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Alberta Energy and Utilities Board
Alberta Geological Survey

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S. Bachu and K. Michael

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Alberta Energy and Utilities Board
Alberta Geological Survey
4th Floor, Twin Atria Building
4999 – 98th Avenue
Edmonton, Alberta
T6B 2X3
Canada

Telephone: (780) 422-3767 (Information Sales)
Fax: (780) 422-1918
E-mail: EUB.AGS-Infosales@gov.ab.ca

Website: www.ags.gov.ab.ca

Executive Summary

The coalbed methane potential and producibility of any coal-bearing strata are strongly affected by the hydrogeological regime of formation waters and by coal permeability, which in turn depends on the effective stress regime of the coal seams. Peat accumulated in the Alberta basin during the late Cretaceous and early Tertiary led to the formation of coal deposits in the Upper Cretaceous Belly River Group and Horseshoe Canyon Formation, and the Upper Cretaceous–Paleocene Scollard and Paskapoo formations. The flow of formation waters in these strata is driven by gravity (topography) and erosional rebound, and is controlled by rock absolute permeability, gas generation and capillary pressure to gas (relative permeability).

The permeability of coal seams decreases west-southwestward with increasing burial depth, from the order of several darcies (D) and higher in the shallow (<50 m) zones, to millidarcies and less in the deep zones (>1500 m). The minimum effective stress, which affects coal permeability by closing fractures, increases west-southwestward from zero at the erosional edge of the strata to approximately 20 MPa near the Rocky Mountain deformation front. Fractures, including those in coal seams, will generally be vertical, and will propagate on a southwest-northeast axis along the direction of the maximum horizontal stress.

The flow of formation waters indicates that the coalbed methane in deep coal seams in west-central Alberta (Edmonton and Belly River groups) is most likely of thermogenic origin. The gas content of the coal may be quite low, as the underpressuring caused by erosional rebound could have drawn the gas out of coal into the adjacent sandstone units where it has accumulated in stratigraphic traps created by a changing depositional environment. The coalbed methane in shallower coal in and near the subcrop regions of the Upper Cretaceous–Tertiary strata is probably of thermogenic and biogenic origin. These coals seams, although of low rank, may contain significant amounts of late-stage biogenic methane.

From the point of view of produced water, the salinity of formation water in shallow coal seams, where the flow is driven by topography, is low, generally less than 1500 mg/l, although in places it may reach 3000–5000 mg/l. The salinity of formation water in the deeper strata in west-central Alberta, where the flow is driven by erosional rebound, is significantly higher, reaching up to 18 000 mg/l. This affects treatment and/or disposal strategies with regard to the water produced concurrent to coalbed methane.

From a strictly hydrogeological and permeability/stress regime point of view, the region that probably has good CBM potential and producibility from coal seams in the Upper Cretaceous–Tertiary strata of the Alberta basin extends from the west-northwest, at the top of the Scollard–Paskapoo succession, to central and southern Alberta, along and near the subcrop area of the stratigraphically deeper Edmonton and Belly River groups. The deep Edmonton and Belly River strata in western and central Alberta most likely have a reduced CBM potential due to possibly lower gas content and to low permeability. These considerations need to be applied against studies of coal thickness, rank and gas content to identify the best targets for CBM exploration and production in Alberta.

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1 Introduction

The term ‘coalbed methane’ is typically applied to gases contained in coal beds, because methane is the dominant gas. However, significant amounts of CO_2 and longer chain hydrocarbon gases, such as ethane and propane, are also commonly found in coalbed gases. Coalbed methane (CBM) resources worldwide may be as high as 8870 Tcf (250×10^{12} m^3), several times greater than the collective reserves of all known conventional gas fields (Gayer and Harris, 1996). However, CBM has not been generally exploited because of the abundance of, and better economic conditions for, other fossil-energy resources. Although coal has been extracted for a long time in many sedimentary basins, CBM was seen primarily as a danger in underground mining, and only recently has CBM been recognized as a valuable energy resource that can be economically exploited.

Due to special tax credits, the development of unconventional gas resources in the United States has grown considerably since the late 1980s, so that, by the end of 1994, CBM accounted for 5% of their natural gas production and 6% of their proven reserves (Stevens et al., 1996). The principal producing areas in the United States are the mature San Juan basin in Colorado and New Mexico, and the Black Warrior basin in Alabama, which account for 80% and 17%, respectively, of their total CBM production (Murray, 1996). The Powder River basin in Wyoming and Montana has recently emerged as a CBM producer (Montgomery, 1999), and other basins with future potential are the Greater Green River basin in Wyoming and the Piceance basin in Colorado (Stevens et al., 1996). Production occurs at depths varying from as shallow as 45 m in thick Paleocene coal beds of the Powder River basin to approximately 2000 m in Upper Cretaceous coal beds of the Piceance basin (Montgomery, 1999).

All CBM-producing basins in the United States, except for the Black Warrior, are Rocky Mountain basins. Also, within the contiguous United States, as much as 79% of CBM resources, estimated at 675 Tcf, are found in late Cretaceous and early Tertiary coal in undeformed foreland basins of the Rocky Mountain region (Murray, 1996; Montgomery, 1999). Although the Alberta basin is also a foreland Rocky Mountain basin that contains extensive late Cretaceous and early Tertiary coal beds, its CBM potential has not been truly evaluated and exploration is only in an incipient stage (approx. 170 wells), driven mainly by the recent spike in the price of natural gas and declining gas reserves. Because of limited exploration and production, estimates of CBM potential for Alberta vary widely between 187 Tcf (McLeod et al., 2000) and 540 Tcf (Canadian Gas Potential Committee, 1997).

Currently, Canada’s energy needs are met by abundant coal and hydrocarbon fuels, and hydroelectric and nuclear power. However, the National Energy Board forecasts that unconventional gas, mainly CBM, will be required to meet Canadian demand by 2008, and could constitute up to 65% of supply by 2025. Lately, concerns about anthropogenic greenhouse gases and global climate change have led to the consideration of CO_2 sequestration in coal beds by adsorption trapping (Gunter et al., 1997; Byrer and Guthrie, 1999; Bachu, 2001). Injection of CO_2 into coal beds enhances coalbed-methane recovery (ECBMR) because more methane is released from the coal matrix than with conventional methods, as a result of the higher affinity of coal for CO_2 than for methane. The current study, whose results are presented in this report, attempts to fill a knowledge gap in establishing the future of CBM in Alberta, acknowledging that CBM production from, and CO_2 injection into, coal seams depend on their hydrogeological and stress regimes.

1.1 Coalbed Methane in Rocky Mountain Basins

Coalification is the process by which peat is transformed into coal during progressive burial, a process that involves the expulsion of volatiles (mainly methane), water and carbon dioxide. Gases can be generated from coal beds during three stages:

- Early biogenic gas is formed during an early shallow-burial phase, dominated by microbial degeneration of original organic material in the early stages of coalification, and coupled with physical compaction, maceration and water expulsion.
- Thermogenic gas is formed by thermal processes during the main stages of abiogenic coalification.
- Late-stage biogenic gas is generated by bacterial activity associated with groundwater systems, regardless of the coal's rank.

The most commonly encountered coalbed gases in Rocky Mountain basins are of the second and third types, and mixes of these two (Johnson and Flores, 1998). Low-rank coal deposits that exist at shallow depths and have significant outcrop exposure may contain mainly late-stage biogenic methane, which seems to be the case with the CBM-producing Fruitland Formation in the San Juan basin and the Fort Union Formation in the Powder River basin (Scott et al., 1994; Montgomery, 1999).

Coal in the Rocky Mountain foreland basins was deposited during three different time periods: 1) late Jurassic–early Cretaceous, 2) late Cretaceous, and 3) Paleocene and Eocene. The thickest and most extensive Upper Cretaceous coal beds were deposited from latest Cenomanian through middle Maastrichtian time in coastal-plain settings along the margins of the Western Interior epicontinental seaway that covered much of the foreland basin formed, during the Cretaceous, east of the Rocky Mountain overthrust belt. The large foreland basin that extended from the Arctic Ocean to the Gulf of Mexico during the Cretaceous has been partitioned by the Tertiary Laramide orogeny into the very large Alberta basin in Canada and much smaller basins in the United States, such as the Powder River, Wind River, Hanna, Greater Green River, Piceance, Uinta, San Juan and Raton basins (Johnson and Flores, 1998).

Coalification in the American Rocky Mountain basins occurred as a result of 1) burial by foreland-basin sediments during the Cretaceous; 2) burial by Laramide-basin sediments from late Cretaceous through Eocene, and subsequent burial beneath Oligocene and younger sedimentary and volcanic rocks; and 3) increased geothermal gradients related to Oligocene and younger igneous events (Johnson and Flores, 1998). In the Alberta basin, the first two factors are the most likely causes of coalification, because igneous events are minor and isolated. Estimates of the amount of overburden removed by Tertiary to Recent erosion range from 1000 m to approximately 4000 m (Nurkowski, 1984; Kalkreuth and McMechan, 1988; Bustin, 1991). This indicates that the initial peat accumulations have been subjected to high temperatures and pressures, sufficient for coalification and gas generation, a process that seems to be still active today (Michael and Bachu, 2001).

Coaly intervals in American Rocky Mountain basins occur in thick stratigraphic intervals that are either water saturated or almost completely charged with gas (Johnson and Flores, 1998). In the former case, water in hydrodynamic equilibrium with outcrop seems to be the reservoir-pressuring agent. In the latter case, which occurs in the structurally deeper parts of these basins, coal beds, sandstone, and even mudstone and shale are gas charged, with much of the gas originating from coal beds and carbonaceous shale (Meissner, 1984). Water is present at near-irreducible levels in all lithological units. All of these deposits 1) cut across structural and stratigraphic boundaries; 2) have low in situ sandstone permeability; 3) commonly occur downdip from more permeable water-saturated aquifers and reservoirs; 4) typically have no obvious structural and/or stratigraphic trapping mechanism; and 5) seem to be always either over- or underpressured (Johnson and Flores, 1998). The abnormal pressures indicate that the pressuring agent is not water in equilibrium with outcrop, but rather the hydrocarbons within these tight reservoirs (Johnson and Flores, 1998).

Low permeability in tight sandstone in these basins is caused by the intergranular precipitation of illite-smectite clays, probably due to the highly reactive water expelled from coal during the early stages of coalification, prior to thermogenic gas generation (Law et al., 1983; Meissner, 1984). The gas generated in the deep, thermally mature areas of these basins is inhibited from migrating upward by the low relative permeability of these sandstone beds to gas (Masters, 1979, 1984; Spencer, 1985, 1987). The capillary seal is activated as gas replaces water in the pore space, so that the basin-centerd gas accumulations seal themselves as they form. An overpressured accumulation can evolve into an underpressured one if a basin undergoes significant cooling as a result of uplift and overburden removal (Law and Dickinson, 1985). This process would explain the underpressuring along the margins of the basin-center gas accumulations (Johnson and Flores, 1998) that is also observed in the Alberta basin (Michael and Bachu, 2001).

1.2 Coalbed Methane Producibility

Gas is stored within the coal as 1) limited free gas within the micropores and cleats (fractures) of the coal; 2) dissolved gas in the water within the coal; 3) adsorbed gas held by molecular attraction on the surfaces of coal particles, micropores and cleats; and 4) absorbed gas within the molecular structure of the coal (Yee et al., 1993). The ability of any particular coal to store gases is a function of several factors, including coal rank and quality, burial depth (because increasing pressure and temperature allow for increased storage) and water saturation. Thus, unlike conventional hydrocarbon plays, coal in CBM plays acts as both the source rock and the reservoir for the gas.

Gas migration within coal takes place by a combination of desorption, diffusion and free-phase flow, and occurs as a direct result of decrease in pressure. The relationship between the volume of released gas and a given pressure drop is complex, nonlinear and specific to each coal (Levine, 1993), so it must be individually established in each case. Because the permeability of the coal matrix is extremely low, fluid conductivity in coal depends upon fracture (i.e., cleat development and permeability; Montgomery, 1999). The dual role of the coal bed, as both gas source and reservoir, leads to the following paradox: in order for gas to be trapped, the coal must be either sealed or have very low permeability, whereas the gas must readily migrate to the production well (i.e., the coal should have high permeability) to facilitate production.

Recent studies (e.g., Scott et al., 1994; Tyler et al., 1997) have shown that coalbed methane producibility depends on the following interrelated factors:

- geological factors, such as tectonic, structural and depositional setting
- coal distribution and properties, such as rank and gas content
- coal permeability
- hydrogeology of formation waters

The tectonic and structural setting determines the subsidence regime, sedimentation patterns and locus of peat accumulations (Pashin, 1994). It dictates whether coalification proceeds to ranks sufficient for thermogenic gas generation through burial and thermal history, and it initiates stress-induced fractures in coal for enhanced permeability (Tyler et al., 1997). The depositional setting imposes a strong control on CBM producibility, because it determines the size, thickness, orientation and stratigraphy of the coalbed reservoirs (Pashin, 1994).

Coal rank, ash content and maceral composition influence the volume of generated methane, coal-gas content and gas composition. Coalbed-gas composition directly relates to coal rank, maceral composition and basin hydrodynamics (Scott et al., 1994; Tyler et al., 1997). Hydrodynamics affects CBM producibility by maintaining (or not) the pressure needed for gas sorption on the coal surface. Vigorous flow of formation waters provides the means for long-distance migration to traps and introduces bacteria that may generate secondary biogenic gases.

Production rates of coalbed methane are extremely sensitive to reservoir properties, of which permeability is one of the critical (Schraufnagel, 1993; Zuber et al., 1996). Low permeability is one of the leading causes for the lack of development of coalbed methane in Rocky Mountain basins (Johnson and Flores, 1998; Montgomery, 1999). Coal permeability depends largely on the fracture (cleat) density, width and orientation. Cleats, which occur in two orthogonal systems (face and butt cleats) nearly perpendicular to bedding, are the result of a number of interdependent factors, including paleotectonic stress (Close, 1993). Regardless of the quantity of gas in place, there is a permeability value below which the resource cannot be produced economically, estimated to be 10^{-15} m^2 (1 mD; Zuber et al., 1996).

Data from the Piceance, San Juan and Black Warrior basins in the United States, and from the Sydney and Bowen basins in Australia, document a decrease in permeability with burial depth. Thus, low permeability is likely to be a problem with deep coal seams, in that coalbed reservoirs deeper than 1500 m generally have permeabilities below what is presently required for economic production (Zuber et al., 1996). Characteristic permeability values for CBM plays in the San Juan and Black Warrior basins range from 2×10^{-15} m^2 to 35×10^{-15} m^2 (2–35 mD; Sawyer et al., 1990; Mavor et al., 1994). Actually, because of high permeability, orders of magnitude higher than the confining sandstone, the coal beds of the Fruitland Formation in the San Juan basin act as the main aquifer (Scott et al., 1994; Kaiser and Ayers, 1994).

Very little information exists regarding the permeability of coal beds in the Alberta basin, the available data generally indicating low permeability (Dawson, 1995). Extensive studies of coal beds in the Sydney and Bowden basins in Australia, and in the Black Warrior basin in Alabama, show that coal permeability correlates strongly with stress magnitude (Enever et al., 1994, 1999; Sparks et al., 1995; Bustin, 1997). Thus, the stress regime in the Cretaceous coal-bearing strata in the plains of the Alberta basin may indicate areas of enhanced coalbed permeability and therefore CBM producibility.

1.3 Hydrodynamics and Water Production

Hydrodynamics is critical for CBM generation, accumulation and producibility. For instance, methane-generating bacteria are introduced by groundwater. In the San Juan basin, the distribution of chemically dry gases coincides with meteoric recharge, low-chloride formation water of meteoric origin, and regional overpressure of artesian origin (Scott et al., 1994). Highly permeable, laterally continuous Fruitland coal beds in the northern, highly productive region of the basin extend to, and crop out at, the elevated recharge area in the foothills of the San Juan

Mountains. Overpressuring is caused by recharge at high elevation, aquifer confinement and basinward pinch-out of aquifer coal beds. Recharge is limited in the remaining, less productive part of the basin, due to erosional truncation, low rainfall and poorer aquifer quality (Scott et al., 1994). Similarly, in the Powder River basin, thick, laterally continuous Fort Union coal beds in downdip areas are artesian aquifers with significant amounts of late-stage biogenic methane (Montgomery, 1999).

Because many coal beds, particularly at shallow depths, are active aquifers, knowledge of existing hydrogeological conditions is necessary for determining gas potential. In other cases, groundwater is the carrier agent, entraining deep CBM and bringing it to shallower depths where it accumulates, as in the Columbia basin (Johnson et al., 1993). Yet, in other cases, unfavourable hydrodynamics may lead to low CBM potential, as in the William Forks Formation in the Sand Wash basin, where water flow is from areas of low thermal maturity to areas of high thermal maturity, so that only relatively small volumes of gas are available for eventual resorption or to be swept basinward for conventional trapping (Hamilton, 1993). Thus, hydrodynamics is a critical element in establishing the methane potential of coalbeds.

Because gas adsorption on the coal depends on pressure, gas recovery is achieved by decreasing the pressure through dewatering. Continuous water production from a coal bed results in a corresponding progressive increase in gas production up to a certain limit, which depends on coal thickness, depth (original pressure and temperature), absolute and relative permeability, compressibility and gas saturation (Montgomery, 1999). However, the same dewatering that leads to methane production may place limits on actual development because of environmental issues and high cost associated with water disposal (Montgomery, 1999; Johnson and Flores, 1998).

The means and cost of water disposal are major economic factors in CBM development, as demonstrated by the American experience in the Black Warrior, Appalachian, San Juan and Alaskan basins (Ortiz et al., 1993; Cox, 1993; Zuber, 1998; Triolo et al., 2000). Depending on composition, the produced water can be disposed of by 1) direct discharge onto the surface, where it can seep down into shallow potable aquifers; 2) controlled discharge into surface streams; 3) underground injection into deep formations using wells; 4) concentration of produced saline water in a multiple-effect evaporator; and 5) conversion of wastewater into clean water by various processes. Of these, underground injection is the most commonly used, either because of environmental regulations or because of the high cost of other methods (Ortiz et al., 1993; Zuber, 1998; Triolo et al., 2000).

If the salinity of produced water is greater than 10 000 mg/l, then the water is classified the same as water from an oil or gas well and can be disposed of only by deep injection (Nackles et al., 1992). The quality of the produced water is critical in selecting a chemically compatible disposal horizon and strategies; otherwise, injectivity may decline to the point of requiring well abandonment, as in the case of several wells in the San Juan basin (Cox, 1993). In the case of coal seams in hydraulic communication with the surface, the water is of meteoric origin and sufficiently fresh (low salinity) as to allow disposal at surface (released into streams or on the ground) of the produced water, as in the Powder River basin. Thus, success in CBM development is contingent on the ability to economically dewater the coal and dispose of the produced water.

The above discussions show that the development of viable CBM production in the Alberta basin depends as much on coal permeability, hydrodynamics and water quality as on coal gas content. It is therefore necessary to study the hydrogeology and stress regimes of the coal-bearing strata. The study area, chosen to cover the known Upper Cretaceous–Tertiary coal deposits in Alberta, extends from the Canada–United States border (latitude 49°N) in the south to latitude 56°N in the north (Twp. 1 to 80), and from the Alberta–Saskatchewan border (longitude 110°W) in the east to longitude 120°W and the edge of the Rocky Mountain deformation front in the west.

2 Geology of the Upper Cretaceous–Tertiary Coal-Bearing Strata in the Alberta Basin

The Alberta basin, initiated during the late Proterozoic by rifting of the North American craton, lies on a stable Precambrian platform and is bounded by the Intramontane and Omineca orogenic belts to the west and southwest, the Tathlina High to the north, the Canadian Precambrian Shield to the northeast, and the Williston basin to the east and southeast. The undeformed part of the basin comprises a first-order wedge of sedimentary rocks that increases in thickness from zero at the edge of the Canadian Shield in the northeast to more than 6000 m at the edge of the thrust and fold belt in the southwest. The basin has a gently dipping east flank against the Precambrian basement and a steeply upturned and highly faulted west flank against the frontal thrust of the Rocky Mountain overthrust belt.

The Alberta basin consists of a passive-margin succession, dominated by carbonate and evaporite deposition with some intervening shale, followed by a foreland-basin succession dominated by clastic, largely shale deposition since the middle Jurassic (Porter at al., 1982). Pre-Cretaceous erosion has partially removed older strata, which subcrop at the unconformity from southwest to northeast, with increasing age, from Jurassic to middle Devonian. Continued uplift associated with the Columbian orogeny in the early Cretaceous provided abundant sediment to the foredeep trough, resulting in fluvial deposition in the southern and central parts of the basin and coeval marine-shale deposition in the northern part of the Mannville Group. The Colorado Group succession of thick marine shale and several thin, isolated, intervening sandstone sheets was deposited during the following lull in plate convergence and major sea-level rise in the early late Cretaceous.

The late Cretaceous docking of the oceanic Insular Superterrane (Alexander–Wrangellia Terrane; Cant and Stockmal, 1989) resulted in rapid deposition of a second-order wedge of continental and marine sediments during the Campanian to Paleocene, comprising three third-order, generally regressive wedges of marine to nonmarine, coarsening-upward, synorogenic molasse sediments. The lull in tectonic activity ended with the deposition of the thick and competent marine shale of the Lea Park Formation and its equivalent in southern Alberta, the Pakowki Formation. The first major influx of Cordilleran clastic detritus of fluvial origin created the thick, coal-bearing Belly River Group. The Bow Island Arch, present in the south, may represent the inflexion point between the rapidly subsiding Alberta basin to the west and the intracratonic Williston basin to the east. Another major rise in relative sea level resulted in the shale deposition of the Bearpaw Formation in the southern part of the basin. During the late Cretaceous to early Tertiary, two other major, coal-bearing, coarse-clastic successions, the Horseshoe Canyon and Scollard formations, were deposited in the southern part of the basin. They were similarly derived from the Cordillera, and are separated by the marine shale of the Battle Formation In the west-central part of the basin, where the Bearpaw Formation is absent due to nondeposition, the coarse clastic deposits of the Belly River Group and Horseshoe Canyon Formation are undistinguishable from each other and form the Wapiti Group. Similarly, the Bearpaw Formation is absent close to and along the thrust and fold belt, where the Belly River Group and Horseshoe Canyon Formation coalesce into the Brazeau Group.

Coarse clastic deposition continued in the early Tertiary with deposition of the Paskapoo Formation. Subsequent to this cycle, a period of tectonic compression and uplift followed in the early Tertiary (the Laramide orogeny), leading to the deposition of fluvial-channel sandstone, siltstone and shale. Between 1600 and 3800 m of sediments were deposited in the southern part of the Alberta basin and subsequently removed by erosion since the Paleocene (Nurkowski, 1984; Bustin, 1991). As a result, the Lea Park–Paskapoo succession is exposed at the top of the bedrock under unconsolidated Quaternary sediments of preglacial and glacial origin, with increasing age from the basin foredeep in the southwest to the basin edge in the northeast (Figure 1). The stratigraphic nomenclature and delineation of the coal-bearing Cretaceous–Tertiary strata in the Alberta basin are presented in Figure 2.

Surface topography, the result of Tertiary to Recent erosion, drops gently in the study area from an elevation of more than 1300 m in the southwest and west near the thrust and fold belt (the Swan Hills in the northwest and the Cypress Hills in the southeast), to approximately 500 m in the northeast (Figure 3). Drift thickness varies from a few metres to more than 100 m in the hills along the thrust and deformation front (in the Cypress Hills in the southeast and in buried channels in the north and northeast; Figure 4). Accordingly, the top of the bedrock varies in elevation from more than 1200 m in the west-southwest and at the Cypress Hills, to less than 500 m in the northeast (Figure 5).

Peat accumulated in the Alberta basin during the late Jurassic and early Cretaceous, and during the late Cretaceous and early Tertiary, leading to the formation of coal deposits in the Lower Cretaceous Mannville Group, the Upper Cretaceous Belly River Group and Horseshoe Canyon Formation, and the Upper Cretaceous–Paleocene Scollard and Paskapoo formations. Unlike in some Rocky Mountain basins in the United States, large-scale volcanism and igneous events are absent from the Alberta basin, and only small-scale pipes and intrusions are present. As a result, coal rank and gas content are the result of burial only. The stratigraphic location of various Upper Cretaceous–Tertiary coal zones is shown in Figure 2. Coal in this succession ranges from lignite to high-volatile bituminous in rank, generally increasing in rank from east to west, consistent with increasing depth (Bustin, 1991). The coal seams dip to the west and occur at depths ranging from surface outcrop to more than 2500 m.

2.1 Belly River Group

The top of the Lea Park Formation, which dips southwestward from outcrop in the northeastern part of the study area to less than –1200 m elevation in the southwest near the Mesozoic deformation front (Figure 6), constitutes the base of the Belly River Group, which comprises (from oldest to youngest) the Foremost, Oldman and Dinosaur Park formations (Hamblin and Abrahamson, 1996). The top of the Belly River Group, defined by the base of the Bearpaw Formation shale, varies in elevation from more than 1100 m at outcrop in the south near the Canada–United States border and more than 600 m at outcrop in the northeast, to less than –600 m in the west (Figure 7). The Belly River, a dominantly fluvial clastic wedge, becomes thinner and younger to the east and northeast as the underlying, interfingering Pakowki–Lea Park marine shale thickens. Three coal zones, the McKay, Taber and Lethbridge, are found in the Belly River Group, with the last two defining the top of the Foremost and Dinosaur Park formations, respectively (Hamblin and Abrahamson, 1996).

The ‘Basal Belly River’ sandstone, found at the base of both Belly River and Wapiti groups, is a marine-nonmarine transitional coastal system, oriented approximately north-south, that can be divided into a series of at least seven stacked, composite, primarily regressive, fourth-order cycles

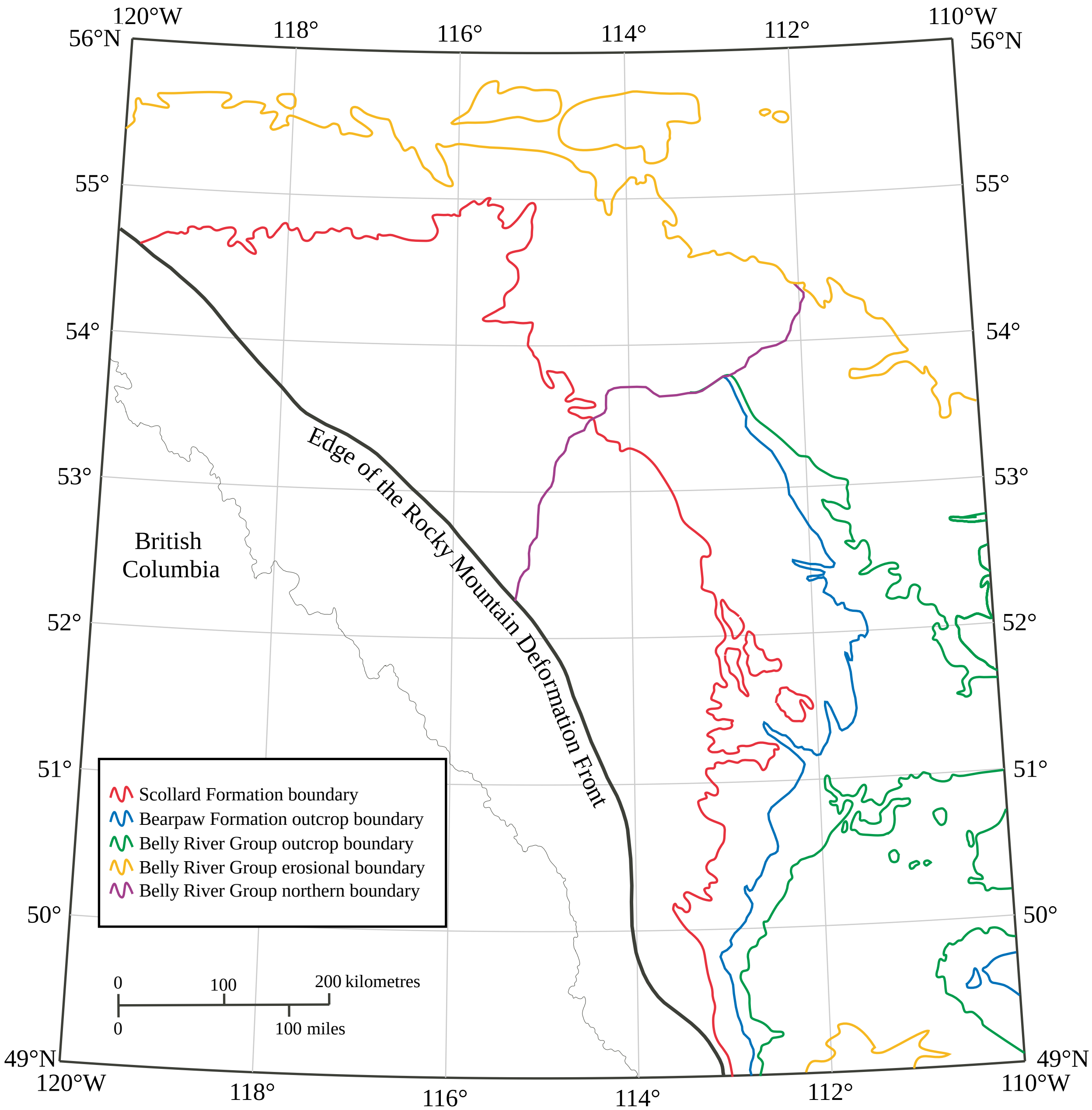


Figure 1. Erosional boundaries and outcrop at the top of the bedrock of the Upper Cretaceous - Tertiary coal-bearing strata in the Alberta basin.

