



What is Shale Gas? An Introduction to Shale-Gas Geology in Alberta

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Abstract

The purpose of this report is to define and describe gas shales and discuss Alberta's potential for shale gas production.

Shale is traditionally regarded as a potential source rock and seal/cap rock for conventional hydrocarbon reservoirs. More recently, shale has been recognized as a potential unconventional reservoir for hydrocarbons, although with lower permeability and a larger content of organic matter than conventional reservoirs. In a shale reservoir, gas typically occurs in two modes: adsorbed on organic matter within the shale bed in a similar manner to coal bed methane, and as free gas in porosity within the shale matrix, similar to conventional reservoirs. The low permeability of shale reservoirs dictates that specialized completions techniques are necessary to enable production.

This report discusses relevant geological and geochemical criteria required for viable shale gas plays, including the type, amount and maturation of organic matter within a shale bed, gas contents and permeability. The nature of the reservoir, including mineralogy, fractures, porosity and permeability will determine suitability for different completions technologies and influence drainage area from a wellbore.

Numerous shale plays in the United States are in production. A selection of plays is discussed as possible analogues for Alberta shale gas potential. Similarities and differences, with emphasis on geological, geochemical and mineralogical components are presented to highlight the potential for Alberta shale gas production.

1 Introduction

Shale gas exploration and production is in its infancy in Alberta, so currently there is limited data to estimate the shale gas resource potential in the province. Knowledge obtained from American projects indicates that shale gas has the potential to add substantially to Alberta's resource and reserve base. In this report we define resources as 'the maximum gas in place, without regard to the technology necessary to extract gas nor the present price of the gas.' Reserves are defined as 'an estimation of how much can be produced at the current price with present technology.' Resources assigned to shale gas projects in the United States are in the range 35–250 Tcf for each project (Curtis, 2002; Faraj et al., 2004), with recoverable reserves being about 5%–20% of resources, given the present state of technology. The resource potential of Alberta shale gas is immense (*see* Section 4); Alberta may contain as many as 15 formations that exhibit shale gas potential, with multiple shale gas pools, in a spatial sense, potentially associated with many of the formations.

In general, shale gas projects involve drilling many low-flow-rate wells (e.g. 560–8400 m³/d; 20–300 mcf/d) that decline slowly and produce for 2–4 decades or more (Curtis, 2002). More rarely, the initial flow rate may be very high (e.g., 28 000–280 000 m³/d; ~1–10 mmcf/d); however this rate generally declines to a low-flow-rate within a few months or years (Bowker, 2007).

This report is organized in the following manner:

- Section 2 discusses fundamental geological and geochemical aspects of shale that are relevant to Alberta shale gas development.
- Section 3 reviews geochemical and geological aspects of four main shale gas producing areas in the United States and suggests analogues for these plays in Alberta based on our knowledge of the Western Canada Sedimentary Basin (WCSB) and our own recent data collection and analysis.
- Section 4 summarizes some of the published resource estimates for Alberta.
- Section 5 summarizes some of the current shale gas projects in the WCSB.

2 Background: Shale Gas Characteristics

2.1 Definition of a Gas Shale

The definition of gas shale that best describes the reservoir is “organic-rich, and fine-grained” (Bustin, 2006). However, the term ‘shale’ is used very loosely and—by intent—does not describe the lithology of the reservoir. Lithological variations in American shale gas reservoirs indicate that natural gas is hosted not only in shale but also a wide spectrum of lithology and texture from mudstone (i.e., nonfissile shale) to siltstone and fine-grained sandstone, any of which may be of siliceous or carbonate composition. In the WCSB, much of what is described as shale is often siltstone, or encompasses multiple rock types, such as siltstone or sandstone laminations interbedded with shale laminations or beds. The presence of multiple rock types in organic-rich ‘shale’ implies that there are multiple gas storage mechanisms, as gas may be adsorbed on organic matter and stored as free gas in micropores and macropores. Laminations serve a dual purpose because they both store free gas and transmit gas desorbed from organic matter in shale to the well bore. The determination of the permeability and porosity of the laminations, and the linking of these laminations via a hydraulic fracture (frac) to the well bore, are key requirements for efficient development. Additionally, solute or solution gas may be held in micropores and nanopores of bitumen (Bustin, 2006) and may be an additional source of gas, although traditionally this is thought to be a minor component. Free gas may be a more dominant source of production than desorbed gas or solute gas in a shale gas reservoir. Determining the percentage of free gas versus solute gas versus desorbed gas is important for resource and reserve evaluation and is a significant issue in gas production and reserve calculations, as desorbed gas diffuses at a lower pressure than free gas.

