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BASIN-SCALE GEOLOGY AND HYDROGEOLOGY OF COALBED-METHANE BEARING STRATA IN ROCKY MOUNTAIN SEDIMENTARY BASINS

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1.0 ABSTRACT

Worldwide resources of methane trapped within the coal porous system are greater than the collective reserves of all known conventional gas fields. However, only in very few places, primarily in the United States, has this energy source been commercially tapped. Except for the Black Warrior basin in Alabama, all major basins in the United States where coalbed methane is produced or have producibility potential are foreland Rocky Mountain sedimentary basins. The coal beds in these basins are found in Upper Cretaceous and Tertiary strata. Canada also has abundant coal resources, particularly in the Upper Cretaceous-Tertiary succession of the Rocky Mountain foreland of the Alberta basin. Coalbed methane resource estimates for the Alberta basin vary between 300 and 540 Tcf. Coalbed methane producibility depends in an interrelated manner on geological factors, such as tectonic, structural and depositional setting, on coal distribution and properties, such as rank and gas content, and on hydrogeological factors, such as permeability and flow of formation waters. Several studies of coalbed methane potential and producibility in US Rocky Mountain foreland basins address in a comprehensive, multi-disciplinary manner all factors relating to coalbed methane potential and producibility. No comprehensive study exists to date for Canadian coalbed methane resources. An overview of the geological and coal characteristics of coal-bearing basins in the US and Canada was recently completed by the Geological Survey of Canada (GSC). However, no review of the hydrogeology of the coal-bearing strata and of the effect of groundwater flow on coalbed methane migration, accumulation and producibility was undertaken. Together with the GSC report, this review should provide the regional-scale information and understanding of the various geological and hydrogeological conditions in these basins and how they affect coalbed methane producibility. Particular attention is given to the Alberta basin, as it has probably the largest untapped resources.

2.0 INTRODUCTION

From a tectonic point of view, the sedimentary basins in United States and Canada are of various origin and type, such as intracratonic (e.g., the Williston basin in the Dakotas and Saskatchewan), intermontane (e.g., the Skeena basin in British Columbia), foreland (along the eastern side of the Rocky Mountain and the western side of the Appalachian Mountains), and passive-margin (along the Atlantic coast of the US). Generally, coals were deposited in fluvio-deltaic and lacustrine environments. Coal is absent from those basins or sedimentary successions formed during the passive-margin stage of basin evolution, or in marine environments. For the sedimentary basins where coal represents a valuable and accessible resource, there are many studies regarding the geology and properties of coal deposits. However, very few studies are available regarding the hydrogeology and rock properties of the coal beds and adjacent strata, and coalbed methane producibility.

Due to special tax credits, the development of unconventional gas resources in the United States grew considerably since the late 1980's, so that by the end of 1994, coalbed methane (CBM) accounted for 5% of the US natural gas production and 6% of the proven reserves (Stevens et al., 1996). Most of the CBM resources in the US (Figure 1) occur in Rocky Mountain foreland basins which contain coals of Cretaceous and Tertiary age and are largely undeformed (Murray, 1996). From this point of view, these basins are very much like the Alberta basin, which is the basin with the greatest CBM potential in Canada. The CBM production of the Appalachian and Midcontinent Paleozoic coal basins in USA appears to be relatively modest, considering their vast areas. With only about 20 m net of coal being present at best, little incentive exists for exploration under current market conditions (Fails, 1996). The principal producing areas in the US are the mature San Juan basin in Colorado and New Mexico, and the Black Warrior basin in Alabama, which account for 80% and 17% of total coalbed methane production in the US, respectively (Murray, 1996). New emerging basins are the Central Appalachian basin in West Virginia and the Raton basin in Colorado-New Mexico (Stevens et al., 1996). Other basins with future potential are the Greater Green River basin in Wyoming, the Piceance basin in Colorado, and the Powder River basin in Montana and Wyoming. The Uinta and Wind River basins have small CBM resources (Tyler et al., 1995).

Canada contains abundant coal resources spread throughout sedimentary basins in British Columbia, Alberta, Saskatchewan, the Maritimes, Yukon and Northwest Territories. Although many of them contain coal of suitable quality and sufficient depth to be considered for CBM reservoirs, the coalbed methane potential has not been truly evaluated, and only limited exploration drilling has taken place to date (more than 140 CBM wells). In Canada there is no CBM production of any significance because the country's energy needs are currently met by abundant coal and hydrocarbon fuels, and hydroelectric and nuclear power. Any CBM production is subeconomic at current market prices. The major Canadian coal-bearing regions can be divided into: coastal British Columbia, intermontane British Columbia, the deformed part of the Alberta basin (Rocky Mountain ranges and foothills), the

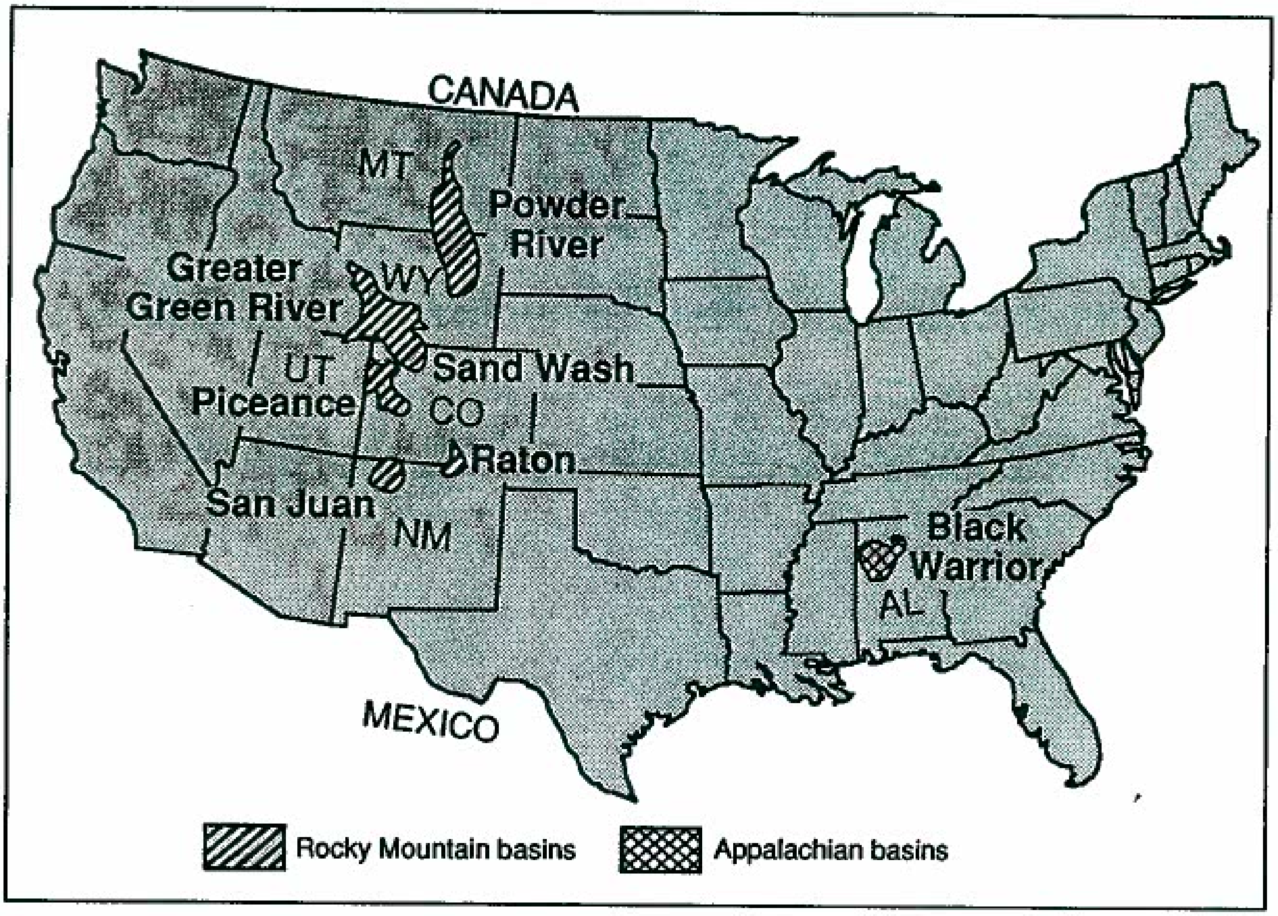


Figure 1: Location of coal basins with coalbed methane potential and production in U.S.A.

undeformed Alberta and Williston basins (called also the Western Canada Sedimentary Basin, or the Interior Plains Basin), the Hudson Bay lowland, Atlantic Canada (or Maritimes), and northern Canada (Figure 2). Of these, the Hudson Bay lowland and northern Canada present significant challenges from the point of view of accessibility, climate and infrastructure. Some intermontane basins present also infrastructure and accessibility problems. As such, although coal bearing, these regions are most probably the least suited for CBM exploration and production.

Dawson (1995) compared the CBM potential of Canada with that of the US, but his review addresses only elements relating to the geology of the coal-bearing strata and coal characteristics. No hydrogeological factors, such as permeability and the flow of formation water, were analyzed or discussed, although they have been recognized as playing an important role in evaluating the CBM potential and producibility (Tyler et al., 1995). Generally, the geology and coal properties of coal-bearing strata in the Canadian sedimentary basins have been studied to various degrees, but, except for the Alberta and Williston basins, there are no regional-scale hydrogeological studies regarding these basins. This review addresses the basin-scale geology and hydrogeology of coal-bearing strata in Rocky Mountain sedimentary basins as a complementary review to that of Dawson (1995). Because the Alberta basin is by far the most significant basin in Canada with regard to both coal resources and CBM potential, it is discussed in much more detail. For a review of the geology and coal characteristics of the Black Warrior basin and other non-Rocky Mountain Canadian basins, the interested reader should see Dawson's (1995) report.

3.0 COALBED METHANE PRODUCIBILITY

Coalbed methane (CBM), as the name indicates, is methane trapped within the porous system in coal beds deposited in sedimentary basins throughout the world. 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, coalbed methane has not been generally exploited, because of the abundance of, and better economic conditions for other fossil energy resources. Unlike conventional hydrocarbon plays, in CBM plays coal acts as both the source rock and the reservoir for the gas. This dual role of the coal bed leads to a paradox, namely, that in order for gas to be trapped, the coal has to be either sealed or have very low permeability, while, for exploitation, the gas must readily migrate to the production well (i.e., the coal should have high permeability).

Although coal has been extracted for a long time in many sedimentary basins, coalbed methane was seen not as a potential energy resource, but as a danger in underground mining. Only recently coalbed methane has been recognized as a valuable energy resource which can be economically exploited, such that in the last decade it started to become a major source of natural gas in the United States. For this reason, there are not many studies of coalbed methane potential.

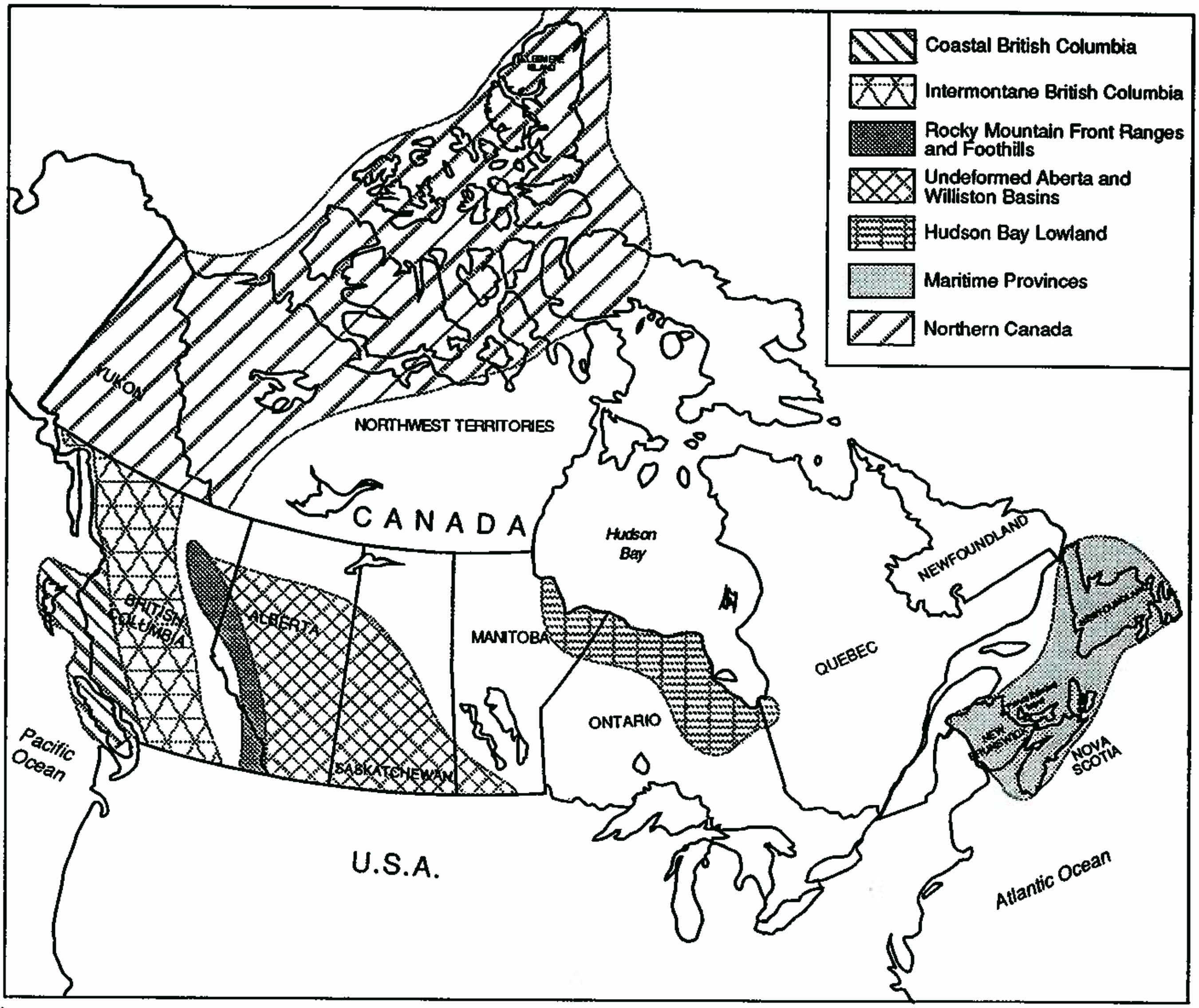


Figure 2: Major coal-bearing regions of Canada (from Smith, 1989).

