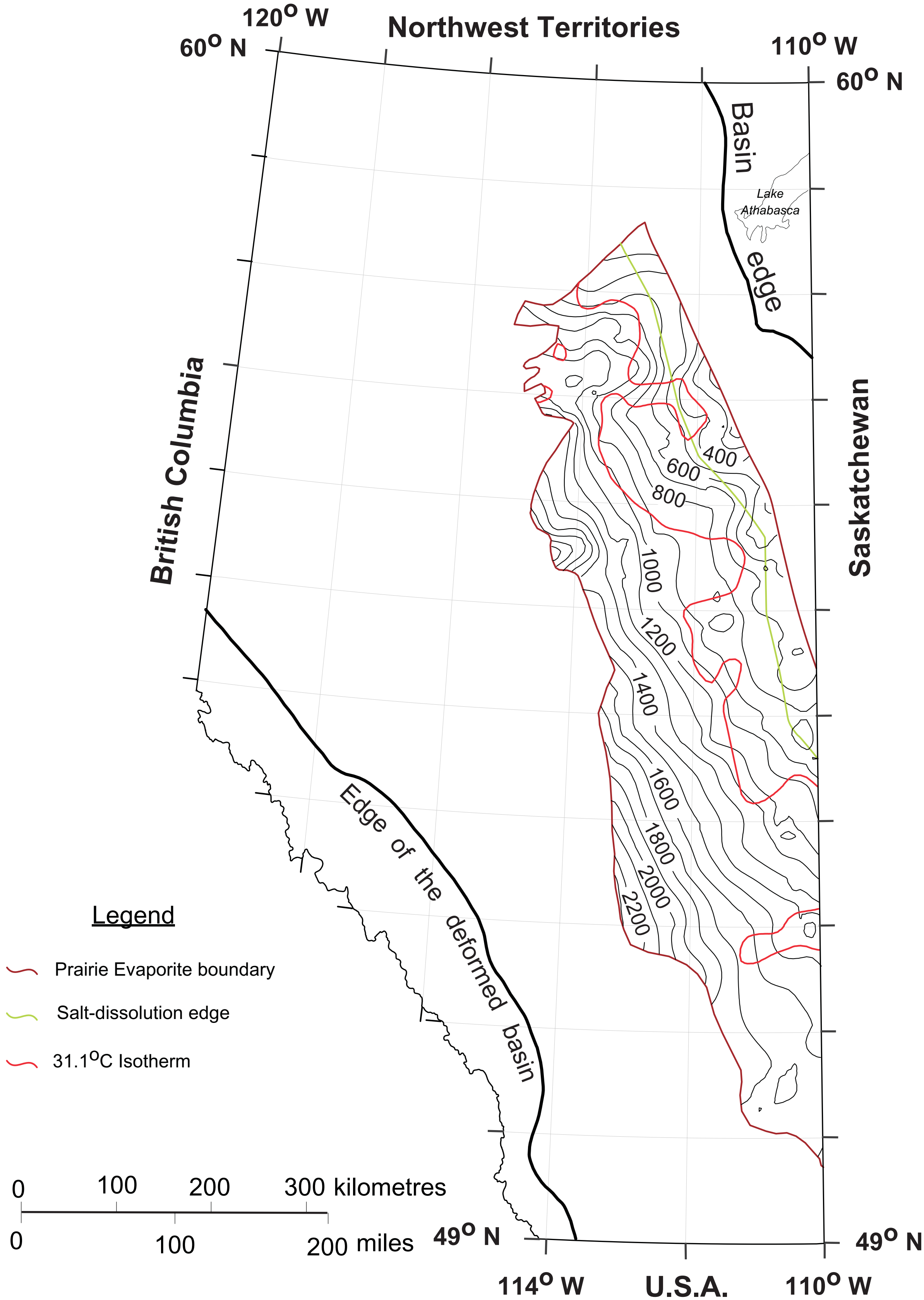



Figure 47: Depth (m) to the top of the Prairie Evaporite Formation, in areas where the halite content is between 40 and 90 percent.