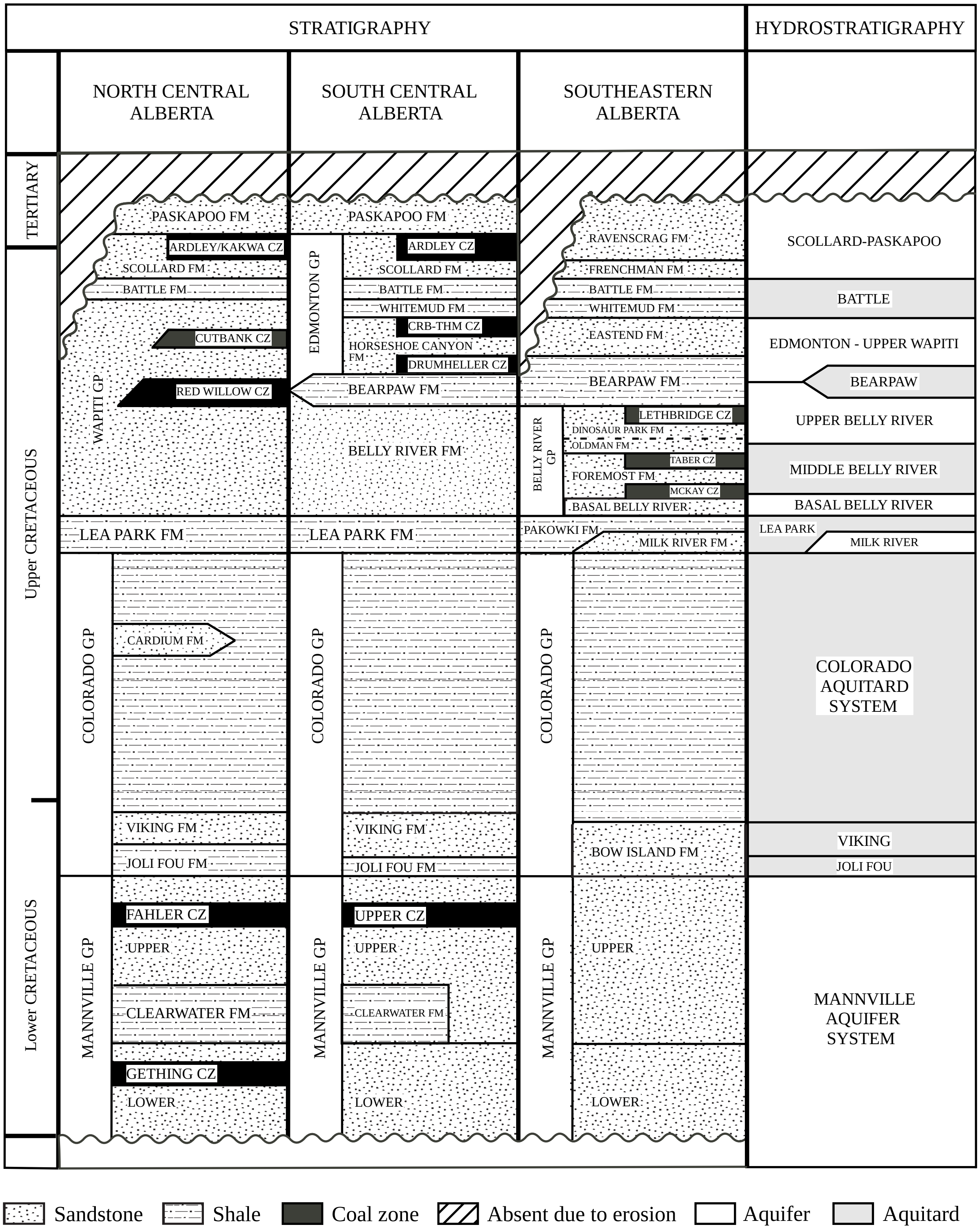


Figure 2. Stratigraphic and hydrostratigraphic nomenclature and delineation of the coal-bearing Cretaceous - Tertiary strata in the Alberta Basin, and position of coal zones (hydrostratigraphyof the pre-Lea Park sucession after Bachu, 1995).

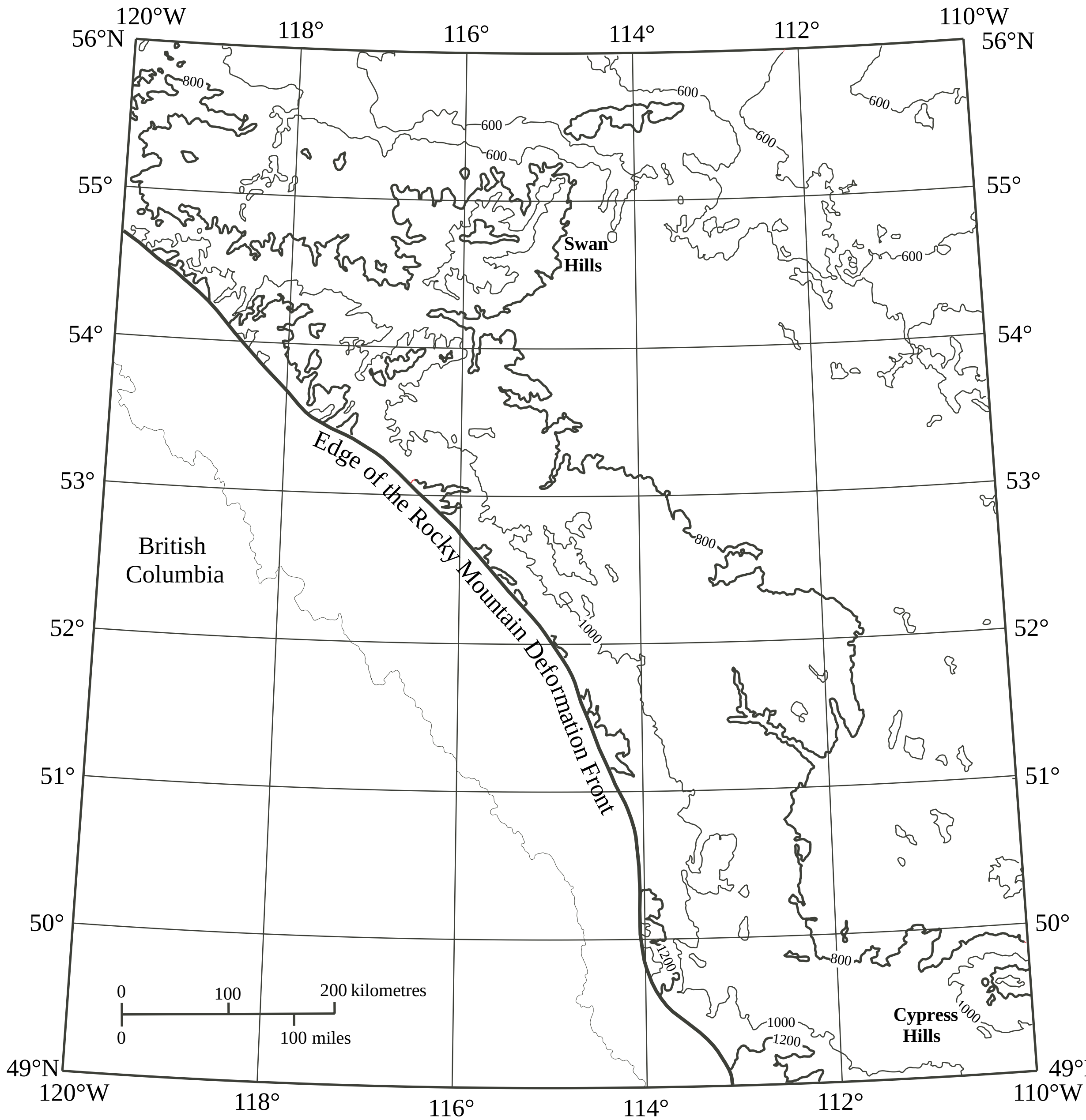


Figure 3. Surface topography of the study area (contour interval: 200 m).

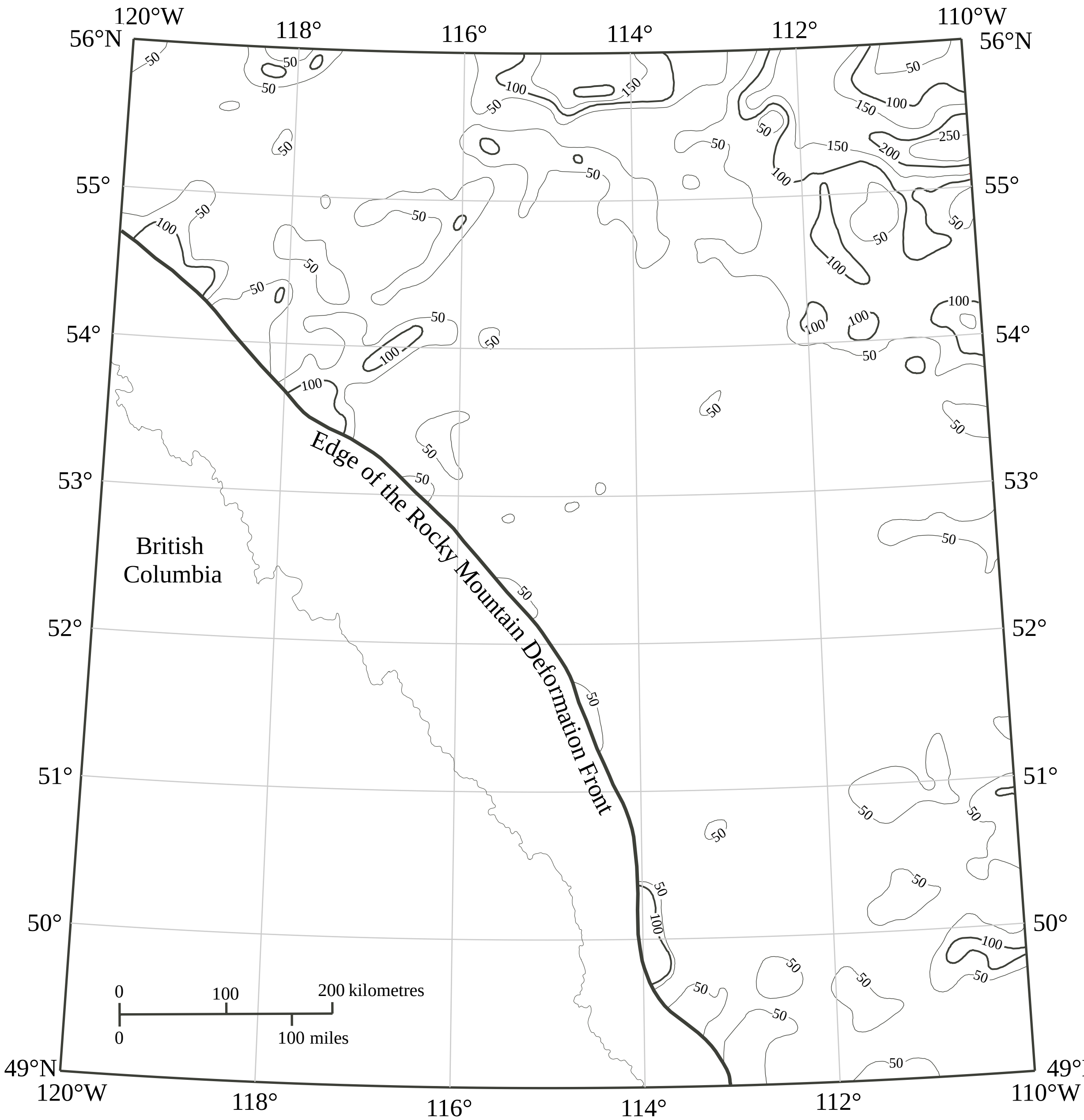


Figure 4. Drift thickness in the study area (from Fenton, et al., 1994; contour interval in m).

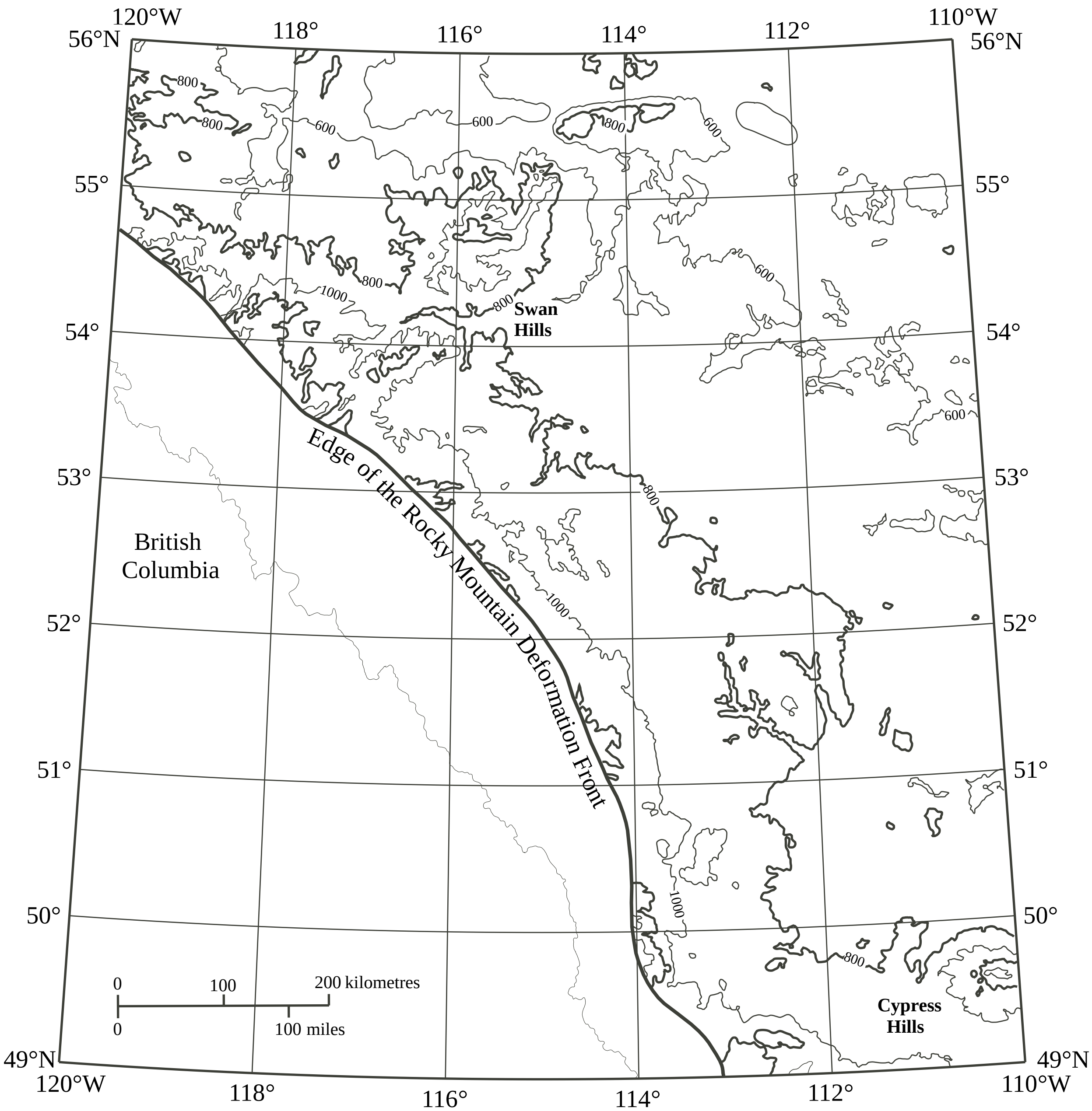


Figure 5. Bedrock elevation in the study area (contour interval: 200 m).

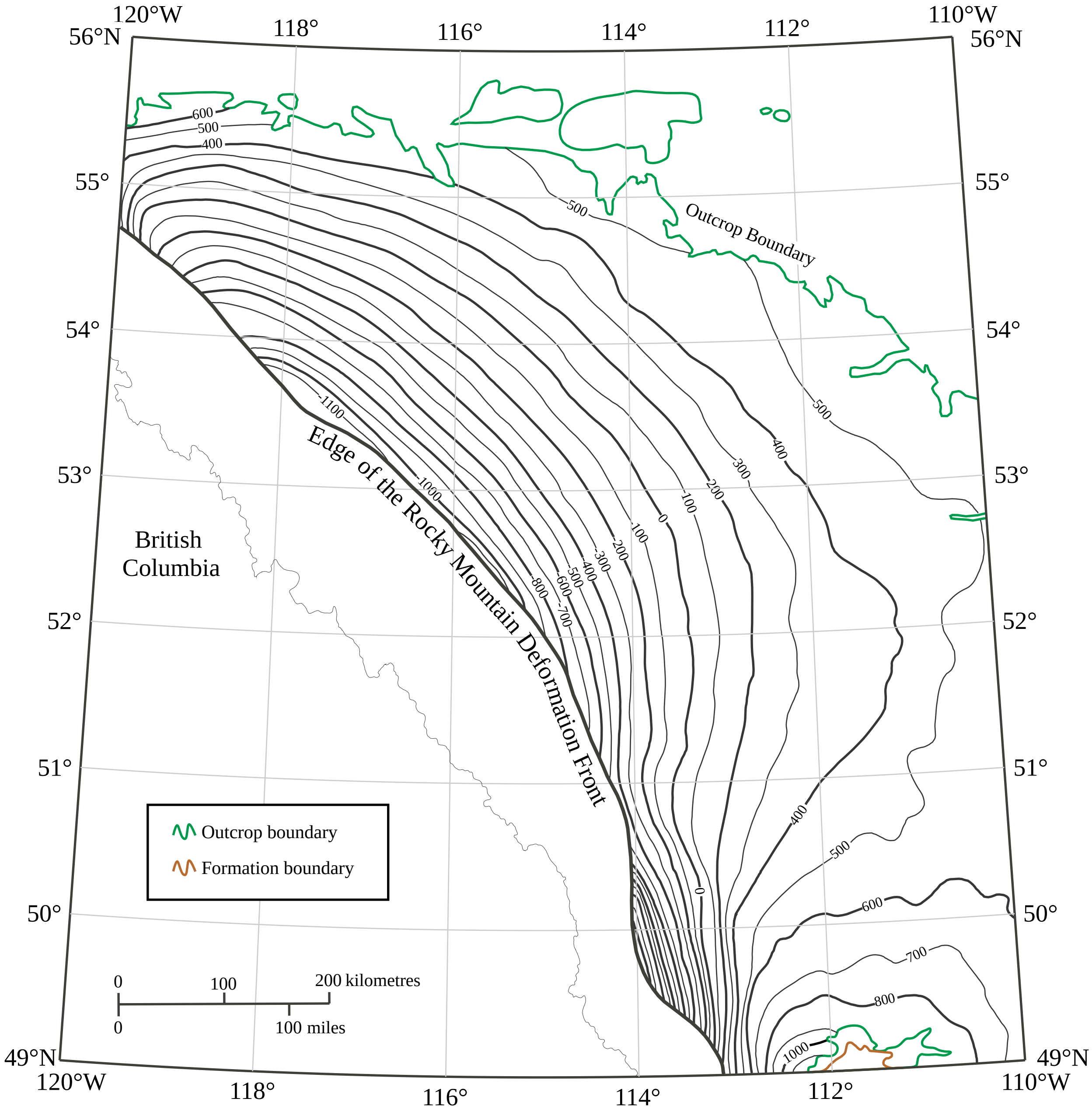


Figure 6. Structure elevation at the top of the Lea Park Formation in the subsurface (contour interval in m).

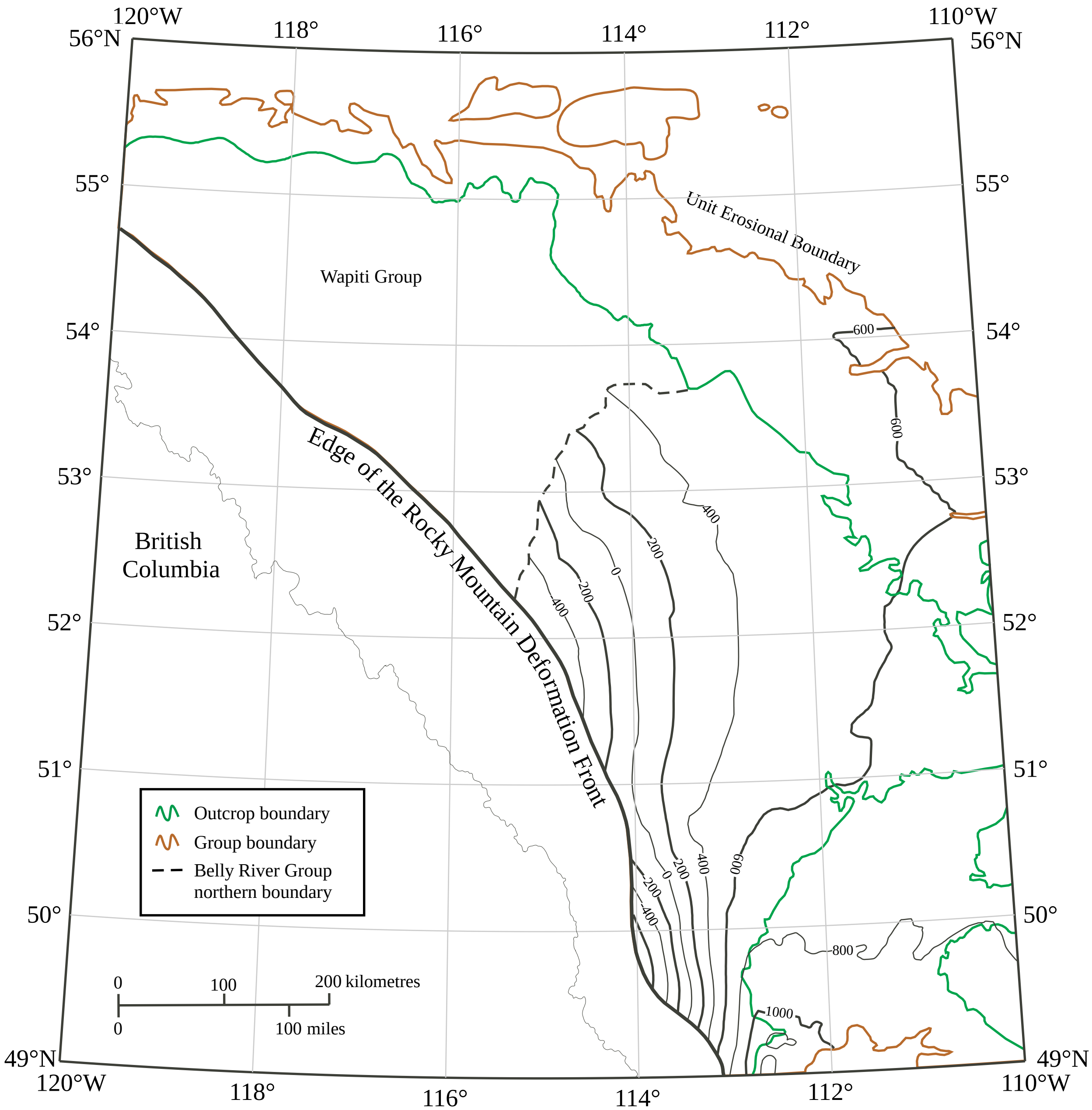


Figure 7. Structure elevation at the top of the Belly River Group (in the northern part it is the undifferentiated Wapiti Group; contour interval in m).

of subregional extent (Hamblin and Abrahamson, 1996). Each cycle is characterized by continental-coaly deposits in the west and a central belt composed of stacked shoreline sandstone, thinning to the east. The center of maximum sand deposition in each successive cycle is located east of, and stratigraphically higher than, the preceding one (Hamblin and Abrahamson, 1996). The top of the Basal Belly River sandstone varies in elevation from approximately 500 m near or at (undefined) outcrop to less than –1000 m in the west (Figure 8). Many oil pools and hundreds of gas pools are found in the Basal Belly River sandstone in southern and central Alberta.

The McKay Coal Zone near the base of the Foremost Formation and immediately overlying the Basal Belly River sandstone is present in the Alberta basin but passes eastward into marine shale in the Williston basin. The nonmarine strata overlying the Basal Belly River cycles comprise the remainder of the Foremost Formation and are dominantly siltstone. Fluvial-channel or valley-fill sandstone units are present throughout this eastward-thinning sedimentary wedge. The Taber Coal Zone, marking the top of the Foremost Formation, also thins eastward and overlies the basal Belly River sandstone due to the eastward pinch-out of the bulk of the Foremost Formation (Figure 9).

The primarily transgressive Oldman Formation in the middle of the Belly River Group is present throughout southern and central Alberta and disappears to the north and northeast due to thinning and to truncation by the overlying Dinosaur Park Formation. It can be informally divided into two units, the lower Comrey Member sandstone and an 'upper siltstone' member (Hamblin, 1997a). The Dinosaur Park Formation at the top of the Belly River Group is dominated by thick, multistoried sandstone units, up to 40 m thick, in its lower portion and by siltstone and coal in the upper portion (Hamblin, 1997b). It thins out to the south due to depositional changes. The Lethbridge Coal Zone, at the top of the formation, is overlain by the transgressive marine shale of the Bearpaw Formation. A significant number of gas pools are found in the Oldman and Dinosaur Park formations.

2.2 Edmonton Group

The Horseshoe Canyon Formation strata of the Edmonton Group (Figure 2) represent part of a vast, east-thinning wedge of generally nonmarine sediments deposited along the western margin of the subsiding Bearpaw seaway. The underlying Bearpaw Formation, consisting of predominantly marine shale, represents the last major marine transgression preserved in the stratigraphic record of the Alberta basin. It is up to 350 m thick and thins westward and northward due to facies change, eventually pinching out close to the thrust and fold belt and in central Alberta (Catuneanu et al., 1997). The Bearpaw Formation crops out in southern Alberta over a wide geographic area (Figure 1).

Isostatic relaxation and uplift led to the eastward withdrawal of the Bearpaw sea and deposition of the Horseshoe Canyon Formation nonmarine clastic wedge, characterized by 1) great lateral and vertical facies variability; 2) bentonite; and 3) abundant thin coal beds found in the Drumheller, Daly and Carbon Thomson coal zones (Hamblin and Lee, 1997). The Horseshoe Canyon Formation is conformably overlain by the fluvial sandstone of the Whitemud Formation, which is in turn overlain conformably by the lacustrine shale of the Battle Formation. The latter contains several thin tuff beds, the Kneehills Tuff Zone. The top of the Edmonton Group ranges in elevation from less than 200 m in the west to approximately 800 m at outcrop (Figure 10), and contains a small number of gas pools.

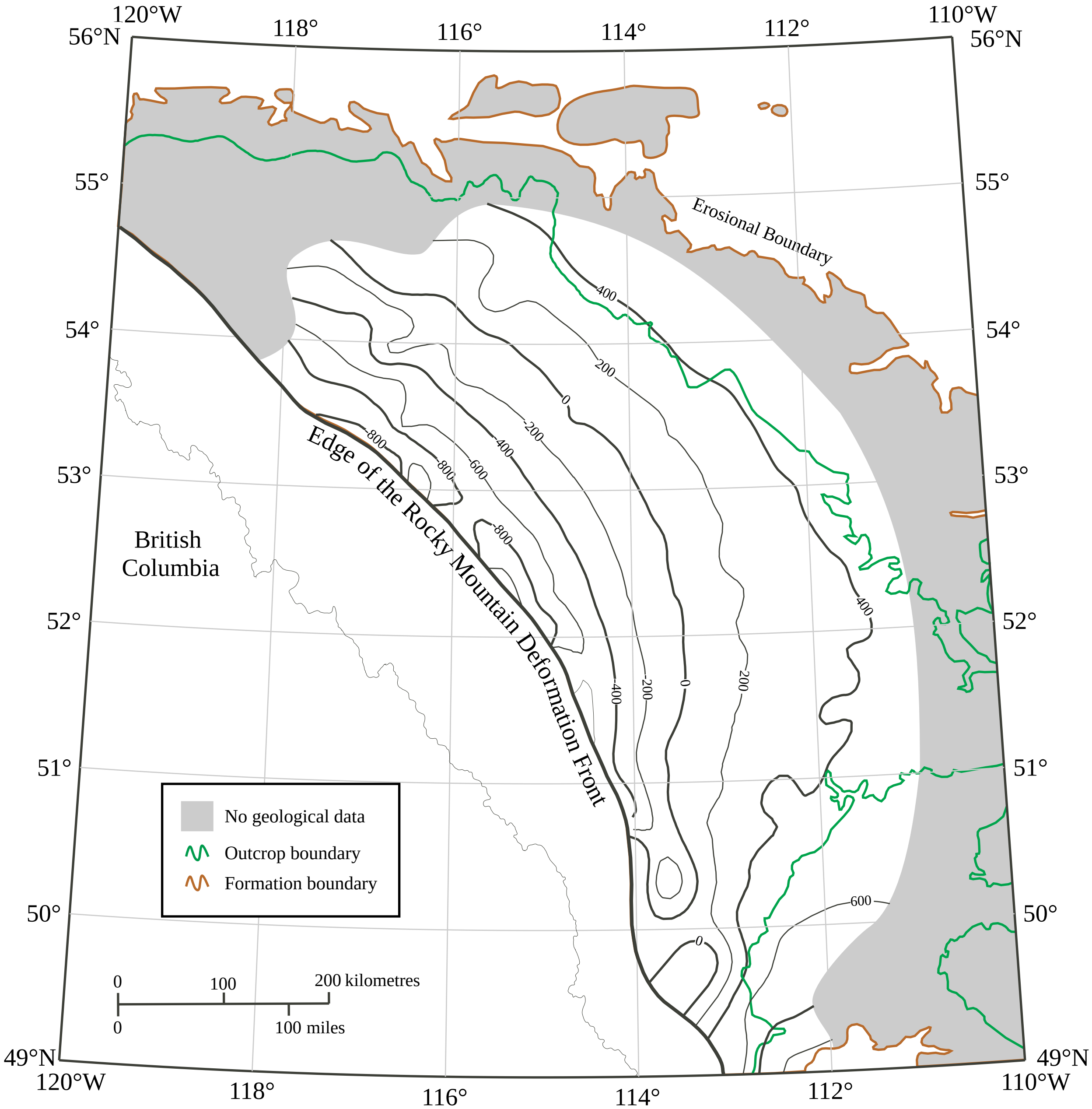


Figure 8. Structure elevation at the top of the Basal Belly River sandstone (contour interval in m).