Recent studies (e.g., Tyler et al., 1995) have shown (Figure 3) that coalbed methane producibility depends in an interdependent manner on:

- Geological factors such as tectonic, structural and depositional setting;
- Coal distribution and properties, such as rank and gas content; and
- Hydrogeological factors such as permeability and the flow of formation waters.

The underlying control on developing CBM resources in a sedimentary basin is the tectonic and structural setting (Tyler et al., 1995). This is because it determines the subsidence regime, sedimentation patterns and the locus of peat accumulations, 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. The depositional setting imposes a strong control on coalbed methane producibility because it determines the size, thickness, orientation and stratigraphy of the coalbed reservoirs. Maximum coal thickness is considered to be a critical parameter for coalbed methane productivity, whereas net coal thickness indicates gas resources (Kaiser and Ayers, 1994a).

Coal rank, ash content and maceral composition influence the volume of generated methane, coal gas content and gas composition, respectively (Langenberg et al., 1990). Coalbed gas composition directly relates to coal rank, maceral composition and basin hydrodynamics (Tyler et al., 1995). Hydrodynamics affects coalbed methane 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 for generating secondary biogenic gases. On the other hand, basin hydrodynamics can be detrimental if too much water is produced. Because generally water is produced as a byproduct of coalbed gas operations, water management can represent a large portion of the operating costs of a coalbed extraction project (Schraufnagel, 1993). Coal seam continuity is critical to coalbed methane and water production because: 1) coal seams with considerable continuity provide pathways for diffusion and long-distance migration of coal gases, and 2) continuous high-permeable coals are major aquifers. The nature of interactions between these fluids can determine the economic viability of coal gas production, and, therefore, a basin's potential (Hamilton, 1993).

In some cases, depending on salinity, water produced from a coalbed methane well is classified the same as water from an oil or gas well and can only be disposed by deep well injection. Finding zones that can accept large volumes of water for extended periods of time is critical to the successful operation of a water-disposal well. Injection zones must have significant porosity and permeability, and the water has to have salinity levels above the 10,000 mg/l level (Nackles et al., 1992). In other cases, usually for coal seams in hydraulic communication with the surface, the water is of meteoric origin and sufficiently fresh (low salinity) as not to pose this disposal challenge. In these cases, the produced water is disposed of at surface (released into streams or on the ground).

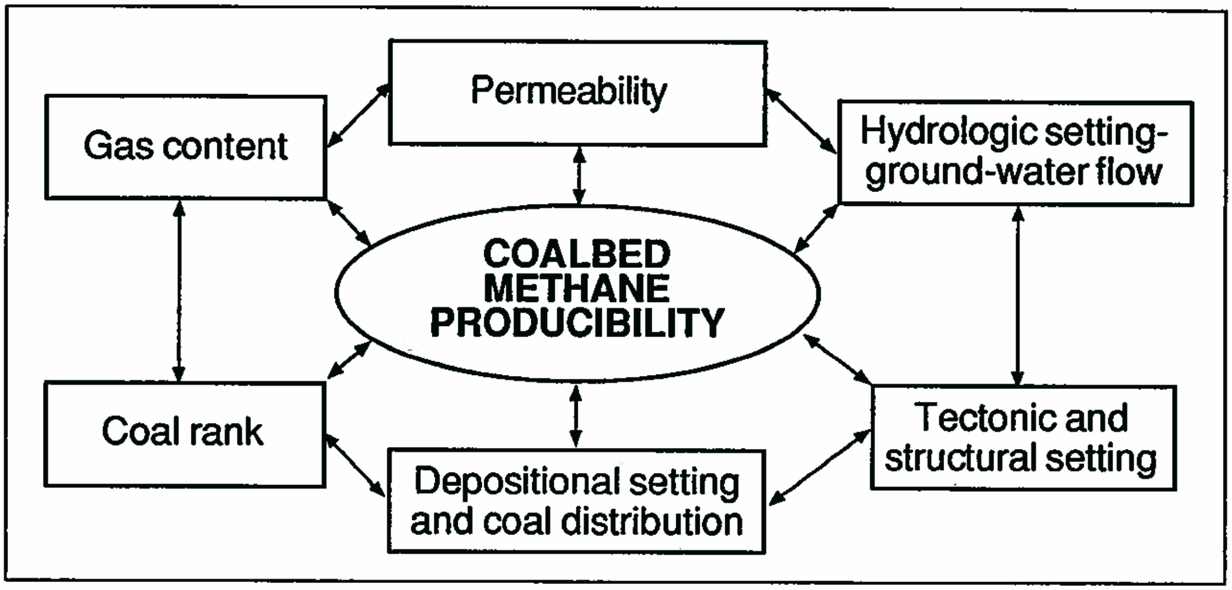


Figure 3: Diagrammatic representation of the various factors critical to coalbed methane producibility (from Tyler et al., 1995)

As pointed out by Schraufnagel (1993) and Zuber et al. (1996), production rates of coalbed methane are extremely sensitive to reservoir properties, of which permeability is one of the critical parameters. Regardless of the quantity of gas in place, there is a permeability value below which the resource cannot be produced economically at current market conditions. For coalbed methane in the US, this threshold value is 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 US indicate a decrease in permeability with lithostatic depth. Thus, low permeability is likely to be a problem with deep coal seams in that coalbed reservoirs deeper than 1,500 m generally have permeabilities below what is required at present for economic production (Zuber et al., 1996). However, if market conditions change in the future, methane production from deep coal seams of low permeability may become economical. Porosity is another rock property of importance in assessing the reservoir resources and producibility. Various reservoir simulations of coalbed methane production from the San Juan and Black Warrior basins in the US used characteristic values of 2-35 x 10^{-15} m^2 (2-35 md) for permeability and < 3 % for porosity (Sawyer et al, 1987, 1990; Mavor et al., 1994). In addition to the properties of the reservoir itself, it is important to know the properties of the confining beds, because, depending on their values, the reservoir may be entirely confined or in communication with adjacent strata. This may have a significant impact on coalbed methane production.

To the elements identified by Tyler et al. (1995) as interdependently playing a role in coalbed methane producibility (Figure 3), one should add the paleo and present geothermal regimes of the coal-bearing strata as an indirect factor, because they affect the coal rank and maturation. Generally, the burial depth represents a measure of coal rank and maturation because of temperature (and pressure) increase with depth. However, this is not a sufficient measure of coal quality. Paleo and present geothermal regimes, hence temperature, of the coal-bearing strata could be influenced by other tectono-geological and geophysical processes such as basement intrusives, basement heat flow, and cooling or warming by descending or ascending formation waters, respectively, thus thermally altering the coals. This is, for example, the case of some basins in US where coals are of higher rank and maturation than coals at comparable depths in other basins.

4.0 UNITED STATES ROCKY MOUNTAIN COAL BASINS

4.1 San Juan Basin

The San Juan sedimentary basin, located in northern New Mexico and southern Colorado near the "Four States Corner", formed as a result of Laramide tectonics in late Cretaceous-early Tertiary. A late Oligocene thermal event of volcanic origin provided the heat source for hydrocarbon generation in the basin (Bond, 1984; Meissner, 1984). Regional uplift since Miocene time led to erosion which exposed various units along the basin edges. The basin has an asymmetrical synclinal elliptical shape roughly 160 km long by 150 km wide. The basin is bounded by a series of uplifts, and is generally defined by the outcrops of the Upper Cretaceous Fruitland Formation. The sedimentary succession is mostly of Cretaceous and Tertiary age. In the northeast, where the basin is bordered by the San Juan Mountains, the sedimentary units, including coal-bearing strata, dip steeply (40-60°) to the southwest toward the basin depocentre, while in the south the beds gently dip (10°) to the north (Figure 4). A structural hingeline appears to contain a series of normal faults (up to 70 m vertical displacement) paralleling the northwesterly trending basin axis located along the northern flank of the basin (Kaiser and Ayers, 1994b).

Northeastward prograding of the Western Interior Seaway during late Cretaceous led to the deposition, in ascending order, of marine shales (Lewis Formation), coastal sandstones (Pictured Cliffs Formation), and continental interbedded sandstone, siltstone, shale and coal of both marine and nonmarine origin of the main coal-bearing Upper Cretaceous Fruitland Formation. The latter is unconformably overlain by the shales of the Kirtland Formation, which, in turn, is overlain by the Paleocene sandstone-dominated Ojo Alamo Formation (Figure 4). The Fruitland Formation averages 100 m in thickness, with most of the productive coal zones within the lower half of the stratigraphic interval. Up to 14 coal seams are present, ranging in thickness from 2 to 10 m, with a total net coal thickness exceeding 25 m. The coals are laterally continuous, thinning toward the southwestern and northeastern parts of the basin. The vertical displacement along the hinge line offsets the coal beds, leading to a local discontinuity which affects the unit hydrogeology (Kaiser and Ayers, 1994b). From the point of view of methane production, the best part of the basin, called the "fairway", is in the north, covering an area of approximately 95 by 75 km^2.

The coal seams are the primary aquifer in the San Juan basin, being pervasively fractured (cleated) and having a permeability higher that the associated low-permeability sandstones by several orders of magnitude. As a result, hydrostratigraphically, the San Juan basin presents the unusual situation whereby, due to the permeability contrast, the embedding sandstones act as confining aquitards to the "coal-based" aquifer. Regional recharge of the Fruitland coal aquifer takes place at high elevations at outcrop along the wet northern margin of the basin in the foothills of the San Juan Mountains (Kaiser and Ayers, 1994b). Along the eastern, southern and western outcrop margins of the aquifer, recharge is local and limited because of the topographically low outcrop belt (lower than the basin interior), poor aquifer quality (low permeability) and low rainfall. Direct, vertical recharge over the basin area is captured by the Ojo Alamo aquifer, where flow is topographically driven in local systems (Figure 4) (Kaiser et al., 1994a). On a regional scale, the flow in the Fruitland aquifer converges from the northeast and southeast toward the San Juan River valley, which is a regional discharge area (Figure 4), as demonstrated by salinity and hydraulic head distributions (Kaiser and Ayers, 1994b, Kaiser et al., 1994a). The flow of formation waters is driven by present-day topography, which explains the artesian conditions (hydraulic heads higher than the ground elevation, or "overpressuring") in the northern part of the basin in the Fruitland aquifer. This is due to an elevated recharge area at the basin northern margin, to regional aquifer confinement by the Kirtland shaly aquitard, and to aquifer basinward pinch-out (Kaiser et al., 1994a). The potentiometric surface is independent of the land surface, as expected for a confined aquifer, and flattens in the middle of the basin, indicating a region of high permeability and/or increased aquifer thickness. Toward the southern part of the basin, the potentiometric surface steepens again, indicating a decrease in permeability and thickness. In the central and southern areas, the aquifer is "underpressurized", i.e. the