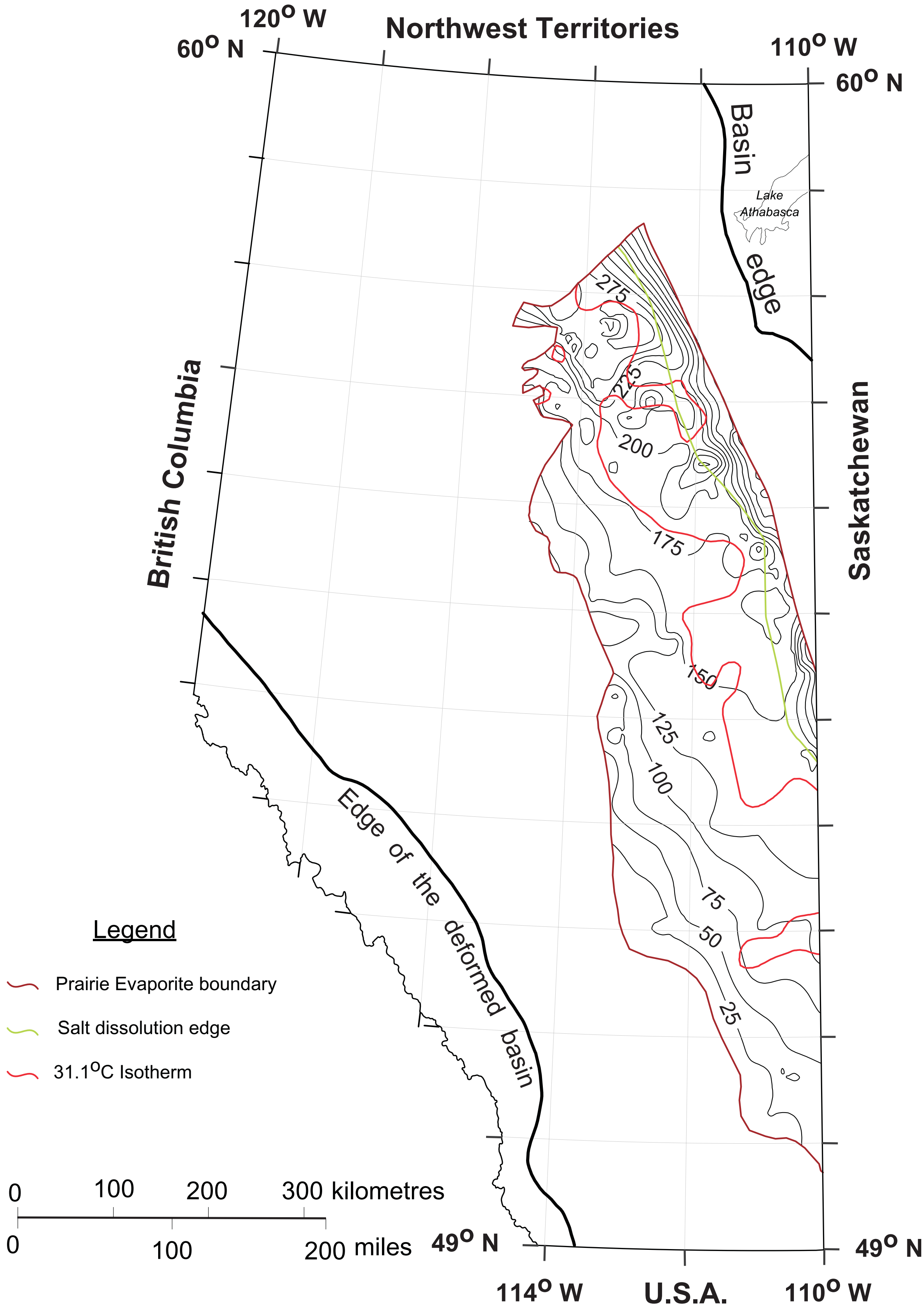



Figure 48: Isopachs (m) of the Prairie Evaporite Formation in areas where the halite content is between 40 and 90 percent.

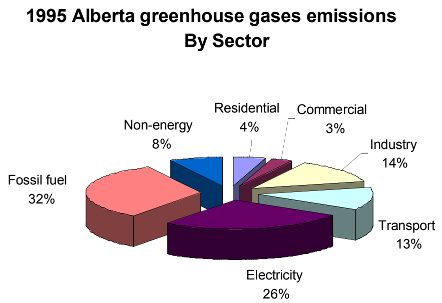
# 7 Suitability of Alberta's Subsurface for $CO_2$ Sequestration

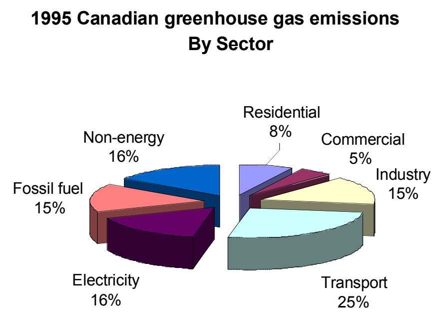
In 1995, Alberta produced 151 Mt $CO_2$, an increase of 16 per cent compared with 1990 (Environment Canada, 1997). Although energy efficiency improved, the total amount of $CO_2$ emitted into the atmosphere continued to increase as a result of economic development and population growth, such that Alberta's greenhouse-gas emissions in 1997 were 21 per cent higher than in 1990 (Edmonton Journal, 2000). Alberta's greenhouse-gas emissions profile is unique in Canada and is different from the national profile (Figure 49) because the province is a major producer of fossil fuels. Major $CO_2$ producers in Alberta are the power-generation industry (approximately 32 per cent), fossil-fuel producers such as oil-sands plants, (approximately 17 per cent), industrial fuel users (approximately 11.4 per cent), the petrochemical industry (approximately 6 per cent), the upstream oil and gas industry (approximately 6 per cent), and cement and lime plants (approximately 0.6 per cent, but very concentrated). These producers, particularly power-generation, petrochemical, oil-sands, and cement plants, constitute major point sources where $CO_2$ can be captured and separated from other combustion gases. The location of Alberta's major $CO_2$ producers is shown in Figure 50.

A significant reduction of $CO_2$ emissions in Alberta cannot be achieved only by increasing $CO_2$ utilization, fossil-fuel switching at existing coal-fired power plants, or switching to renewable energy resources or nuclear-power generation. Improving energy efficiency and conservation are technology-based ways to reduce $CO_2$ emissions; however, these are not enough to reduce $CO_2$ emissions to levels 6 per cent lower than those of 1990, as stipulated in the Kyoto Protocol. Sequestration of $CO_2$ in geological media is the most likely solution, in the short to medium term, for reducing $CO_2$ emissions into the atmosphere in Alberta, because it is immediately applicable from a technological viewpoint and because Alberta's subsurface is generally suitable for $CO_2$ sequestration.

Injection and sequestration of $CO_2$ is already practised in Alberta on a reduced scale by the energy industry. The driver is not a reduction of $CO_2$ emissions into the atmosphere, but the need, imposed by regulatory agencies, to address the issue of acid gas (a mixture of $CO_2$ and $H_2S$). Acid gas is disposed of by injection back into a gas reservoir or into a deep aquifer at more than 20 gas plants in Alberta (Figure 51; Wichert and Royan, 1997). More than 700 t/d (0.25 Mt/y) of $CO_2$ are disposed of this way. It is used for EOR in a Viking oil field at Joffre (Figures 22 and 52). Outside Alberta, $CO_2$ is used in EOR operations at more than 60 locations around the world, mostly in the West Texas Basin in the United States, where $CO_2$ from natural sources has been used for more than 40 years (Bergman, 1999). PanCanadian Petroleum is planning to use $CO_2$, produced at a coal gasification plant in North Dakota, to enhance the oil recovery from the Weyburn oil field in southeastern Saskatchewan. Carbon dioxide is used to enhance coalbed methane recovery (ECBMR) in the San Juan Basin in the United States, and it is stored in large amounts in the Utsira aquifer at the Sleipner West oil field in the North Sea (Bergman, 1999). All these examples show that the technology for $CO_2$ capture, transport, and injection is already available and being applied.