The lack of a strict definition for shale causes an additional degree of difficulty for resource evaluation. Such a broad spectrum of lithology appears to form a transition with other resources, such as ‘tight gas’ (Petroleum Technology Alliance of Canada, 2005), where the difference between it and gas shale may be that tight gas reservoirs generally contain no organic matter (Petroleum Technology Alliance of Canada, 2005), a differentiation we follow here.

The variety of rock types observed in organic-rich ‘shale’ implies the presence of a range of different types of ‘shale gas’ reservoirs. Each reservoir may have distinct geochemical and geological characteristics that may require equally unique methods of drilling, completion, production and resource and reserve evaluation, as indicated by American experience over approximately the last 20 years (Cramer, 2008). Additionally, we do not overlook that shale still has the potential to be a seal or cap rock and that not all shale are necessarily reservoir rocks.

2.2 Characteristics of Shale: What Makes a Shale Gas Play?

Conceptually, an Alberta shale gas play is little different than shale gas plays in the United States, in that finding organic-rich, gas-prone shale is generally not difficult; rather, finding the permeable ‘sweet spots,’ the most brittle and fracturable strata, or the most gas-saturated sediment is more challenging. In all cases, a thorough understanding of the fundamental geochemical and geological attributes of ‘shale’ is essential for resource assessment, development and environmental stewardship.

Four properties that are important characteristics in each shale gas play are the

- 1) maturity of the organic matter;
- 2) type of gas generated and stored in the reservoir (i.e., biogenic or thermogenic);
- 3) TOC content of the strata; and
- 4) permeability of the reservoir (*see* Table 1).

Gas from shale is generated in two different ways, although a mixture of gas types is possible: thermogenic gas is generated from cracking of organic matter or the secondary cracking of oil; and biogenic gas, such as in the Antrim shale gas field in Michigan, is generated from microbes in areas of fresh water recharge (Martini et al., 1998, 2003, 2004). Thermogenic gas is associated with mature organic matter that has been subjected to relatively high temperature and pressure in order to generate hydrocarbons. Broadly speaking, more mature organic matter should generate higher gas-in-place resources than less mature organic matter, all other factors being equal. Organic maturity is often expressed in terms of vitrinite reflectance (% R_o), where a value above approximately 1.0%–1.1% R_o indicates the organic matter is sufficiently mature to generate gas and could be an effective source rock. Generally speaking, well-fractured shale that contains an abundance of mature organic matter and is deep or under high pressure will yield a high initial flow rate. For example, horizontal wells in the Barnett with a high initial reservoir pressure can yield an initial flow rate of a few million cubic feet per day after induced fracturing. However, the initial rate declines rapidly, by about 50%–60%, after the first year (Hayden and Pursell, 2005); thereafter, gas flow is dominated by the rate of diffusion from the matrix to the induced fractures (Bustin et al., 2008). An average flow rate per horizontal well, after about 3–5 years with no additional induced fracturing, is in the area of 5 663–11 326 m³/d (cubic metres per day) or 200–400 mcf/d (thousand cubic feet per day) with an ~10% decline per year thereafter.

Biogenic gas can be associated with either mature or immature organic matter, and its presence is a focal point of some studies by the United States Geological Survey (C. Swezey, pers. comm., 2007). Biogenic gas can add substantially to shale gas reserves. For example, the most prolific unconventional gas field in the United States to date, the San Juan Basin coalbed methane (CBM) gas field, is a mixture of both gases and has generated much of its gas from biogenic processes (Scott et al., 1994). Likewise, gas from the

Table 1. Shale gas properties of the four main producing shale gas basins in the United States (modified after Faraj et al., 2004).

Characteristic	Barnett	Ohio and Equivalents	Antrim	Lewis
Basin	Fort Worth	Appalachian	Michigan	San Juan
Age	Mississippian	Late Devonian	Late Devonian	Late Cretaceous
Depth (feet)	6500–8500	2000–5000	600–2000	3000–6000
Thickness (feet)	200–300	300–2000	160	1000–1500
Net thickness (feet)	50–100	30–100	70–120	200–300
Bottom hole temp. (°F)	200	100	75	130–170
Pressure gradient psi/foot	0.43–0.44	0.15–0.4	0.35	0.2–0.25
Maturity (% R _o)	1.1–1.4	1–1.3	0.4–1.6	1.6–1.88
Total organic carbon (wt. %)	1–4.5	0.5–23	0.5–20	0.5–2.5
Total porosity (%)	1–6	2–5	2–10	.5–5
Water Saturation (S _w)	10–80	10–80	10–80	10–80
Gas content standard cubic feet/ton	300–350	60–100	40–100	15–45
Adsorbed gas (% of total)	20	50	70	13–40
Gas production (mcf/day per well)	100–1000	30–500	40–500	100–200
Water production (Bwp, barrels of water per day)	0	0	20–100	0
Well spacing (acres)	80–160	40–160	40–160	80–320
Recovery factor	8–15	10–20	20–60	5–15
Gas-in-place (Bcf/section)	30–40	5–10	8–16	90
Resources (Tcf)	26.2 ⁽¹⁾	225–250	12–20	100

⁽¹⁾Data from Pollastro et al. (2004).