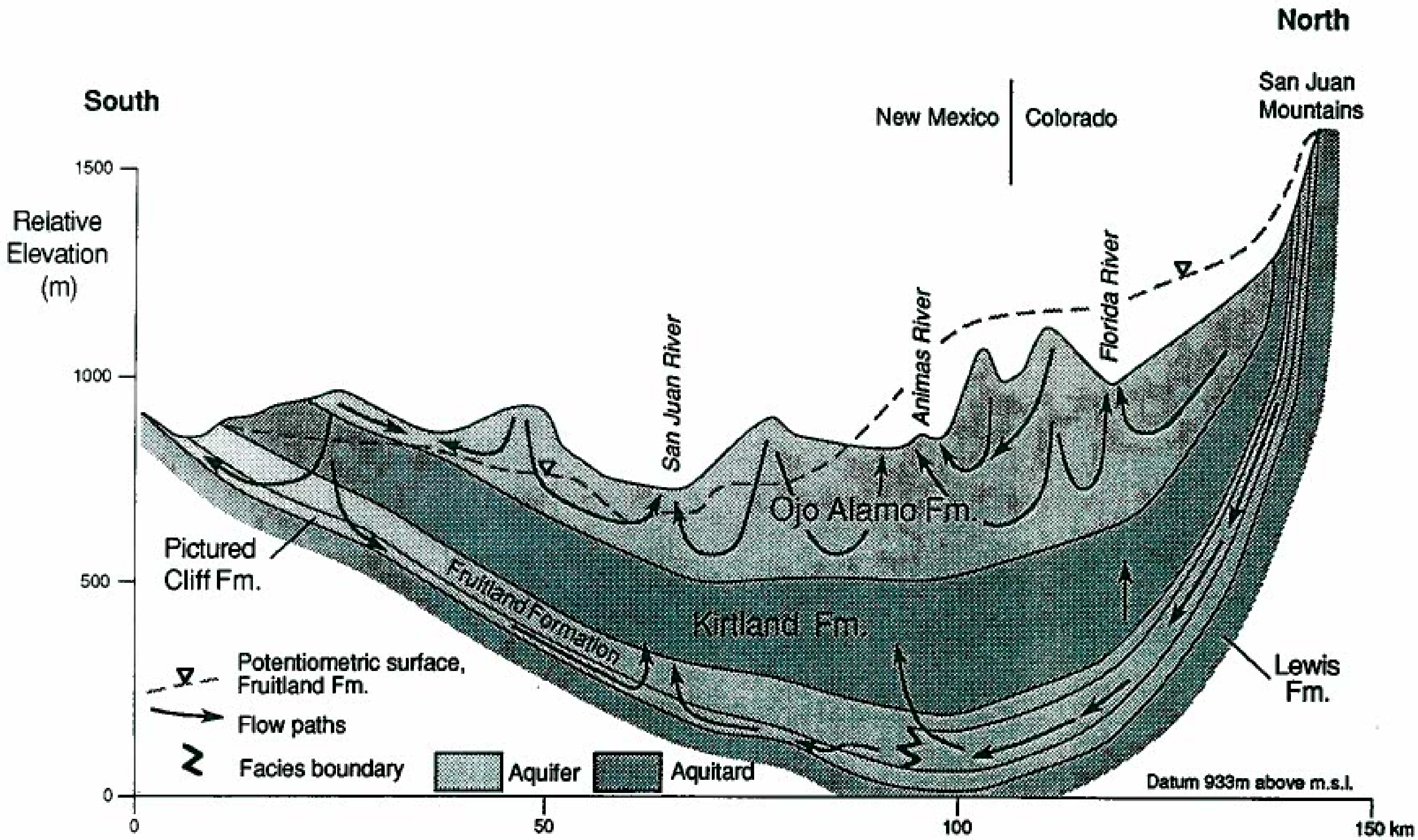


Figure 4: Representative diagrammatic cross-section through the San Jaun basin showing main stratigraphy, hydrostratigraphy and main flow paths of formation water (from Kaiser et al., 1994).

hydraulic heads are lower than the ground elevation The change of hydrodynamic conditions from artesian (overpressurized) to underpressurized takes place approximately at the basin hinge line, with the associated vertical displacement, confirming aquifer discontinuity (permeability barrier). Due to this permeability barrier, upwards flow takes place at discharge toward the Animas River valley (Figure 4) (Kaiser and Ayers, 1994b). If not for this permeability barrier, artesian conditions (overpressuring) would extend over most of the basin. Analyses of formation waters indicate that the formation water in the Fruitland Formation is of meteoric origin (low chloride, high bicarbonate) in the northern, recharge area, while modified marine saline waters, with high NaCl content, are present in the southern part (Kaiser and Ayers, 1994b).

Because of high permeability and artesian conditions in the northern part of the basin, this region is the most productive in terms of coalbed methane, although large quantities of water are produced. In the southern, underpressurized part, less or no water is produced due to the low permeability; however, substantial quantities of methane are still produced (Scott and Kaiser, 1991; Kaiser and Ayers, 1994a). Coalbed methane is produced from a variety of hydrogeological conditions (over- and underpressured beds), showing that overpressure is not necessarily a pre-condition for coalbed methane production (Kaiser and Ayers, 1994a). Permeability is the most critical parameter for coalbed methane production (Kaiser and Ayers, 1994a).

Analyses of sandstone and coal core samples from the Fruitland Formation indicate porosity values of 1.8-7.2 % and less than 3 %, respectively (Holditch et al., 1990). The measured intrinsic permeability of Fruitland Formation coals and sandstones varies between 2×10^{-18} and 811×10^{-15} m^2 (0.002 and 811 md), with a formation average of 26×10^{-15} m^2 (26 md) (Oldaker, 1991). Permeability values are not related to depth, coal presence, or composite samples (Oldaker, 1991). Based on history-match analysis, an effective porosity of 1.5 %, an effective gas permeability of 1-4 10^{-15} m^2 (1-4 md) and an effective water permeability of 2-12 10^{-15} m^2 (2-12 md) were obtained for a well 850 m deep in the San Juan basin (Zuber and Boyer II, 1989). In the underpressured part of the formation, profitable gas production is obtained from gas reservoirs characterized by absolute natural fracture permeability of greater than 10^{-14} m^2 (10 md), which is controlled mainly by depositional environments and structural/tectonic regime (Close et al., 1997). Regarding absolute permeability, it was observed that it has increased in producing reservoirs with continued production as a result, most probably, of the shrinkage of the coal matrix caused by gas desorption (Mavor and Vaughn, 1997). This indicates that reservoirs with initial poor permeability may become more productive and profitable in time, after initially poor production.

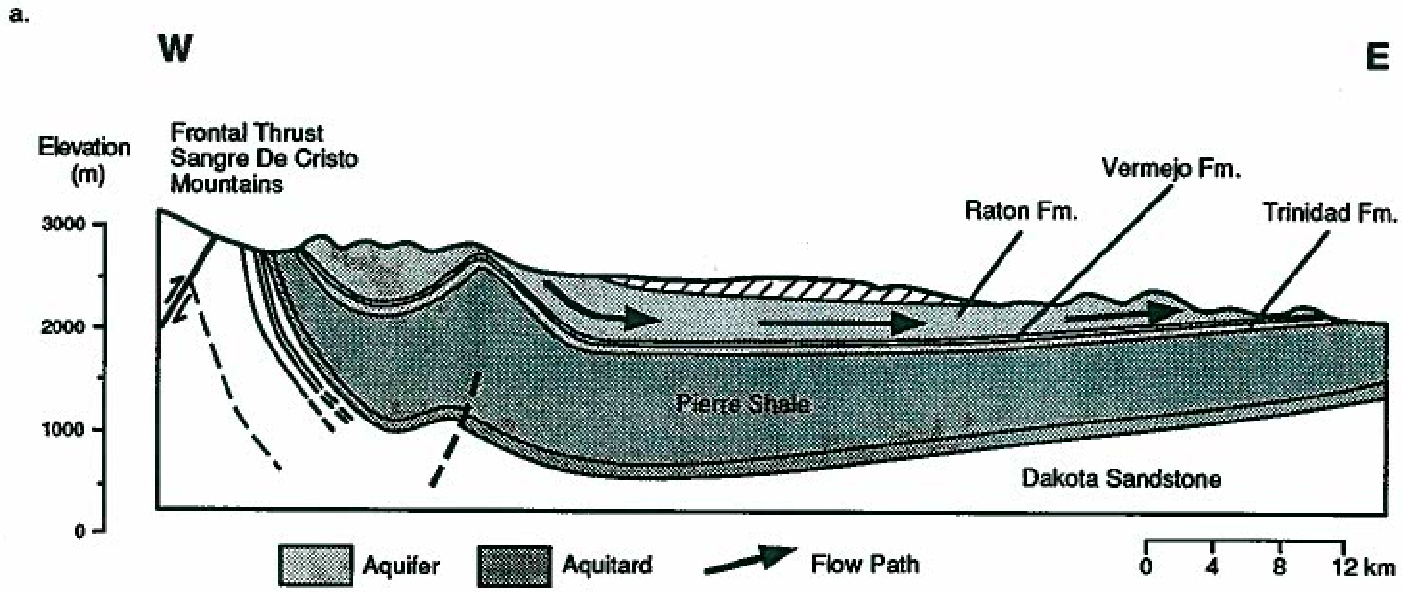
4.2 Raton Basin

The small Raton basin located in southern Colorado and northeastern New Mexico (Figure 1) is the most southern structural basin associated with the Rocky Mountain foreland region, encompassing an area of approximately 5,500 km^2. The basin contains a nearly complete Cretaceous and Tertiary succession, which includes the coal-bearing Vermejo and Raton formations. Depths to the Upper Cretaceous - Paleocene coal-bearing horizons range from surface outcrop along the basin perimeter to more than 1,200 m near the structural axis of the basin. Major intrusive events during the middle Tertiary probably led to high heat flow and elevated geothermal gradients, which have thermally altered the Vermejo and Raton coal beds over short distances. The Vermejo Formation and the underlying sandstone Trinidad Formation are equivalent to the Picture Cliffs - Fruitland succession in the San Juan basin. Coal rank ranges from high-volatile C bituminous ($R_o = 0.57$) to anthracite in the vicinity of the igneous intrusives (Tyler et al., 1995).

The Raton, Vermejo and Trinidad formations form an unconfined hydrostratigraphic unit underlain by the shaly Pierre Shale aquitard. Regional-scale groundwater flow is from west, at the flanks of the Sangre de Cristo Mountains, to the east (Figure 5a) (Tyler et al., 1995). Flow from west to east is supported by low-chloride formation waters in the west and high-chloride formation waters in the east. Dikes and sills are groundwater conduits (Tyler et al., 1995). In the absence of a confining layer, normal pressure values would be expected throughout the basin. Observed underpressures indicate lithologic heterogeneity and insulation from the water table or from recharge at elevated outcrop by low-permeability rocks. Nevertheless, meteoric circulation is indicated by low-chloride coalbed water. Low-permeability sandstones and coal-seam lenticularity probably limit hydraulic connection with the water table and recharge areas (Tyler et al., 1995). The underpressure may reflect also dikes and sills that act as high-permeability drains (Tyler et al., 1995), allowing the upstream propagation of low hydraulic heads from discharge areas (Belitz and Bredehoeft, 1988).

4.3 Greater Green River Basin

The Greater Green River basin in southwestern Wyoming and northwestern Colorado covers approximately 45,000 km^2. The sedimentary succession comprises rocks from Cambrian to Tertiary, although most of them are of late Cretaceous, Paleocene and Eocene age. Cretaceous and Tertiary strata are coal-bearing, ranging in depth from outcrop to more than 4,900 m. During the Cretaceous, the basin was near the western margin of the Western Interior Seaway, a shallow sea which extended from north to south across much of the North American continent (from the Beaufort and Alberta basins to the Gulf of Mexico). The basin records three major pro-gradational cycles in late Cretaceous, pre-Laramide sequences which extended Upper Cretaceous coal-bearing strata far eastward (Frontier Formation, Mesaverde Group and Lance Formation, with the latter being considered as the equivalent of the Fruitland Formation in the San Juan basin). Basement uplifts subsequently broke the foreland of the Cordilleran Thrust Belt into four smaller structural and depositional subbasins during the Tertiary Laramide Orogeny, namely the Green River, Great Divide, Washakie and Sand Wash. The Fort Union Formation, deposited during Paleocene, consists of sandstones, siltstone, shale and coal deposited in fluvial, floodplain and lacustrine settings. Uplift, erosion and subsequent deposition followed during Eocene, so that by middle Eocene time the Greater Green River basin probably became a closed topographic basin containing an extensive lacustrine system (Tyler et al., 1995). Dikes, sills and other intrusives were emplaced during late Tertiary, which thermally altered the coals locally. Generally, this area coincides with a broad zone of high heat flow.