There are two major barriers to the large-scale sequestration of $CO_2$ in geological media. The first one is knowledge related, and pertains to the identification and characterization of potential



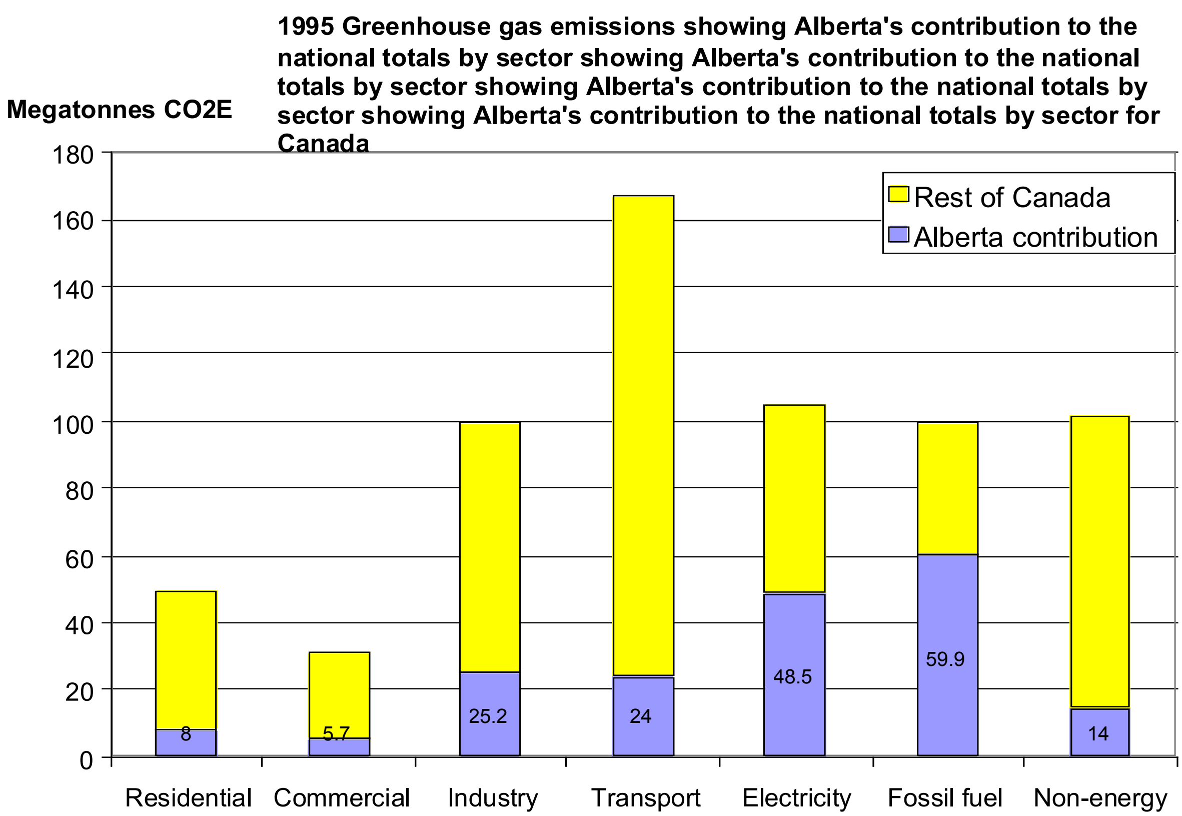




Figure 49: Alberta and Canada’s 1995 greenhouse gas emission profile.

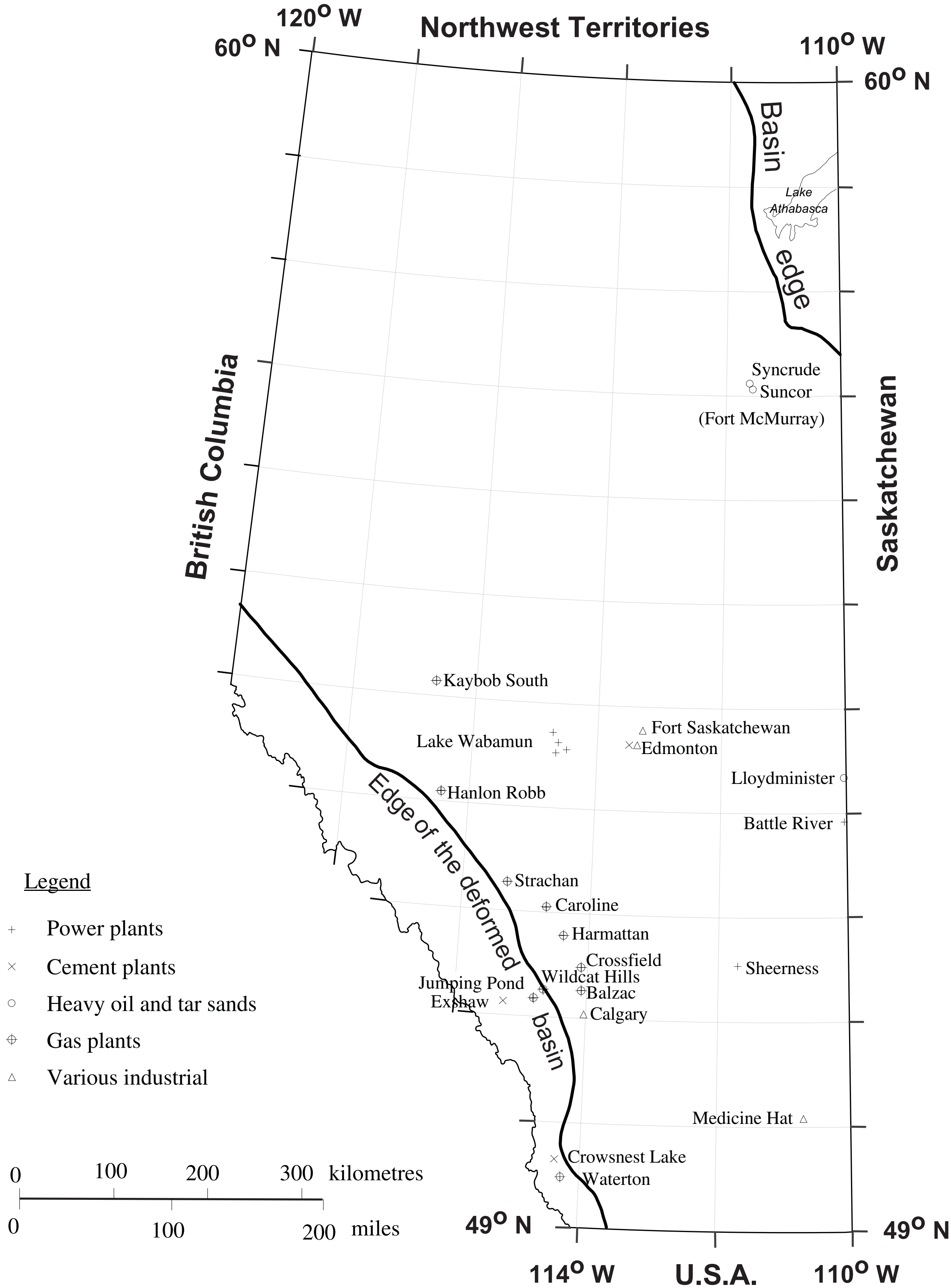



Figure 50: Location of main $CO_2$ producers in Alberta.