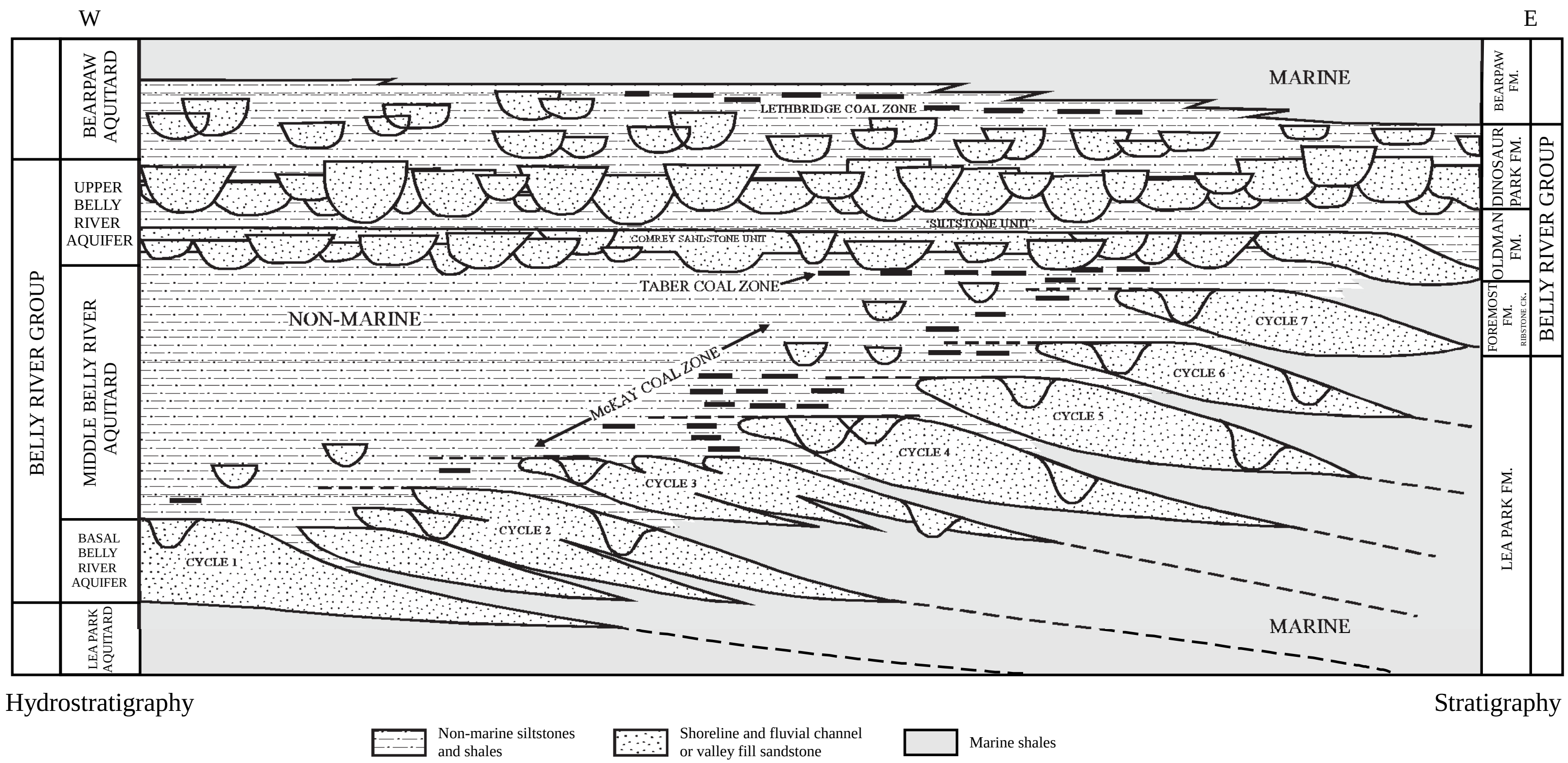


Figure 9. Diagrammatic west-east cross-section through the Belly River Group (from Hamblin and Lee, 1997).

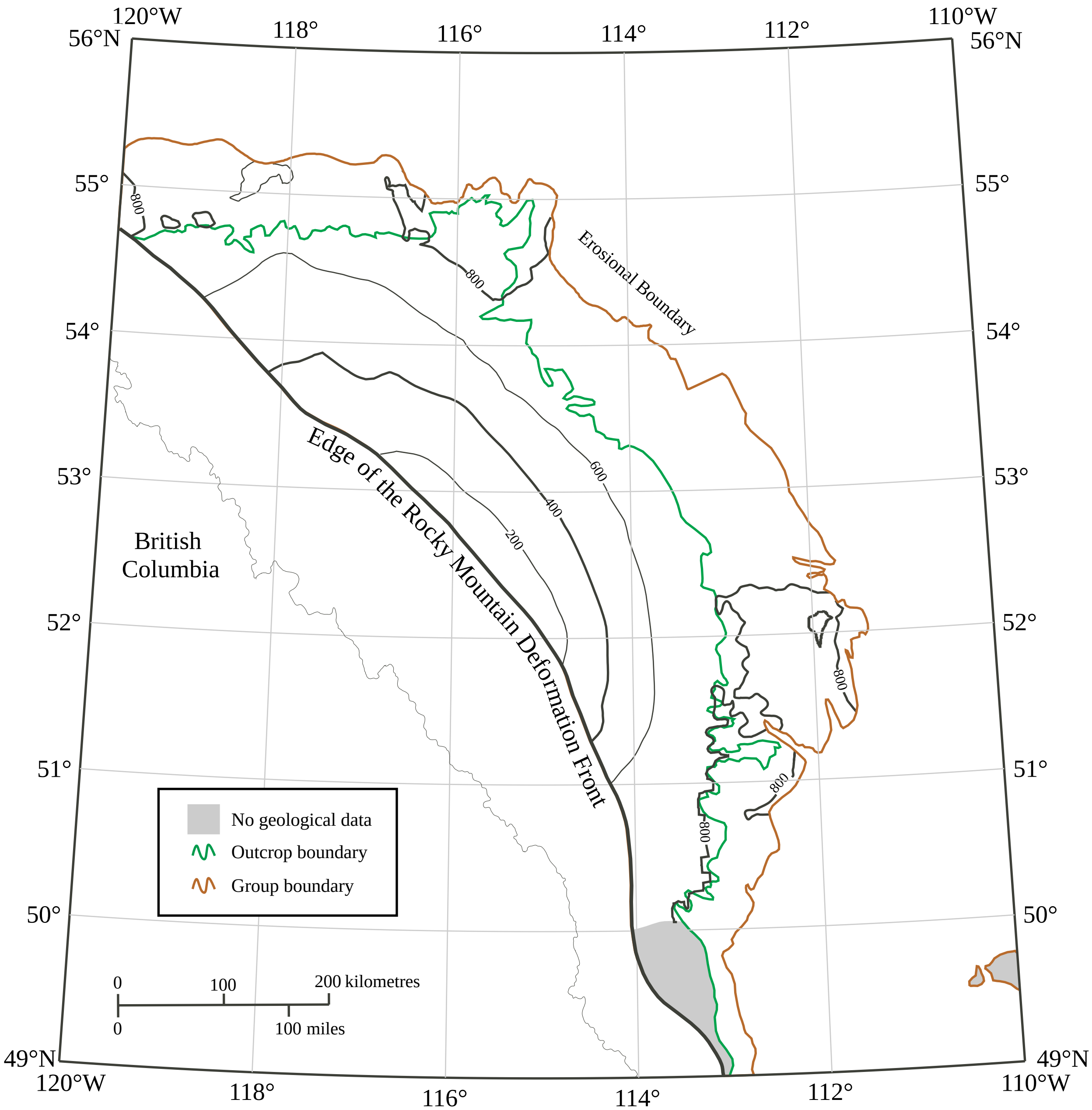


Figure 10. Structure elevation at the top of the Battle Formation (contour interval in m).

2.3 Wapiti Group

Campanian to Paleocene terrestrial rocks of northwestern Alberta (western Alberta basin), which overlie the shale of the Lea Park Formation, have been traditionally defined as the Wapiti Group (Figure 2). The basal 30 m or so of the lower Wapiti Group, consisting of thick coarse-grained sandstone and capped by a thin coaly horizon (Smoky River), correlate with the basal Belly River sand that occurs in the southern part of the basin. (Dawson et al., 1994a). The unit becomes more coarse grained westward, and contains conglomeratic beds several metres thick. Several cycles of sandstone and siltstone overlie the basal unit and complete the lower Wapiti Group. The Red Willow Coal Zone, containing up to eight coal seams, is present approximately 100 m below the top of the lower Wapiti Group (Dawson et al., 1994a). Fluvial sandstone units in the area are commonly prolific hydrocarbon pools. The upper Wapiti Group consists of interbedded fine-grained sandstone and mudstone, and contains up to 12 coal seams of varying thickness (the Cutbank Coal Zone). The Wapiti Group is capped by the shale of the Battle Formation.

2.4 Scollard Formation

The Scollard Formation represents part of an eastward-thinning wedge of generally fluvial strata that extends from the late Cretaceous–early Paleocene deformation front to Manitoba, and was deposited in a rapidly subsiding basin. The base and top of the Scollard Formation wedge are unconformable, and the Cretaceous–Tertiary boundary divides it into lower and upper members. The lower part is dominated by coarse-grained clastic rocks, whereas the upper part is dominated by finer grained sedimentary rocks that show an increase in metamorphic rock fragments (Hamblin and Lee, 1997). The upper member, commonly referred to as the Ardley Coal Zone, contains economic coal resources (Dawson et al., 1994a).

2.5 Paskapoo Formation

The Paskapoo Formation is a nonmarine, conglomeratic, fining-upward sandstone succession, more than 850 m thick, at the top of the bedrock succession. It unconformably overlies the Ardley Coal Zone at the top of the Scollard Formation (Demchuk and Hills, 1991). Thin coal beds are present throughout the formation. Elevation varies from approximately 1400 m near the deformation front in the west to approximately 700 m in the northeast (Figure 11).

The coal beds of the Belly River Group and Horseshoe Canyon Formation are thin and discontinuous, and their rank may be too low to have significant CBM potential, whereas the coal beds of the Paskapoo Formation are too shallow and of too limited an areal extent to be a target (Dawson, 1995). The coal beds of the Scollard Formation contain the laterally extensive Ardley Coal Zone, estimated to contain more than 100 Tcf of methane, that would be a primary exploration target (Richardson, 1991). However, the Horseshoe Canyon–Paskapoo succession is the time equivalent of the coal-bearing and CBM-producing Mesaverde Group in the Greater Green River basin, and of the Fruitland, Vermejo, Lance and Fort Union formations in the San Juan, Raton, Greater Green River, Piceance and Powder River basins, respectively, all of which were deposited in the greater Rocky Mountain foreland basin prior to the Laramide orogeny. Recent experience with shallow, low-rank coal in the Powder River basin suggests that all Upper Cretaceous–Tertiary coal beds in the Alberta basin may have CBM potential and could be productive if other conditions are being met.

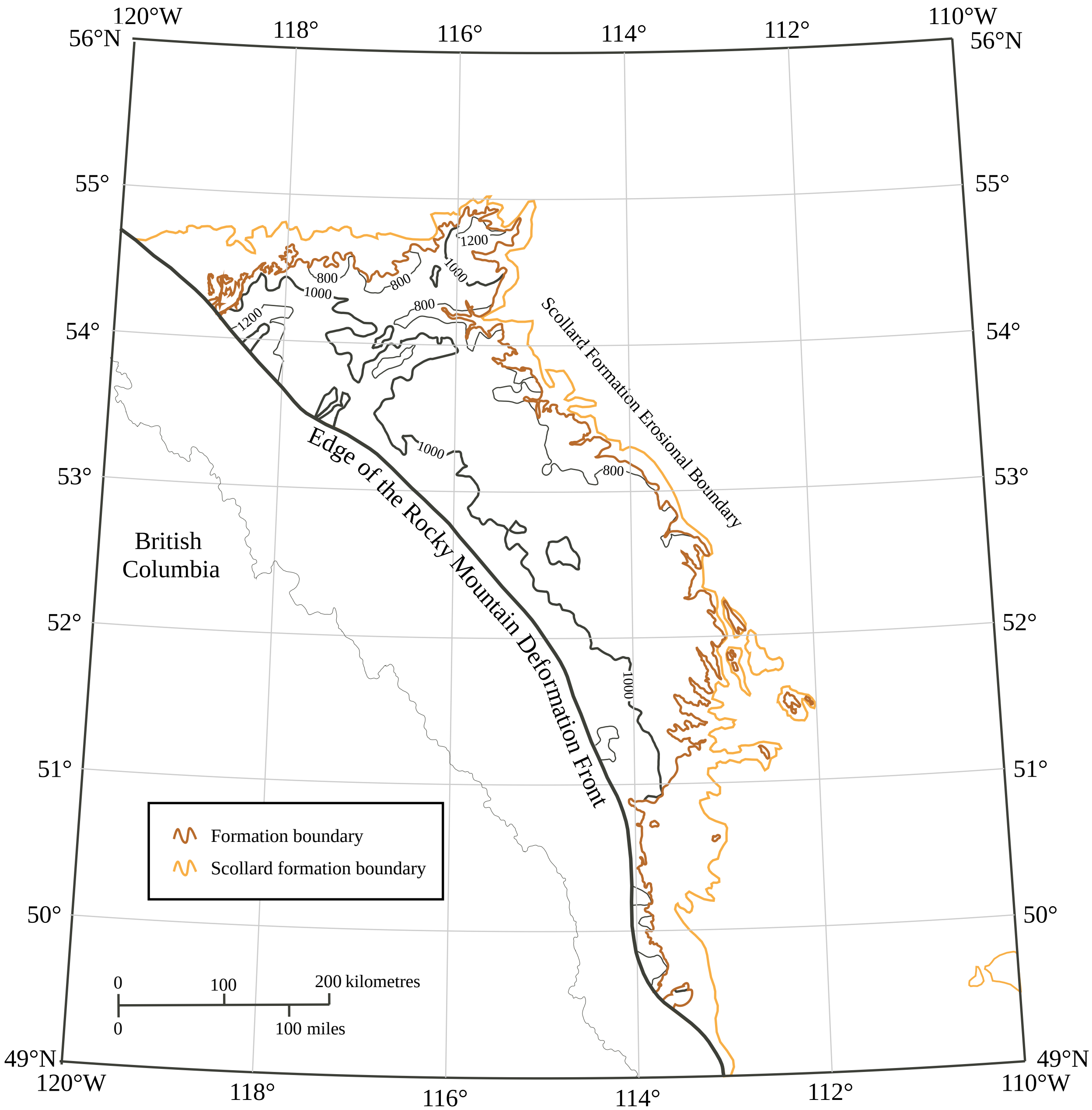


Figure 11. Structure elevation at the top of the Paskapoo Formation (contour interval in m).

3 Hydrogeology of the Upper Cretaceous–Tertiary Coal-Bearing Strata in the Alberta Basin

On the basis of geology and lithology, the Upper Cretaceous–Tertiary succession in the Alberta basin can be divided hydrostratigraphically into the following succession of aquifers and aquitards (Figure 2), in ascending order:

1) Lea Park aquitard at the base of the succession, comprising the shale of the Lea Park Formation and its equivalent Pakowki Formation
2) Basal Belly River aquifer, consisting of the Basal Belly River and the lowermost Wapiti Group sandstone
3) Middle Belly River aquitard, consisting of the siltstone of the Foremost Formation
4) Upper Belly River aquifer, consisting of the sandstones of the Oldman and Dinosaur Park formations and the upper sandstone of the Lower Wapiti Group
5) Bearpaw aquitard, comprising the upper siltstone of the Dinosaur Park Formation and the shale of the Bearpaw Formation
6) Edmonton–Upper Wapiti aquifer, consisting of the sandstones of the Horseshoe Canyon and Whitemud formations of the Edmonton Group in the south, and of the Upper Wapiti Group in the north
7) Battle aquitard
8) Scollard–Paskapoo aquifer, at the top of the succession

This preliminary delineation was subsequently confirmed by analysis of the formation-water chemistry and pressure data.

3.1 Chemistry of Formation Waters

The chemistry of formation waters in the Upper Cretaceous–Tertiary succession of the Alberta basin is based on analyses collected by the energy industry during hydrocarbon exploration and production, and submitted to the Alberta Energy and Utilities Board. Data collected in the 1970–1980 period by the Alberta Research Council from shallow wells, as part of a groundwater-mapping program, were also used in the current analysis. As a result, good chemistry-data coverage was achieved for all the aquifers (Table 1). Data from shallow water wells, filed with Alberta Environment, were not used in this analysis.

Table 1. Number of formation-water analyses and drill-stem tests (DSTs) used in the analysis of the hydrogeological regime in the coal-bearing Upper Cretaceous–Tertiary strata of the Alberta basin.

Aquifer	Original No. of Water Analyses	Final No. of Water Analyses	Original No. of DSTs	Final No. of DSTs
Paskapoo	718	705	24	21
Edmonton/U. Wapiti	329	275	59	55
Upper Belly River	4255	1260	792	587
Basal Belly River	1294	442	1193	1137
Total	6596	2682	2068	1800

Chloride (Cl) rather than salinity (total dissolved solids or TDS) was used initially in the analysis because Cl is both the most commonly determined parameter and one of the most conservative elements found in formation waters. Thus, the initial database was augmented with analyses that do not report TDS but do report Cl. However, the final analysis, presented here, is based on TDS because the total salinity is the element of interest. The formation-water analyses were processed and culled using the methodology described by Hitchon and Brulotte (1994) and Hitchon (1996). Analyses that report OH^- (indicative of mud contamination), pH less than 5 (indicative of acid-wash contamination), pH greater than 10 (indicative of delay in analysis) or K/Na greater than 0.05 (indicative of KCl contamination) were automatically eliminated. Further culling was based on elimination of

- duplicate analyses;
- production from a swab, tank separator or treater, provided that the Cl value was anomalous; and
- analysis from a drill-stem test that recovered only mud.

The final number of formation water analyses used in this study is shown in Table 1.

As a general trend, salinity in the Upper Cretaceous–Tertiary succession increases stratigraphically and with depth. As expected for an aquifer at the top of the bedrock, salinity in the Scollard–Paskapoo aquifer is low, varying in the approximate range 100–3000 mg/l. Salinity is less than 1000 mg/l over most of the area, except for a narrow region along the aquifer boundary in the southeast, where it is as high as 3000 mg/l (Figure 12). Salinity in the Edmonton–Upper Wapiti aquifer is higher, particularly in the central area, with values varying from less than 1000 mg/l in the outcrop areas in the northeast and northwest, to more than 7000 mg/l in the center (Figure 13). Salinity in the outcrop area in the east is in the 2000–3000 mg/l range, higher than in the outcrop area in the north. Salinity in both the Basal and Upper Belly River aquifers is significantly higher than in the overlying units and varies from less than 1000 mg/l in the south-southeast, northeast and north-northwest, to more than 15 000 mg/l in the center (Figure 14 and Figure 15). A few areas near the thrust and fold belt display lower salinity than those further into the basin. The high-salinity areas are generally spotty and localized off-center to the northeast, toward outcrop. An analysis of water type in the Belly River Group shows that it is predominantly Na-HCO_3-Cl water in the south-southeast, northeast and north-northwest, indicating freshwater of meteoric origin, whereas the higher salinity water in the center of the basin is of predominantly Na-Cl type (Figure 16). Generally, for all units, the south-southeastern and northeastern low-salinity areas coincide with subcrop beneath the unconsolidated Quaternary cover, whereas the higher salinity areas are located in the center of the basin. Also, all units display lower salinity in the northern part of the basin, where the Bearpaw aquitard is absent. Because of relatively low salinity and the compensating effects of increases in both salinity and temperature with depth, the density of formation waters in the Upper Cretaceous–Tertiary succession varies between 1000 kg/m^3 at the surface and 1010 kg/m^3 in the Basal Belly River aquifer.

3.2 Hydrodynamics

The hydrodynamic analysis of formation-water flow in the Upper Cretaceous–Tertiary succession of the Alberta basin is based on pressure data from drill-stem tests (DSTs), performed by the energy industry during hydrocarbon exploration and production, and filed with the Alberta Energy and Utilities Board. The initial 2068 DSTs were culled down to 1800 (Table 1) on the basis of DST quality and production-induced drawdown, according to the methodology described by Barson et al. (2001). As expected, the number of DSTs is small for the top units where no hydrocarbons are present, and large for the Belly River Group, where gas is being produced from

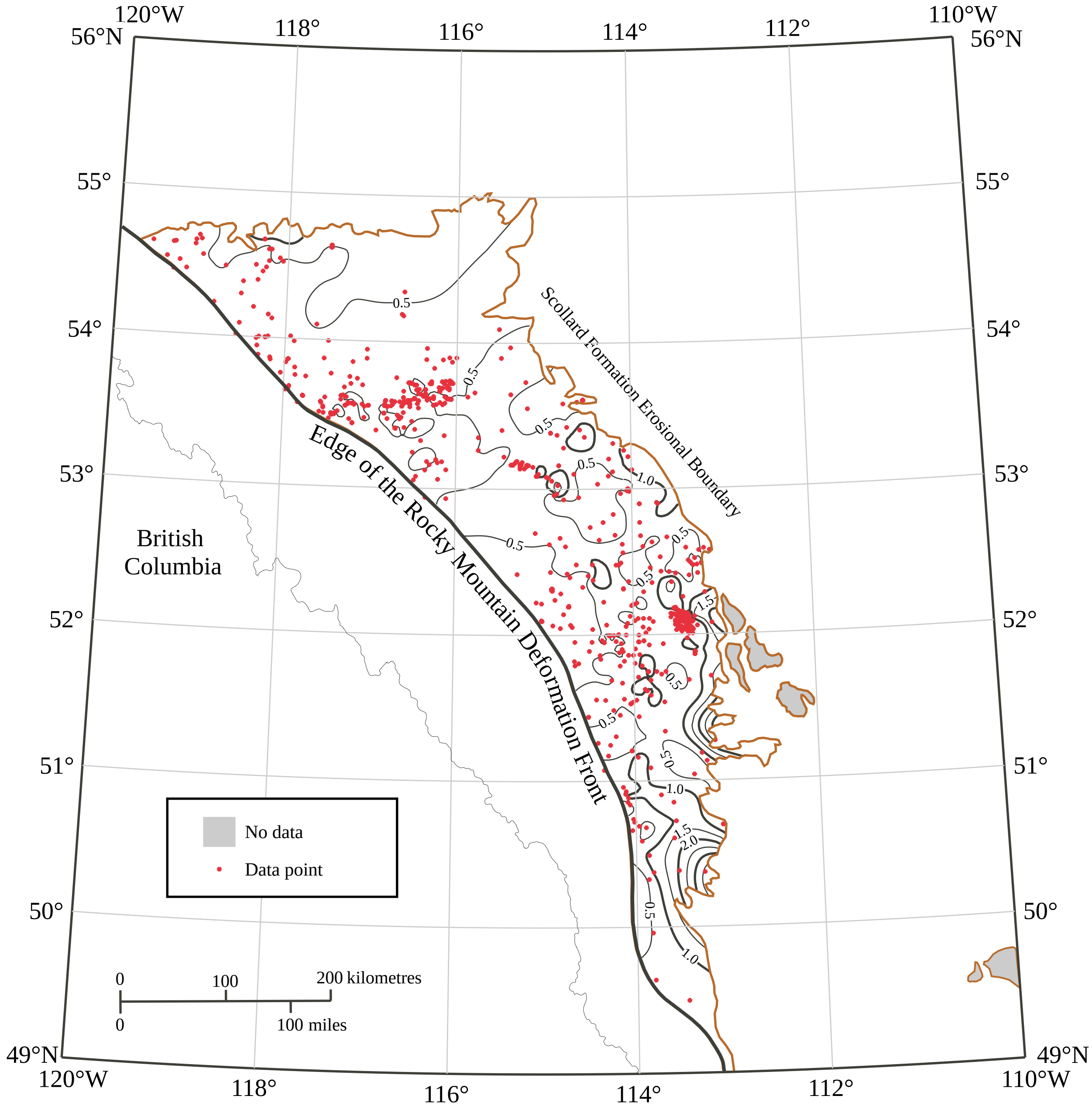


Figure 12. Salinity in the Scollard-Paskapoo aquifer (contours in g/l).

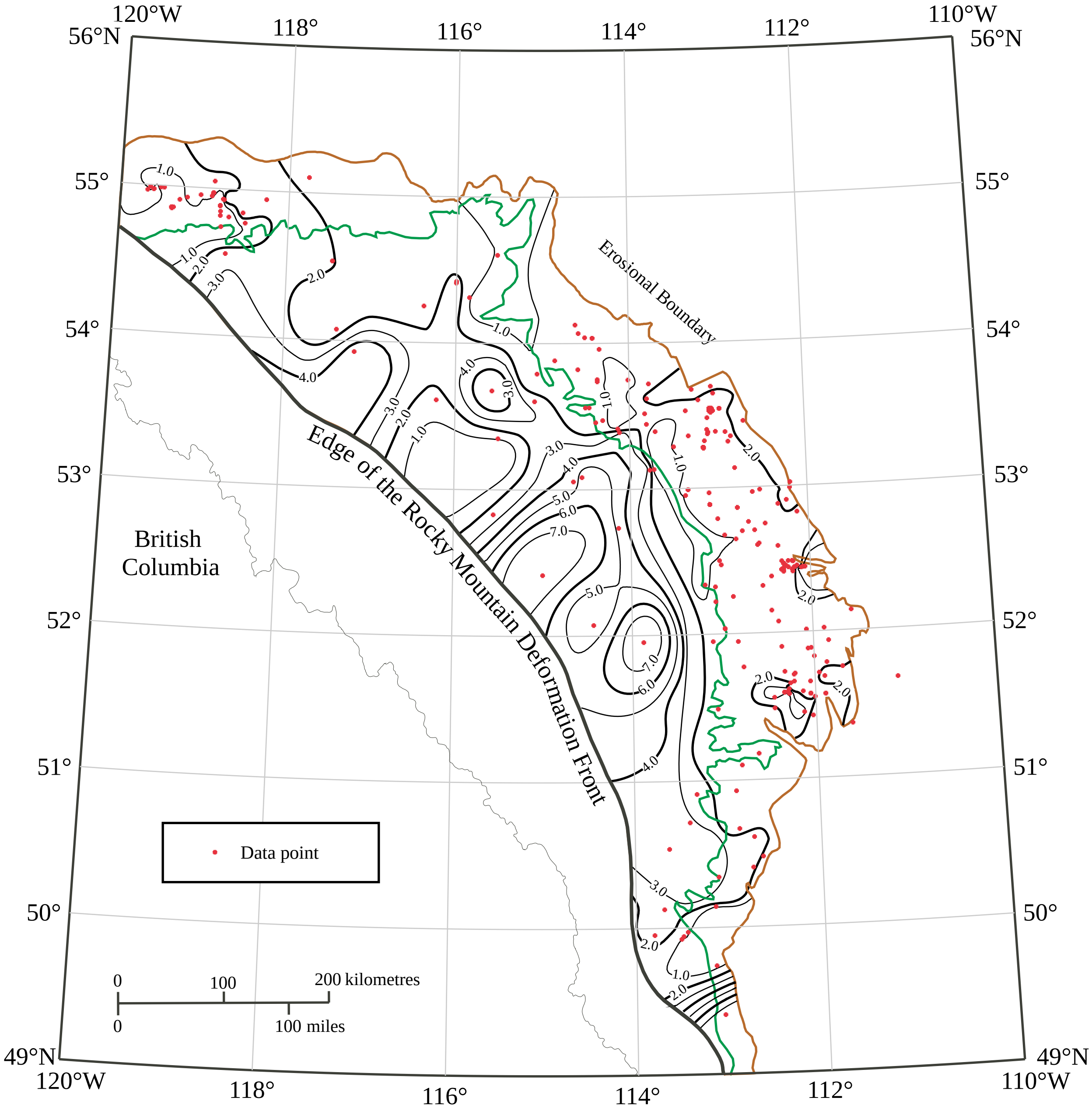


Figure 13. Salinity in the Edmonton - Upper Wapiti aquifer (contours in g/l).

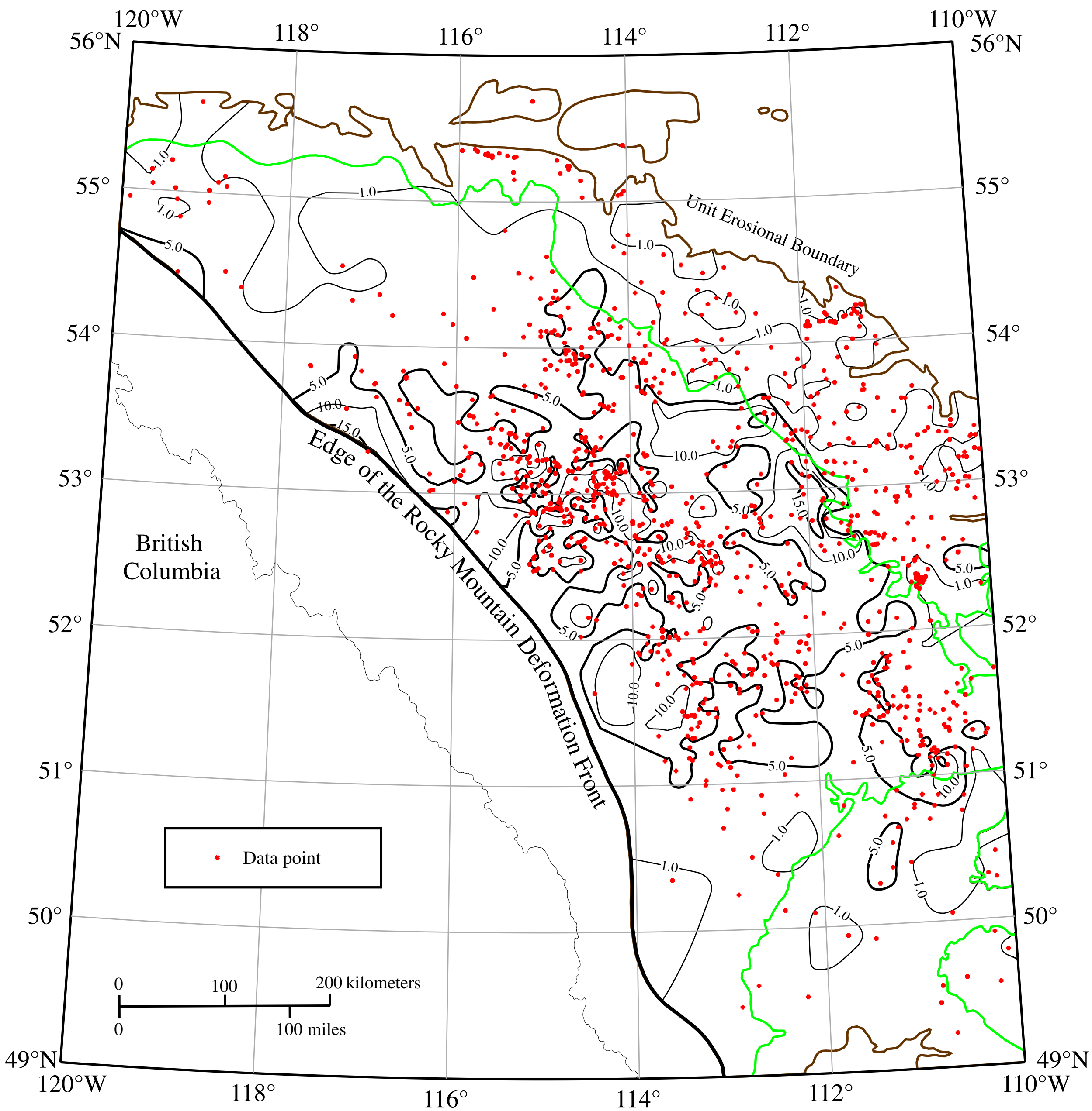


Figure 14. Salinity in the Upper Belly River aquifer (contours in g/l).