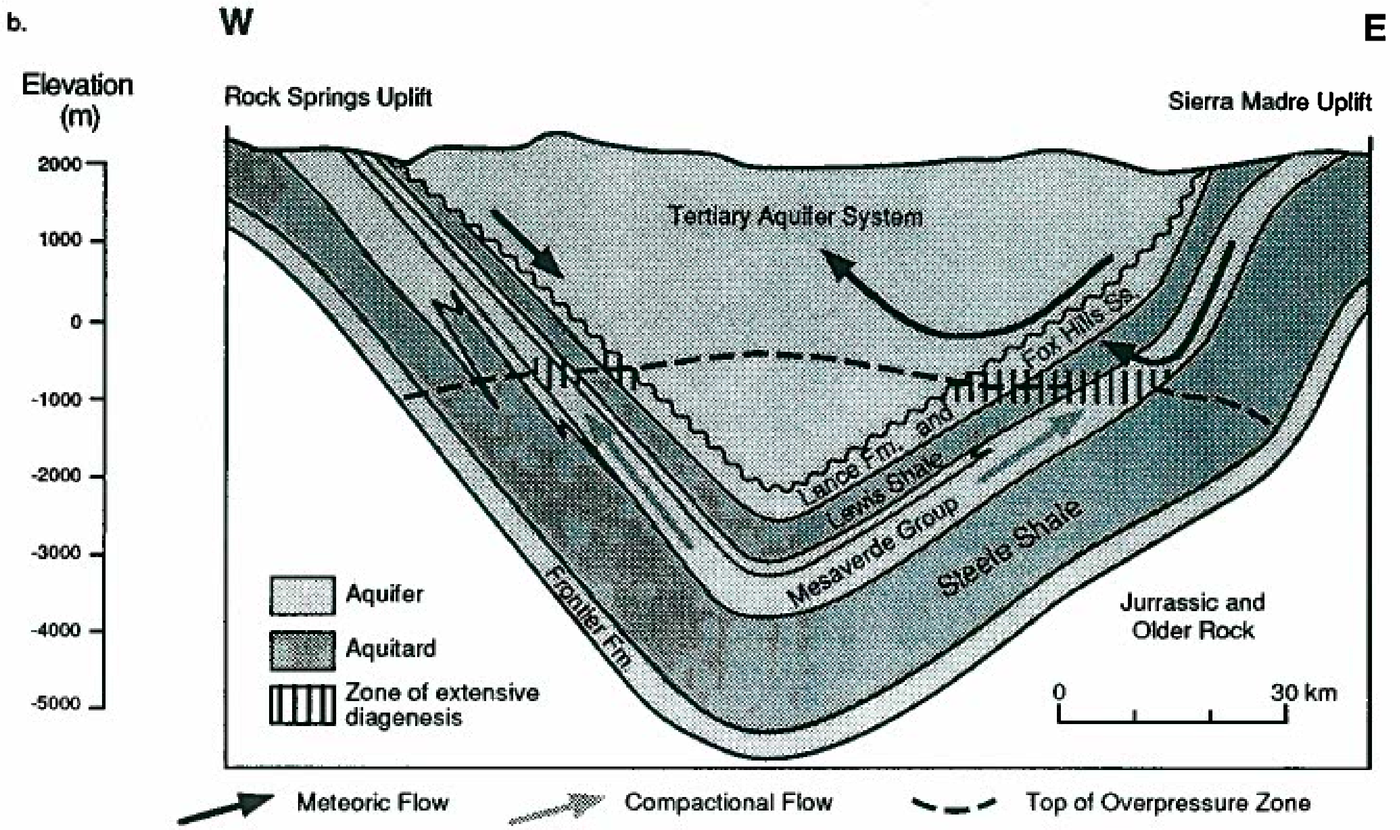


Figure 5: Diagrammatic representation of groundwater flow in the coal-bearing strata of: a) the Raton basin; and b) the Washakie sub-basin, Greater Green River basin (from Tyler et al.,1995)

The coals in the lower units are of considerable thickness and lateral continuity, whereas coals in the upper shaly units are shallowly buried and laterally discontinuous. The thermal maturity of the coals ranges from subbituminous (R_o < 0.4%) to semi-anthracite (R_o > 2.4%). The gas content of the coals is independent of coal rank, suggesting that basin hydrodynamics plays an important role in coalbed methane producibility (Tyler et al., 1995). The major coal-bearing hydrostratigraphic units are the Mesaverde aquifer and the Tertiary aquifer system, the latter comprising the Fort Union and Wasatch aquifers. The Mesaverde aquifer is confined by the Mancos and Lewis shaly aquitards. The coal beds are the most important aquifers because of their high permeability ($5x10^{-14}$ to $1.5x10^{-12}$ m^2, or 50 to 1500 md) caused by a complex network of extensional fractures and cleats (Tyler et al., 1995). The Tertiary aquifers are also confined by shaly aquitards. Permeability of Tertiary sandstone aquifers varies from 10^{-14} to 10^{-12} m^2 (tens to thousands of milidarcies).

The Mesaverde aquifer crops out in the southeast along the foothills of the Sierra Madre-Park and White River uplifts, where it is recharged by meteoric water (Tyler et al., 1995). The flow is basinward, gravity driven, toward an area of hydrocarbon overpressure (equivalent freshwater hydraulic heads higher than outcrop elevations - Tyler et al., 1995) at the basin center (Figure 5b). The flow of meteoric water is deflected upwards toward discharge at the basin center by the area of high pressure in the deep basin. The discharge takes place along fault systems and facies changes. Artesian overpressure has been identified along the eastern flank, and reflects proximity to the recharge area, basinward confinement and high permeability (Tyler at al., 1995). Overpressure in the deep basin (Figure 5b) is predicated by low permeability (< 10^{-16} m^2 or 0.1 md) and active hydrocarbon generation (Tyler et al. 1995). Compactional water moves updip, outward toward the basin edges (Figure 5b). Zones of diagenesis reflect the mixing of meteoric and compactional water. The salinity of formation waters is relatively low (TDS < 10,000 mg/l). In the Tertiary aquifers, groundwater flow is driven by gravity from recharge areas along the foothills of the Sierra Madre-Park, Wind River and Uinta uplifts, and Wyoming Mountains, toward discharge at low-elevation along the Green River valley. Salinity (TDS) increases basinward from outcrop.

Because of high permeability, coalbed methane wells drilled in the Greater Green River basin produced negligible volumes of gas and very large amounts of water. Initial water production increases with permeability, and high water production indicates high permeability of the coal beds. Because of proximity to the recharge area and high permeability, dewatering (depressuring) coal beds near the basin margin may be uneconomical (Tyler et al., 1995).

4.4 Sand Wash Basin

The Sand Wash Basin is located mostly in northwestern Colorado at the border with Utah, with a small portion in southwestern Wyoming (Figure 1), being actually a sub-basin of the Great Green River. The basin is a structurally complex intermontane basin containing three major progradational cycles in Upper Cretaceous strata (Tyler and Tremain, 1994). The potential coalbed methane reservoirs are situated in the Upper Cretaceous fluvial-lacustrine sediments of the Williams Fork Formation of the Mesaverde Group, and Lower Tertiary Fort Union Formation (Tyler and Tremain, 1994).

The William Forks Formation can be divided into four genetic depositional sequences that are each bounded by regionally extensive shale markers (Hamilton, 1993). Coal is present throughout the entire Williams Fork succession; however, only the two lowermost units contain thick, laterally extensive coals. These coals are concentrated in the eastern half of the basin, where net coal thickness averages 28 m in Unit 1 and 10 m in Unit 2 (Hamilton, 1993). Early thermogenic, thermogenic and secondary biogenic gases are found in the coal beds (Scott, 1994a). The thermogenic gases formed through maturation of organic material, while the biogenic gases formed through degradation of organic compounds by bacteria transported by meteoric water flowing basinward from recharge areas (Scott, 1994). Coalbed wells produced large volumes of water, indicating high permeability linked probably to stress (Tyler and Tremain, 1994), and little gas because of low gas content and unfavorable hydrodynamics (Hamilton, 1993). The low gas content reflects low coal rank (high-volatile C to B bituminous). Because the coals in these two units were not deposited in the western, more thermally mature part of the basin, they could not serve as conduits for long-distance gas migration. The Mesaverde Group is a thick, regionally interconnected aquifer system of high transmissivity, confined by the shaly Lewis and Mancos aquitards. The coal beds may be the most permeable aquifers, with permeability values ranging from tens to thousands of milidarcies (Scott and Kaiser, 1994a), creating a highly unfavorable hydrodynamic regime. The regional groundwater flow is from meteoric recharge in the east and southeast at outcrop in the foothills, to discharge in the central part of the basin (Scott and Kaiser, 1994). Artesian conditions are present in the eastern part, while the rest of the unit is normally-to-under pressured (Scott and Kaiser, 1994a). The flow corresponds to a direction from areas of low thermal maturity to areas of high thermal maturity. Consequently, only relatively small volumes of gas may be available for eventual resorption or to be swept basinward for conventional trapping (Hamilton, 1993). However, some prospective areas exist in the basin, with high gas content and poor hydrodynamic connection to the recharge area at outcrop, hence with improved chances for depressuring the coalbeds (Hamilton, 1993).

The Paleocene Fort Union Formation can be divided into a lower coal-bearing unit, a mudstone unit, a sandy unit, and an upper shaly unit (Tyler and McMurry, 1994). Maximum coal development corresponds to fluvial deposits; individual seams have a maximum thickness of 6 to 15 m. The coalbed gases are secondary biogenic or early thermogenic. The gas content is low, due to a combination of low coal rank and gas migration in an active hydrodynamic flow system (Scott, 1994b). Hydrogeologically, the Fort Union Formation is part of a larger Upper Cretaceous/Lower Tertiary aquifer system confined by the shaly underlying and overlying Lewis and Green River aquitards, respectively (Scott and Kaiser, 1994b). The larger regional flow system is near dynamic equilibrium among basinward flow of meteoric water and outward flow driven by compaction. Artesian pressures present in places are controlled by faulting and permeability variations related to facies changes. (Scott and Kaiser, 1994b). Figure 6 shows the main directions of groundwater flow in the Sand

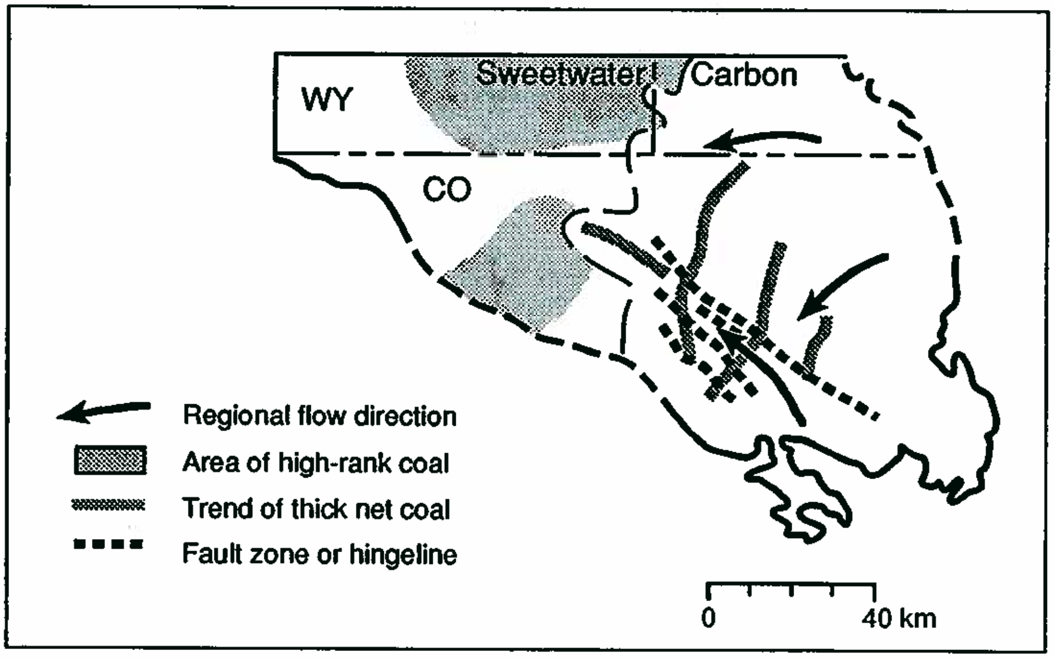


Figure 6: Representation of main directions of groundwater flow in the Sand Wash basin (from Kaiser et al., 1994)

Wash basin through thick coals of low thermal maturity towards a leaky, regional fault system along which high- and low-gas-content coals occur.