Antrim Shale Formation in the Michigan Basin is largely biogenic gas that has been generated in the last 10 000–20 000 years (Martini et al., 1998, 2003, 2004) and has produced more than 2.4 Tcf as of 2006 (Wood, 2006). A mixture of gases is suggested for the New Albany Shale Formation in the Illinois Basin (Wipf and Party, 2006) and is certainly possible in Alberta shale (*see* Section 3.2).

Total organic carbon (TOC) is a fundamental attribute of gas shale and is a measure of present-day organic richness. The TOC content, together with the thickness of organic shale and organic maturity, are key attributes that aid in determining the economic viability of a shale gas play. There is no unique combination or minimum amount of these factors that determines economic viability. The factors are highly variable between shale of different ages and can vary, in fact, within a single deposit or stratum of shale over short distances. At the low end of these factors, there is very little gas generated. At higher values, more gas is generated and stored in the shale (if it has not been expelled from the source rock), and the shale can be a target for exploration and production. However, the presence of sufficient

quantities of gas does not guarantee economic success, since shale has very low permeability and the withdrawal of gas is a difficult proposition that depends largely upon efficient drilling and completion techniques.

Induced fracturing may occur many times during the productive life of a shale gas reservoir (Walser and Pursell, 2008). Shale, in particular, exhibits permeability lower than CBM or tight gas and, because of this, forms the source and seal of many conventional oil and gas pools. Hence, not all shale is capable of sustaining an economic rate of production. In this respect, permeability of the shale matrix is the most important parameter influencing sustainable shale gas production (Bennett et al., 1991a, b; Davies et al., 1991; Davies and Vessell, 2002; Gingras et al., 2004; Pemberton and Gingras, 2005; Bustin et al., 2008). To sustain yearly production, gas must diffuse from the low-permeability matrix to induced or natural fractures. Generally, higher matrix permeability results in a higher rate of diffusion to fractures and a higher rate of flow to the wellbore (Bustin et al., 2008). Furthermore, more fractured shale (i.e., shorter fracture spacing), given sufficient matrix permeability, should result in higher production rates (Bustin et al., 2008), a greater recovery of hydrocarbons and a larger drainage area (Cramer, 2008; Walser and Pursell, 2008). Additionally, microfractures within shale matrix may be important for economic production; however, these microfractures are not easily determined *in situ* in a reservoir (Tinker and Potter, 2007), and only further research and analysis will determine their role in shale gas production.

A brief review of shale gas plays in the United States reveals a variety of geochemical and geological parameters unique to each play (e.g., Faraj et al., 2004; Table 1; *see also* Section 3). Some of these parameters have been used (e.g., Mullen et al., 2006; Grieser et al., 2008) to categorize different types of shale gas plays in the United States. Wipf and Party (2006) reviewed American shale gas plays and classified gas shale into six categories: biogenic, thermogenic, mixed thermogenic-biogenic, fractured, thermogenic hybrid and one group with no definitive origin. In Alberta, the number of prospective formations is caused, in part, by the broad definition of shale gas. In this respect, we include traditional 'source beds' that are reasonably well studied, along with other relatively organic-rich beds, of either carbonate or siliciclastic composition, where data may be obtained from published literature or other public sources (e.g., ST-105 at the ERCB, formerly Guide 14). Initial observations suggest there are more than 15 formations in Alberta (Figure 1) with some degree of organic richness. As mentioned earlier, some shale gas reservoirs will be difficult to differentiate from 'tight gas' reservoirs. For example, the Lewis Shale Formation in the San Juan Basin of New Mexico may contain as little as 0.5 wt. % TOC and has been referred to as a 'hybrid' conventional gas-unconventional shale gas play by Wipf and Party (2006). Nonetheless, desorbed gas may account for 50% or more of the production from the Lewis Shale (Dube et al., 2000). In this same respect, the Montney Formation in the WCSB has been referred to as a shale gas play that exhibits characteristics of both conventional and unconventional reservoirs (Ross, 2008).