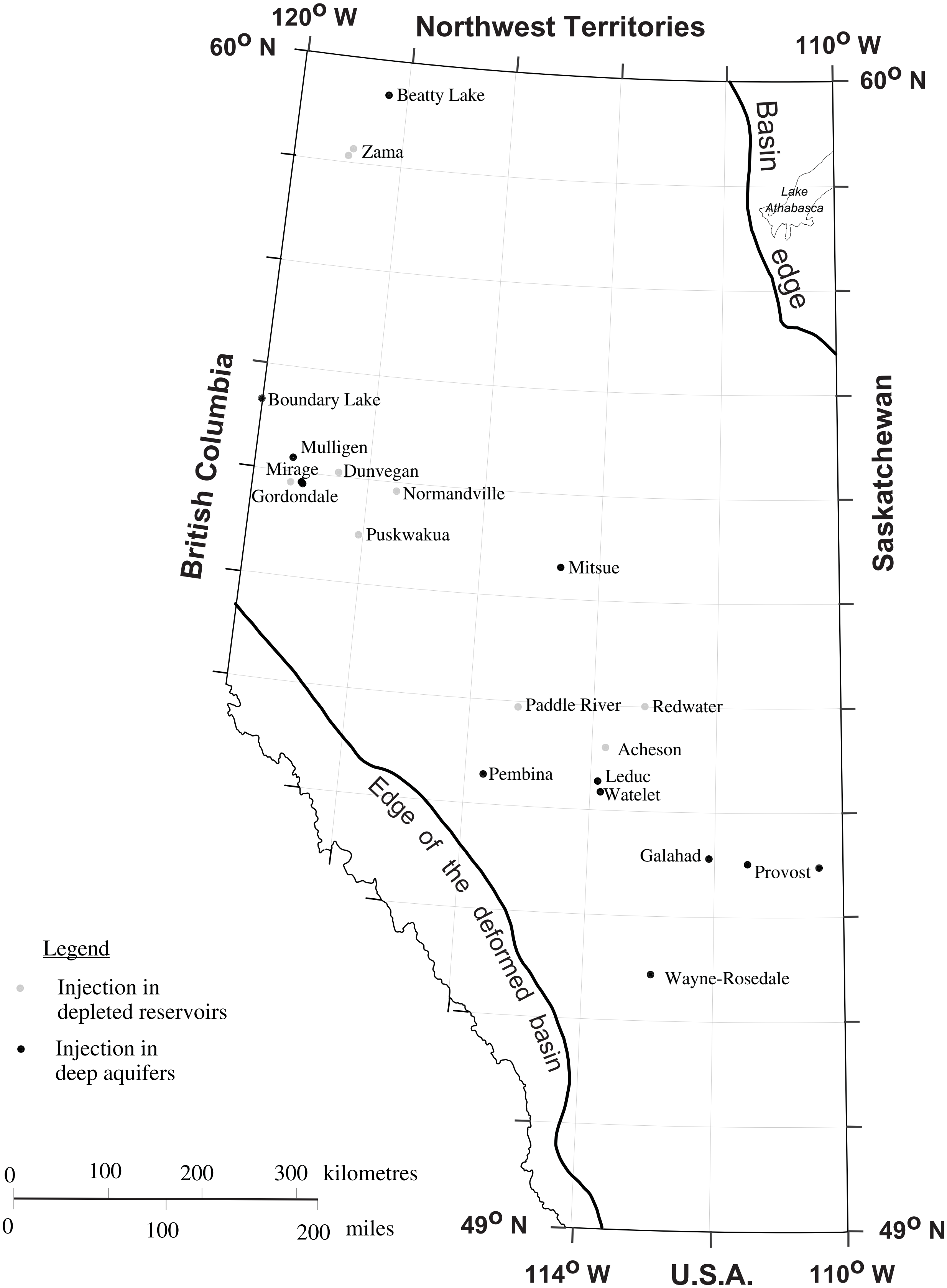



Figure 51: Location of acid-gas injection sites in Alberta.

sites for $CO_2$ sequestration. The second one is technological and economic, and relates to the currently very high cost of $CO_2$ capture and transport with available technology.

Based on the geological, geothermal, and hydrodynamic characteristics of the Alberta Basin, Alberta can be divided into six different regions (Figure 52), each characterized by specific possibilities in terms of $CO_2$ sequestration in geological media.

## 7.1 Northeastern Alberta

This region extends from approximately 55ºN to the Northwest Territories border and from the edge of the Alberta Basin and Saskatchewan border in the east to approximately 115ºW; its western and southwestern boundaries parallel the basin edge (Figure 52). It comprises the exposed Precambrian Shield in the extreme northeast, the Athabasca area (including the oil sands), and Wood Buffalo National Park. Because this region is situated at the shallow edge of the Alberta Basin, it is **generally not suitable** for $CO_2$ sequestration in geological media for the following reasons:

1) Because of the shallow depth, in situ temperatures are less than or close to 31.1ºC and pressures are less than 7.38 MPa. Thus, $CO_2$ will always be in gaseous phase in this region.
2) The flow of meteoric water is in shallow, local groundwater flow systems, and that of connate water is in intermediate and local flow systems, which all discharge along river valleys, such as those of the Athabasca and Peace rivers, and along the Precambrian Shield. Thus, $CO_2$ cannot be injected and sequestered in aquifers because of the high potential for the gaseous $CO_2$ to migrate to the top of the aquifer and escape back into the atmosphere.
3) There are no coal beds in the area, except for the very shallow and discontinuous Mannville coal beds at Firebag, near Fort McMurray. These coal beds are not suitable for $CO_2$ injection and CBM production because of a) their shallowness, b) having been mined until recently, c) their limited potential, and d) the possibility of $CO_2$ escaping into adjacent strata and then to the surface.
4) There are no hydrocarbon reservoirs, except for bitumen and shallow gas of biogenic origin in the Athabasca area. The bitumen reservoirs are not depleted. Bitumen is mined north of Fort McMurray, and in situ production by steam-based methods is only in the early stages of development. In addition, the sealing of the depleted bitumen reservoirs may be very poor, because bitumen is kept in place more by its extremely low viscosity than by good sealing caprock. Thus, $CO_2$ injected into depleted bitumen reservoirs may escape into the overlying shallow Cretaceous aquifers. Depleted gas reservoirs in the Athabasca area may serve for $CO_2$ sequestration, although the potential in terms of volume may be small.
5) There are salt beds in the area that could serve for cavern sequestration of $CO_2$, such as the Lower and Upper Lotsberg salts in the south, and the Cold Lake and Prairie formations (Figure 39). Salt was mined in the past at Fort McMurray (Figure 40). However, mining the salt for caverns creates environmental problems related to brine disposal.