4.5 Piceance Basin

The Piceance basin in northwestern Colorado is an asymmetric, elongated, northwest-trending structural basin of late Cretaceous to early Tertiary age. The basin has a tectonic history similar to that of the Great Green River basin. The potential coalbed methane reservoirs are contained in Upper Cretaceous strata (Iles and Williams Fork formations of the Mesaverde Group) which cover an area of approximately 19,000 km^2. The depth of the coal-bearing strata varies from outcrop along the basin margin to more than 3,700 m along the basin structural axis. Coal rank ranges from high-volatile C bituminous (R_o = 0.5%) to semi-anthracite (R_o > 2.4%).

The Mesaverde Group is a coal-bearing aquifer underlain by the shaly Mancos aquitard and overlain by Lower Tertiary aquitards. The aquifer crops out along the northern, eastern and southwestern margins of the basin, which presumably are recharge areas (Tyler et al., 1995). The groundwater flow is basinward along the topographic gradient and structural dip. The Colorado River valley is a regional discharge area, where Mesaverde groundwater converges and turns upward (Figure 7a) (Tyler et al., 1995). Mesaverde coals are overpressured, underpressured and normally pressured in places. The overpressuring, which occurs in a small area, is assumed to be of artesian origin (Tyler et al., 1995). This hypothesis is supported by low-chloride waters, flowing wells, direct connection with recharge areas at topographically high elevations, and structurally enhanced permeability in the 10 to 20 md (10 to 20 x 10^{-15} m^2) range. Formation temperatures in the overpressure region are less than 95 °C, below the threshold for hydrocarbon-generation, which, otherwise, could be another source of overpressuring. Confinement is provided locally by shales and low-permeability sandstones. Because the confining layer is not regional in nature, the artesian overpressuring is limited to a relatively small part of the basin. Significant coalbed methane production may be precluded in this part of the basin by the absence of reservoir continuity, high permeability and vigorous groundwater flow (Tyler et al., 1997).

The area of overpressure is surrounded by an extensive underpressured region. The reason for underpressuring is assumed to be aquathermal cooling after uplift and erosion (Tyler et al., 1995). Low permeability values observed in the Piceance basin indicate that the Mesaverde strata are generally too tight (low permeability) to transmit recharge flow basinward, thus remaining underpressured. Underpressured coals have permeabilities of the order of 10^{-18} m^2 (several µd). The very low permeability may ultimately limit the coalbed methane potential of the Piceance basin (Tyler et al., 1995).

4.6 Powder River Basin

The Powder River basin is located in northeastern Wyoming and southeastern Montana, covering approximately 67,000 km^2. The basin is filled by Paleozoic and Lower Mesozoic

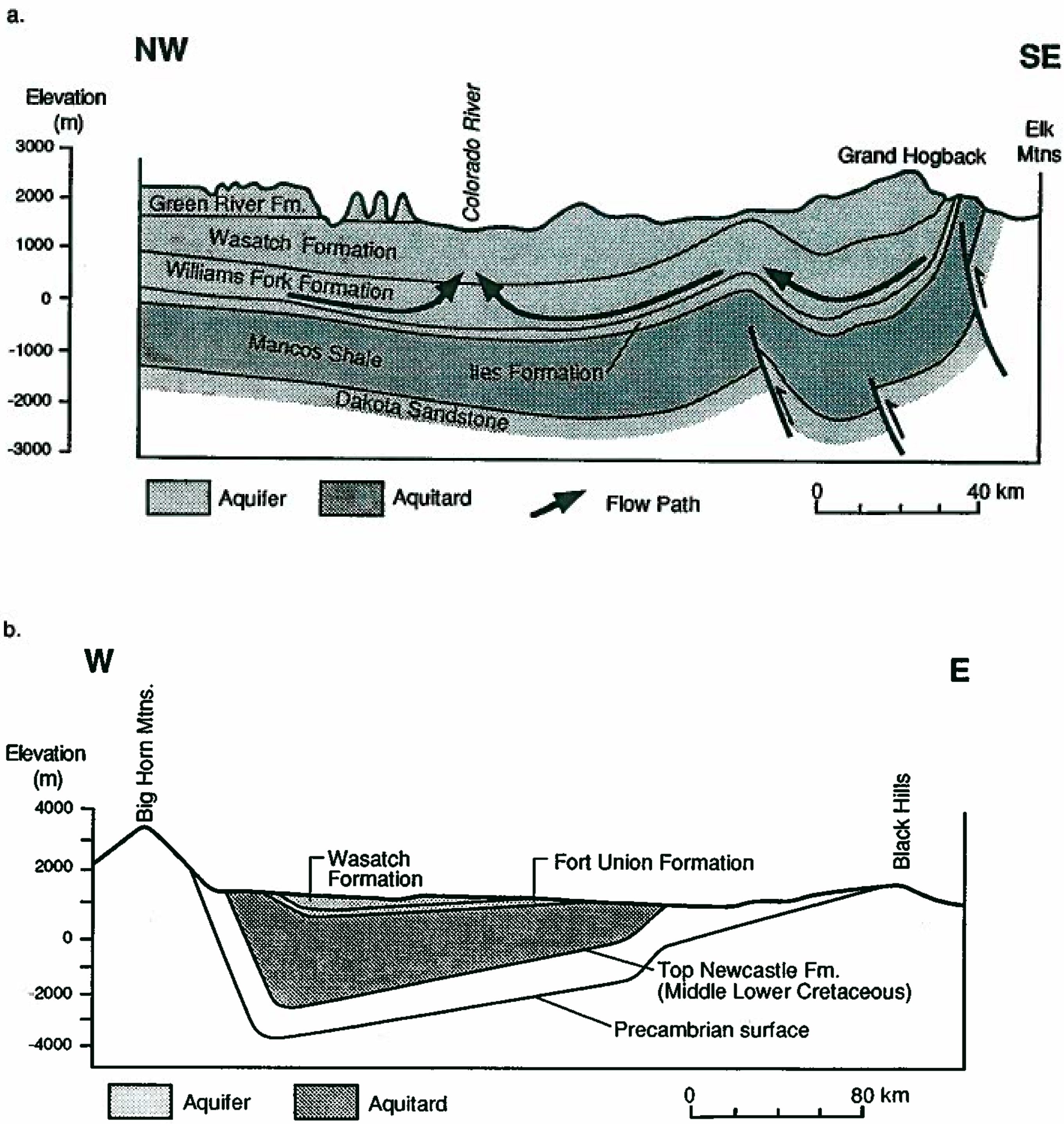


Figure 7: Diagrammatic representation of groundwater flow in the coal-bearing strata of: a) the Piceance basin; and b) the Powder River basin (from Tyler et al.,1995).

rocks, mostly of marine origin, and a younger succession of Upper Cretaceous and Lower Tertiary coal-bearing rocks of continental origin. Nearby orogenic uplifts provided the source areas of Mesaverde, Meeteetse and Lance formations (Upper Cretaceous), Fort Union Formation (Paleocene) and Wasatch Formation (Lower Eocene). Upper Cretaceous rocks are exposed only on the southwest and east sides of the basin, while the Paleocene strata are exposed around the basin periphery. The Eocene Wasatch Formation is exposed throughout most of the centre of the basin (Figure 7b). The Wasatch and Fort Union coals are thermally immature; thus they have not yet reached the main gas-generating stage (Tyler et al., 1995).

The Fort Union and Wasatch formations form a single hydrostratigraphic unit. The Fort Union Formation is recharged mainly along the eastern margin of the basin, while the Wasatch Formation is recharged directly from infiltration and precipitation. Artesian conditions may develop basinward as coal seams become confined by shale beds and pinch out (Tyler et al., 1995). Fort Union coal seams are major aquifers that would be difficult to dewater for economic production of coalbed methane (Tyler et al., 1995).

5.0 THE ALBERTA BASIN

The Alberta basin is very rich in energy resources, both coal and hydrocarbons in various stages of maturation and degradation: conventional oil and natural gas, heavy oil and oil sands. The basin is in a mature stage of exploration and exploitation, with expanding activity taking place due to increased energy demand. Current economic forecasts predict that production of oil and natural gas from the Alberta basin has attained its peak and will start declining, while energy demand will continue to increase. The shortfall in the near future will be probably made up by synthetic oil produced by increased extraction and upgrading of heavy oils and bitumen from oil sands. The heavy oil and bitumen extraction and upgrading require large amounts of water and result in very large emissions to the atmosphere of greenhouse gases like CO_2. Pressure by the public and governments for limiting and actually reducing the release to the atmosphere of greenhouse gases is increasing, and the demand for more environmentally-friendly fuels like gas will increase. At the same time, oil production from oil sands will probably reach a plateau at some stage in the near future due to technological limitations and environmental pressures related to land protection and reclamation, competition for usage of limited water resources, and the need to reduce atmospheric emissions. Coal production and usage will probably meet similar limitations. On the other hand, the Alberta basin, with its huge coal deposits, contains correspondingly significant coalbed methane resources. Similar to other Rocky Mountains foreland basins, the coals in the Alberta basin are found in Cretaceous and Tertiary strata, mostly at depths too great for mining. The coalbed methane in place in the basin was recently estimated to be up to 543 Tcf (Canadian Gas Potential Committee, 1997), although this figure is still subject to debate. Thus, in the medium to long term future, the energy industry will most probably move toward exploiting Alberta's coalbed methane resources. Methane is also an important feedstock for the petrochemical industry, which is growing fast in Alberta. Based on studies in the proof-of-concept stage, it seems that exploiting coalbed methane brings the added advantage of reducing atmospheric greenhouse emissions by injecting CO_2 into coal beds.

Due to higher affinity between CO_2 and coal (approximately 4 times higher), the former will displace methane from the coalbeds, enhancing methane production while sequestering CO_2. This short-to-medium term scenario shows that there is a compelling need to assess the potential and producibility of coalbed methane from Alberta coals.

The basin, situated on a stable Precambrian platform, is bounded by: the Intramontane and Omineca belts to the west and southwest, by the Tathlina High to the north (which separates it from the Mackenzie Trough leading to the Beaufort basin), by the Canadian Precambrian Shield to the northeast, and by the Williston basin to the east and southeast, from which it is separated by the Bow Island arch (Figure 8a). The present-day topography, which is the result of Tertiary-to-Recent erosion, shows a general, basin-scale trend from highs in the 1200 m range in the southwest, to the lowest point in the basin located in the northeast at Great Slave Lake, where elevations are in the 200 m range. The undeformed part of the basin comprises a wedge of sedimentary rocks increasing in thickness from zero m at the Canadian Shield in the northeast to close to 6000 m in the southwest at the thrust and fold belt (Figure 8b).

As a result of more than 200,000 wells drilled in the basin to date, there is a wealth of information consisting of stratigraphic picks, core and formation water analyses, drill stem tests and bottom hole temperature measurements. Thermal maturity data are much more scarce. Based on this extremely large data base, a good understanding of basin geology and regional-scale hydrogeology has been achieved.

5.1 Basin Geology

The basin evolution and geology described herein is based on the geological record and paleogeographic reconstructions (Mossop and Shetsen, 1994). Figure 9 presents the main basin-scale stratigraphic delineation and nomenclature representative for the southern two thirds of the basin where coal-bearing strata are found. The Alberta basin consists of a passive margin succession, dominated by carbonate and evaporite deposition with some intervening shales, followed by a foreland-basin succession dominated by clastic, mainly shale deposition since middle Jurassic time (Porter at al., 1982). Pre-Cretaceous erosion has partially removed older strata which subcrop at the unconformity from southwest to northeast with increasing age. Successively older strata subcrop from the southwest to the northeast under a thin veneer of Quaternary unconsolidated sediments of pre- and glacial origin, as a result of uneven deposition since early Tertiary and of Tertiary-to-Recent erosion. The latter has removed up to 3800 m of strata in the southwest (Bustin, 1992) but only up to 1000 m in the north (Kalkreuth and McMechan, 1984).