Shale gas reservoirs generally recover less gas (from <5% to 20%) relative to conventional gas reservoirs (~50-90%) (Faraj et al., 2004), although the naturally well-fractured Antrim Shale may have a recovery factor as high as 50%–60%. More recently, there have been suggestions that the Haynesville shale in Louisiana may have a recovery factor as high as 30% (Durham, 2008). To increase the recovery factor, innovation in drilling and completion technology is paramount in low-permeability shale reservoirs.

In the initial state of pool development, permeability 'sweet spots' are often sought because they result in higher rates of daily production and increased recovery of gas compared to less permeable shale. But these sweet spots are small, relative to the size of unconventional pools, so horizontal drilling and new completion techniques (such as 'staged fracs' and 'simultaneous fracs'; Cramer, 2008) were developed to improve economics both inside and outside of 'sweet spots.' The result is a significant increase in economically producible reserves and a substantial extension of the area of economically producible gas.

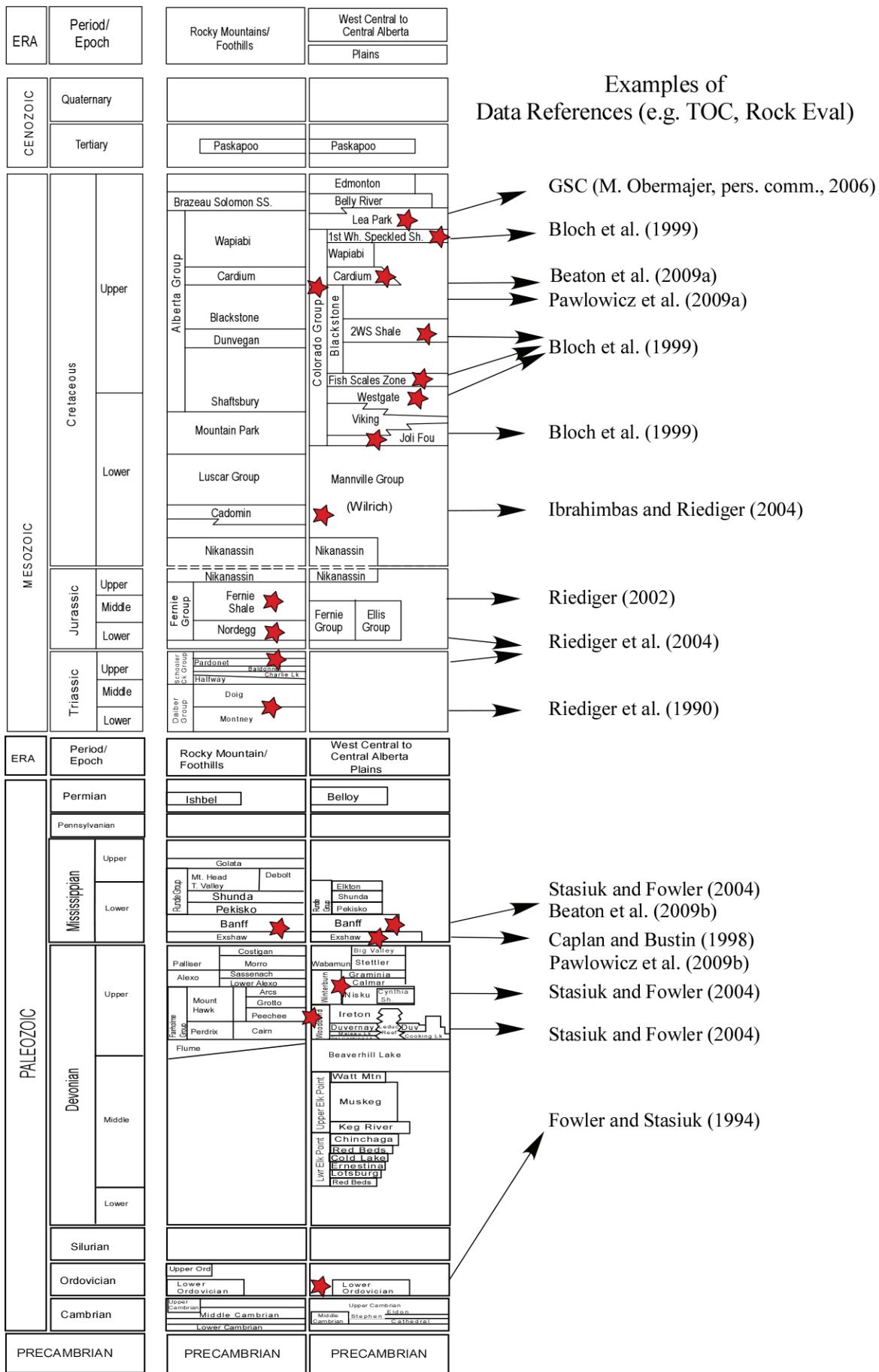


Figure 1. Preliminary list of potential shale gas formations in Alberta, with accompanying data reference.