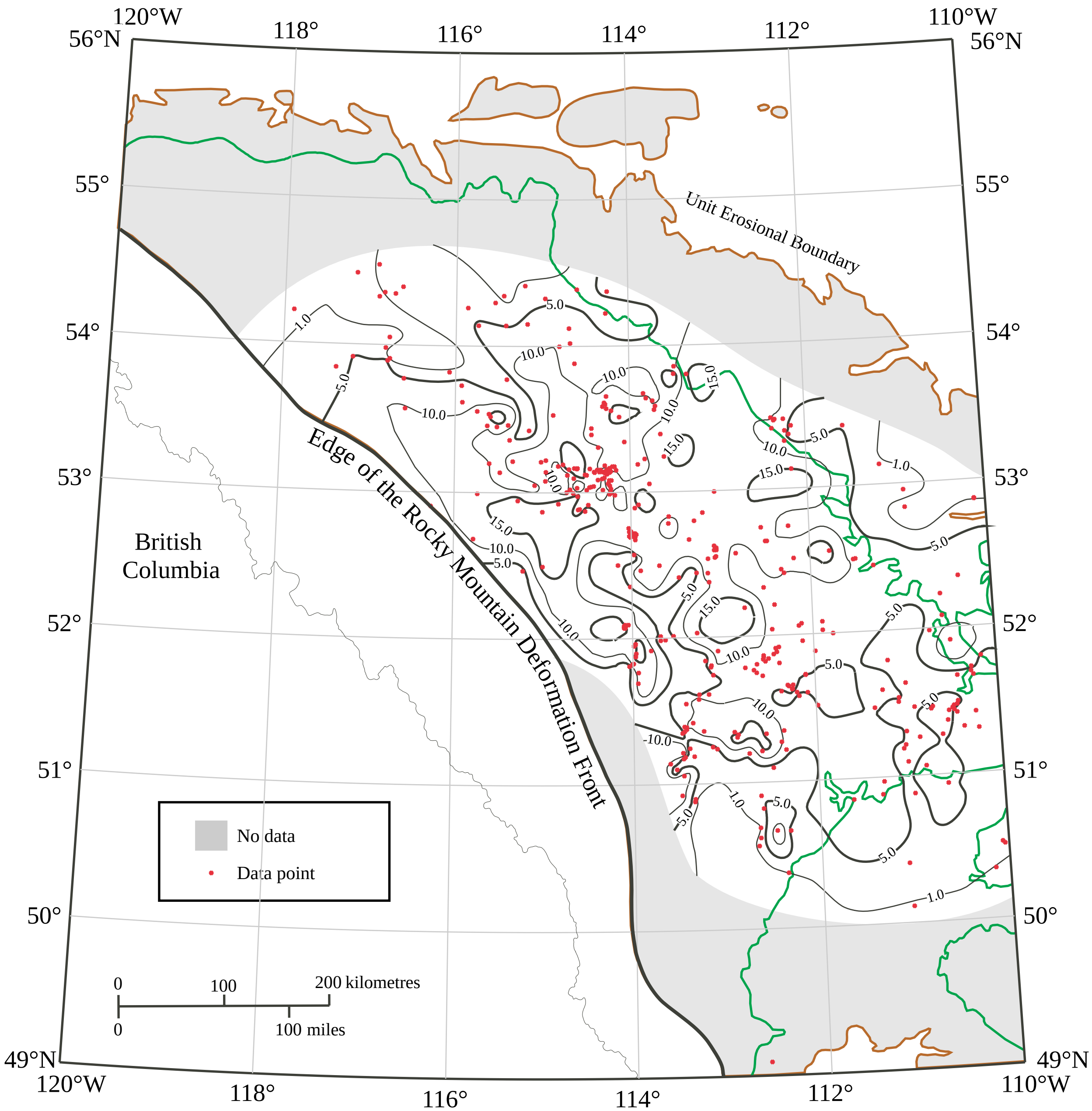


Figure 15. Salinity in the Basal Belly River aquifer (contours in g/l).

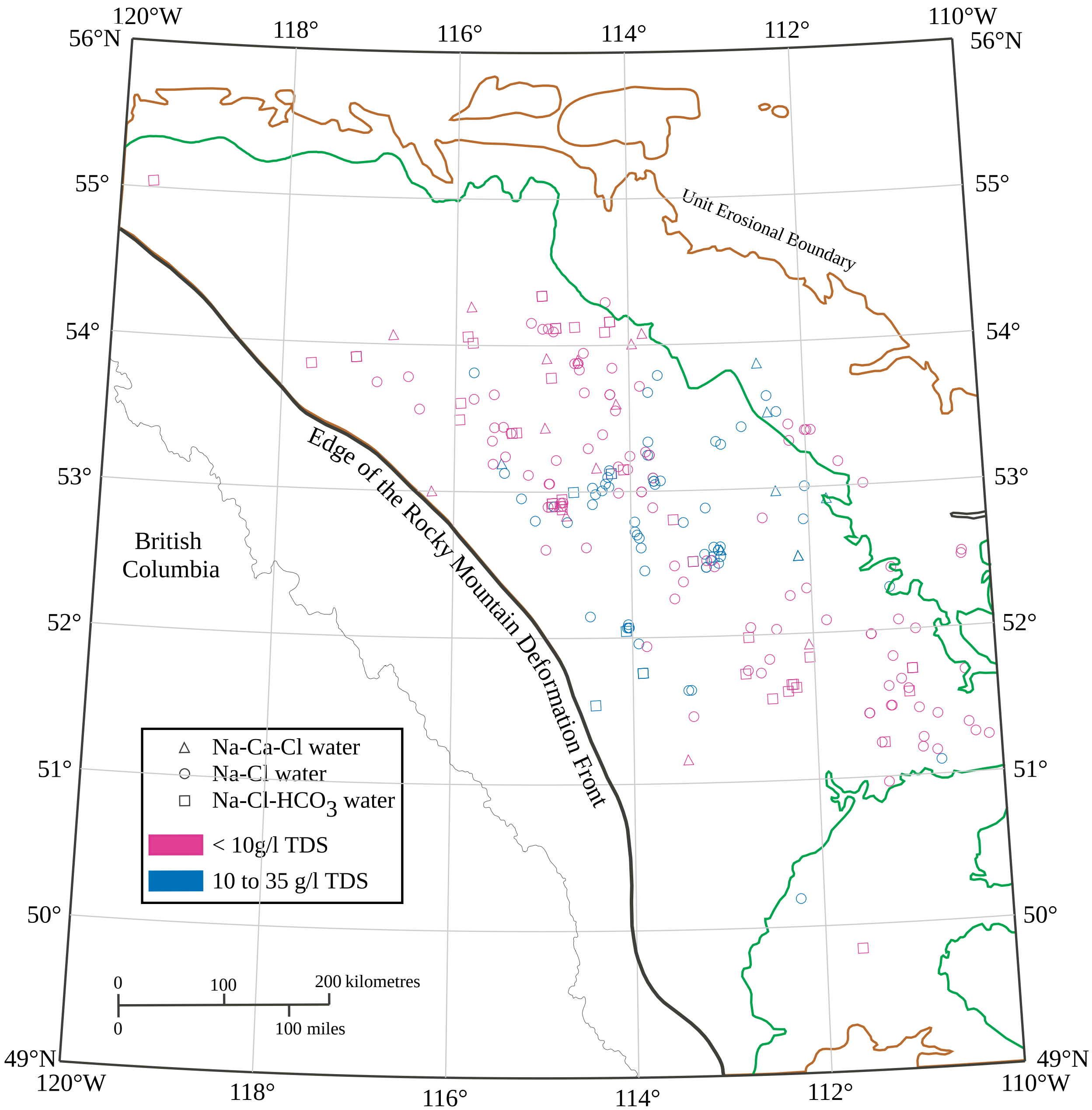


Figure 16. Salinity (TDS) and type of formation water in the Belly River Group.

several hundred pools. The distribution of freshwater hydraulic heads allows for a sufficiently accurate analysis of the hydrodynamic regime of formation waters, because of the small deviation of water density from that of freshwater (Bachu, 1995; Bachu and Michael, 2002).

The position of the water table in the unconfined aquifer at the top of the sedimentary cover was constructed using information filed with Alberta Environment regarding the water level in 184 271 water wells used for potable water, and topographic information regarding the water elevation in rivers and lakes to which the shallow groundwater aquifers are connected. The water table (Figure 17) mimics the topography (Figure 3), varying in depth from 0 to 40 m below the ground surface.

On a regional scale, hydraulic heads in the Scollard–Paskapoo aquifer, as determined from only 21 DSTs, indicate flow from high elevation (greater than 1000 m) near the thrust and fold belt in the west to lower elevation (approximately 700 m and less) in the northeast (Figure 18). The flow pattern depicted in Figure 18 is due more to the sparse data distribution than to its character. While the general, regional-scale trend is correct, local variations probably mean that, in reality, it should resemble the water table in the immediately overlying strata (Figure 17). Hydraulic heads in the northern and southern parts of the underlying Edmonton–Upper Wapiti aquifer (Figure 19) display the same general pattern of high values (greater than 1000 m) in the west, near the thrust and fold belt, and low values (less than 600 m) in the northeast, indicating the same west to northeast flow pattern. In the central area, a significant closed low of about 300 m is present (Figure 19), indicating flow toward a 'sink'.

The distribution of hydraulic heads in the underlying Upper Belly River aquifer (Figure 20) is significantly different from those in the top aquifers. In the northern part of the study area, hydraulic heads are still high in the west (greater than 800 m) and decrease northeastward to less than 700 m. In the northeast, east and southeast, hydraulic heads in the 600, 700 and 800 m range correspond to ground elevations at or near subcrop beneath the Quaternary cover, and indicate flow along decreasing topographic elevations. This pattern is completely reversed in the central area, where hydraulic heads drop from more than 600 m and approximately 700 m near subcrop in the east to less than 400 m in the west, near the thrust and fold belt (Figure 20), opposite to the northeastward decrease in ground elevation and water table (Figure 3 and Figure 18). A similar pattern in hydraulic heads is present in the Basal Belly River aquifer (Figure 21). Hydraulic heads in the 800–900 m range in the extreme northwest and southeast, in the 700 m range in the east and northwest, and in the 600 m range in the northeast all correspond to ground elevation in these areas. Hydraulic heads in the central area and in the northeast, near the thrust and fold belt, decrease west-southwestward to less than 200 m in a consistent, general trend (Figure 21). Although similar, the general pattern in hydraulic-head distribution in the Upper and Basal Belly River aquifers is not identical. Differences in hydraulic heads between the two aquifers range from less than –100 m to more than +100 m (Figure 22). While some of the small differences in the south, east, northeast and northwest could be attributed to different, sometimes scarce data distributions and to mapping algorithms, the differences in the central and western areas must be considered real because of the extremely high data density (Figure 20 and Figure 21).

3.3 Flow of Formation Waters

The flow of formation waters in the Upper Cretaceous–Tertiary, post–Lea Park succession in the Alberta basin is fairly complex, as indicated by salinity and hydraulic-head distributions. Generally, the system is underpressured, with no artesian conditions anywhere and with severe

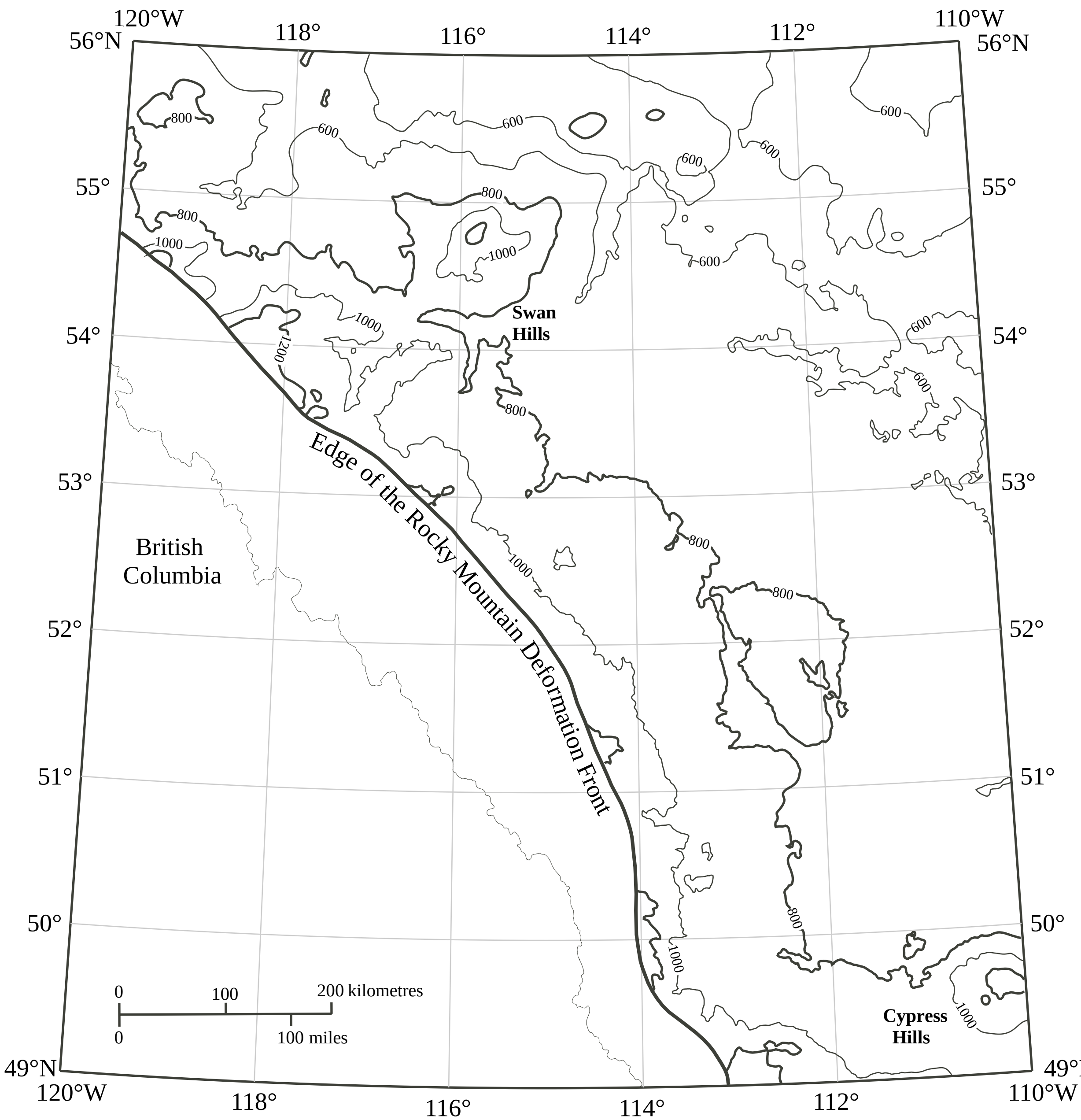


Figure 17. Elevation of the water table in the unconfined aquifer at top of sedimentary succession in the study area in the Alberta Basin (contour interval: 200 m).

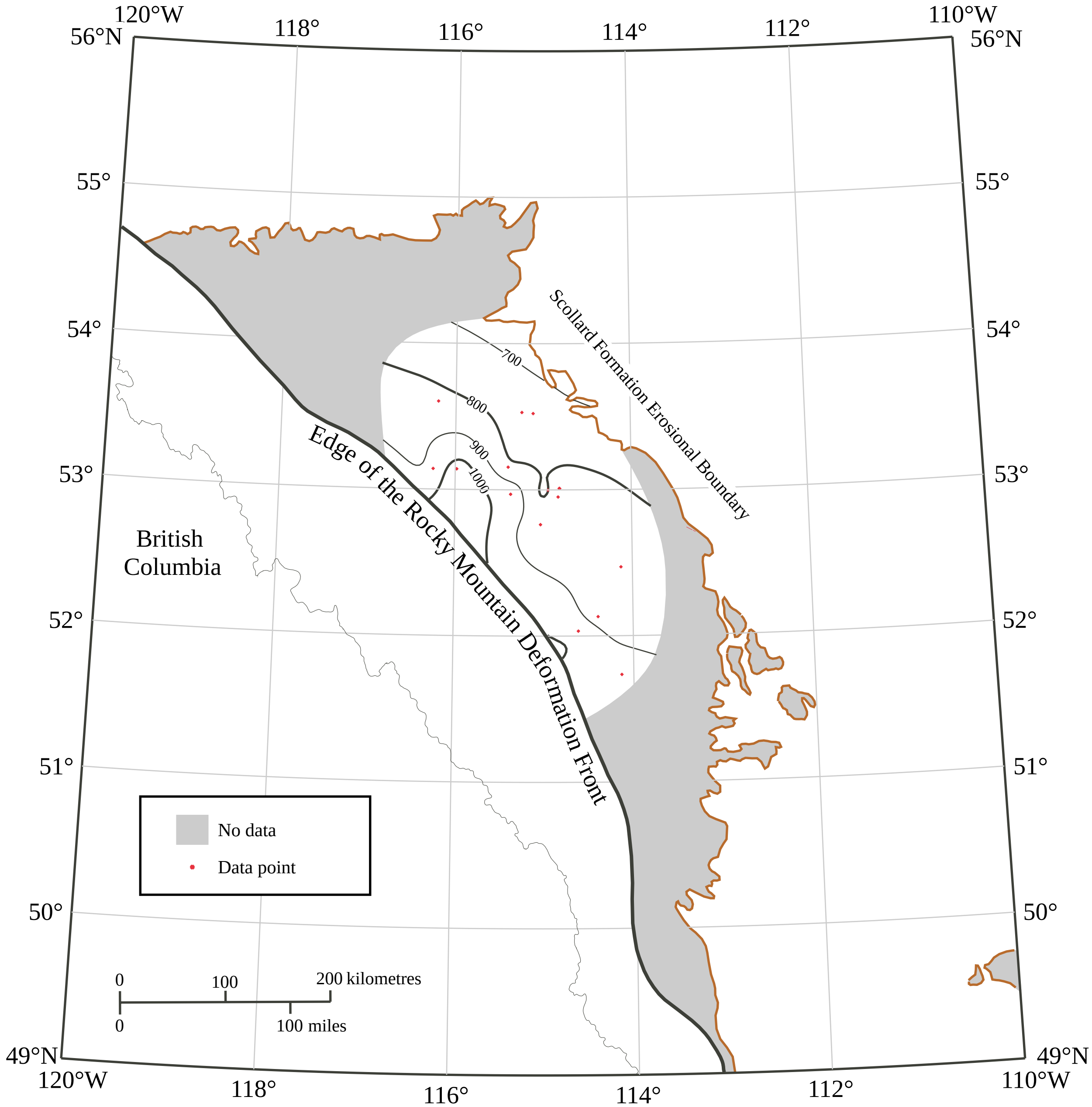


Figure 18. Hydraulic head distribution in the Scollard-Paskapoo aquifer (contour interval in m).

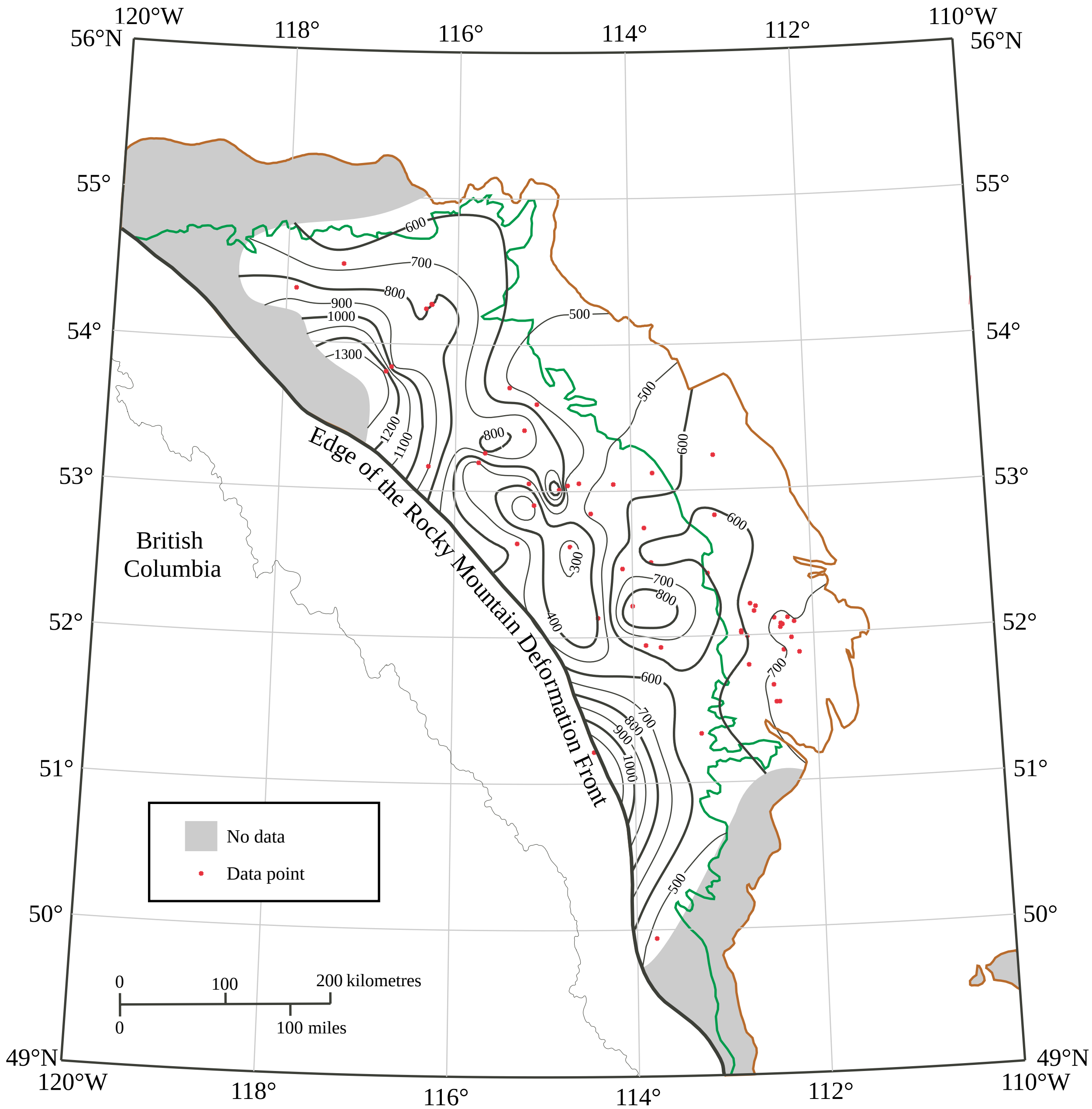


Figure 19. Hydraulic head distribution in the Edmonton - Upper Wapiti aquifer (contour interval in m).

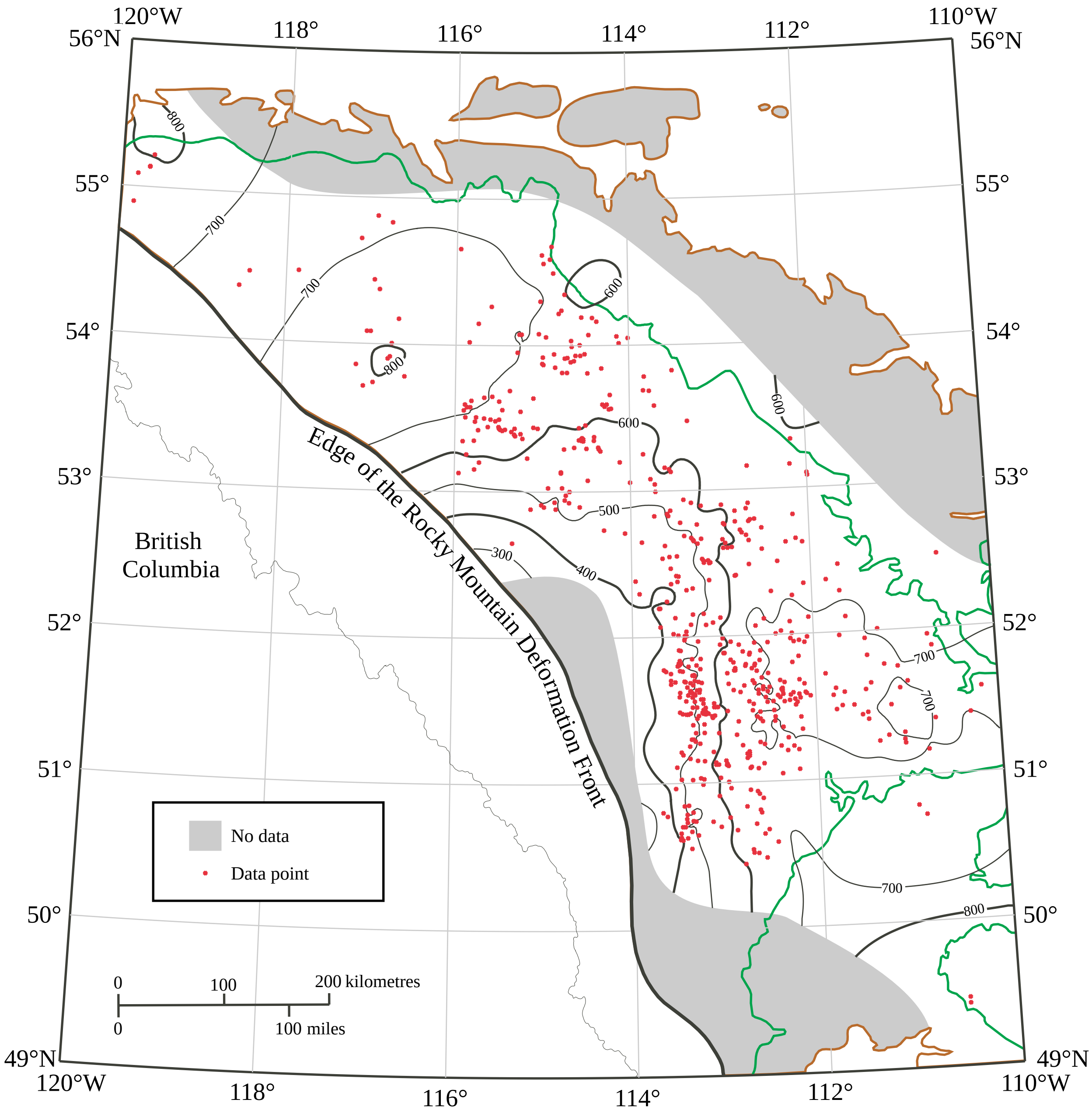


Figure 20. Hydraulic head distribution in the Upper Belly River aquifer (contour interval in m).

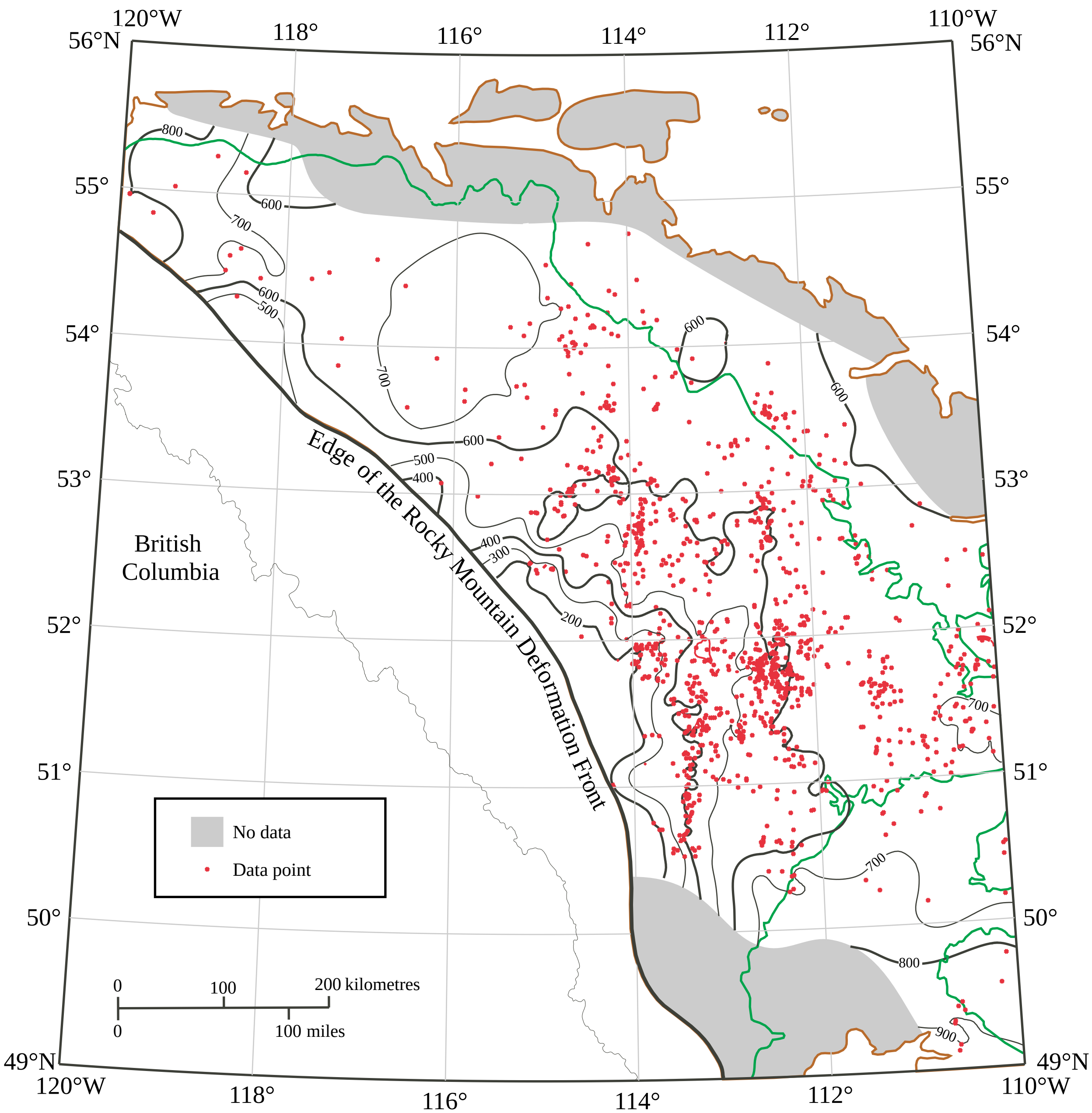


Figure 21. Hydraulic head distribution in the Basal Belly River aquifer (contour interval in m).