The Alberta basin was initiated during the late Proterozoic by rifting of the North American craton. Shallow-shelf sands and muds were deposited during the middle Cambrian to early Ordovician. Significant early-Devonian erosion removed the entire Ordovician-Silurian succession from the stratigraphic record, and the Cambrian rocks in the northern half of the basin. The Lower and Middle Devonian deposition consists of red beds, siltstone, claystones and interbedded thick successions of halite and anhydrite (the Lower Elk Point Group),

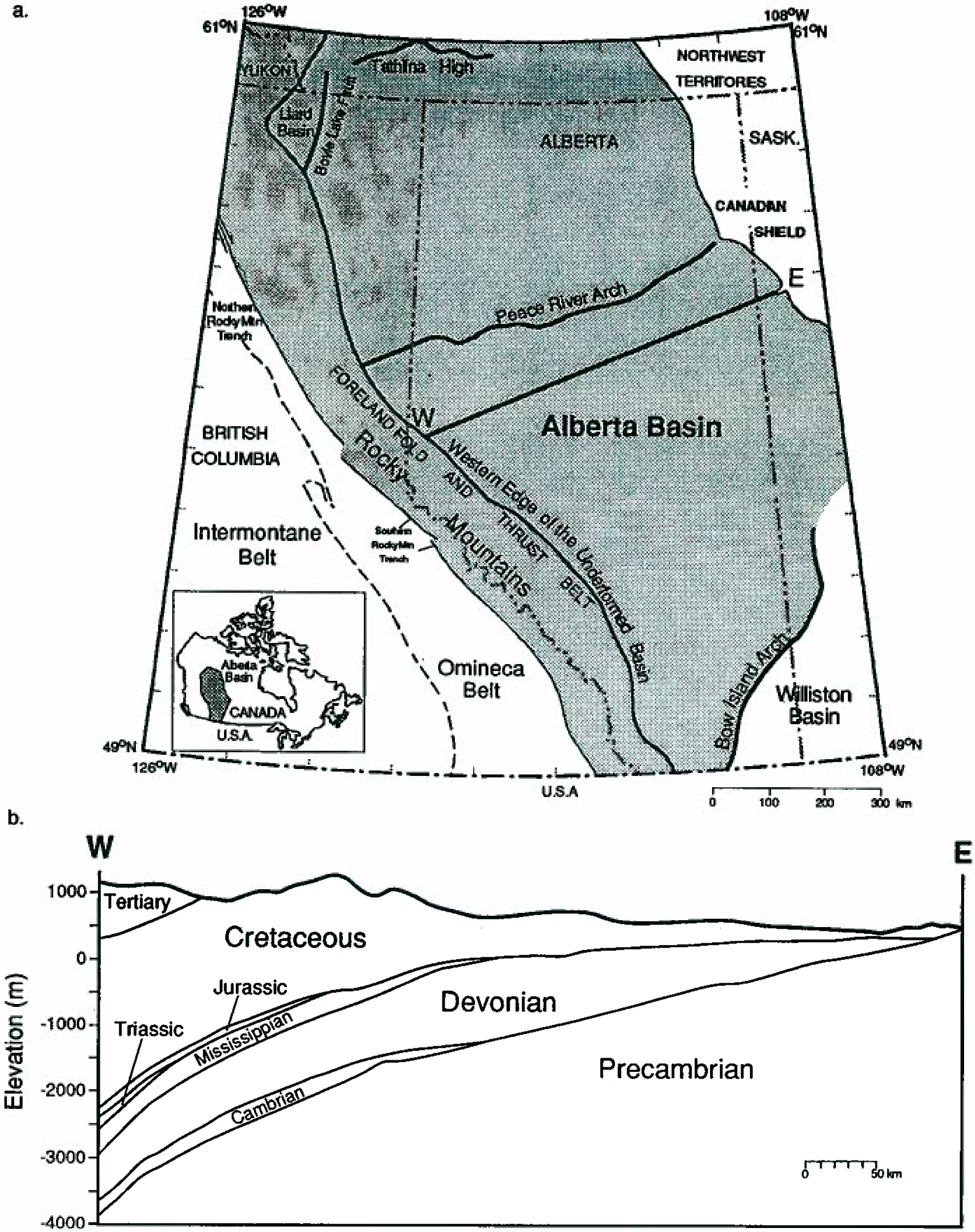


Figure 8: Major features of the Alberta basin: a) plan view showing basin location and main structural elements; and b) west-east cross section showing the main stratigraphic intervals present in the basin (line W-E of cross section represented in Fig. 8a).

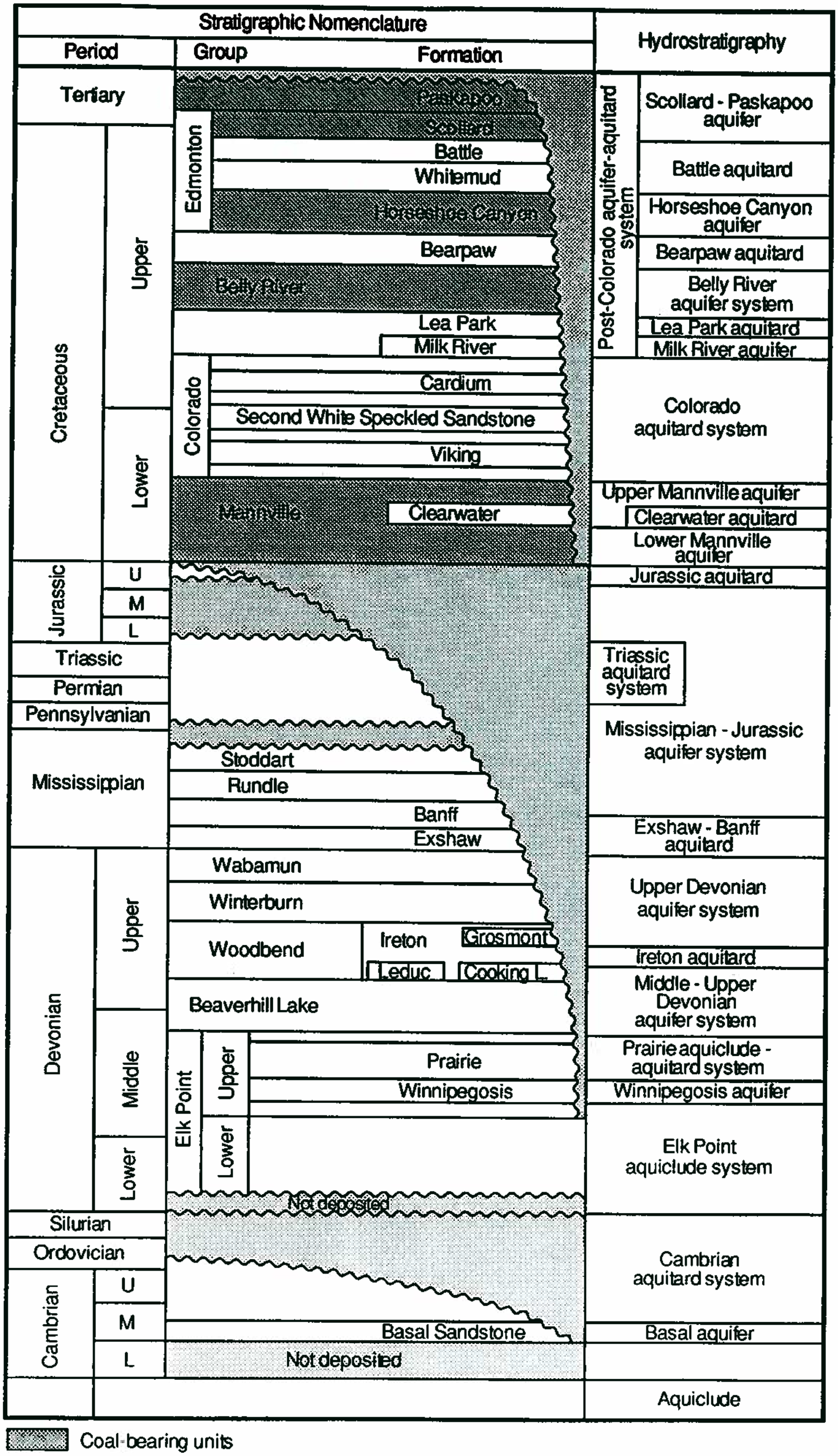


Figure 9: Basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature, Alberta basin (after Bachu, 1995)

followed by platform and reef carbonates (the Winnipegosis Formation) and evaporites (the Prairie Formation). Cyclic deposition continued during the rest of the Devonian with platform-carbonates (the Beaverhill Lake Group), shelf marginal reefs (the Leduc and Cooking Lake formations), terrigenous sediments on the submerged carbonate platform (the Ireton Formation), and thick platform carbonates with minor intervening shales (the Winterburn and Wabamun groups). The thin, organic-rich shales of the Exshaw Formation were deposited during the very late Devonian to early Carboniferous. The beginning of the convergent margin on the western edge of the North American proto-continent in early Carboniferous led to deposition of fine-grained siliciclastics in the northern and western parts of the basin, and of transgressive-regressive cycles of carbonates and nearshore siliciclastics in the south-southeast (the Banff Formation and the Rundle and Stoddart groups). Permian rocks were completely stripped away over most of the basin by aerial erosion. Deep-water carbonates, fine-grained and shallow-water siliciclastics (red beds, muds and silt) and evaporites were deposited during the Triassic. Finally, the passive-margin stage of evolution in the Alberta basin ended with pre-orogenic Lower Jurassic deposition of thin limestones, phosphates and organic-rich shales. As expected for deposition in a marine environment, no coals are found in the passive-margin succession of the Alberta basin.

Convergence of allochthonous terranes on the western margin, and foreland-basin sedimentation of deep-water shales and sandstones in the Alberta basin, started in early middle Jurassic time. Coarse clastics shed from the rising Columbian Orogen to the west were deposited as Upper Jurassic sandstones. The westward basin downwarping led to extensive pre-Cretaceous erosion, which exposed from west to east successively older Paleozoic strata. Continued uplift associated with the Columbian Orogeny provided abundant sediments to the foredeep trough, resulting in fluvial deposition in the southern and central parts of the basin, coeval with marine clastics (shales) deposition in the northern part. This Cretaceous succession forms the Mannville Group, which is very rich in hydrocarbons and coals. In general, Mannville Group strata are continental in nature.

A succession of thick marine shales and several thin, isolated, intervening sandstone sheets (the Colorado Group and Lea Park Formation) were deposited during the following major sea-level rise. Subsequently, a major influx of Cordilleran clastic detritus created a thick, sandstone-dominated unit in the southern and west-central parts of the basin (the Belly River Group). Another major rise in relative sea-level resulted in shale deposition of the Bearpaw Formation. During late Cretaceous to early Tertiary, another succession of coarse clastics derived from the Cordillera (the Horseshoe Canyon Formation), shale-dominated units (the Whitemud and Battle formations) and coarse clastics of the Scollard and Paskapoo formations, was deposited in the southern part of the basin. Coals are present both in this and the previous succession. The Upper Cretaceous - Lower Tertiary succession of the Edmonton Group and Paskapoo Formation (Figure 9) is the time equivalent of the 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 and Piceance basins, respectively.

Subsequent to this cycle, a period of tectonic compression and uplift followed in early Tertiary (the Laramide Orogeny), leading to the deposition of fluvial-channel sandstones, siltstones and shales. Most of the sediments deposited during this orogenic event were subsequently removed by erosion since Paleocene time. All the rocks exposed during basin evolution are covered by a thin veneer of pre- and glacial unconsolidated sediments of Laurentide and Cordilleran origin, comprising mostly till, with sand and gravel channels present in places.

5.2 Coals in the Alberta Basin

Coal deposits of the **Rocky Mountain Front Ranges** are found in the Jurassic to early Cretaceous Kootenay Group in southeastern British Columbia and southwestern Alberta. The Kootenay Group, which is a Mannville Group equivalent, attains a thickness of more than 1100 m and consists mostly of interbedded siltstone, shale, sandstone, conglomerate and coal. Individual coal seams reach up to 18 m in thickness. The region is structurally complex, with extensive folding and faulting. The coals have commonly been subjected to deformation associated with the Laramide Orogeny. Coals mined in the past have been reported as being "gassy" (Dawson, 1995).

The **Inner Foothills Belt** contains coals of Cretaceous age and extends from the central Alberta Foothills northwest into British Columbia near the Yukon border. In the southern part coal is present in the Gates Formation of the Lower Cretaceous Luscar Group, while in the northern part coal is present in the Gates and Gething formations of the Fort St. John Group. Both Luscar and Fort St. John groups are generally equivalent to the Mannville Group. The coal seams, which reach up to 13 m in thickness and are commonly folded and faulted, have been subjected to tectonic stresses during the Laramide Orogeny.

Coals of the **Outer Foothills** occur in Upper Cretaceous and Tertiary strata in a narrow belt (10 to 30 km wide) which extends along the Rocky Mountain in the southern part of the basin. In the southern part, coals are present in the 700 to 900 m thick Belly River Group. Further to the north, coals are found in the strata of the Brazeau Formation, which is equivalent to the Belly River Group and Horseshoe Canyon Formation in the undeformed succession of the Alberta basin. Coal seams are generally thin (less than 3 m thick) and discontinuous. In central Alberta, thick coals are present in the Coalspur Formation (Scollard Formation equivalent) of Upper Cretaceous-Paleocene (Tertiary) age. Seams in excess of 6 m in thickness lie within a 250 m thick succession of interbedded sandstone, siltstone and shale. These coal zones are laterally continuous and have been correlated to be equivalent to the Ardley Coal Zone in the undeformed Alberta basin. Also in this area, coals of the Lower Cretaceous Jewel Seam could contain about 100 Bcf of methane (Langenberg, 1991).