A recent innovation in completion technology has been the addition of 3% HCl to induced fracturing in the Barnett Shale, which appears to increase the daily flow rate by enhancing matrix permeability and may add to the estimated ultimate recovery (Grieser et al., 2008). Additionally, refracturing the reservoir has become relatively common (Cramer, 2008) and can yield additional recoverable reserves “as high as 0.7 Bcf per frac,” according to Devon Energy Corp. (2007, p. 9). Devon’s recovery factor (as suggested in the latter document) is in the range 11%–13% of gas-in-place (and perhaps as high as 16%, (Devon Energy Corp., 2006). Rocks with interlaminated shale and siltstone is a shale gas target (e.g., Lewis Shale, New Mexico; Colorado Group, Alberta) that may require new techniques for detection in well logs, as well as new completion and drilling techniques. The silt laminations are too thin to be detected on well logs and to allow an accurate determination of how many laminations are in a given interval. Also, well logs are unable to accurately determine the percentage of porosity in shale or the laminations, the degree of water saturation in a reservoir or the relative degree of permeability in each lamination. Laminations both store gas (free gas) and are pathways of transport for diffusion of gas from shale to the well bore. Initial analyses of the Colorado Group (Beaton et al. 2009a; Pawlowicz et al. 2009a; Rokosh et al. 2009a) suggest that laminated strata will be one of the main shale reservoir types in the shallow zones of eastern Alberta. It will be extremely difficult to accurately determine recoverable reserves and resources from these pools if we cannot accurately ‘read’ the porosity, permeability and water saturation of these laminations, let alone determine how many laminations may occur within a given thickness of strata. These laminations are also particularly difficult completion targets. Normally, induced fractures are meant to extend laterally rather than vertically in a reservoir, yet the laminations may span tens of metres vertically. Therefore, a horizontal frac may miss many productive shale and silt laminations. Induced fracturing techniques may have to be altered, or new techniques developed for this type of shale gas reservoir.

An additional factor to consider is shale thickness. The substantial thickness of shale is one of the primary reasons, along with a large surface area of fine-grained sediment and organic matter for adsorption of gas, that shale resource evaluations yield such high values. Therefore, a general rule is that thicker shale is a better target. Shale targets such as the Bakken oil play in the Williston Basin (itself a hybrid conventional-unconventional play), however, are less than 50 m thick in many areas and are yielding apparently economic rates of flow. The required thickness to economically develop a shale gas target may decrease as drilling and completion techniques improve, as porosity and permeability detection techniques progress in unconventional targets and, perhaps, as the price of gas increases. Such a situation would add a substantial amount of resources and reserves to the province.

There is a variety of other factors that must be reviewed when trying to locate and produce shale gas. Factors such as brittleness/fracturability, gas generative capacity, kerogen type, percentage of heavy hydrocarbon components, textural variations, mineralogy, microporosity, extent of burrowing, presence of natural fractures, and fresh water recharge may all come into play in resource and production evaluations.

The primary point of this subsection is that the geochemical and geological characteristics of each pool are relatively unique and must be carefully examined to determine resources. Furthermore, a valuable lesson obtained from knowledge of American shale gas experience is that innovation in unconventional drilling and completion techniques has added substantial reserves to otherwise uneconomic areas and has also been a key part of safe and efficient development (Cramer, 2008; Grieser et al., 2008).

2.3 Are All Shale Beds Prospective for Shale Gas?

Shale forms the source and seal for many reservoirs in the WCSB. Although shale seals can, to some extent, store organic matter and hydrocarbons, the effective porosity of a shale seal is, strictly speaking, too limited to economically transmit hydrocarbons. Thus, not all shale is an economic target for gas. The identification of shale seals has implications in resource evaluation as well as in reservoir pool

delineation. For example, a 200 m thick shale bed may contain a single pool of gas or a number of vertically separated pools; producing a pool located in the upper portion of a shale bed may have no material effect on the pressure in the lower portion of the shale as long as a seal is laterally continuous. The potential to ‘bypass’ reserves without knowledge of shale seals may be substantial. Another example involves shale beds that consist of laminated shale and siltstone. There may be a few dozen or more shale and siltstone couplets within a given metre of shale, with only some of the shale or silt laminations either permeable enough to transmit hydrocarbons or laterally extensive enough to be an effective conduit. This results in the potential to have many small, stacked ‘pools’ within a few metres of shale. Knowledge of such a scenario is critical for efficient completion and drainage of a well. Hence, knowledge of shale seals is as important to shale gas resource development as is knowledge of shale permeability (Dawson and Almon, 2002).