The Syncrude and Suncor oil-sands plants north of Fort McMurray are major $CO_2$ producers in the area (Figure 50), with more mines and in-situ plants coming on stream in the near-future.

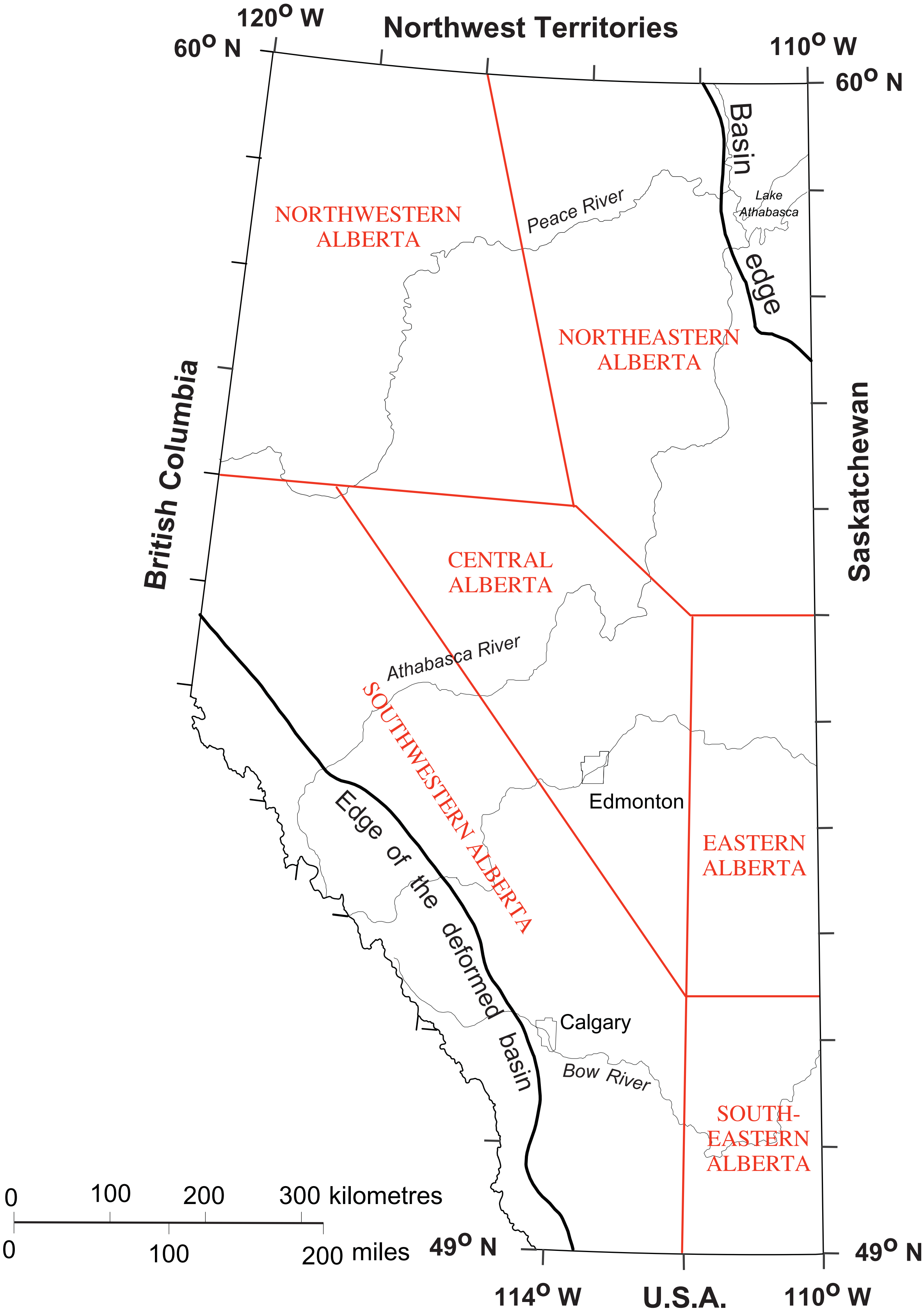



Figure 52: Suitability of Alberta for $CO_2$ sequestration in geological media (see text for explanation).

Although the northeastern region is generally not suitable for $CO_2$ sequestration, the following possibilities could still be available:

· injection of gaseous $CO_2$ into the carbonate Winnipegosis aquifer, which is overlain by regional shaly aquitards
· storage of $CO_2$ as a liquid at high pressure in mined salt caverns, as long as the injection pressure remains safely below the fracturing threshold
· storage of gaseous $CO_2$ in depleted shallow gas reservoirs in the Woodbend, Winterburn, and Mannville groups

The $CO_2$ would probably have to be captured at source and piped to the injection and sequestration site.