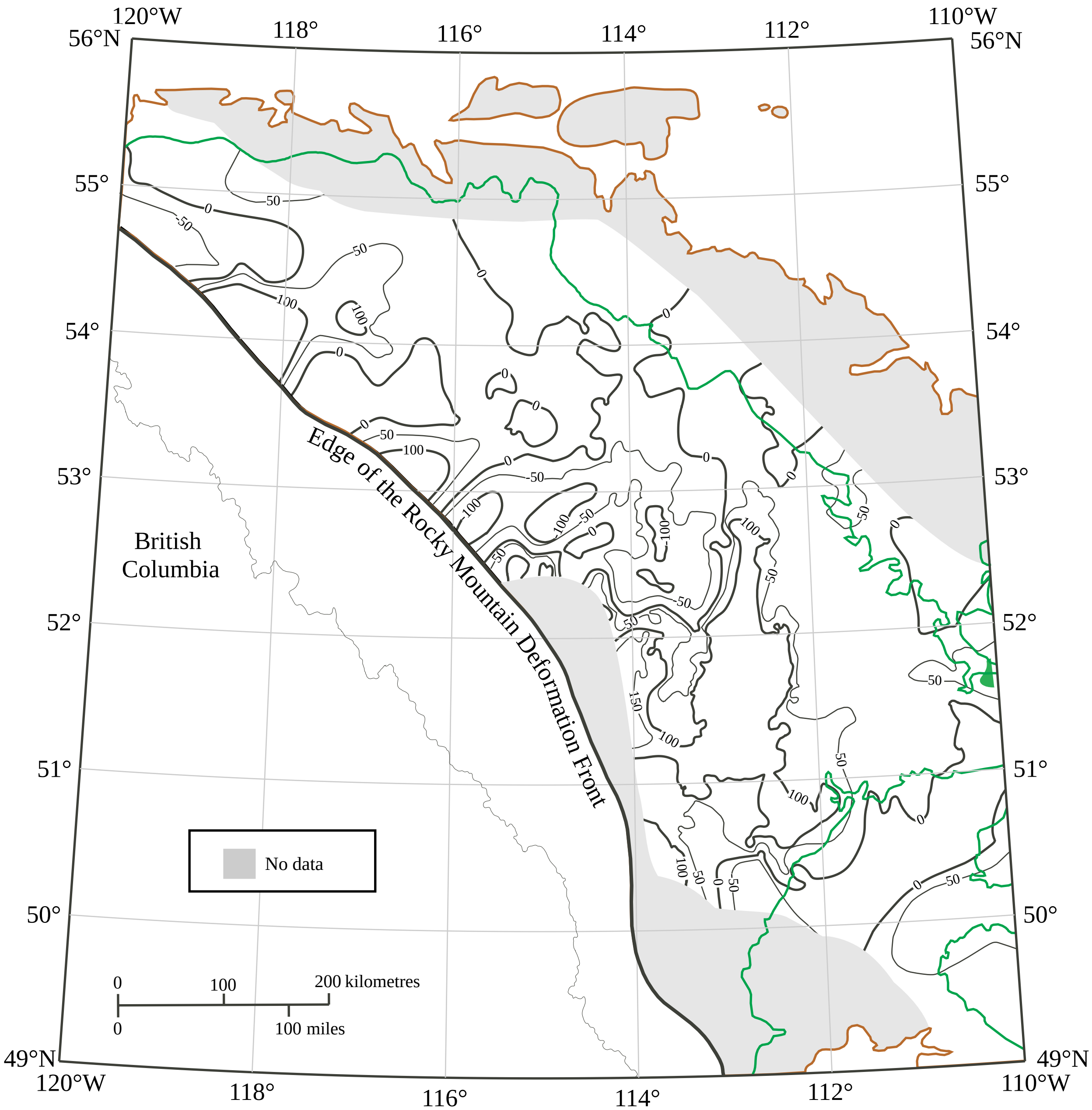


Figure 22. Difference in hydraulic heads between the Upper and Basal Belly River aquifers.

underpressuring that reaches up to 10 MPa (1000 m water column) in the Basal Belly River aquifer near the thrust and fold belt.

The flow of low-salinity water of meteoric origin in the Scollard–Paskapoo aquifer at the top of the bedrock is in equilibrium with, and driven by, topography from recharge areas at high elevation near the thrust and fold belt to discharge areas in the east-northeast (Figure 17). The flow of water in the Edmonton–Upper Wapiti aquifer is driven northeastward by topography in the northern and southern areas. High hydraulic heads and low salinity in the southwest, and in the north-northwest at the Swan Hills (Figure 13 and Figure 18), indicate recharge, with the discharge taking place at lower elevation at subcrop and at outcrop along river valleys. The higher salinity and low hydraulic heads in the center of the area indicate flow driven inward by erosional rebound of the underlying Bearpaw shale and other less widespread shale units in the Edmonton Group, as identified previously in this aquifer in western and central Alberta (Bachu and Underschultz, 1995; Parks and Toth, 1995). The inability of meteoric water to replenish the aquifer from recharge at subcrop in the east and from the northern and southern recharge areas indicates that some lateral permeability barrier must exist within the Edmonton Group strata in the area.

In both Belly River aquifers, relatively lower salinity (Figure 14 and Figure 15), high bicarbonate content (Figure 16) and high hydraulic heads (Figure 20 and Figure 21) in the south-southeast, east-northeast and north-northwest indicate recharge by meteoric water and flow driven by topography. Recharge takes place at high elevation in the south and subcrop in the south-southeast, at the Swan Hills in the north-northwest, near the thrust and fold belt in the extreme northwest, and at low elevation along subcrop in the northeast. Hydraulic heads decrease westward from this recharge area to less than 300 m close to the thrust and fold belt (Figure 20 and Figure 21). A ‘deep basin’ style of oil accumulation was previously identified in the Belly River Group in the Pembina area, where updip sandstone pinch-outs trap hydrocarbons and a permeability barrier must separate or compartmentalize the Basal Belly River aquifer in this region (Putnam, 1993; Michael and Bachu, 2001)

The high salinity and Na-Cl character of formation waters, and the west-southwestward decrease in hydraulic heads (progressive underpressuring) in the center of the Upper and Basal Belly River aquifers indicates flow driven by rebound of the shale in the underlying, intervening and overlying Lea Park, Foremost and Bearpaw formations. The rebound in the Foremost Formation is confirmed by the underpressuring of isolated, individual fluvial-channel or valley-fill sandstone units, as shown by some 150 DSTs. The rebound can be postorogenic (Putnam, 1993; Bachu and Underschultz, 1995) or postglacial (Michael and Bachu, 2001).

Hydraulic-head contours (Figure 20 and Figure 21) and gas accumulations (Hamblin and Lee, 1997) in the underpressured region of the Upper and Basal Belly River aquifers are oriented along depositional and structural strike (Putnam, 1993) and seem to align with the boundaries of the seven fourth-order regressive cycles (Figure 23) identified by Hamblin and Abrahamson (1996). Pressures in both Upper and Basal Belly River aquifers in the underpressured south-central area, which extends approximately from 51°30’N to 53°N and from 112°W to the Rocky Mountain deformation front, seem to group both on pressure-elevation plots (Figure 24 and Figure 25) and geographically (Figure 26) in a pattern that generally matches the Belly River Group depositional systems (Figure 23). An analysis of fluid saturations and pressure distributions along a west-east cross-section in the Belly River Group, represented diagrammatically in Figure 27, shows that, in the central area, the easternmost sandstone is water saturated and subnormally pressured, the central sandstone is mainly gas saturated, and the westernmost sandstone is again water saturated and severely underpressured (Figure 24, Figure

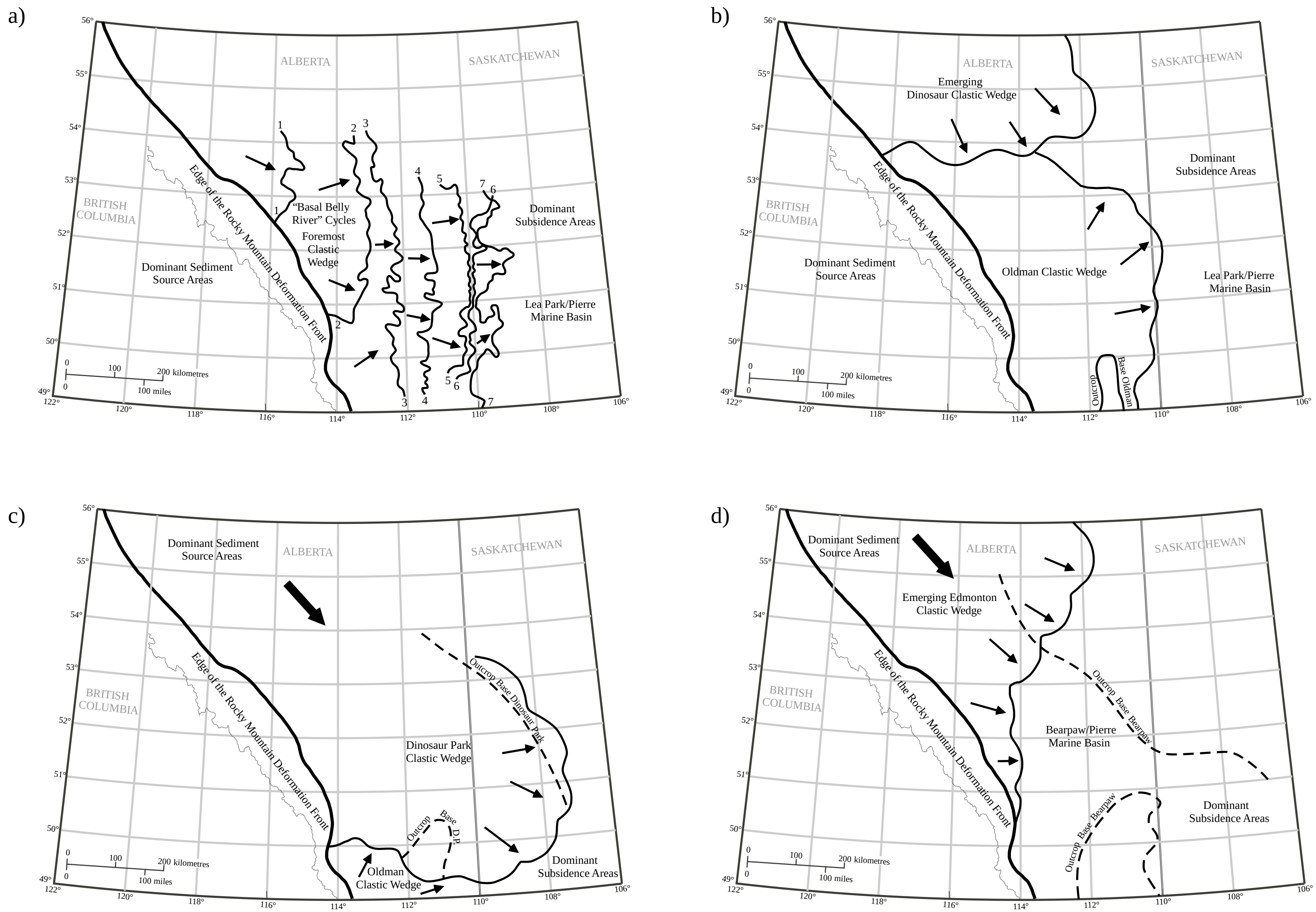


Figure 23. Evolution of the Belly River Group depositional systems and location of depositional boundaries (from Hamblin and Lee, 1997): a) Basal Belly River, b) Oldman Formation, c) Dinosaur Park Formation, and d) Bearpaw Formation (see Figure 2 for stratigraphic position).

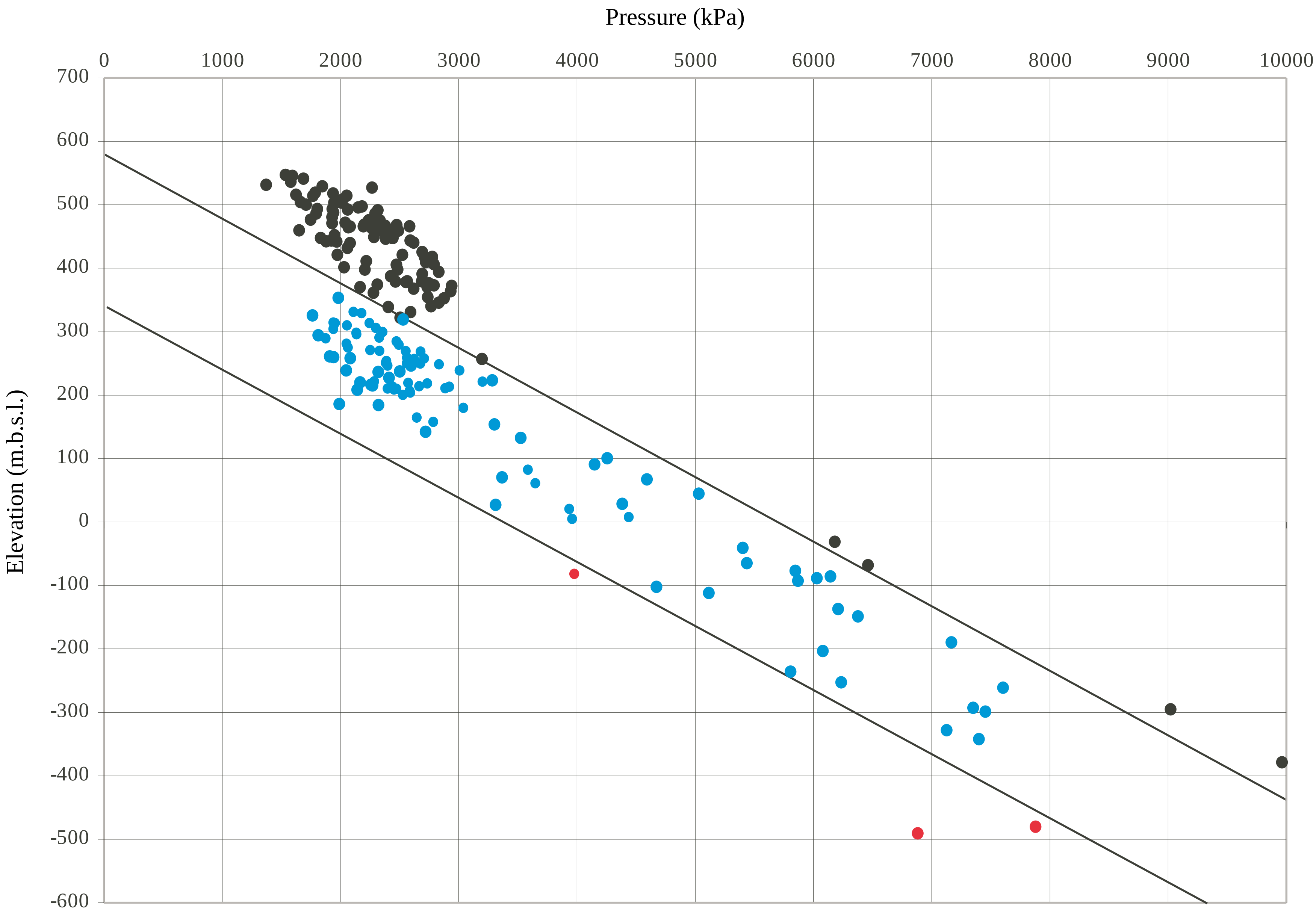


Figure 24. Distribution of pressure with elevation in the underpressured region of the Upper Belly River aquifer, extending from 51°30'N to 53°N and 112°W to the Rocky Mountain deformation front; see Figure 26 for the geographic distribution of the pressure data.

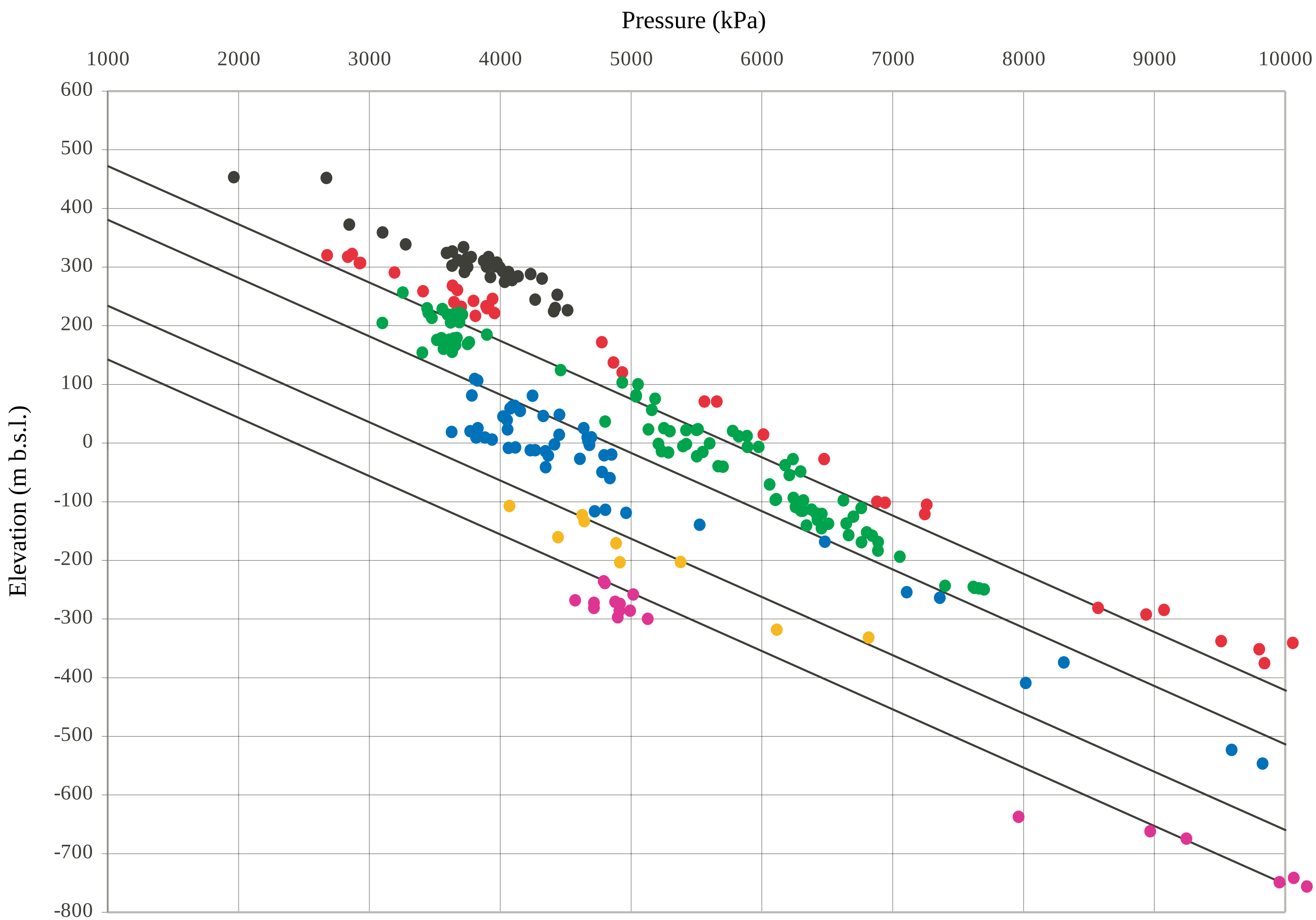
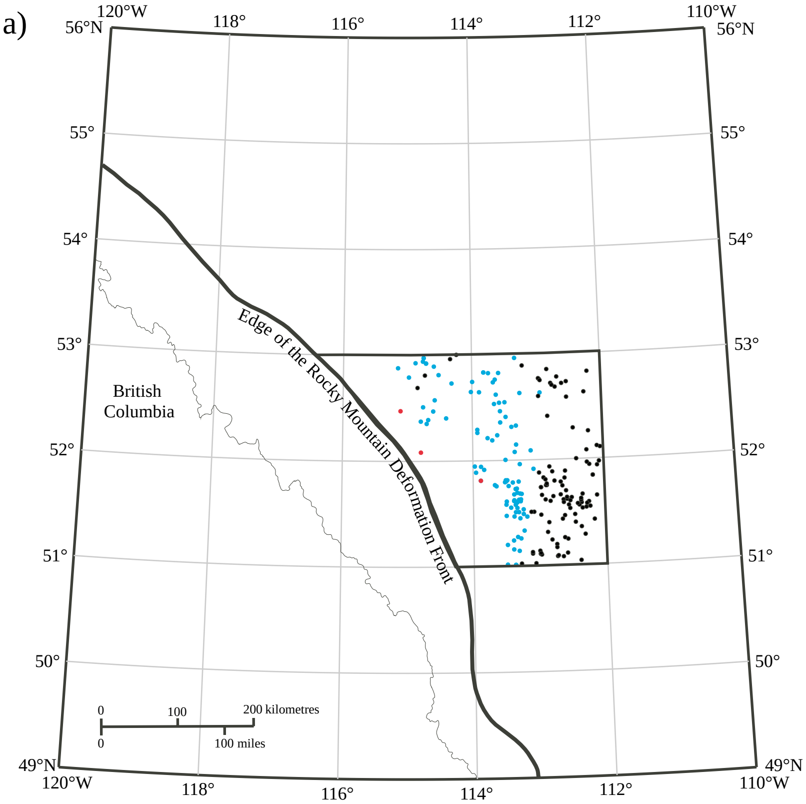


Figure 25. Distribution of pressure with elevation in the underpressured region of the Basal Belly River aquifer, extending from 51°30'N to 53°N and 112°W to the Rocky Mountain deformation front; see Figure 26 for the geographic distribution of the pressure data.

a)



b)

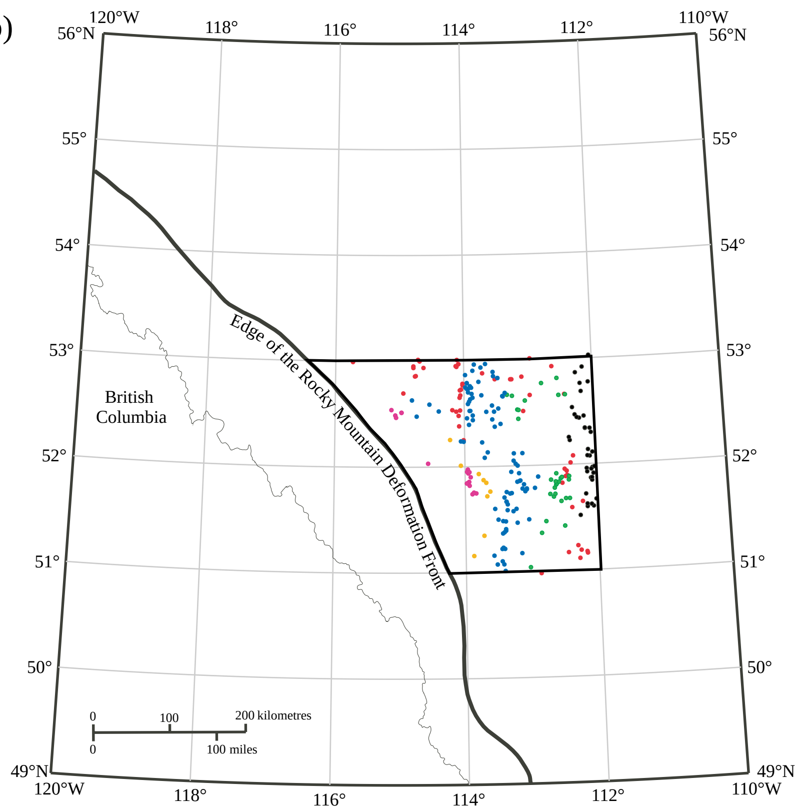


Figure 26. Geographic location of pressure data in the underpressured west-central area of the Belly River Group: a) Upper Belly River aquifer, and b) Basal Belly River aquifer.

25 and Figure 27). Generally, the location of the gas-saturated sandstone in the Basal Belly River (Figure 27) coincides with the area where hydraulic heads in the Basal Belly River aquifer are lower than those in the overlying Upper Belly River aquifer (Figure 22).

3.4 Flow Systems

The hydrodynamic regime and fluid and pressure distributions in the Upper Cretaceous–Tertiary coal-bearing strata of the Alberta basin are the result of 1) changing depositional environments and lithology; 2) basin history, and hydrocarbon generation and accumulation; and 3) present-day topography. The shale and shale-dominated rocks of the Belly River Group create low-permeability barriers between the sandstone-dominated depositional cycles of the Basal Belly River aquifer and between the Basal and Upper Belly River aquifers. At the peak of burial, the strata of the Belly River and Edmonton groups entered the gas window. Gas of thermogenic origin migrated from shale and coal to sandstone, where it accumulated in regional stratigraphic traps, subparallel to the paleoshoreline, that were created as a result of the various depositional environments and cycles. The weight of the overburden, up to 5000–6000 m at the peak of the Laramide orogeny, squeezed water out of the compacting shale. Erosion since then has removed approximately 2000–4000 m of sediments (Nurkowski, 1984; Bustin, 1991), resulting in erosional rebound of these strata, particularly the shale. Several loading and unloading cycles took place during the Pleistocene, when ice sheets reached a thickness of up to 2000 m. Currently, the Upper Cretaceous–Tertiary strata of the Alberta basin are in posterosional and postglacial rebound. As a result, the flow in the Upper Cretaceous–Tertiary coal-bearing strata in the Alberta basin is driven by topography and by erosional rebound, and is controlled by permeability barriers created by intervening shaly aquitards and gas-saturated sandstone units, resulting in several flow systems being active in the succession.

3.4.1 Flow Systems Driven by Topography

Northern System: In the northern part of the study area (Wapiti Group), where the Bearpaw shale is absent and where the shale content is generally much lower than in the southern and central parts, successively decreasing hydraulic heads from the Edmonton–Upper Wapiti aquifer to the Upper Belly River and Basal Belly River aquifers indicates downward flow characteristic of recharge areas. Here, the entire hydrostratigraphic system down to the Lea Park shaly aquitard is in hydrodynamic equilibrium with the present-day topography. Water of meteoric origin, with low salinity (<5000 mg/l) and a relatively high HCO_3 content (Na-HCO_3-Cl water type), recharges all the aquifers in the succession (Scollard–Paskapoo to Basal Belly River) at topographic highs in the Swan Hills and at the Rocky Mountain deformation front in the west, and discharges at outcrop in the north and northeast (Figure 28 and Figure 29a). The intervening Battle and any other minor shaly aquitards are weak in this region.

Southern System: This system is in equilibrium with, and driven by, topography in the southeast (Figure 28), where the Upper Belly River aquifer crops out under the Quaternary unconsolidated sediments. The flow is driven northeastward, from recharge at high elevations in the south toward lower elevations in the east-central part of the basin. The water is of meteoric origin, with low salinity (<5000 mg/l) and relatively high HCO_3 content (Na-HCO_3-Cl water type).

Top (Roof) Central System: In the center of the study area, the flow system in the aquifers that crop out at the top of the bedrock progressively from west to east (Scollard–Paskapoo, Edmonton–Upper Wapiti, and Upper and Basal Belly River) is also in equilibrium with the present-day topography, as indicated by hydraulic heads, low salinity and high HCO_3 content

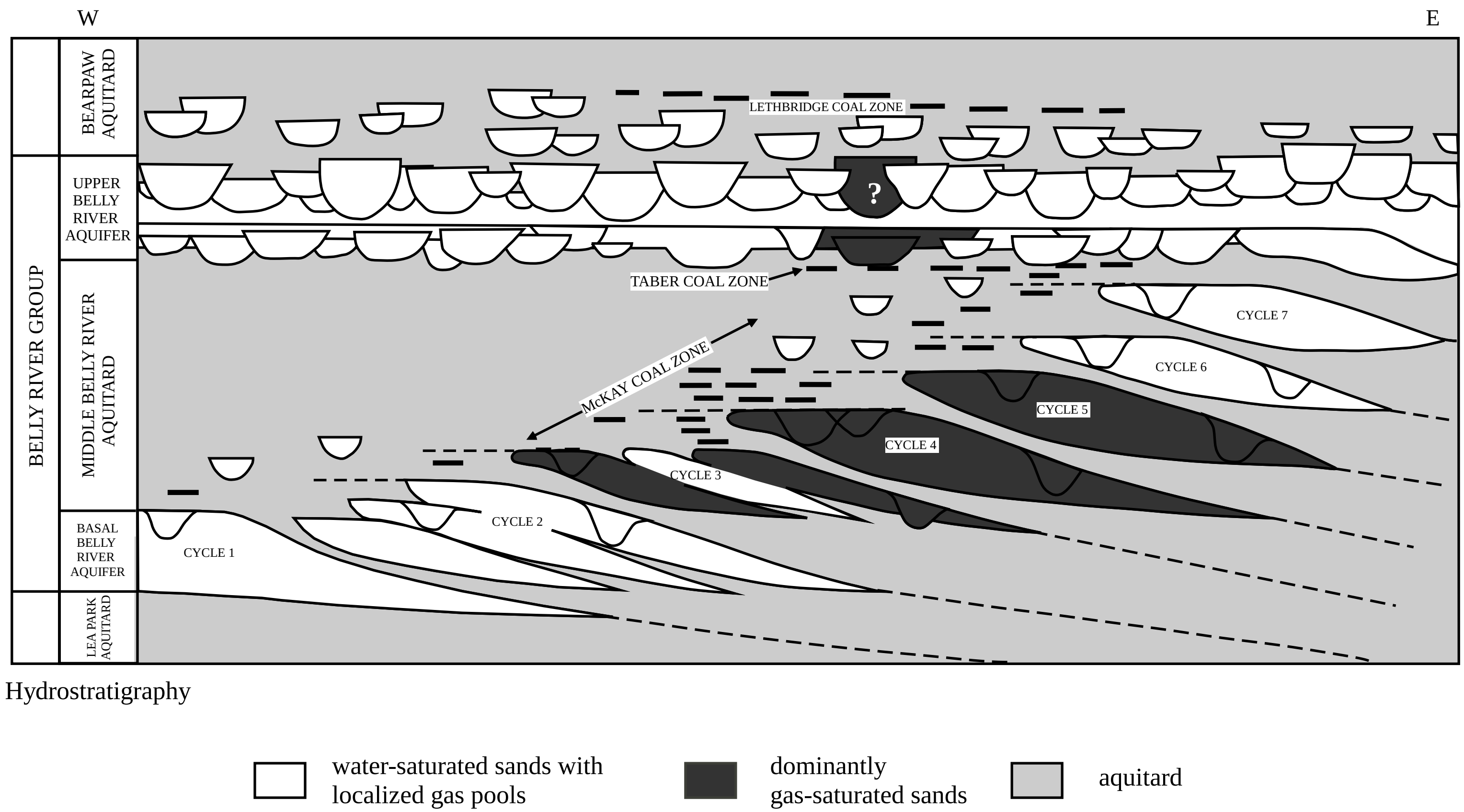


Figure 27. Diagrammatic representation of fluid saturations in the main sandstones in the Belly River Group in central Alberta (stratigraphic architecture after Hamblin and Lee, 1997).