The major coal-bearing units of the **undeformed foreland-basin** succession are the Lower Cretaceous Mannville Group, the Upper Cretaceous Belly River Group and Horseshoe Canyon Formation of the Edmonton Group, and the Upper Cretaceous-Paleocene Scollard and Paskapoo formations. The areal extent of these units in the undeformed part of the Alberta basin is shown in Figure 10. The coal seams are gently dipping to the west and occur at depths ranging from the surface to more than 3000 m. Coals range from lignite to

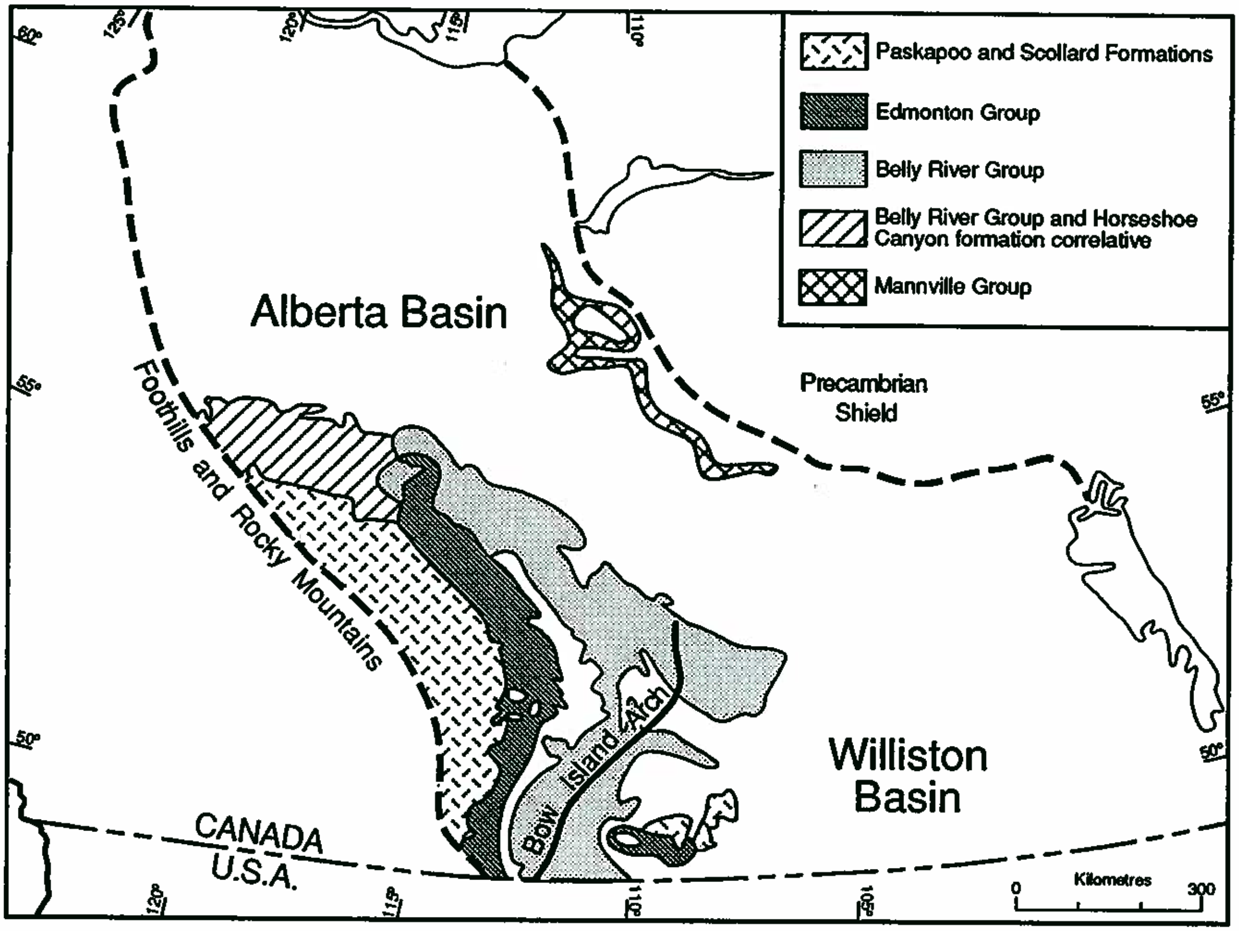


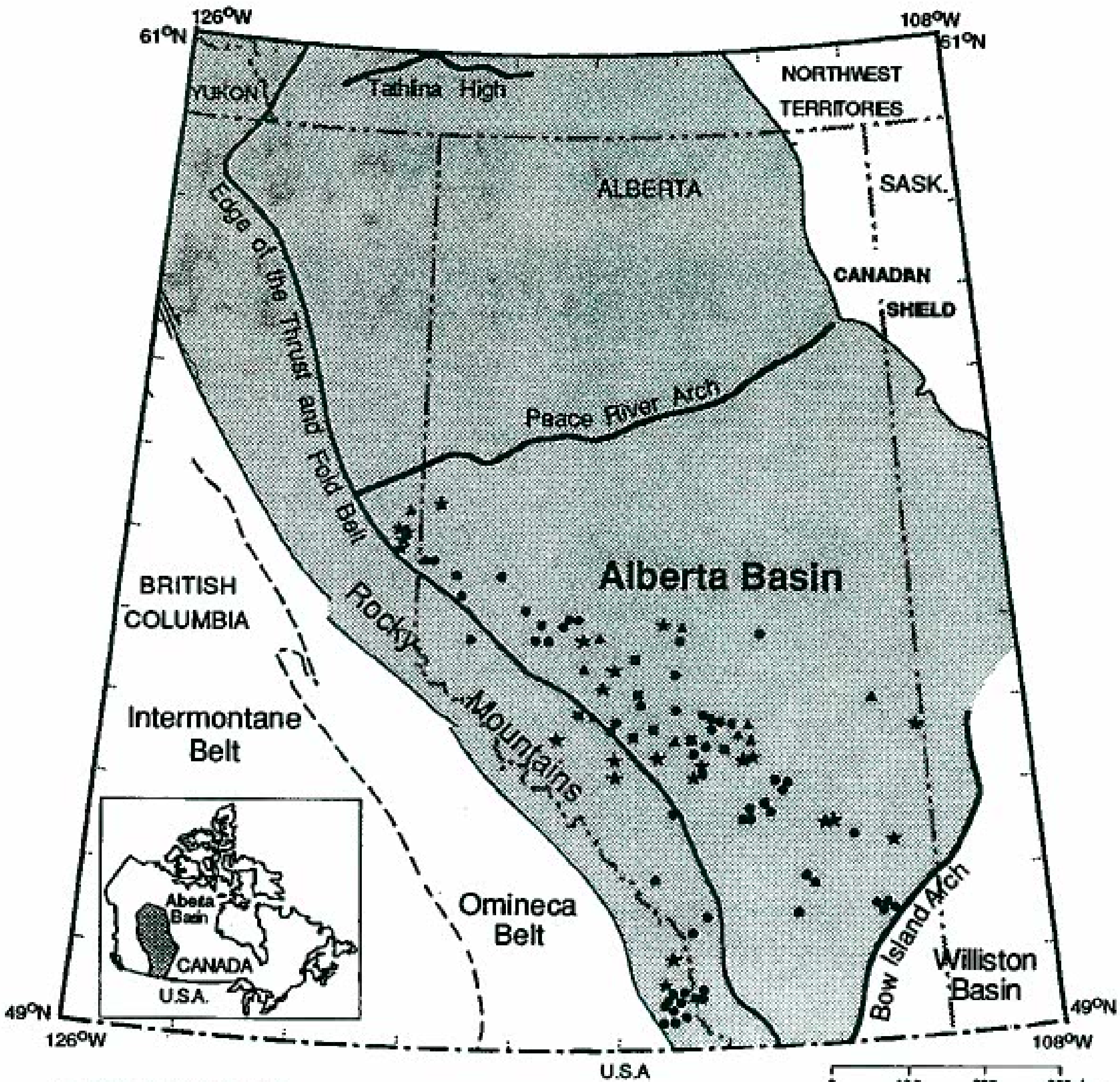
Figure 10: Lateral extent and outcrop areas of the main coal-bearing units in the undeformed Alberta basin (after Smith, 1989).

bituminous in rank, generally increasing in rank from east to west, which corresponds to increasing depth. The coals of Belly River Group and Horseshoe Canyon Formation are thin, discontinuous, and believed to be of too low rank to have significant CBM potential (Dawson, 1995). In addition, the only places they attain significant thickness are in areas where they are of low rank and at very shallow depths. In the Mannville Group, coal seams range in thickness from less than 1 m to more than 15 m. Thick cumulative coals are found near the edge of and extending into the Thrust and Fold Belt, where medium-volatile to semi-anthracite coals are found, favorable to coalbed methane generation (Langenberg et al., 1997). Total resources in the Mannville strata are estimated to be of the order of more than 160 Tcf. (Langenberg et al., 1997). However, the great depth in those parts of the basin may make coalbed methane production uneconomic. The coals of the Paleocene Scollard Formation, stratigraphically equivalent to the Coalspur Formation of the Outer Foothills, and of the Paskapoo Formation, contain the laterally extensive Ardley coal zone. The Ardley coals are subbituminous in rank, and are estimated to contain more than 100 Tcf of methane, of which approximately 25 Tcf could be available in coal seams thicker than 2.5 m (Richardson, 1991). Generally, the coals of the Mannville Group and Scollard Formation are considered to be the main coalbed methane targets because they are the only coals which have thick seams at depths and rank suitable for coalbed methane potential.

A number of coalbed methane wells have been drilled in the Alberta basin (Figure 11), which were more or less successful in terms of CBM production. Permeability values estimated from drillstem tests vary in a wide range, from 0.001 to 30 md. Extensive exploration for coalbed methane is not been pursued at this time because of the abundance of natural gas.

5.3 Basin Hydrogeology

Whereas little is known about the hydrogeology of the deformed part of the basin (Rocky Mountain and Foothills), the regional-scale hydrogeology of the undeformed part is quite well understood as a result of studies conducted in the last decade. The flow of formation waters in the undeformed part of the basin is extremely complex. Various hydrogeological studies in the basin, reviewed by Bachu (1995), show that the Alberta basin is generally underpressured (pressures bellow hydrostatic) with respect to the present-day topography. Several flow systems, each one driven by a different mechanism, were identified (Bachu, 1995, 1997). These flow systems are represented diagrammatically in Figure 10. In the northern third of the basin, the flow in the entire hydrostratigraphic succession is driven northeastward by basin-scale topography from recharge areas at the Thrust and Fold Belt in British Columbia to discharge areas at Great Slave Lake (Bachu, 1997). In the southern two thirds of the basin, where the coal-bearing strata are found, two megahydrostatic successions and associated flow systems were recognized (Bachu, 1995). The first megastratigraphic succession corresponds to the pre-Cretaceous passive-margin stage of basin development, and consists of thick, carbonate-dominated aquifer systems separated by shaly aquitards and evaporitic aquicludes. Southwest to northeast regional-scale flow in the Basal Cambrian and Winnipegosis aquifers (Figures 9 and 12) is probably driven by past tectonic processes (fossil flow since the tectonic compression during the Laramide Orogeny). Similar flow is present in

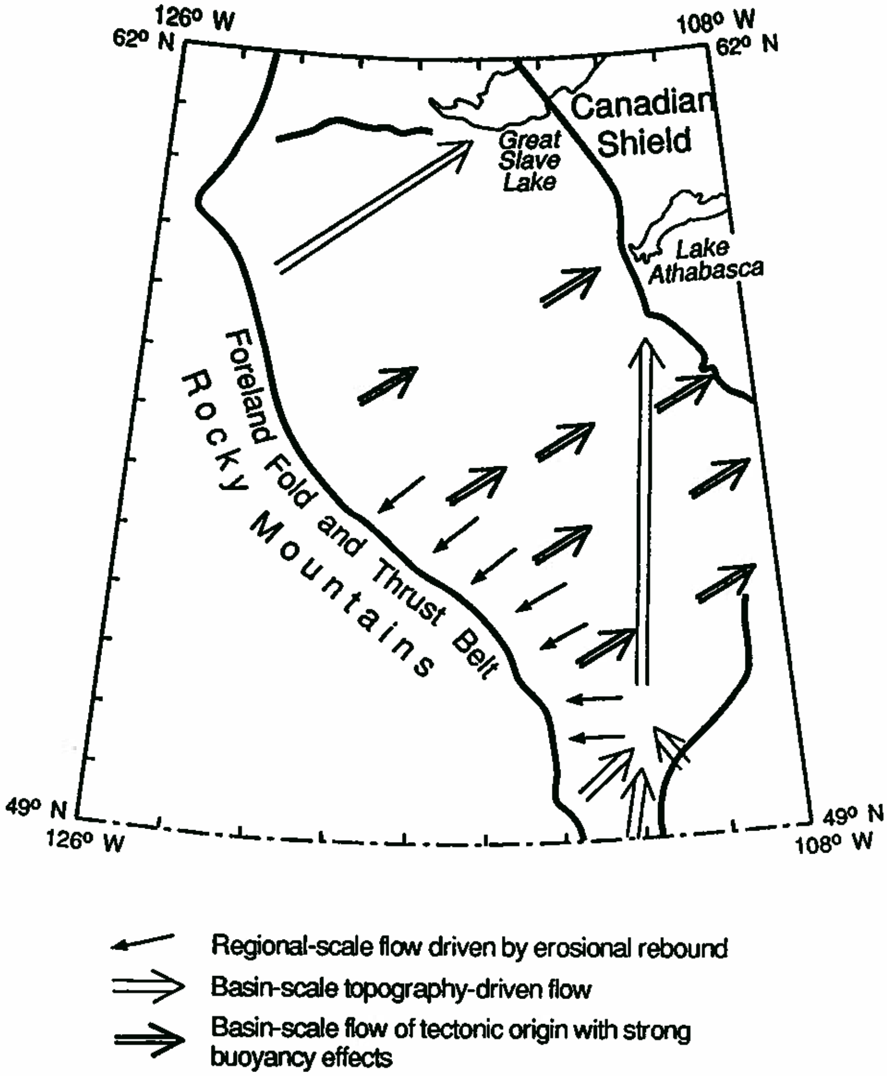


CBM Well Data

- ● Available
- ★ Not available
- ■ New locations (completed)
- ▲ Future locations

Figure 11: Distribution of coalbed methane wells in the Alberta basin (after Sinclair, 1997).

a.



b.