### 7.2 Eastern Alberta

This region extends from approximately 51.5ºN to 55ºN, and from 110ºW to 112ºW, along the Saskatchewan border (Figure 51). Major $CO_2$ producers in the area are the Sheerness and Battle River power plants, the Lloydminster heavy-oil upgrader, and heavy-oil plants, such as Esso's at Cold Lake (Figure 50). This region is **reasonably suitable** for $CO_2$ sequestration in geological media for the following reasons:

1) The basin is relatively shallow. As a result, temperatures in all Cretaceous strata and most of the Devonian are less than 31.1ºC, while pressures are generally less than 7.38 MPa (Figures 9 to 16, and 20 to 21). Thus, $CO_2$ injected into these strata will be mostly in the gaseous phase, and only at great depths could it be liquid.
2) Because of pre-Cretaceous erosion, all deep Devonian aquifers except the Winnipegosis subcrop at the unconformity below the Mannville Group (Figures 12 to 15). Thus, $CO_2$ injected into these aquifers will most likely migrate to the top of the aquifer and flow updip and upwards into the Mannville Group, where it will probably be trapped by the regional-scale Clearwater and Colorado aquitards.
3) Upper Mannville coal beds are present in this region. Although they are relatively shallow, they may not have great potential for $CO_2$ injection and CBM production because of low permeability, having been buried to a depth of more than 2 km at the peak of the Laramide orogeny, and low gas content (Dawson, 1995). Upper Cretaceous Belly River coal beds are too shallow and too close to the surface (Figure 30), so they cannot be considered for $CO_2$ injection and CBM production.
4) Oil, heavy-oil, and gas reservoirs, such as Provost, are abundant in the area, particularly in the Mannville and Viking strata.
5) All Devonian salt beds are present in the area, with salt being mined from the Upper Lotsberg unit and the Prairie Formation (Figures 39 and 40).

The best targets for $CO_2$ sequestration are in EOR operations for heavy-oil production and in depleted oil and gas reservoirs. Aquifer sequestration would be recommended only for the deep Basal Cambrian Sandstone and Winnipegosis aquifers, which are overlain by thick, regional-scale shaly aquitards and halite aquicludes. Injection into Upper Devonian and Cretaceous aquifers is not recommended as long as there are better options available, although it remains a possibility for the future. Storage in salt caverns is possible if the caverns have been developed for other reasons, and as long as the injection and storage pressures remain below the fracturing threshold of the salt. Storage of $CO_2$ in coal beds probably has limited potential. Injection of the $CO_2$ could probably be done close to the production facility, with little or no transportation required.

### 7.3 Southeastern Alberta

This region extends from the United States border to 51.5ºN, and from 110ºW to 112ºW (Figure 51). Major $CO_2$ producers are in the Medicine Hat area (Figure 50). This region is **suitable** for $CO_2$ sequestration in geological media for the following reasons:

1) The region straddles the Bow Island Arch, which is a basement high that separates the Alberta and Williston basins (Figure 3). Geothermal gradients in the area are low, around 20ºC, so the 31.1ºC isotherm is reached at greater depths than in the north.
2) The Cambrian and Devonian aquifers are confined by regional-scale, thick aquitards. Upper Devonian aquifers, such as Winterburn and Wabamun, subcrop at the pre-Cretaceous unconformity at the northern edge of the area. Carboniferous, Mannville, and Viking aquifers are confined by thick Colorado shaly aquitards.
3) Oil reservoirs are found mainly in Carboniferous and Mannville strata, while gas reservoirs are found in the Mannville Group and Viking and Milk River formations (Figures 19, 20 to 22, and 25).
4) Coal is found in Upper Mannville strata, although it is not well delineated, and in very shallow Belly River strata (Figure 30).
5) High salt content (greater than 40 per cent) is found in the Prairie Formation in the northeastern part of this region (Figure 39).

In terms of $CO_2$ sequestration, the best targets are in depleted oil and gas reservoirs, and in EOR operations. Aquifer sequestration is possible in the deep Basal Cambrian Sandstone, Winnipegosis, Beaverhill Lake, and Winterburn aquifers. Injection into the Carboniferous, Mannville, and Viking aquifers is possible, but this option should be used only after the other options are exhausted. Storage in coal beds and salt caverns does not seem to be a viable option. Carbon dioxide could probably be injected close to the production facility, with little or no transportation required.

### 7.4 Northwestern Alberta

This region extends from approximately 115ºW to the British Columbia border, and from 56ºN to the Northwest Territories border (Figure 51). There are no major $CO_2$ producers in this region, except for energy exploration and production, and the region is **suitable** for $CO_2$ sequestration in geological media for the following reasons:

1) The basin is deep enough, and geothermal gradients are high enough, that the 31.1ºC isotherm and 7.38 MPa isobar are reached at moderate depths. Thus, the sedimentary succession below the isotherm and isobar has sufficient thickness (Figure 8). In the southwestern corner of this region, the Peace River Arch, a basement high, creates flow paths around and along its edges (Figures 11 to 13).

2) All the deep Paleozoic aquifers are confined by shaly aquitards and overlain by the thick Colorado shale. The flow of formation waters in these aquifers is part of a long-range basin-scale system (Figures 28 and 29a).
3) Major oil and gas fields are found in Devonian carbonate reefs, such as Rainbow and Zama in the Elk Point Group, and in Carboniferous, Permian, and Triassic platform carbonate rocks (Figures 11 to 18).
4) There are no coal beds in this region.
5) The thin Cold Lake salt is present only in the northwest (Figure 46).

The best targets for $CO_2$ sequestration are in depleted oil and gas reservoirs, and in EOR operations in Devonian to Triassic reservoirs. Aquifer sequestration is possible in the carbonate Devonian to Carboniferous aquifers. Because of the depth of these reservoirs and aquifers, $CO_2$ will be in supercritical state in almost all cases. Injection could probably be done close to the production facility, with little or no transportation required.

## 7.5 Central Alberta

This region is centred around Edmonton and comprises major industrial and energy $CO_2$ producers such as the petrochemical industry in Fort Saskatchewan, a cement plant, refineries and power plants in Edmonton, and the major power plants at Lake Wabamun (Figure 51). Fortunately, this region is **extremely suitable** for $CO_2$ sequestration in geological media for the following reasons:

1) The region is located at the centre of the basin, such that sufficient thickness of the sedimentary succession is available below the 31.1ºC isotherm and 7.38 MPa isobar (Figures 8 to 14).
2) The deep Cambrian and Devonian aquifers in the succession are confined by regional-scale aquitards and aquicludes (Figures 8 to 14). The Cretaceous Mannville and Viking aquifers are also confined by thick Colorado shale units.
3) There are many oil and gas reservoirs in various stages of depletion in Devonian to Viking strata, such as Leduc and Redwater (Figures 8 to 16 and 20 to 22).
4) Coal beds are found in the Edmonton Group and Belly River strata (Figure 30), with promising potential for $CO_2$ sequestration and CBM production.
5) Salt beds are present, with salt being mined from the Upper Lotsberg unit at Fort Saskatchewan (Figures 39 and 40).