2.4 Drainage Area and Spacing Units of Shale Gas Plays

Determining the drainage area of shale gas plays is perhaps one of the most important aspects of pool development and resource assessment. In terms of resource assessment, the drainage area of a well should correspond to the cell size of the assessment unit (Schenk, 2002). The areal extent of a drainage area per well will determine the number of wells drilled, for example, within a section to effectively maximize gas recovery. Ideally, the drainage area of a shale gas well will coincide with the designated spacing unit; but this may not be the case. Often, the effective drainage area of a well is not determined until after a pool is delineated and infill drilling occurs.

Microseismic and tiltmeter mapping of induced fracture patterns are presently two of the primary tools for mapping the extent of low-permeability drainage areas. The experience of Grieser et al. (2008) in the Barnett Shale suggests that the drainage area after a frac job on a horizontal well was about one-quarter the size of the total fractured area. Thus, the drainage area of low-matrix-permeability reservoirs is presently thought to be restricted to a small area beyond the extent of an individual induced fracture. Extrapolation of this relationship suggests that the distance gas flows in extremely low-permeability shale reservoirs may be expressed in terms of metres or tens of metres, rather than hundreds of metres. Gas drainage therefore is dependant on the degree of permeability of shale, the presence and extent of high permeability silt laminae and the efficiency of induced fracturing.

Horizontal drilling is now the established method to drain the Barnett and its age equivalents in nearby sedimentary basins; however, horizontal drilling is not as prolific in any of the other shale gas formations in the United States. The recent success of horizontal wells in the Barnett Shale (circa 2003) has spurred interest in older plays, such as the Appalachian shale units. Research in other plays is ongoing (e.g., Antrim Shale; Wood, 2006) because of the potential for increased recovery per unit cost. However, the steep learning curve for shale geology and geochemistry results in an equally steep learning curve in drilling and completion using horizontal technology in each play. More work is needed in this area, and this research will be very helpful in Alberta, both to maximize recoverable reserves and to reduce the footprint of surface disturbance by wells.

The drainage area of vertical shale gas wells is generally much smaller than that of horizontal wells. According to Shelby Geological Consulting, the drainage area of the Fayetteville Shale (Shelby, 2006) in Arkansas (akin to the Barnett Shale; Wipf and Party, 2006) is about 5–20 acres for vertical wells and 18–62 acres for horizontal wells. Southwestern Energy Company (2005) estimated that the drainage area for vertical wells on their acreage—also a Fayetteville play—was as low as 20 acres per well after induced fracturing. Devon Energy Corp. (2007) has asserted that spacing for horizontal wells on their Barnett acreage will be as low as 20 acres per well. Contrary to these examples of small spacing units, the Antrim spacing units were recently increased from 40 acres per well to a minimum of 80 acres per well in many counties (Michigan Department of Environmental Quality, 2005). Obviously, each shale play has its own unique spacing characteristics and, no doubt, the values quoted may change for other types of shale gas

plays. As drilling and completion techniques advance, gas recovery per well generally improves and, perhaps, the drainage area per well may increase (e.g., Muskwa shale, British Columbia; Daily Oil Bulletin, 2008), or at least recovery per well may increase within the same drainage area.

An example of spacing units of vertical wells for a number of American shale gas plays is listed in Table 2 (Faraj et al., 2004). As stated earlier, the size of a drainage area does not necessarily equate to the size of a spacing unit, and there is no standard size for a shale gas drainage area per well, each play is relatively unique.

Table 2. Well spacing of shale gas plays in the United States (*modified after Faraj et al., 2004*).

	Barnett	Appalachian	Antrim	Lewis
Well spacing (acres)	80–160	40–160	40–160	80–320

3 Shale Gas–Equivalent Plays in Canada and the United States

Shale gas has been produced in the United States since the early 1820s, when gas from black Devonian shale was used to light local streets and homes in Fredonia, New York. Presently, the United States produces about 1 Tcf per year (estimate circa 2006) of shale gas (United States Energy Information Administration, 2008), with an expansion of exploration occurring (Wipf and Party 2006) outside the four main production areas (e.g., Appalachian Basin, eastern United States; Forth Worth Basin, Texas; San Juan Basin, New Mexico–Colorado; Michigan Basin, Michigan). A document available to AAPG Energy Minerals Division members (Wipf and Party, 2006) shows more than 20 shale formations in the United States listed as a current ‘shale play;’ that number has increased to more than 40 at present (B. Cardott, Chair, Shale Gas Section, Energy and Minerals Division, American Association of Petroleum Geologists, pers. comm., 2008). The annual energy outlook (United States Energy Information Administration, 2008) of the United States Department of Energy estimates that shale gas production will increase to about 2.3 Tcf by 2030, at which point unconventional gas should account for about 50% of domestic supplies.