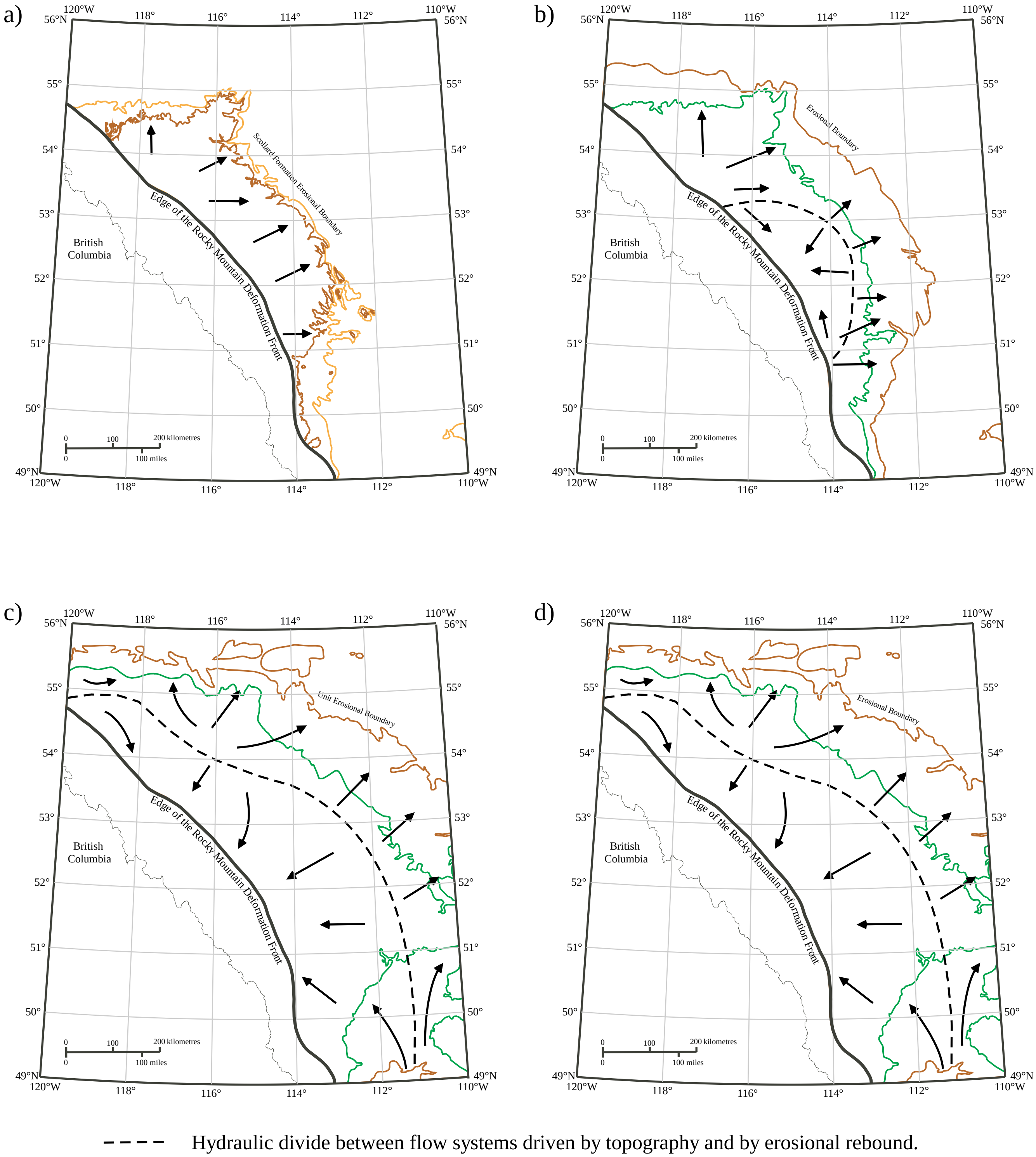


Figure 28. Diagrammatic plan-view representation of the flow systems in the coal-bearing Upper Cretaceous-Tertiary strata of the Alberta Basin: a) Scollard-Paskapoo aquifer; b) Edmonton-Upper Wapiti aquifer; c) Upper Belly River aquifer; and d) Basal Belly River aquifer.

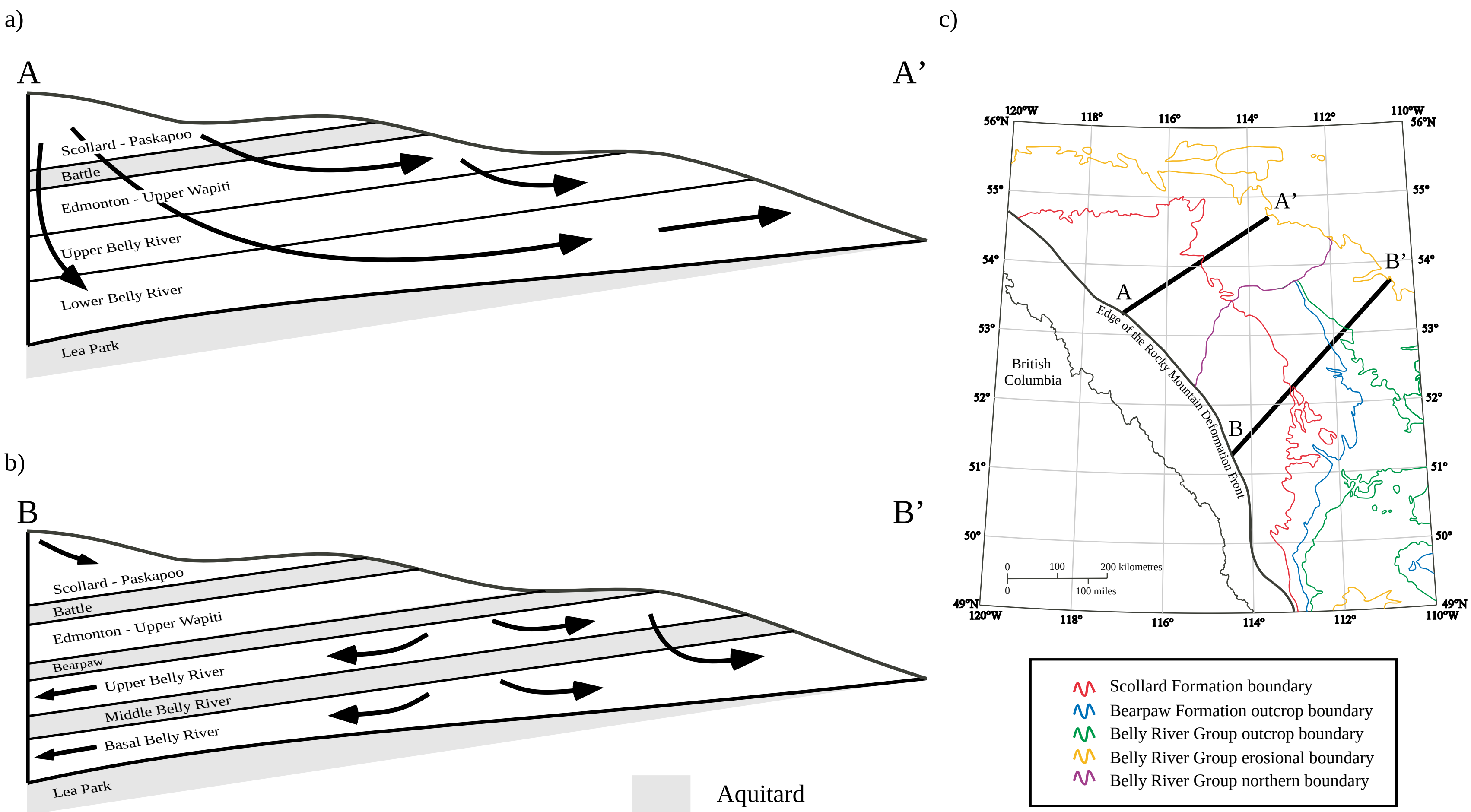


Figure 29. Diagrammatic cross-sectional representation of the flow systems in the coal-bearing Upper Cretaceous -Tertiary strata of the Alberta basin: a) northern part of the basin; b) south-central part of the basin; and c) approximate location of cross sections.

(Figure 28). For the Belly River aquifers, this area corresponds to the easternmost water-saturated sandstone of the Basal Belly River (cycles 7 and 8) and Upper Belly aquifers (Figure 27). The Middle Belly River aquitard in this region is weak, as a result of thinning.

3.4.2 Flow Systems Driven by Erosional Rebound

Deep Central Systems: The erosional rebound of the Lea Park, Belly River and Bearpaw shale units generates an inward driving force, from the boundaries at outcrop of the Edmonton–Wapiti and Belly River aquifers toward their deeper parts, evident in the central and western parts of the study area (Figure 28 and Figure 29b). There is capillary sealing between downdip gas-saturated sandstone and updip water-saturated sandstone (Revil et al., 1998), present also in deeper Cretaceous strata in the Alberta basin (Michael and Bachu, 2001), and low permeability depositional barriers in the Belly River and Edmonton groups (Putnam, 1993; Hamblin, 1997a, b; Hamblin and Abrahamson, 1996). This creates barriers (Figure 27) that do not allow the inward flow of meteoric water from outcrop areas that would equilibrate pressures in these aquifers with current basin topography. As a result, the salinity of formation waters in these aquifers in this area is relatively high (between 5000 and 18 000 mg/l) and the HCO_3 content is low (Na-Cl water type), indicating a relatively long residence time of this water. Hydraulic heads reach values significantly lower (<300 m near the thrust and fold belt) than in the discharge areas of the topography-driven systems, where they are in the 600 m range. The erosional-rebound sink in the central and western part of the study area also draws fresh meteoric water from recharge areas at high elevation in the Swan Hills to the northwest and in the south-southeast (Figure 28). The intervening Middle Belly River and Bearpaw aquitards are strong, as demonstrated by the significant differences in hydraulic heads between the flow systems in the Basal Belly River, Upper Belly River and Edmonton–Wapiti aquifers (Figure 19, Figure 20, Figure 21 and Figure 22).

4 Hydrogeology of Shallow Coal Aquifers in the Alberta Basin

During the 1970s, the Groundwater Department of the Alberta Research Council conducted a program of hydrogeological mapping of shallow aquifers used for potable water in Alberta. A series of shallow coal aquifers was tested and sampled as part of that program; unfortunately, however, the original data have been lost. Synthesis information survived at the Alberta Geological Survey as an unedited draft of a 1979 Alberta Research Council Earth Sciences Bulletin by D. Chorley and R.I.J. Vogwill, entitled *Coal Aquifers in Alberta*. Numerical and graphic information, and interpretations from that report are presented here because they contain valuable information. However, because they are not backed up by data, the authors of this report cannot assume any responsibility for them.

The data set consisted of 405 ‘apparent hydraulic tests’, 45 long-term aquifer tests, and 120 chemical analyses of water sampled from shallow coal seams (less than 100 m depth). The locations of the 450 hydraulic data points are shown in Figure 30; they are distributed in two arcuate bands from northwest of Edmonton to southeast of Calgary. The western group comprises coal seams of the Paskapoo Formation, the most important being the Ardley Coal Zone. The eastern group comprises coal seams of the Horseshoe Canyon Formation and its equivalent in the Wapiti Group (*see* Figure 2). These formations dip to the southwest at 3–4 m/km.

The 45 long-term aquifer tests consist of many drawdown measurements made at various times, and are reliable indicators of the actual value of coal hydraulic conductivity. They were analyzed using various standard curve-fitting methods (e.g., de Marsily, 1986). The 405 ‘apparent

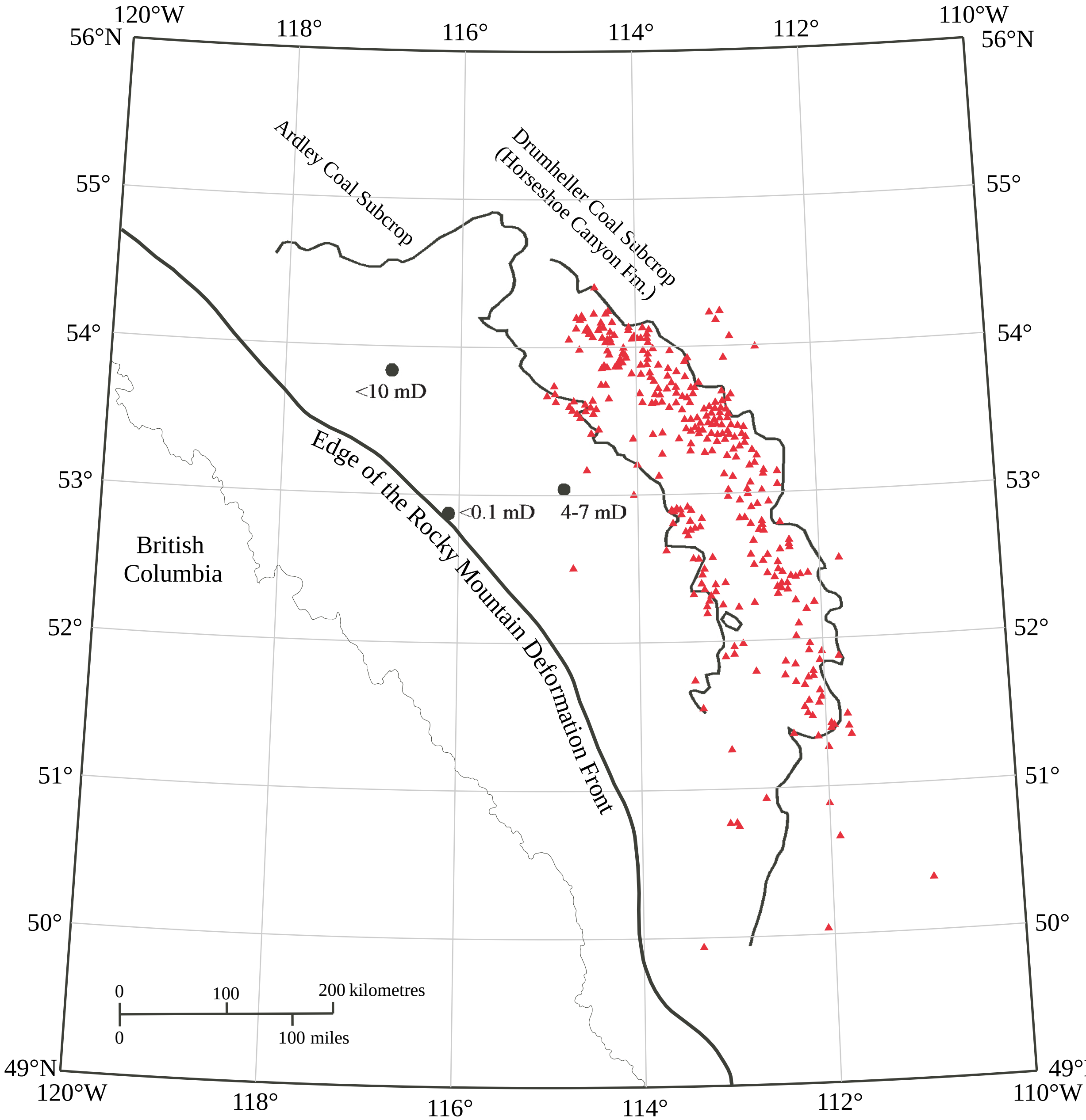


Figure 30. Distribution of coal aquifer test performed by the Groundwater Department of the Alberta Research Council (from an unpublished map). Publicly available permeability values for deeper coals are also shown.

hydraulic tests' consist of only two water-level measurements per location: the original static water level and a pumping water level at a later time. The straight line through these two points is assumed to represent the real drawdown trend, allowing for hydraulic-conductivity estimations. Calculated hydraulic-conductivity values are reported in units of m/d. Given the relationship between permeability 'k' and hydraulic conductivity 'K' (e.g., de Marsily, 1986; Freeze and Cherry, 1979), the former can be calculated from the latter using

$k\ (m^2) \approx 1.2\text{–}1.5 \cdot 10^{-12}\ K\ (m/d)$, or

$k\ (mD) \approx 1200\text{–}1500\ K\ (m/d)$

depending on the value considered for freshwater viscosity.

The average hydraulic conductivity of shallow (<100 m depth) coal aquifers in Alberta, shown at 5 m depth intervals in Figure 31, decreases with depth. The distribution indicates two populations: less than 50 m depth and greater than 50 m depth (still <100 m). The average hydraulic conductivity of the very shallow coal aquifers reaches 19 m/d (permeability of approx. 25–30 D) at 5–15 m depth and then gradually decreases. The average hydraulic conductivity of the slightly deeper coal aquifers (between 50 and 100 m depth) is fairly constant at 2 m/d (permeability of approx. 2.5–3 D). A frequency plot of the two populations (Figure 32) indicates that they are generally distributed log normally. Values of hydraulic conductivity for shallow coal vary over several orders of magnitude, from 0.02 to 800 m/d (permeability values of approx. 25 mD to >1000 D).

The data corresponding to hydraulic conductivity values greater than approximately 15 m/d (permeability of approx. 20 D) deviate from the log-normal straight line for the very shallow coal seams, suggesting that they are from a different, third population. These data originate from areas found either on bedrock highs, such as the Wabamun Lake and Elk Island highs and the Hand and Bear hills, or near preglacial, glacial or postglacial river valleys, such as the Pembina, Battle and Red Deer rivers. The original authors of the draft report attributed the high hydraulic conductivity of coal in these areas to localized changes in the pattern and size of fracture openings. They postulated that the regional pattern in coal hydraulic conductivity, controlled by tectonic stresses, has been locally altered by second-order effects of glacial deformation of bedrock highs that have been subjected to additional stress during ice movement, and by elastic erosional rebound, near or within river valleys, that can be as much as 10% of the valley depth (Matheson and Thomson, 1973). Flexural slip occurs within bedrock layers during elastic rebound, causing higher hydraulic conductivity in nearby coal aquifers due to opening of existing fractures.

The authors of the original report indicated that the storage coefficients for the coal aquifers, as determined from the 45 long-term hydraulic tests, range from 10^{-5} to 10^{-4}, which are typical of fractured or fissured rocks. Unfortunately, in the absence of information about aquifer thickness, it is not possible to make any inference about aquifer compressibility. The drawdown curves indicate three types of aquifer conditions: 'infinite' confined aquifers, bounded aquifers and leaky aquifers.

The 120 chemical analyses of aquifer water indicate that they are $Na\text{-}HCO_3$ (72%), $Na\text{-}SO_4\text{-}Cl$ (18%), $Ca\text{-}HCO_3$ (8%) and Na-Cl (2%) type waters. The coal-aquifer water progresses from calcium bicarbonate at shallow depths (<30 m) to sodium chloride in the deeper zones, in the 'Chebotarev' sequence characteristic of water movement from shallow zones of active flushing into zones where the flow is very sluggish and the water is old (Freeze and Cherry, 1979). Salinity (total dissolved solids) increases with depth from 500 to 1500 mg/l. One should pay

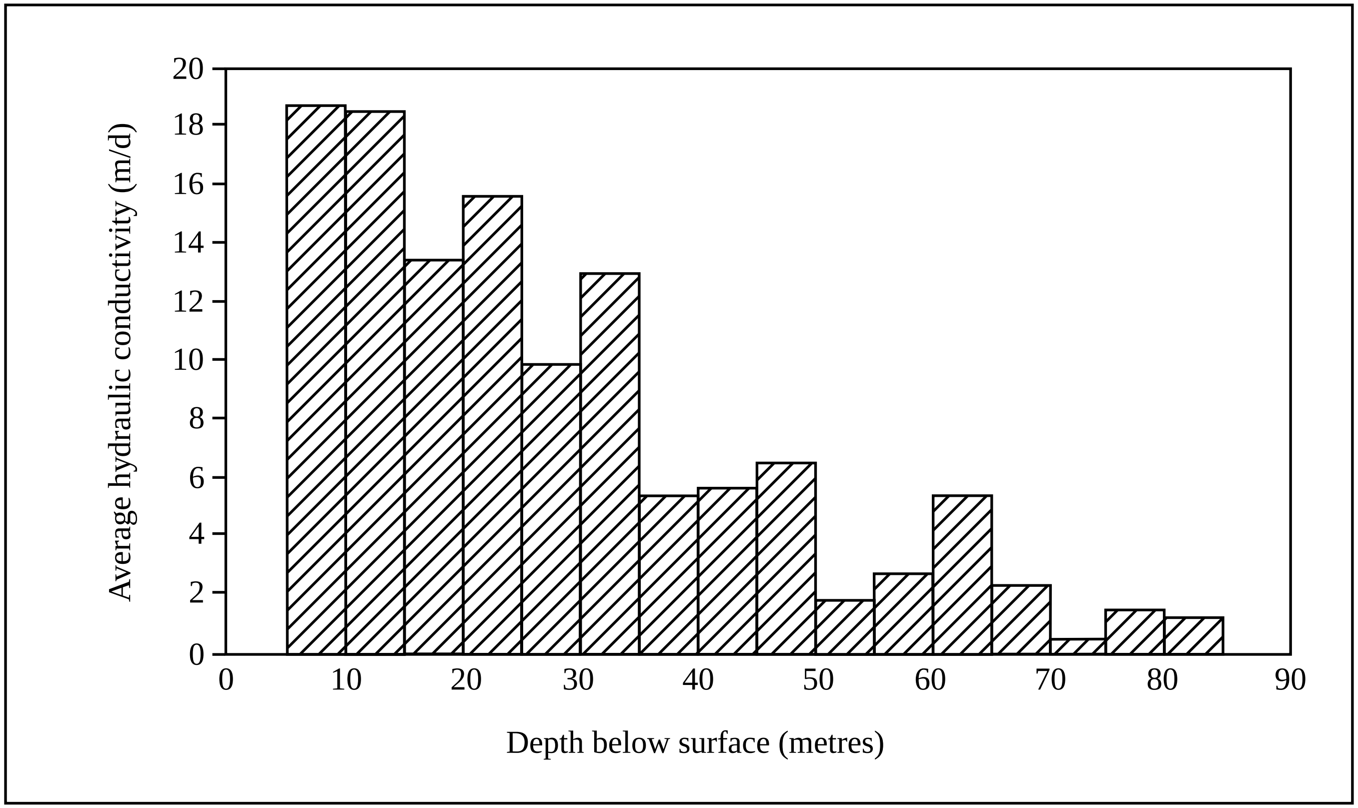


Figure 31. Distribution of hydraulic conductivity with depth, as measured in aquifer tests for shallow coal aquifers in Alberta.

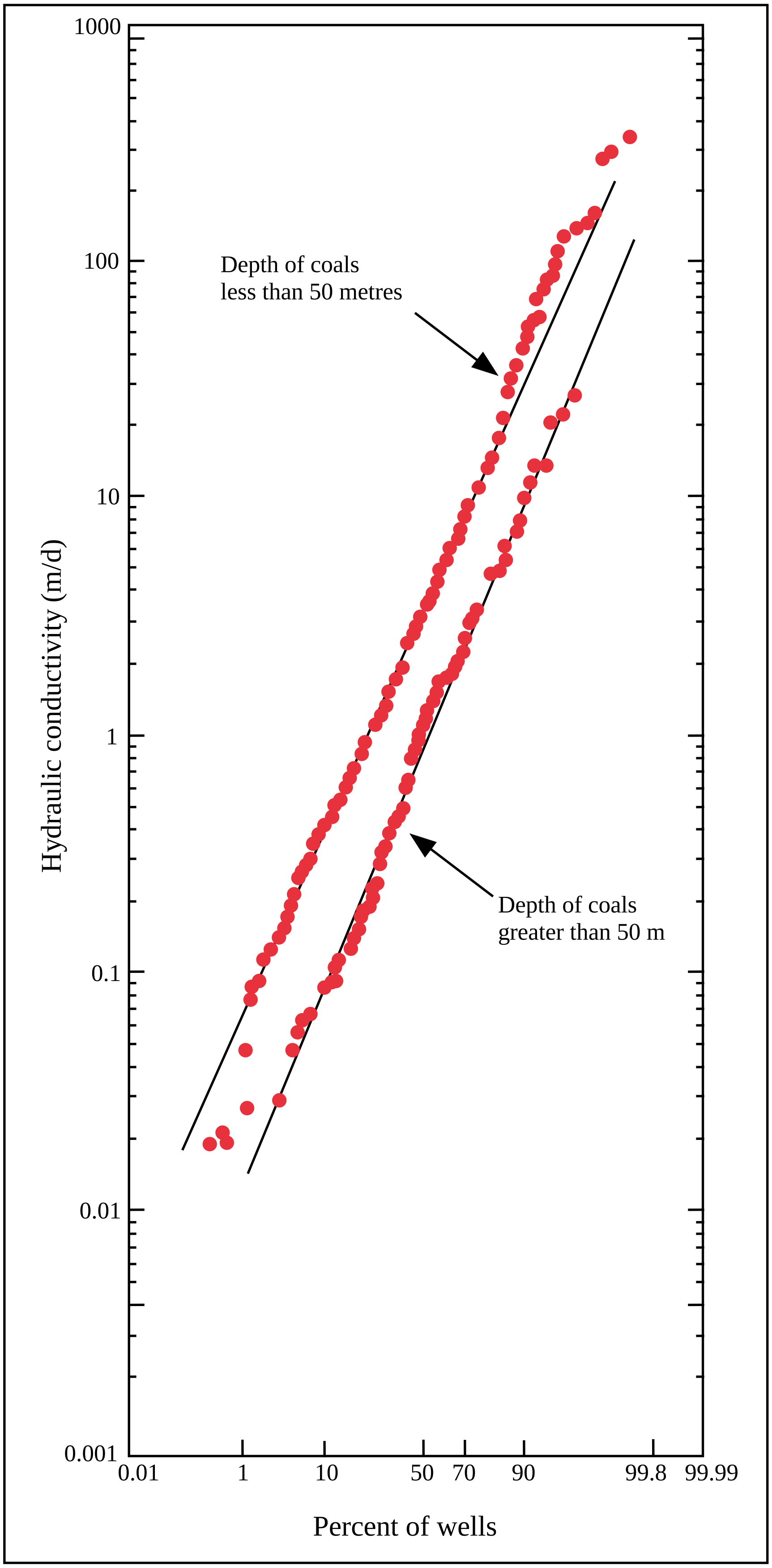


Figure 32. Frequency distribution of hydraulic conductivity for shallow coal aquifers in Alberta.

attention to the fact that the data presented by the authors of this draft report are from the very shallow parts of the coal zones in Alberta (*see* Figure 30), close to outcrop area, and that salinity increases further with depth in both the corresponding Scollard–Paskapoo and Edmonton–Upper Wapiti aquifers (Figure 12 and Figure 13). The variation of water chemical composition coincides with the decrease in hydraulic conductivity at 50–70 m depth. The authors of the report attributed this coincidence to the slower rate of water movement and prevalence of reducing conditions. A marked increase in Cl content and decrease in SO_4 at approximately 40 m depth is attributed to residual Cl within the coal and surrounding marine sediments, due to incomplete flushing. In their interpretation, the chemistry of the coal aquifers substantiates the observation from hydraulic tests that the most active zone of groundwater flow in these aquifers is less than 50–70 m below the ground surface.

The authors of the draft report concluded that the hydraulic and chemical changes in the characteristics of these coal aquifers at 50–70 m below the ground surface may be the result of either a hydrodynamic boundary between different groundwater systems or a general depth limit of significant fracturing in the coal seams.

5 Stress Regime of the Upper Cretaceous–Tertiary Coal-Bearing Strata in the Alberta Basin

Although coal permeability is one of the most critical parameters for CBM producibility, there is very little information regarding the permeability of deeper coal beds in the Alberta basin, the available data generally indicating low permeability (Dawson, 1995). The location and values of the very limited coal-permeability data for the deeper Upper Cretaceous–Tertiary strata of the Alberta basin are shown in Figure 30. These data, combined with the information from the unpublished Alberta Research Council draft report on coal aquifers, clearly indicate a west-southwestward decrease in coal permeability, which correlates strongly with burial depth. Although very few data are available, coal permeability can be qualitatively estimated on the basis of the stress regime of the embedding strata. Extensive studies of coal beds in the Sydney and Bowden basins in Australia, and in the Black Warrior basin in Alabama (Enever et al., 1994, 1999; Sparks et al., 1995; Bustin, 1997), show that coal permeability correlates strongly with the magnitude of the effective stress (Figure 33). Thus, the knowledge of the stress regime in the Cretaceous coal-bearing strata in the plains of the Alberta basin may indicate areas of enhanced coalbed permeability and therefore CBM producibility.

The limited information available on the stress regime in the Alberta basin has been summarized by Bell et al. (1994). Regional stress orientations have been mapped across the Alberta basin (Bell and Babcock, 1986; Bell et al., 1994). Very little information exists on stress magnitudes in coal beds in the Alberta basin: only one subsurface well measurement (Woodland and Bell, 1989) and one set of mine measurements (Kaiser et al., 1982). On the other hand, fracture axes, which may be a diagnostic of principal-stress orientations, have been documented in many shallow coal mines (Campbell, 1979). To augment the database on the stress regime of the coal-bearing Upper Cretaceous–Tertiary strata in Alberta, stress magnitudes have been derived from well logs and from records of microfrac and minifrac tests, leak-off tests and commercial hydraulic fracture treatments measured in oil and gas reservoirs. Unfortunately no direct information exists for the coal beds themselves.

The Alberta plains are essentially flat on a regional scale (Figure 3) and form a surface that is geomechanically free with the atmosphere. Therefore, it is reasonable to assume that one of the

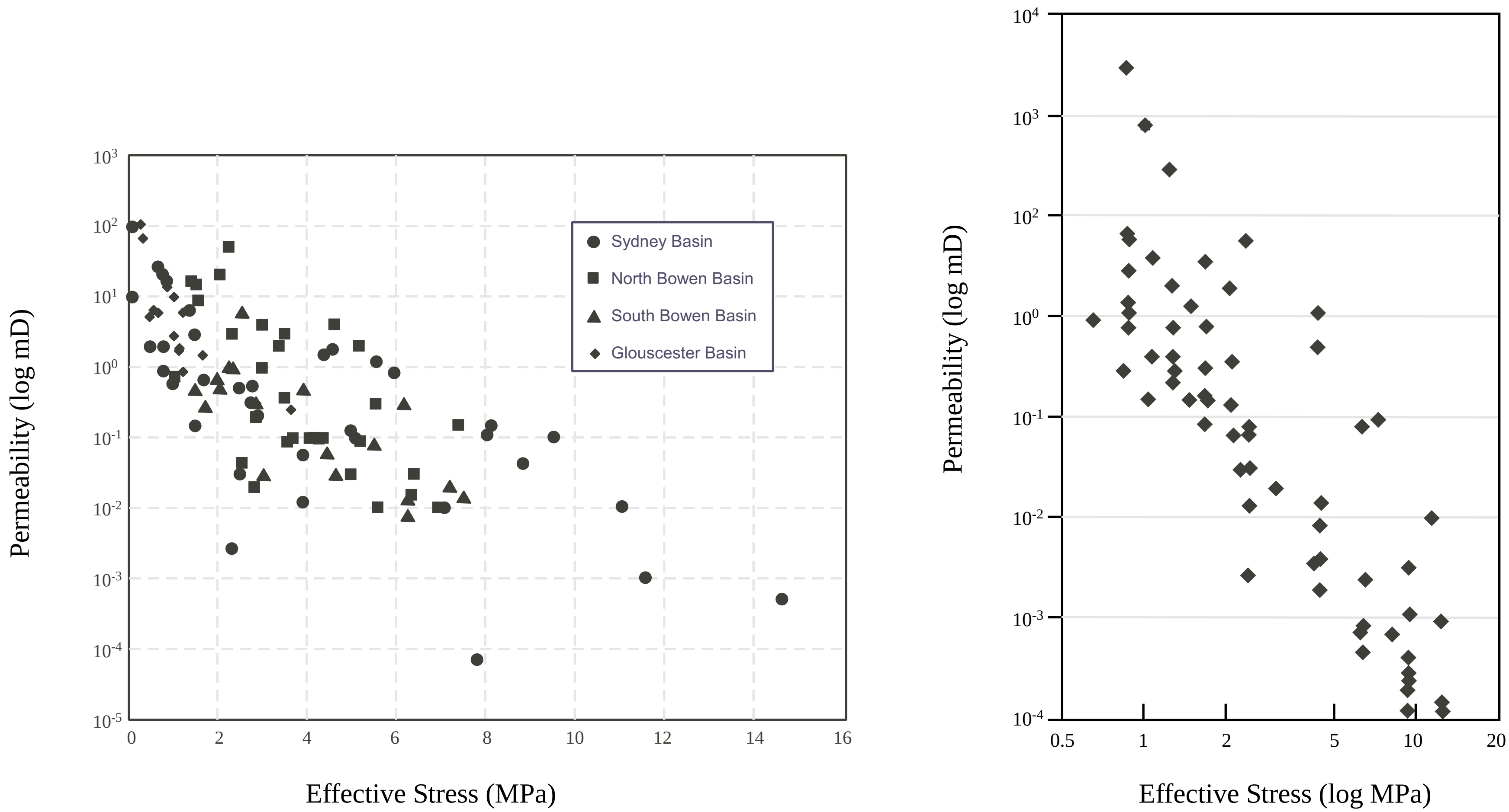


Figure 33. Dependence of coal permeability on effective stress, as identified in Australian coal basins: a) Sydney and Bowen basins (Enever et al., 1998), and b) Sydney basin (Bustin, 1997).

principal stresses will be vertical, and the requirement for orthogonality constrains the other two principal stresses to be horizontal. These three stress directions are therefore designated S_V, S_{Hmin} and S_{Hmax}. The magnitude of the vertical stress is equivalent to the weight of the overburden; thus, the vertical stress magnitude at a certain depth was calculated by integrating density logs from the surface to that depth. Vertical stress gradients, which represent the average gradient from the surface to that depth, were then calculated by dividing the stress magnitude by the corresponding depth.