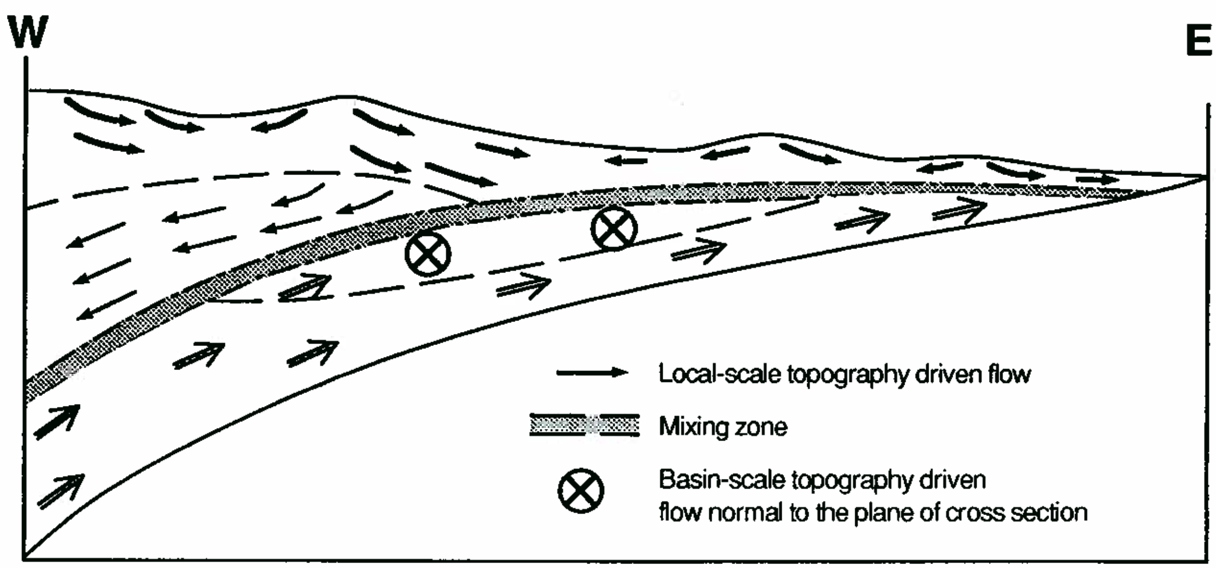


Figure 12: Diagrammatic representation of flow systems in the Alberta basin (after Bachu, 1995,1997): a) Plan view, and b) in cross-section (Line of cross-section W-E represented in Fig.8a).

Middle and Upper Devonian aquifer systems in the area adjacent to the Thrust and Fold Belt (Figures 9 and 12). A northeastward basin-scale flow system is driven by basin topography in the Mississippian-Jurassic aquifer system, and, progressively northeastward, in the Upper Devonian aquifer system in areas where the former is absent due to pre-Cretaceous erosion (Figure 12). This flow system is recharged at outcrop of Mississippian strata in Montana, and discharges in northeastern Alberta at Devonian outcrops along the Athabasca and Peace rivers, and at Lake Athabasca. The salinity of formation waters in the pre-Cretaceous aquifers is high, particularly in the vicinity of evaporitic beds, and generally increase both northward and with depth.

The second megahydrostratigraphic succession corresponds to the foreland stage of basin evolution and consists (Figure 9) of thick, shaly aquitards and aquitard systems (the Clearwater, Colorado, Lea Park, Bearpaw and Battle) and sandstone aquifers (the Lower and Upper Mannville, Viking and Cardium within the Colorado Group, Milk River, Belly River, Horseshoe Canyon and Scollard). In a broad area close to the Thrust and Fold Belt in the southwestern part of the Alberta basin, the flow of formation waters in isolated aquifers, such as Viking, Belly River and Horseshoe Canyon, is driven downdip, basinward to the southwest by erosional rebound in the thick intervening shaly aquitards (Figure 12). Formation pressure in these aquifers reaches very low values, with hydraulic heads lower than the lowest elevation in the basin at Great Slave Lake some 1500 km to the north (Bachu and Underschultz, 1995). The flow in the same aquifers in the shallower, east-northeastward parts of the basin is driven outward updip by basin- and local-scale topography (Bachu and Underschultz, 1995). This combination of flow systems driven by different mechanisms in these aquifers shows that the flow of formation waters is still in a transient state of adjusting to the present-day topography. Flow in shallow systems at the top of the hydrostratigraphic succession is driven by local topography. The salinity of formation waters in this succession is significantly lower than in the pre-Cretaceous one, leading to flow-retarding buoyancy effects which preclude the deep penetration of fresh meteoric water into Paleozoic units. Mixing of connate and meteoric waters and interference between the major flow systems takes place in the Mannville aquifers along the sub-Cretaceous unconformity, where successively older pre-Cretaceous aquifers subcrop from west to east (Figure 12).

The basin-scale permeability of aquifer rocks in the Alberta basin is low, of the order of 10^{-15} to 10^{-14} m^2 (1 to 10 md). Only locally is rock permeability high, sometimes reaching values of the order of 10^{-12} m^2 (10^3 md) (Hitchon et al., 1990; Bachu and Underschultz, 1993; Bachu, 1997).

6.0 COMPARISON BETWEEN THE ALBERTA AND THE US ROCKY MOUNTAIN BASINS

The Alberta basin is a Rocky Mountain foreland basin like the San Juan, Raton, Greater Green River (including the Sand Wash), Piceance and Powder River basins in the US. Unlike the US basins, which are relatively small, mainly intermontane and disconnected (fragmented) because of basement uplift and thrusting during the Laramide Orogeny, the Alberta basin, located west of the Canadian Precambrian Shield, is significantly larger in size.

The coal-bearing strata were deposited in fluvial, floodplain and continental environments during the Upper Cretaceous and Tertiary in the US and Alberta basins. However, unlike the US basins, extensive coals were deposited in the Alberta basin in the same type of environments in the Lower Cretaceous strata of the Mannville Group. Due to Tertiary-to-Recent erosion, coals in the Alberta basin are found over a large depth span, from very shallow to very deep (more than 2000 m depth near the thrust and fold belt). Unlike some US basins, large-scale magmatism and volcanism are absent in the Alberta basin, although it is believed that local features, such as pipes and intrusives, are present. Thus, the coal rank (maturity) and coal gas content are the result of burial only, with no local influences of high heat flow and geothermal gradients resulting from intrusives. Structural elements caused by basement tectonism during the Laramide Orogeny likely contributed to increased permeability in some coal seams in the US basins, while, generally, no such effects are evident as yet in the Alberta basin which lies on a stable Precambrian platform. However, lack of detection to date of tectonic influences does not preclude their existence. Structural and depositional characteristics may play a significant role in permeability enhancement in coal seams.

Hydrogeological regimes are similar in the US basins, with groundwater flow being driven by present-day topography from recharge areas at high elevations to discharge areas at low elevations. The latter may be the basin center, a major river valley, or outcrops. The formation water is generally of meteoric origin, being characterized by low salinity. In contrast, the flow of formation water in coal-bearing Cretaceous and Tertiary strata in the Alberta basin is driven both by erosional rebound in adjacent confining shales, inward toward the basin foredeep, and by present-day topography outwardly toward outcrop. Except for the uppermost coal-bearing strata (Scollard and Paskapoo) which are in hydraulic continuity with the surface, the salinity of formation waters in the deeper units is also higher than the salinity of waters in the US basins, thus affecting disposal strategies. Coal seams in US basins are overpressured, underpressured or normally pressured, depending mainly on the location and continuity of zones of high or low permeability in relation to either recharge or discharge areas. The zones of high permeability and artesian overpressure affect coalbed methane producibility in the sense that large amounts of formation water are produced, which need to be disposed of. In contrast, the coal-bearing formations in the Alberta basin are generally underpressured. As a result of erosional rebound in the adjacent shaly formations, the underpressuring is particularly severe in the southwestern part of the basin near the Rocky Mountain Thrust and Fold Belt. Thus, it is expected that only small amounts of formation water will be produced, but also less coalbed methane if only conventional extraction methods, such as water depressuring, are used. Also, coalbed underpressuring results usually in lower gas content, although hydrostatic underpressuring does not necessarily means low pressures. Thus, the pressure in deep coal seams in the vicinity of the Thrust and Fold Belt may be sufficiently high in absolute value to constrain methane's move out of the coal matrix. Unlike some US basins, the permeability of coal seams and adjacent strata in the Alberta basin seems so far to be low, with correspondingly low-to-negligible water production. However, a quick comparison of the size of the relatively small US basins with the much larger Alberta basin, with few and sparsely distributed CBM wells drilled so far, indicates that the data obtained to date regarding coal permeability and CBM producibility in the Alberta basin are inconclusive. The geological and hydrogeological complexity of the Alberta basin, and the sparse CBM well distribution do not allow interpolation or extrapolation of the data to any other part of the basin. Thus, in order to define better the coalbed methane potential and producibility in the Alberta basin there is need for further studies, both at the regional and local scales, based on the comprehensive multi-disciplinary approach applied for US basins. This would include basin tectonics, stratigraphy and structure of the coal-bearing units, coal properties, and hydrogeological and geothermal regimes in the same respective units.

7.0 CONCLUSIONS

Cretaceous and Tertiary strata in Rocky Mountain foreland basins both in US and Canada are very rich in coal of various rank and quality, depending on the degree of maturation and composition. Coalbed methane is an integral, currently very little utilized, energy source contained in these coals, except for the San Juan basin in US. The potential of these basins for coalbed methane is significant, particularly in the Alberta basin because of the large areal extent of multiple coal beds of various rank and gas content, beds located at depths varying from very shallow to very deep. However, coalbed methane producibility, as opposed to potential, depends on a series of tectonic, structural, depositional, maturation and hydrogeological factors. The review of basin-scale geology and hydrogeology of the coal-bearing strata in these basins shows that coalbed methane can be produced economically under a variety of hydrogeological conditions, varying from underpressured to overpressured. Flow systems and directions influence gas migration pathways and accumulations. The most important element in coalbed methane producibility, beside gas content, is reservoir (coal) permeability, which depends on structure, depositional conditions, and stress regime. Permeability also strongly influences water production. Experience with long-term producing wells in US indicates that the coalbed methane producibility is likely to increase in time due to changes in coal permeability caused by changes in the stress regime as gas production continues. Thus, although coal permeability in the Alberta basin seems to be low based on the limited and sparsely-distributed number of wells drilled so far, the potential exists for reservoirs characterized locally by higher permeability. Also, the economics of coalbed methane production will be influenced by the reservoir depth, by the degree of maturation and gas content of the coal beds, and by the hydrodynamic conditions of formation water flow. Based on the multidisciplinary approach inherent in the coalbed methane producibility model, a better analysis of all the available data and physical processes relating to coalbed methane production is needed in order to establish the true potential of coalbed methane in the Alberta basin, and identify possible exploration targets.

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