In this section, shale gas plays in the four main areas of the United States are briefly examined and characteristics of each pool are outlined. More detailed summaries of the specific geology and geochemistry of these plays can be found in many other publications (e.g., Curtis, 2002; Hamblin, 2006). Our purpose is simply to observe fundamental American shale characteristics, such as TOC, organic maturity, fracturing and sedimentology, in productive areas and to use these characteristics as references to evaluate and categorize Alberta formations. We are not looking for duplicate characteristics between Alberta and the United States, as each shale play will be relatively unique in this respect. Rather, we observe the fundamental properties in each area, determine the critical factors that concern shale gas development, and then apply those factors as a guide to examine Alberta’s shale gas potential. One point is abundantly clear in our initial examination; the concept or characteristics of an American shale gas play are more important than finding a play in Alberta of equivalent geological age. For example, there appears to be no age equivalent for the Barnett Shale in the Alberta portion of the WCSB. Yet, the concept of shale gas production from a relatively deep (~2500 m) and brittle, silty, organic-rich shale in the foothills of the Ouachita Mountains of Texas certainly applies to formations in the foothills of the WCSB. Recent public information that has compared the discovery of shale gas in the Devonian Muskwa Formation in British Columbia (approximately equivalent to the Ireton Formation in Alberta) with the Mississippian Barnett Formation in Texas confirms our position (Daily Oil Bulletin, 2008). Much of the above information has been obtained from public publications; however, new information is constantly being released on shale plays. This brief summary may be considered a perpetual work in progress. We

have also included a table of shale gas properties (Table 1; Faraj et al., 2004) that compares many of the characteristics of the main producing strata discussed in this report.

3.1 Appalachian Black Shales and Analogues in the WCSB

The Appalachian black and grey shales cover the largest geographic area of the shale gas plays (Figure 2; Devonian Ohio shale) and contain the oldest shale gas fields in the United States. The Appalachian Ohio Shale Formation and equivalents (Figure 3) are Devonian and roughly equivalent to the Wabamun Formation in the WCSB (although the slightly earlier Rhinestreet black shale may be an Ireton-Nisku equivalent). The Appalachian shale units were deposited in a subsiding foreland basin (Figure 4), and they thicken to the east more than 2000 m. The maximum thickness of black shale is about 150 m. The black shale is thermally mature, with a maximum vitrinite reflectance of about 1.3% and a TOC content up to 4.7 wt. %, both parameters increasing to the west. Carbon content of the grey shale is highest in the middle of the basin and decreases to the east and west (Roen, 1984). Typically, TOC in grey shale is lower than that of the black shale. According to Ryder (1995), the depth of production ranges from “several tens of feet” to more than 5000 ft. (1524 m).

Natural fracturing is a very important part of the play, and the highest flow rates may be associated with the most fractured areas (Curtis, 2002). Apparently, fractures are more likely to be present in black shale than grey shale (Ryder, 1995); the result is that some producing horizons may be sealed by less fractured grey shale. However, shale microfabric may also be an important contributor to permeability and production. According to a microfabric analysis of grey and black shale by Davies et al. (1991) and Davies and Vessell (2002), grey shale in their study area may be more permeable than black shale, owing to a more open and chaotic microfabric. A fairly rigorous gas production analysis comparing well production from grey shale and black shale implied that production efficiency (average mcf/d per perforation) was 3.5 times greater in grey shale than black shale, although black shale was more often perforated and, as a result, produced a greater total of gas. The observation of increased permeability and production in bioturbated grey shale over black shale is intriguing and merits consideration in Alberta. The production analysis was only from eight wells; however, if the analysis holds true over a much larger area, then there is also potential in Alberta for shale gas exploration to expand beyond areas of classic, organic-rich black shale.