Unlike the continuous S_v versus depth profiles, which can be generated from density logs, all of the fracture measurements used for determining the horizontal stress regime refer only to the interval in which the test was performed. Thus, individual measurements need to be treated as local gradients at given depths. Maps of S_{Hmin} gradients can be generated based on the actual data; these maps can then be used to calculate the magnitude of S_{Hmin} at a desired depth or stratigraphic horizon. The magnitudes and gradients of S_{Hmin} were determined from microfracturing, minifracturing and leak-off tests, respectively, and from fracture-breakdown pressures. Leak-off tests and fracture-breakdown pressures with gradients of less than 12 kPa/m or greater than 30 kPa/m were not used to estimate S_{Hmin}. The former are too low and the latter too high to reflect accurately the virgin stress magnitudes (Dahlberg and Bell, 1994). Because each type of test corresponds to a different stage of hydraulic-fracture propagation, the gradient values for S_{Hmin} obtained from leak-off tests and fracture-breakdown pressures were normalized to the values obtained from micro- and minifrac tests, which are judged to be the most reliable (Haimson and Fairhurst, 1970). No attempts were made to estimate S_{Hmax} magnitudes because they do not affect coal-fracture opening and permeability.

Horizontal stress orientations were determined by revisiting the breakout analyses previously summarized in the literature, and by analyzing breakouts in additional wells. The methodology used for estimating in situ stress magnitudes and orientations is described in more detail by Bell (in press) and Bell and Bachu (in press).

5.1 Stress Magnitude and Orientation

As a result of eastward erosion of the Upper Cretaceous–Tertiary strata, and because of the lack of log information for the uppermost cased interval in most wells, it is not possible to estimate the magnitude of the vertical stress (S_v) for most of the coal-bearing Upper Cretaceous–Tertiary sedimentary succession in the basin. Thus, vertical-stress magnitudes were calculated for the top of the Lea Park Formation and equivalent units, which constitute the base of the succession. The maps of vertical stress and its magnitude (Figure 34 and Figure 35) are based on data from 25 wells. There is a southwestward increase in vertical-stress magnitude from approximately 5 MPa to more than 40 MPa (Figure 34), consistent with increasing burial depth. Vertical-stress gradients, averaging 22.1 kPa/m, also increase southwestward, from approximately 21 kPa/m to 24 kPa/m (Figure 35). There are two notable low-gradient salients, around latitudes 50°30’N and 55°N.

Some 780 data points (Figure 36) were used to assess the horizontal-stress magnitudes (Figure 37). The data coverage is good within an approximately 200 km wide band immediately northeast of the Rocky Mountain deformation front, but is poor in the northeastern third of the study area, lowering the confidence in the mapped configurations there. Very few downhole procedures involving fracturing have been run in the northeastern part of the study area, except leak-off tests at shallow depths (<300 m), which are likely to provide questionable estimates of S_{Hmin} magnitudes.

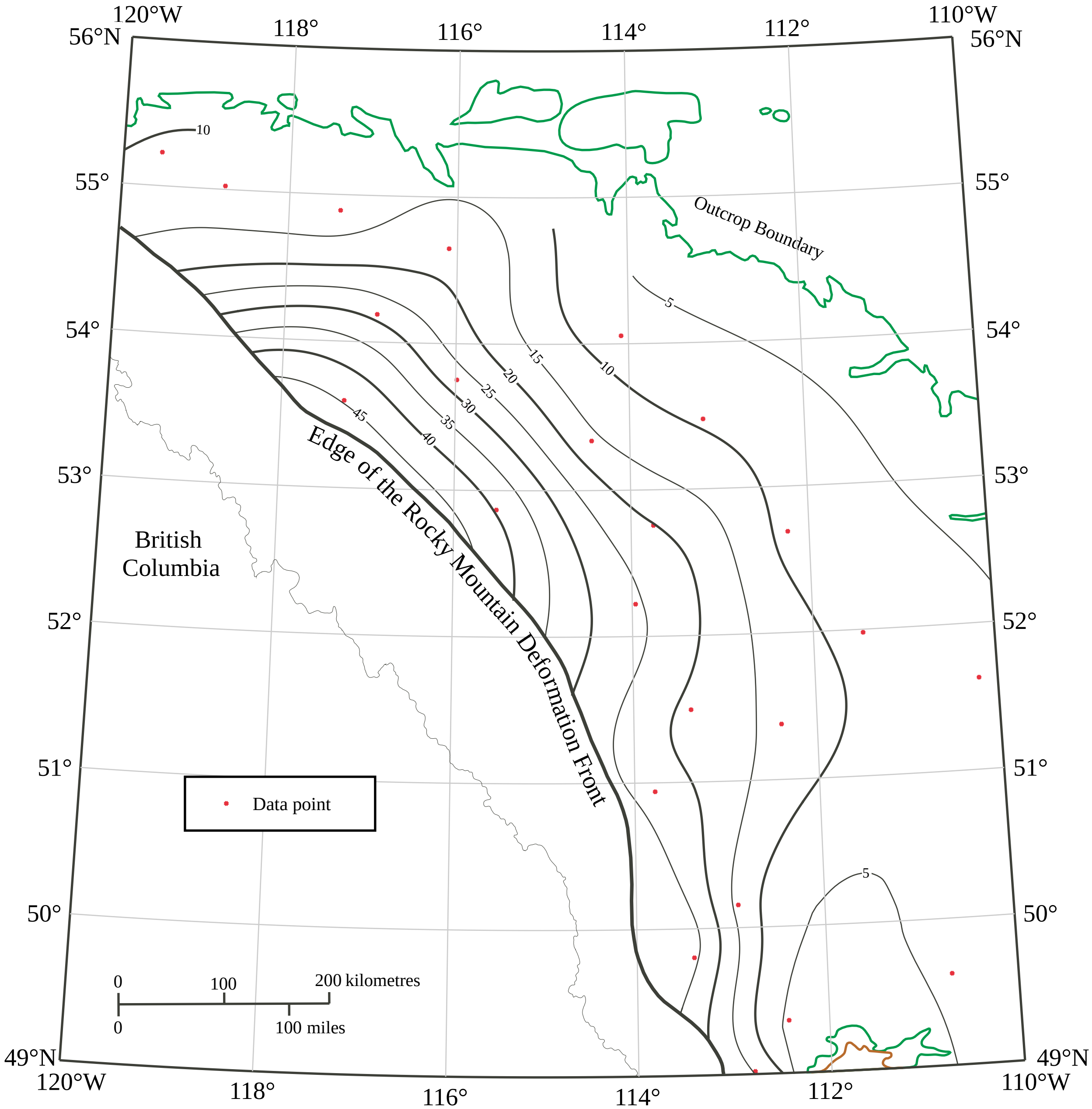


Figure 34. Magnitude (MPa) of the vertical stress (S_V) at the top of the Lea Park Formation.

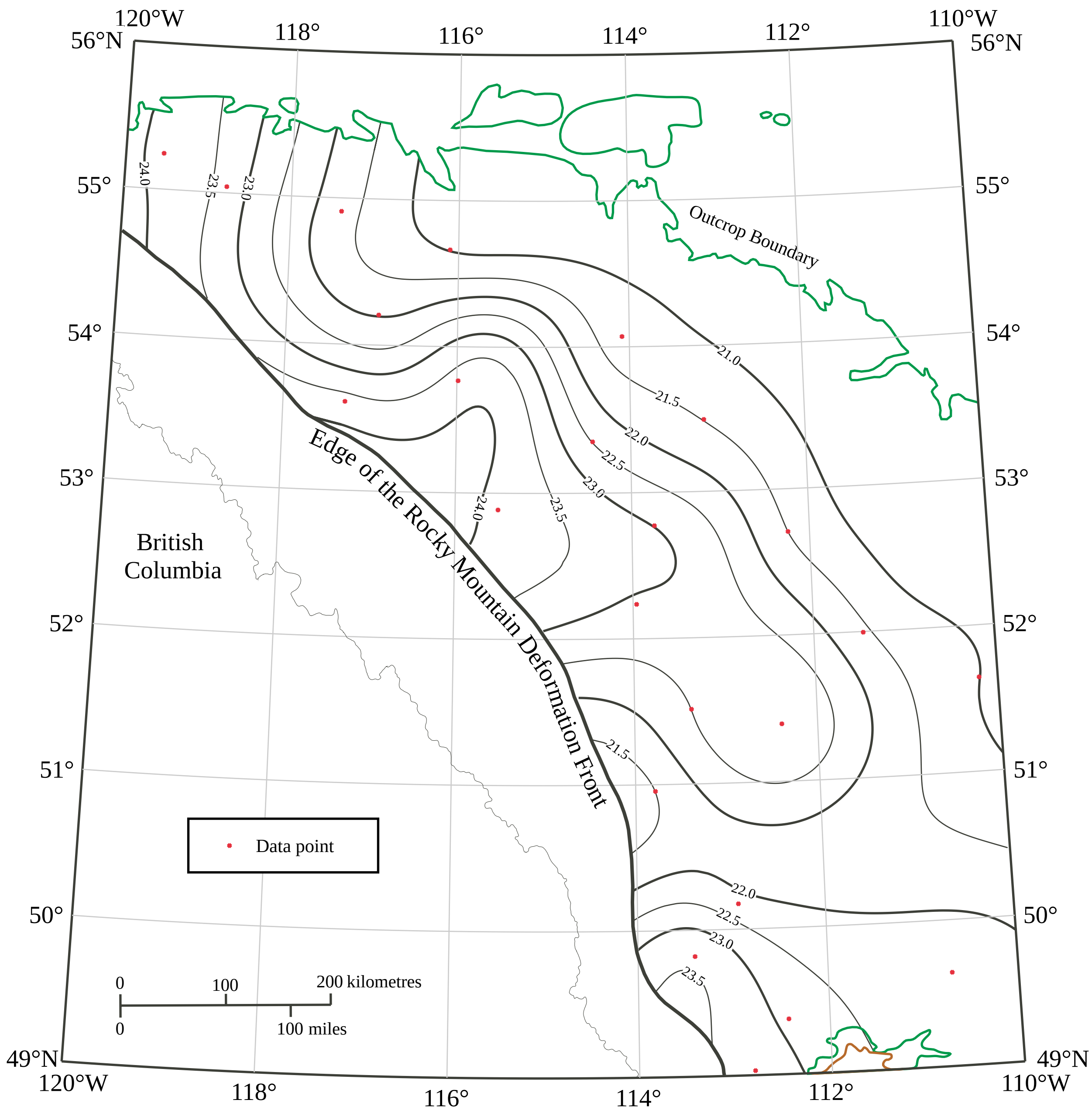


Figure 35. Gradient (kPa/m) of the vertical stress (S_V) at the top of the Lea Park Formation.

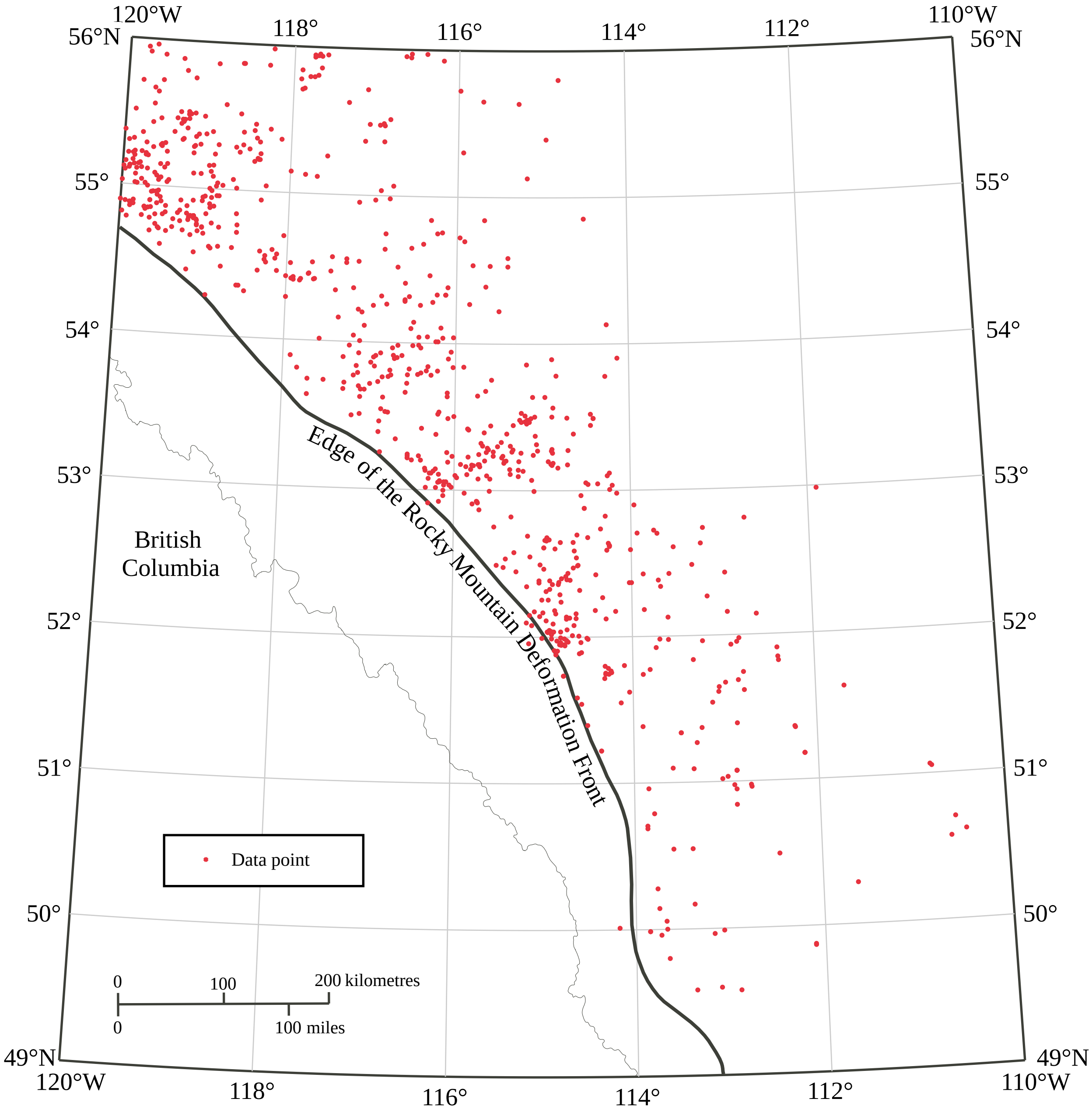


Figure 36. Distribution of microfrac, minifrac, and leak-off tests, and of fracture-breakdown pressures used to calculate gradients of the minimum horizontal (S_{Hmin}) in the coal-bearing Upper Cretaceous - Tertiary strata in the Alberta basin.

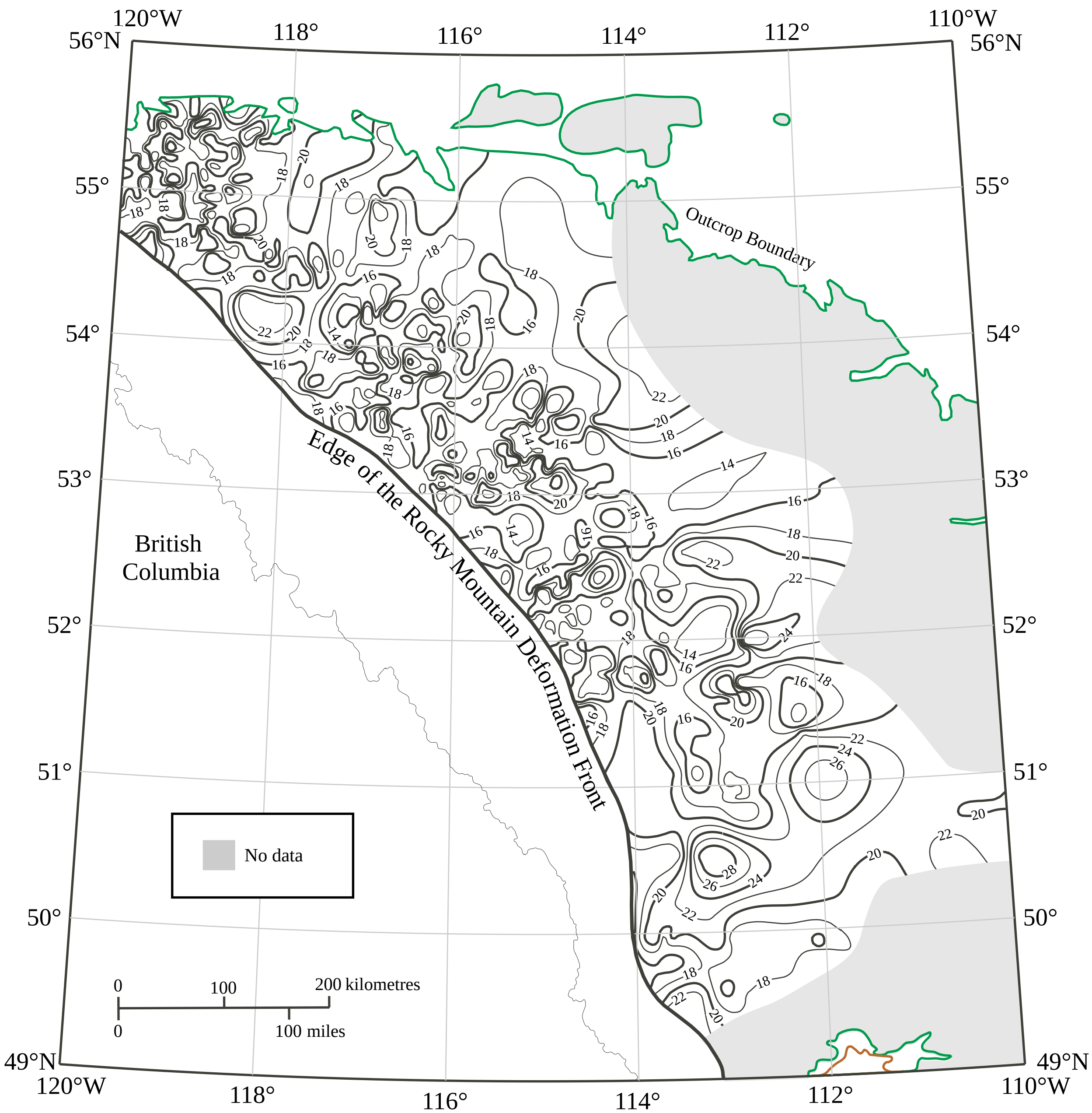


Figure 37. Gradient (kPa/m) of the minimum horizontal stress (S_{Hmin}) in the Upper Cretaceous-Tertiary strata of the Alberta basin (based on the data distribution of Figure 36).

Gradients of the minimum horizontal stress (S_{Hmin}) vary between 12 and 24 kPa/m (Figure 37), but are everywhere less than S_v gradients, except possibly at two sites located near the Mesozoic deformation front, one in the south (Twp. 18, Rge. 23, W 4^{th} Mer.) and one in the Wapiti area (Twp. 67, Rge. 8, W 6^{th} Mer.) in the northwest. Whether this is indeed the case needs to be established through local measurements. Notwithstanding these two data points, the distribution of vertical- and minimum horizontal-stress gradients indicates that S_{Hmin} is less than S_v below depths of 300 m throughout the study area. The distribution of S_{Hmin} magnitude reflects the variations in the stress gradients but, more than anything else, it reflects the present burial depth. The magnitude of S_{Hmin} at the top of the Lea Park Formation varies from less than 5 MPa in the east-northeast to greater than 35 MPa at the Rocky Mountain deformation front in the west, with local values reaching approximately 40 MPa (Figure 38), and is everywhere less than the magnitude of S_v (Figure 35).

The horizontal-stress orientations were derived from breakouts identified on four-arm dipmeter logs in sixteen wells with breakouts in Upper Cretaceous strata, plus those from five additional sites published previously (Mcleod, 1977; Kaiser et al., 1982; Hassan, 1982; McLellan, 1988; all reviewed in Bell et al., 1994). The mean azimuth of S_{Hmin} in the 16 wells varies between 120° and 152° (Figure 39), while the mean azimuth of S_{Hmax} varies accordingly between 030° and 062°, with wellsite standard deviations ranging between 3° and 19°. The orientation (azimuth) of S_{Hmax}, and therefore its trajectory, vary from approximately 030° in southern Alberta to approximately 070° in west-central Alberta, maintaining a direction generally perpendicular to the Rocky Mountain deformation front (Figure 39).

5.2 Stress Regime

The distribution patterns of vertical stress (S_v) indicate that regional topography and maximum depth of burial exert a first-order control on the vertical-stress magnitude. The topographic influence is easy to observe by comparing the relief of the Alberta plains (Figure 3) with the vertical-stress magnitude at the top of the Lea Park Formation (Figure 34). The contours of equal stress parallel the foothills in the west, wrap around the Swan Hills in the northwest and the Cypress Hills in the southeast, and outline the moderate and low topography in southern and central Alberta. The regional-scale control exerted by maximum burial depth is expressed by consistently northeastward-decreasing stress gradients (Figure 35). They decrease from the 24 kPa/m range near the foothills to the 21 kPa/m range in the northeast. This corresponds to the pattern of burial depth in the foreland basin during the Laramide orogeny (Nurkowski, 1984; Bustin, 1991), and to the general loading of a foreland basin away from the deformation front (Beaumont, 1981). The implication is that the sedimentary rocks were less compacted, and are therefore less dense, in a general northeasterly direction. The topographic control is, in an indirect way, also an expression of differential loading as a result of erosion. In addition, stress gradients are higher in southern Alberta (Figure 35).

The increase in vertical-stress gradients is also an indication of higher rock density, and therefore a consequence of previous deeper burial. The west-northwesterly locus of high S_V gradients (Figure 35) generally corresponds to the major depocenter of the Mesozoic foreland basin. These high gradients and S_V magnitudes are caused by higher than average densities for Tertiary and Cretaceous rocks, because they were more deeply buried in the past than equivalent strata (Nurkowski, 1984; Bustin, 1991). In southern Alberta, this inference is supported by stratigraphically deeper erosion (Dawson et al., 1994b), suggesting the possibility of a late Laramide depocenter in this area, although this hypothesis needs further investigation.

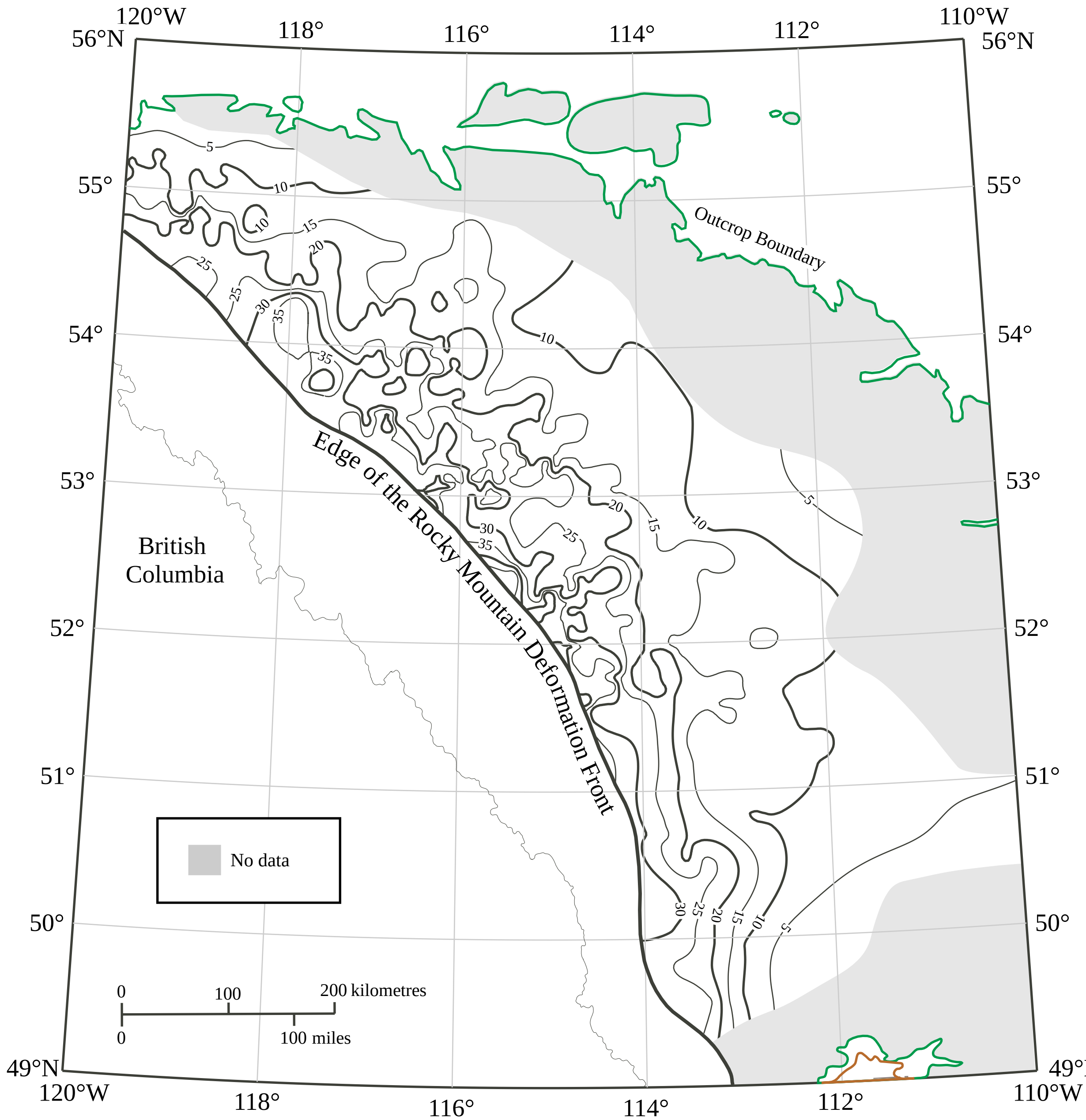


Figure 38. Magnitude (in MPa) of the minimum horizontal stress (S_{Hmin}) at the top of the Lea Park Formation (based on the gradient distribution of Figure 37).

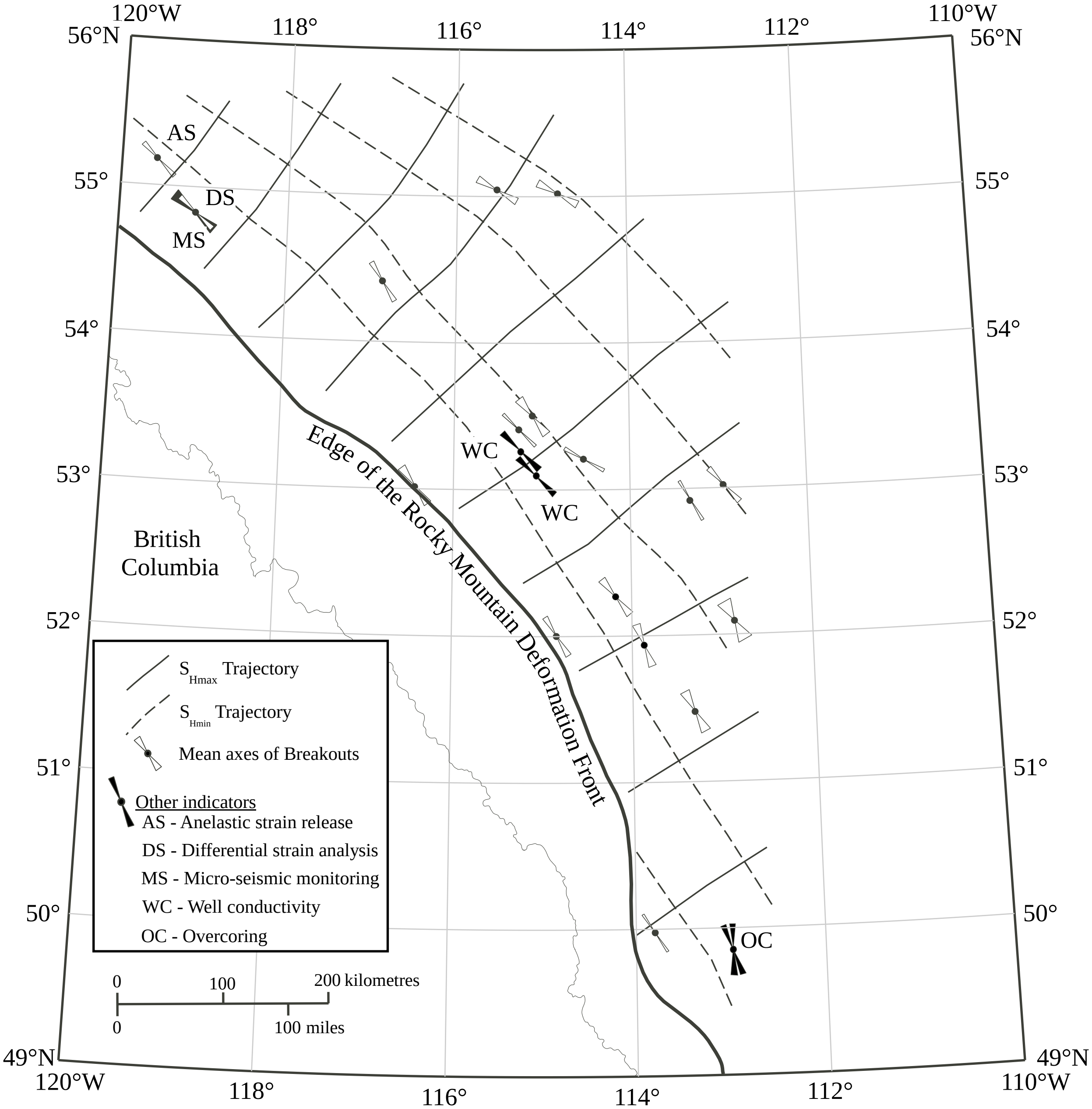


Figure 39. Stress trajectories in the coal-bearing Upper Cretaceous - Tertiary strata of the Alberta basin.