All means of $CO_2$ sequestration in geological media are available and all are good options in central Alberta. Sequestration in EOR operations and in depleted oil and gas reservoirs is possible for reservoirs found in Devonian carbonate rocks and Mannville and Viking sandstone units. Sequestration in coal beds through ECBMR production is possible in Edmonton Group and Belly River coals. Sequestration is also possible in supercritical state in deep Devonian aquifers, and as a liquid or gas in Mannville and Viking aquifers. Finally, sequestration in salt caverns is possible if the caverns have already been created for a different purpose (which they were). In most if not all cases, $CO_2$ can be injected at the producer's site, or with minimum transportation needs.

## 7.6 Southwestern Alberta

Southwestern Alberta, defined as the region along the edge of the deformed basin (thrust and fold belt) from 112ºW at the US border to 56ºN at the British Columbia border (Figure 51), is also **extremely suitable** for $CO_2$ sequestration in geological media for the following reasons:

1) This region comprises the basin foredeep, where the greatest depths (more than 5 km), are attained.
2) All aquifers, from the basement to the Upper Cretaceous Lea Park Formation shale, are confined by regional-scale competent aquitards. The flow of formation waters is driven in long-range regional-scale systems in Cambrian to Lower Cretaceous Mannville aquifers. The flow in Colorado aquifers, such as Viking and Cardium, is driven by erosional rebound in the intervening shale units, forming a hydrodynamic trap (Figures 28 and 29b).
3) There are many oil and gas reservoirs in various stages of depletion. The great majority are at depths for which $CO_2$ would be in supercritical state (Figures 8 to 24).
4) Extensive Lower and Upper Cretaceous coal beds are found in Mannville, Belly River, Edmonton and Scollard strata (Figures 5 and 30) at depths that make them unmineable.

Except for storage in salt caverns, all other means of $CO_2$ sequestration in geological media are available and all are good options in southwestern Alberta. Sequestration in EOR operations and in depleted oil and gas reservoirs is possible for reservoirs throughout the entire sedimentary succession. Sequestration in coal beds and CBM production is possible in Ardley coal beds (Wapiti Group), and in the Edmonton Group and Belly River coal beds. Mannville coal beds are probably too deep and have insufficient permeability to constitute a $CO_2$ sequestration target. Sequestration is possible in supercritical state in all aquifers. Carbon dioxide is produced in southwestern Alberta in and around Calgary, and at various gas plants that run almost parallel to the deformation front (Figure 51). Probably in all cases, $CO_2$ can be injected and sequestered at the producer's site.

A few $CO_2$ producers are located in the Rocky Mountain Foothills, west of the deformation front. They are the cement plants at Exshaw and Waterton, and the Jumping Pond and Wildcat Hills gas plants (Figure 50). The geology and hydrodynamic conditions at these sites may or may not be suitable for $CO_2$ sequestration in geological media. They are probably not suitable, because faults and fractures constitute potential flow paths for the injected $CO_2$. Nevertheless, in the case of these $CO_2$ producers, site-specific studies need to be carried out. If no potential for $CO_2$ sequestration is identified at these sites, then the $CO_2$ would have to be captured and transported eastward by pipeline to a suitable injection site in the undeformed part of the basin.

# 8 Conclusions

The Intergovernmental Panel on Climate Change (1991) reached the conclusion that "the balance of evidence suggests a discernible human impact on the global climate". This impact is caused by anthropogenic greenhouse-gas emissions into the atmosphere, of which $CO_2$ is the most important. Canada, a signatory of the Kyoto Protocol, agreed to reduce by 2012 its $CO_2$ emissions to 6 per cent lower than those of 1990. According to the latest available data, Alberta is the province with the highest $CO_2$ emissions in Canada. Carbon-dioxide emissions in Alberta actually increased by 21 per cent between 1990 and 1997, as a result of population growth, economic development, and increased activity in the energy sector. Thus, in order to meet the commitments undertaken in Kyoto, Alberta must decrease significantly its $CO_2$ emissions into the atmosphere.

Major $CO_2$ producers in Alberta are the power-generation industry (approximately 32 per cent), fossil-fuel producers such as oil-sands plants, (approximately 17 per cent), industrial fuel users (approximately 11.4 per cent), the petrochemical industry (approximately 6 per cent), the upstream oil and gas industry (approximately 6 per cent), and cement and lime plants (approximately 0.6 per cent, but very concentrated). These producers, particularly power-generation, petrochemical, oil-sands, and cement plants, constitute major point sources where $CO_2$ can be captured and separated from other combustion gases. Geographically, the major $CO_2$ sources in Alberta are found near Fort McMurray in the northeast (oil-sands plants), in the Lloydminster-Cold Lake area along Alberta's eastern border (heavy-oil and power plants), in the Edmonton area (refineries and industrial, petrochemical, cement, and power plants), and in the southwest around Calgary and along the foothills (industrial and power, cement, and gas plants).

A decrease in $CO_2$ emissions can be achieved by a variety of means, first and foremost by improving energy efficiency and conservation. Switching to renewable forms of energy, particularly for power generation, is not an option with a significant impact and future in Alberta. Retrofitting existing plants to use gas instead of coal is very expensive. Thus, $CO_2$ capture and sequestration is probably the most viable solution, in the short to medium term, for Alberta to meet its $CO_2$ reduction targets. Since ocean sequestration is not an option for Alberta, and biomass fixation is uncertain at best, geological disposal and sequestration of $CO_2$ seems to be the best available option for long-term $CO_2$ sequestration.

Carbon dioxide can be sequestered in geological media by utilization in enhanced oil recovery (EOR) operations, displacement of methane in coal beds (ECBMR), storage in depleted oil and gas reservoirs, sequestration in deep saline aquifers, and storage in salt caverns. For successful and optimal $CO_2$ sequestration in geological media, Alberta's subsurface needs to meet a series of criteria related to basin tectonic setting and geology, its geothermal and hydrodynamic regimes, and its hydrocarbon potential and maturity. In light of these criteria, the suitability for $CO_2$ sequestration of the Alberta Basin that underlies most of province varies depending on the particular conditions of that region.