The gradients for minimum horizontal stress (S_{Hmin}) display a less definitive regional pattern than the vertical stress gradients (Figure 37); however, S_{Hmin} gradients are also relatively high in southern Alberta. This is a reflection of the high vertical-stress gradients in this area. Gradients for S_{Hmin} become lower toward the northeast, which is probably due to the lesser former depth of burial of the rocks in this region. Unlike the vertical stress, S_{Hmin} magnitudes in southern Alberta are not particularly high. The reason for this is that the Upper Cretaceous strata are shallower in southern Alberta than they are along structural strike to the northwest, so the higher S_{Hmin} gradients do not generate noticeable anomalies of stress magnitude in this region.

Stress trajectories show an unambiguous consistency of S_{Hmin} being approximately parallel to the Rocky Mountain deformation front, in a general northwest-southeast direction, and S_{Hmax} being orthogonal to it (Figure 39). The S_{Hmax} trajectories are closely aligned with the motion vector of the North American Plate, so the anisotropic compressional component of the stress regime is probably caused by contemporary plate tectonics (Zoback et al., 1989). The directional correspondence between the orientation of S_{Hmax} (Figure 39) and cleat (fracture) trends in Cretaceous coal beds in Alberta (Figure 40), as determined in shallow coal mines (Campbell, 1979), is striking. Most cleat axes are aligned within 20° of the S_{Hmax} trajectory. Such fractures will tend to be open and to provide preferred flow paths for water and/or oil and gas. The orientation of stress trajectories is an excellent indicator of permeability anisotropy in the coal bedding planes.

The vertical stress (S_v) in the coal-bearing Upper Cretaceous–Tertiary rocks of the Alberta basin is greater than S_{Hmin} (Figure 34 and Figure 38). This means that fractures, including those in coal seams, will generally be vertical and will propagate on a southwest-northeast axis along the direction of S_{Hmax}. At very shallow depths (<300 m), S_v may be less than S_{Hmin}, which means that shallow fractures will be subhorizontal rather than vertical. Since permeability tends to be greater in fractures in the plane perpendicular to S_{Hmin} (e.g., Heffer and Lean, 1991), at least for depths greater than 300 m, the greatest fracture permeability is likely to occur in vertical fractures aligned close to the S_{Hmax} trajectories.

Although the stress regime is generally, by itself, a potential regional-scale qualitative indicator of coal permeability, the permeability actually depends on the effective stress rather than the total stress. The stress in the sedimentary rocks is taken by both the fluids saturating the pore space, where it is manifested as pressure, and by the rock matrix, including coal. Thus, the effective stress is obtained by subtracting the fluid pressure from the total stress. If the pore space is under- or overpressured as a result of burial history and hydrodynamic regime, then the rocks take on, correspondingly, more or less (effective) stress. Since the minimum horizontal stress in the Upper Cretaceous–Tertiary strata of the Alberta basin is less than the vertical stress, the minimum effective stress, which controls cleat opening and therefore coal permeability, is calculated by subtracting the pressure (p) from S_{Hmin}.

Figure 41 shows the pressure distribution at the top of the Lea Park Formation (base of the Basal Belly River aquifer), calculated on the basis of hydraulic heads in the Basal Belly River aquifer (Figure 21) and elevation of the structure top of the Lea Park Formation (Figure 6). The minimum effective stress increases from zero at the erosional edge of the Basal Belly River aquifer to approximately 20 MPa close to the Rocky Mountain deformation front (Figure 42), consistent with the increasing burial depth. Effective stresses in stratigraphic horizons higher up in the sedimentary succession are correspondingly smaller, but still follow the same pattern. From an exploration point of view, coal permeability in any stratigraphic horizon in the coal-bearing Upper Cretaceous–Tertiary strata of the Alberta basin is probably quite low in a band approximately 150 km wide along the Rocky Mountain deformation front, and higher beyond it

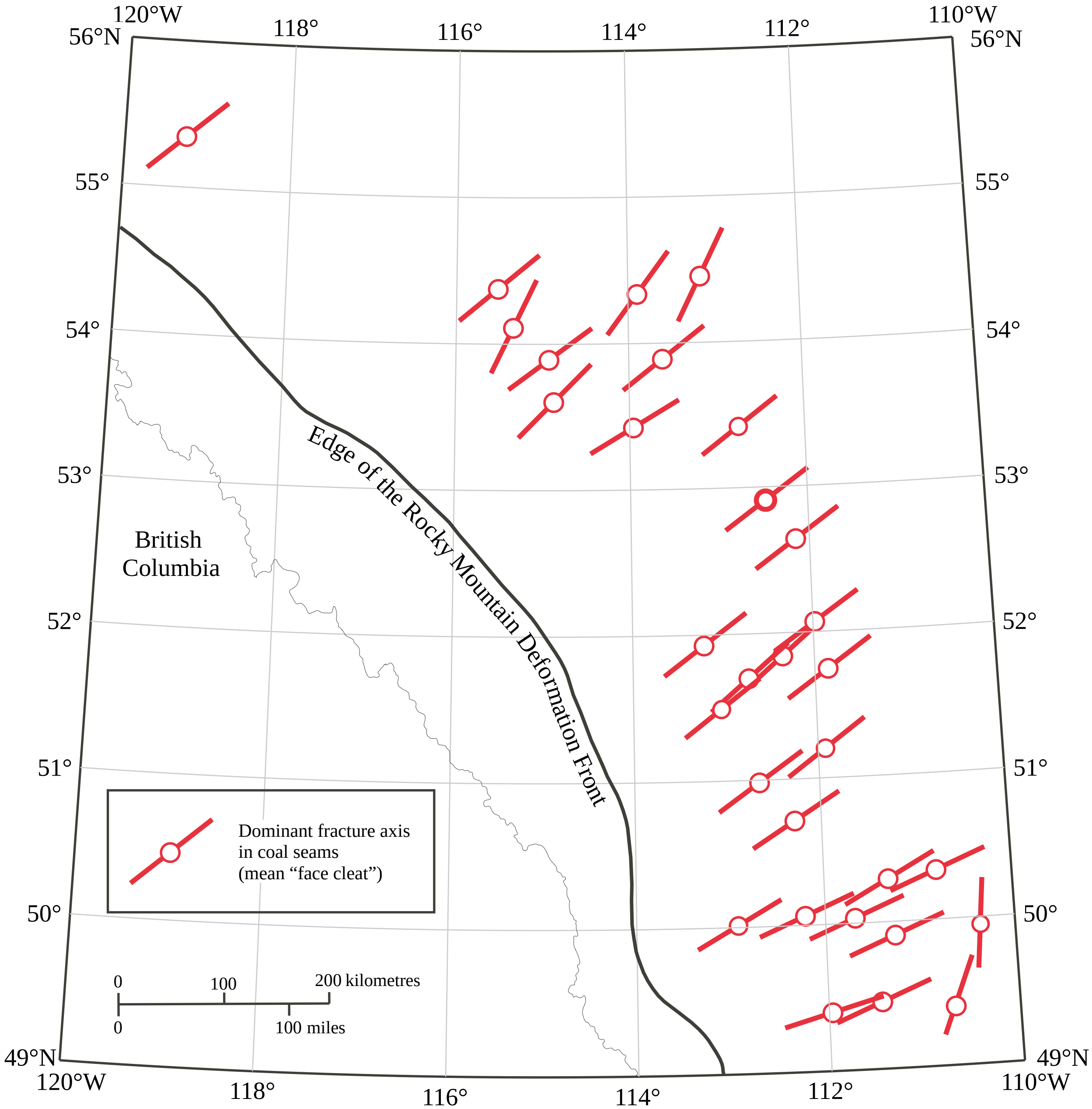


Figure 40. Direction of dominant cleats (fractures) in Cretaceous and Tertiary coal seams in the Alberta basin (after Campbell, 1979).

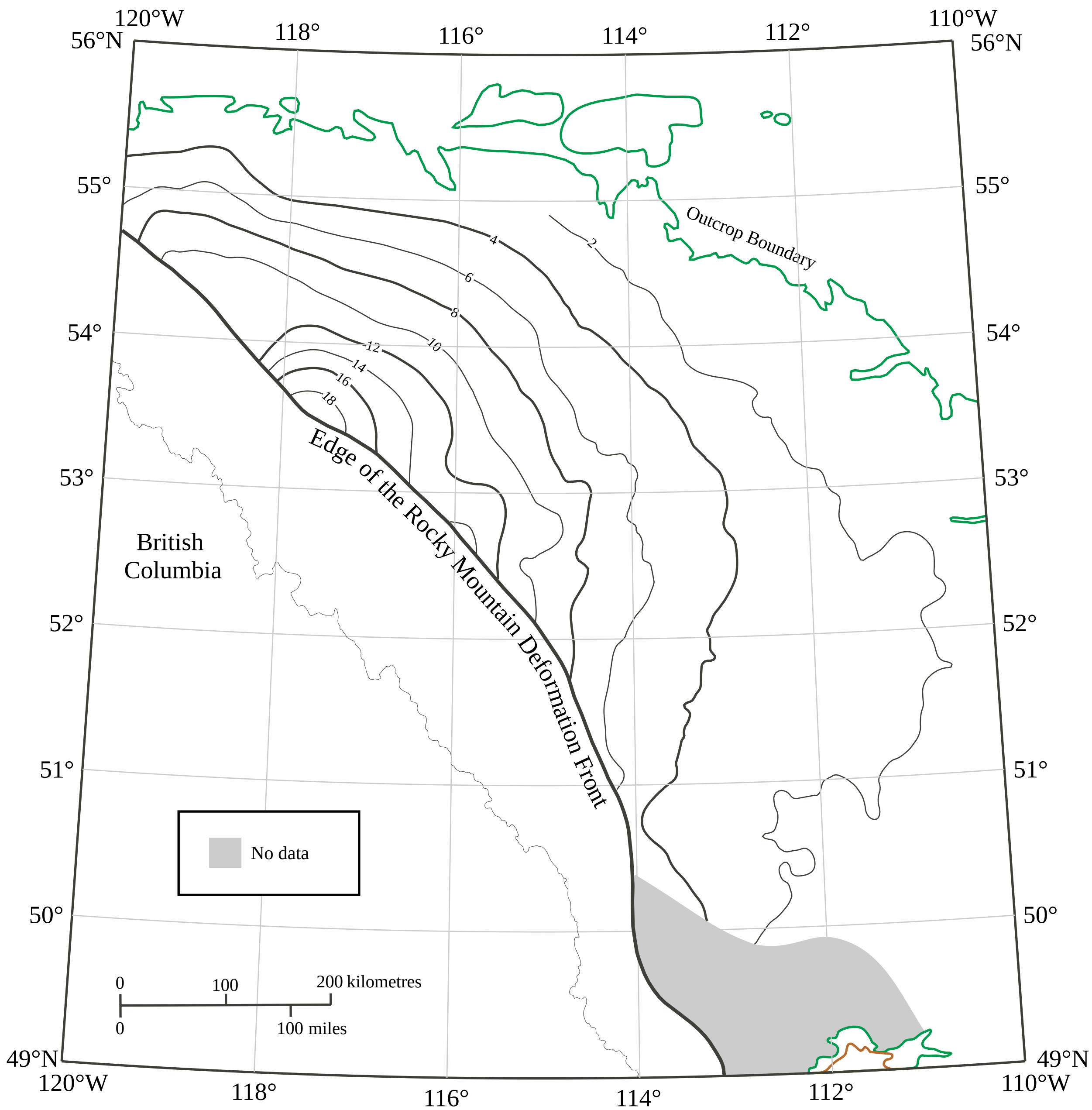


Figure 41. Pressure distribution at the top of the Lea Park Formation (base of the Basal Belly River aquifer) in the Alberta basin (contour interval in MPa).

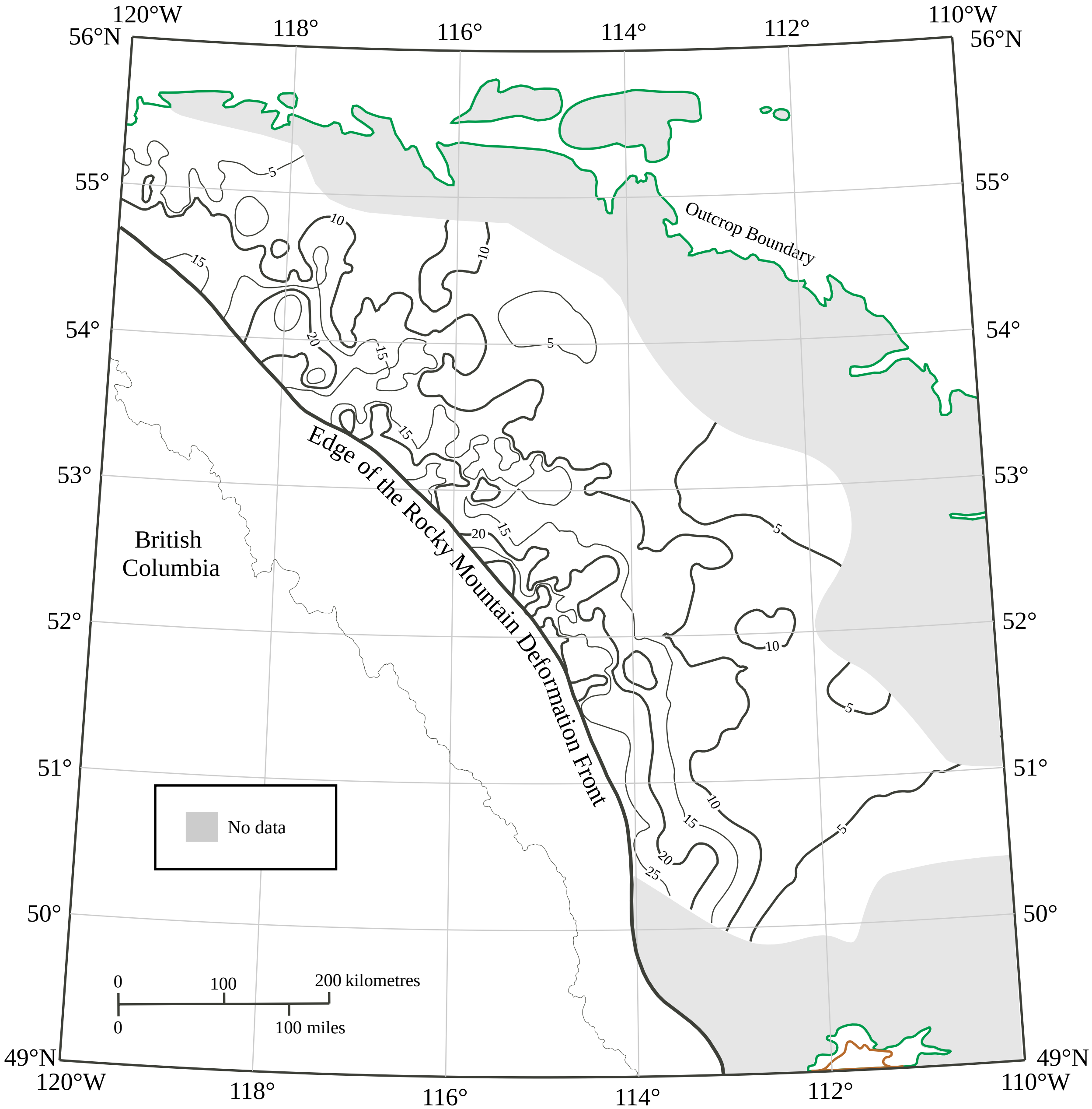


Figure 42. Effective minimum stress at the top of the Lea Park Formation in the Alberta basin (contour interval in MPa).

in north-northwestern, northeastern, eastern and southern Alberta. Local-scale structural features would be superimposed over the basin-scale stress trend, locally affecting coal permeability.

6 Summary, Discussion and Conclusions

The coalbed methane (CBM) potential and producibility of any coal-bearing strata are strongly affected by the hydrogeological regime of formation waters and by coal permeability, which in turn depends on the effective stress regime of the coal. Upper Cretaceous and Tertiary strata in Rocky Mountain foreland basins are rich in coal, and a few are prolific CBM producers or have good CBM potential. In the San Juan basin in the United States, a major CBM producer, the coal zones are aquifers with a strong topography-driven flow that both maintains the necessary pressure and introduces bacteria that are critical in biogenic-gas generation. Other Rocky Mountain basins, such as the Powder River basin, produce CBM from very shallow coal beds. However, the hydrogeological and permeability conditions in the Upper Cretaceous–Tertiary strata in the Alberta basin are quite different from those in basins to the south.

Peat that accumulated in the Alberta basin during the late Cretaceous and early Tertiary led to the formation of coal deposits in the Upper Cretaceous Belly River Group and Horseshoe Canyon Formation, and in the Upper Cretaceous–Paleocene Scollard and Paskapoo formations. Coal rank and gas content are the result of burial only, with coal ranging from lignite to high-volatile bituminous in rank. The coal seams are dipping to the west and occur at depths ranging from surface outcrop to more than 2500 m. The methane accumulated in these coal beds is probably of both thermogenic and biogenic origin.

From a hydrogeological point of view, the post–Lea Park, Upper Cretaceous–Tertiary succession in the Alberta basin comprises, in ascending order, the Basal Belly River, the Upper Belly River, the Edmonton–Upper Wapiti and the Scollard–Paskapoo aquifers, separated by the intervening Middle Belly River, Bearpaw and Battle shaly aquitards. The flow of formation waters in these aquifers is driven by gravity (topography) and erosional rebound, and is controlled by absolute permeability of the rock, gas generation and capillary pressure to gas (relative permeability).

Several flow systems are present in the succession. In the northern part (Wapiti Group), where the Bearpaw shale is absent and the shale content is generally much lower than in the southern and central parts, water of meteoric origin recharges all the aquifers in the succession at topographic highs in the Swan Hills and at the Rocky Mountain deformation front in the west, and discharges at outcrop in the north and northeast. Another topography-driven flow system is present in the south, driven by the high elevation of Belly River outcrop near the Canada–United States border. The flow is driven northeastward toward lower elevations in the east-central part of the basin. In the center of the study area, the flow system in the aquifers that crop out at the top of the bedrock progressively from west to east (Scollard–Paskapoo, Edmonton–Upper Wapiti, and Upper and Basal Belly River) is also driven by present-day topography. The water in all these topography-driven flow systems is characterized by low salinity (<5000 mg/l, but mostly <1500 mg/l) and a relatively high bicarbonate content.

The erosional rebound of the Lea Park, Belly River and Bearpaw shale units in the central part of the Upper Cretaceous–Tertiary coal-bearing strata of the Alberta basin drives the flow in the Basal Belly River, Upper Belly River and Edmonton–Upper Wapiti aquifers downdip and inward, from the east, close to their respective subcrop edge, toward the Rocky Mountain deformation front in the west. Capillary sealing between downdip gas-saturated sandstone and updip water-saturated sandstone, and low permeability depositional barriers in the Belly River and Edmonton groups create barriers that impede and retard the flow of meteoric water from outcrop areas that would equilibrate pressures in these aquifers with current basin topography. The salinity of formation waters in these aquifers in this area is relatively high (between 5000 and 18 000 mg/l) and the bicarbonate content is low.

Water samples from shallow (<100 m depth) coal aquifers analyzed in the 1970s at the Alberta Research Council show that the coal-aquifer water progresses from calcium bicarbonate at shallow depths (<30 m) to sodium chloride in the deeper zones, in a sequence characteristic of water movement from shallow zones of active flushing into zones where the flow is very sluggish and the water is old. Salinity (total dissolved solids) increases with depth from 500 to 1500 mg/l.

The average hydraulic conductivity of shallow (<100 m depth) coal aquifers in Alberta, also measured by the Alberta Research Council, decreases with depth. Values of hydraulic conductivity for these shallow coal beds vary over several orders of magnitude, from 0.02 to 800 m/d (corresponding permeability values of approx. 25 mD to >1000 D). The average hydraulic conductivity of very shallow coal aquifers (<50–60 m depth) reaches 19 m/d (permeability of approx. 25 to 30 D) at 5–15 m depth and then gradually decreases. The average hydraulic conductivity of the slightly deeper coal aquifers (between 50 and 100 m depth) is fairly constant at 2 m/d (permeability of approx. 2.5 to 3 D). Relatively high coal hydraulic-conductivity values (>15 m/d, which corresponds to a permeability of approx. 20 D) occur in areas where the regional pattern of coal hydraulic conductivity, controlled by tectonic stresses, has been locally altered by second-order effects of glacial deformation of bedrock highs that have been subjected to additional stress during ice movement, and to elastic erosional rebound near or within river valleys. A few permeability measurements for deeper coal beds to the west indicate that coal permeability generally decreases west-southwestward with increasing burial depth.

In the absence of direct permeability measurements, the stress regime in the coal-bearing strata, and therefore in the coal beds themselves, provides a qualitative indication of coal permeability. Vertical-stress magnitudes increase southwestward, from approximately 5 MPa in the outcrop area of the Belly River Group to greater than 40 MPa near the Rocky Mountain deformation front, consistent with increasing burial depth. Vertical-stress gradients also increase southwestward, from approximately 21 kPa/m to approximately 24 kPa/m. Regional topography and maximum depth of burial exert a first-order control on the vertical-stress magnitude. Gradients of the minimum horizontal stress vary between 12 and 24 kPa/m, indicating that the minimum horizontal stress is less than the vertical stress, at least below depths of 300 m. The minimum effective stress increases from zero at the erosional edge of the Basal Belly River aquifer to approximately 20 MPa close to the Rocky Mountain deformation front, consistent with the increasing burial depth.

Stress trajectories show that the minimum horizontal stress is approximately parallel to the Rocky Mountain deformation front, in a general northwest-southeast direction, and the maximum horizontal stress is orthogonal to it. The relation between stress magnitudes and their direction indicates that fractures, including those in coal seams, will generally be vertical and will propagate on a southwest-northeast axis along the direction of the maximum horizontal stress. At very shallow depths (<300 m), the vertical stress may be less than the minimum horizontal stress, which means that shallow fractures will be subhorizontal rather than vertical. However, a survey of coal cleat openings in shallow coal seams shows that coal fractures are vertical, even at very shallow depths. The orientation of stress trajectories is an excellent indicator of permeability anisotropy and preferential flow paths in the coal beds.

The history of the Alberta and other Rocky Mountain basins indicates that the methane contained in Upper Cretaceous–Tertiary coal is most likely of thermogenic and late-stage biogenic origin. The hydrogeological regime and flow of formation waters in the Upper Cretaceous–Tertiary, post–Lea Park, coal-bearing sedimentary succession of the Alberta basin suggests that coalbed methane in deep coal seams in west-central Alberta (Edmonton and Belly River groups), where formation-water flow is driven by erosional rebound, is of thermogenic origin. In this region, meteoric water cannot reach these strata because of permeability barriers caused by 1) depositional and lithological changes, and 2) capillarity barriers at the boundary between downdip gas-saturated sands and updip water-saturated sands. The gas content of the coal beds here may be quite low as a result of both uplift and erosional rebound. The decrease in pressure caused by uplift since maximum burial, at the peak of the Laramide orogeny, would cause gas desorption from the coal beds and migration into adjacent sandstone reservoirs, where it has accumulated in stratigraphic traps created by a changing depositional environment. The additional loss of pressure (underpressuring) caused by erosional rebound probably enhanced the gas desorption and migration out of coal beds into the adjacent sandstone units. This would explain the large number of gas pools in the Belly River and Edmonton groups.

The coalbed methane in shallower coal beds in and near the subcrop regions of the Upper Cretaceous–Tertiary strata is probably of mixed origin, with a significant biogenic component (to be verified by gas analyses). Freshwater of meteoric origin penetrates into these strata, and therefore into the coal beds, driven in several systems by present-day topography in the northwest, southeast and along subcrop in the east. Thus, these coal beds, although of low rank, may contain significant amounts of late-stage biogenic methane, which seems to be the case with the CBM-producing Fruitland Formation in the San Juan basin and the Fort Union Formation in the Powder River basin. Based on hydraulic tests conducted in the past in shallow coal aquifers, it seems that the most active zone of groundwater flow in these aquifers is less than 50–70 m below the ground surface.

From a producibility point of view, the deep coal beds seem to have very low permeability (on the order of millidarcies and less), consistent with the closing of coal fractures (cleats) as a result of increasing effective stress with burial depth. Thus, coal permeability in the Edmonton and Belly River groups is probably too low for successful CBM development in a band approximately 150 km wide along the Rocky Mountain deformation front, but higher beyond it in north-northwestern, northeastern, eastern and southern Alberta. Local-scale structural features would be superimposed over the basin-scale stress trend, locally affecting coal permeability. Coal permeability increases with decreasing burial depth, reaching very high values (on the order of darcies and higher) in the upper 50–60 m.

This regional-scale coal-permeability pattern is locally altered by second-order effects of glacial deformation of bedrock highs and elastic erosional rebound near or within river valleys, which produce locally higher coal permeability. Thus, the shallow coal beds in the Scollard–Paskapoo succession (e.g., Ardley Coal Zone), and the Edmonton and Belly River coal beds along the arcuate subcrop region of these strata, probably have sufficient permeability for CBM production. The stress regime in the Upper Cretaceous–Tertiary coal-bearing strata of the Alberta basin indicates that fractures will be vertical and oriented generally in a southwest-northeast direction, perpendicular to the Rocky Mountain deformation front. Thus, wells in a five-spot pattern for enhanced CBM recovery should be sited to take advantage of this configuration of stress trajectories, in order to maximize the benefit of cleat orientation.

From the point of view of produced water, the salinity of formation water in shallow coal seams, where the flow is driven by topography, is low (generally less than 1500 mg/l, although in places it may reach 3000–5000 mg/l). The salinity of formation water in the deeper strata of west-central Alberta, where the flow is driven by erosional rebound, is significantly higher (reaching up to 18 000 mg/l). This affects treatment and/or disposal strategies with regard to the water produced in conjunction with coalbed methane.

From a strictly hydrogeological and permeability-stress regime point of view, the region that probably has good CBM potential and producibility from coal seams in the Upper Cretaceous–Tertiary strata of the Alberta basin extends from the west-northwest, at the top of the Scollard–Paskapoo succession, to central and southern Alberta, along and near the subcrop area of the stratigraphically deeper Edmonton and Belly River groups (Figure 43). The deep Edmonton and Belly River strata in western and central Alberta most likely have a reduced CBM potential due to possibly lower gas content and to low permeability. These considerations need to be applied against studies of coal thickness, rank and gas content to identify the best targets for CBM exploration and production in Alberta.

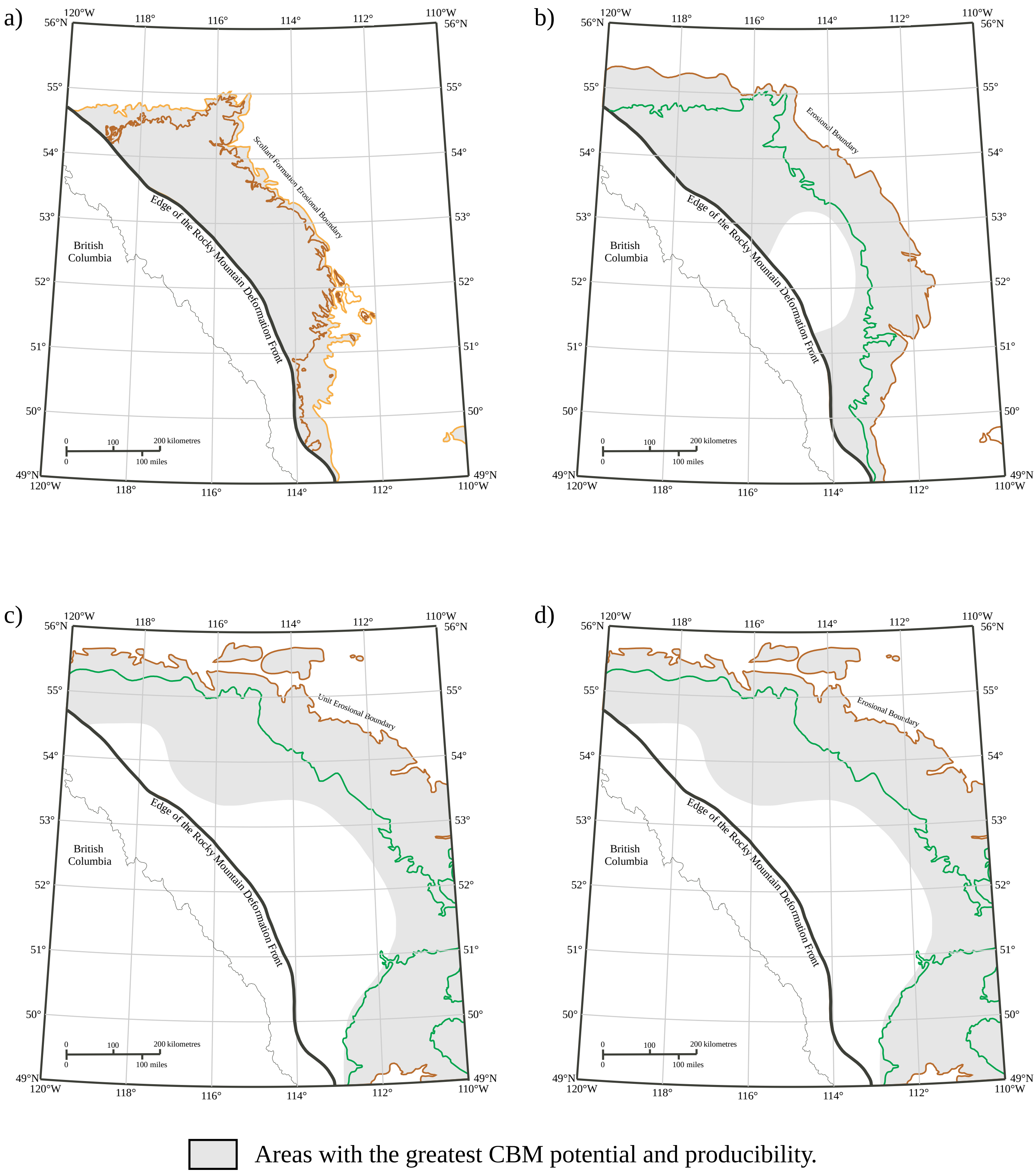


Figure 43. Location of the most prospective regions for CBM exploration and production from the Upper Cretaceous-Tertiary coal-bearing strata in the Alberta basin, as indicated by hydrogeology and stress regime only.

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