Except for the Rocky Mountain Foothills in the southwest and the exposed Precambrain Shield in the northeast corner of the province, Alberta's subsurface is favourable for $CO_2$ sequestration as a result of the layer-cake structure of the basin and the occurrence of regional-scale low-permeability strata, such as evaporitic and shale beds. All five ways of sequestering $CO_2$ in geological media are possible in Alberta. Extensive, thick Devonian salt beds suitable for $CO_2$ storage in salt caverns are found at depth along the eastern part of the basin. Cretaceous coal seams for $CO_2$ replacement of coalbed methane are found at depths varying between 3000 m and outcrop at surface. Gas, oil, and bitumen reservoirs, suitable for $CO_2$ use in EOR operations or storage once the reservoirs are depleted, are found in Devonian to Cretaceous strata. Reservoir depth varies from a few thousand metres in the western part of the province along the thrust and fold belt to near surface in the eastern part of the province. Finally, regional-scale saline aquifers, suitable for hydrodynamic $CO_2$ sequestration, are present throughout the basin.

Because of the thermodynamic properties of $CO_2$, identification of the depths of the 31.1ºC isotherm and the 7.38 MPa isobar is essential in establishing if $CO_2$ could be sequestered as a gas, a liquid, or in supercritical state. Geothermal gradients in Alberta vary from slightly less than 20ºC/km in the south to more than 50ºC/km in the north. As a result, the depth of the 31.1ºC isotherm varies between 1200 m in southern Alberta and 600 m in northern Alberta. Pressures vary in the basin from a few hundred kPa in shallow aquifers to more than 50 MPa at great depths in the southwest.

Based on the geological, geothermal, and hydrodynamic characteristics of the Alberta Basin, Alberta can be divided into six different regions, each characterized by specific possibilities in terms of $CO_2$ sequestration in geological media:

1) Northeastern Alberta is generally not suitable for $CO_2$ sequestration in geological media because of shallow depth. Limited possibilities exist for $CO_2$ sequestration in gaseous phase in the Winnipegosis aquifer, shallow depleted gas reservoirs, and salt caverns.
2) Eastern Alberta is reasonably suitable for $CO_2$ sequestration, mostly as a gas, in EOR operations, depleted oil and gas reservoirs, coal beds, and salt caverns.
3) Southeastern Alberta is suitable for $CO_2$ sequestration, mostly as a gas but also as a liquid and in supercritical state, in EOR operations, depleted oil and gas reservoirs, coal beds, and deep aquifers.
4) Northwestern Alberta is suitable for $CO_2$ sequestration, mostly in supercritical state, in depleted oil and gas reservoirs and deep aquifers.
5) Central Alberta is very suitable for $CO_2$ sequestration, in gaseous, liquid, or supercritical state, in EOR operations, depleted oil and gas reservoirs, coal beds, deep aquifers, and salt caverns.
6) Southwestern Alberta is also very suitable for $CO_2$ sequestration, in gaseous, liquid, or supercritical phase, in EOR operations, depleted oil and gas reservoirs, coal beds, and deep aquifers.

In terms of the major $CO_2$ producers in Alberta, it seems that all but the oil-sands plants in northeastern Alberta have a number of options available for $CO_2$ sequestration in geological media. In order to proceed to an implementation stage, potential specific sites for $CO_2$ geological sequestration must be identified and characterized in the vicinity of the major $CO_2$ producers in Alberta.

## 9 Recommendations for Future Work

The main result of this study was an assessment of the suitability of Alberta's subsurface for $CO_2$ sequestration in geological media. Basically, the Alberta Basin that underlies almost all of Alberta has been assessed on the following criteria: 1) tectonic setting, 2) regional-scale geology and lithology, 3) geothermal regime, 4) hydrostratigraphy and flow of formation waters, 5) pressure regime, and 6) location of major hydrocarbon reservoirs, uneconomic coal seams, and salt beds. As a result of applying this systematic approach (Bachu, 2000), Alberta has been divided into six regions based on **suitability and means for $CO_2$ sequestration**. Having established the suitability (Bachu, 2000), the **capacity** of Alberta's subsurface for sequestering $CO_2$ needs to be established by completing the following work:

- Determination of the **stress regime** of Mannville Group and Upper Cretaceous to Tertiary **coal-bearing strata** in Alberta. This must be done because coal permeability, which depends on stress, is a critical parameter in establishing $CO_2$ injectivity, and therefore injection rates and volumes.

- Determination of **coal thickness, porosity, and gas content** for the evaluation of potential volumes of $CO_2$ that could be sequestered in uneconomic coal beds by adsorption trapping.

- Determination of the **stress regime and fracturing threshold of salt beds** in eastern and northeastern Alberta, in case $CO_2$ storage in salt caverns (cavern trapping) is contemplated for regions that lack other, more economic means of sequestration.

- Analysis of the **porosity and permeability distributions** in aquifers and hydrocarbon reservoirs. Permeability is a critical parameter in establishing $CO_2$ injectivity, while porosity determines the potential volume available for sequestration by hydrodynamic and stratigraphic trapping (Bachu, 2000).

- Determination and inventory of the **stage of depletion of various oil and gas reservoirs** in Alberta, for estimates of potential available volumes for $CO_2$ storage in depleted hydrocarbon reservoirs by stratigraphic (geological) trapping.

- Determination of **$CO_2$ density** at in situ temperature and pressure conditions specific for various regions in Alberta, for use with porosity determinations in estimating the $CO_2$ mass that could be sequestered in a rock unit volume.

- Determination of **$CO_2$ solubility in brines** for the range of salinities encountered in the Alberta Basin, in order to estimate the amount of $CO_2$ that could be sequestered by dissolution in aquifer water (solubility trapping).

- Determination of **$CO_2$ solubility in oil** for the types of oils found in Alberta, in order to estimate the amount of $CO_2$ that could be sequestered by dissolution in the residual oil in abandoned oil reservoirs (solubility trapping).

The result of this recommended work will be an evaluation of the **capacity** of Alberta's subsurface for $CO_2$ sequestration in geological media.

The next steps in completing the evaluation of Alberta's potential for $CO_2$ sequestration in geological media should be

1) determination of the **long-term fate and retention time** of injected $CO_2$, by a combination of **monitoring** at sites where acid gas or $CO_2$ is injected and **numerical modelling** for the specific conditions in Alberta; and

2) selection and analysis of **specific sequestration sites** in the vicinity of major $CO_2$ producers.

At the end of this process, government and industry in Alberta will have complete knowledge and a clear understanding of the potential and capacity to sequester $CO_2$ in Alberta's subsurface.

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