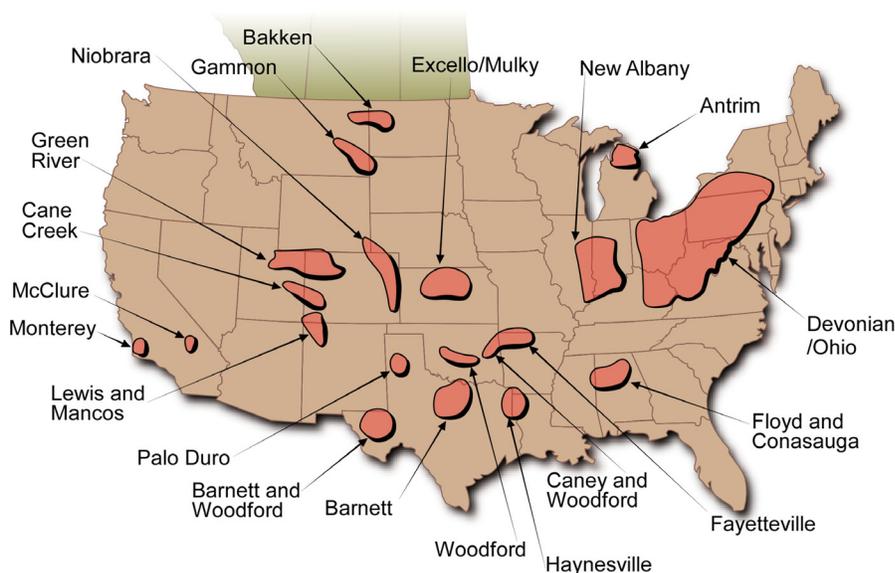
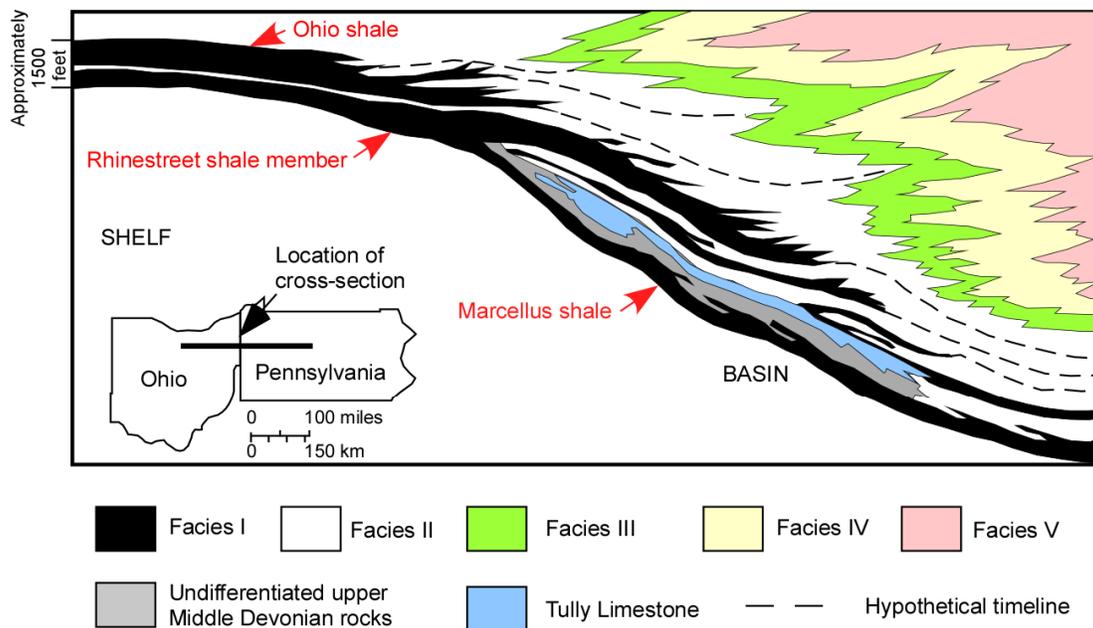


Figure 2. Shale basins in the United States (*modified after Collins, 2008*).



Facies I – Dark coloured basinal shale rich in organic matter. Facies II – Interbedded shale and very thin-bedded siltstone, with small amounts of thin bedded fine-grained sandstone; generally deposited as turbidites on the frontal slopes of the deltas. Facies III – Thin-bedded, fossiliferous marine clastic rocks. Facies IV – Interbedded varicoloured mudrock, shale, siltstone, sandstone and conglomerate, with minor amounts of fossiliferous marine limestone. Facies V – Generally varicoloured nonmarine siliciclastic rocks.

Figure 3. West to east cross-section of the Devonian Appalachian shale basin (modified after Milici 2005).

The Appalachian shale units are an archetypical shale gas play, where the key points appear to be natural fracturing and elevated TOC with relatively mature organic matter at a moderate depth (600–1500 m) (Ryder, 1995). Both oil and gas are produced from some wells (Milici, 2005), although gas production dominates and, because of the long chains of oil molecules, may indicate larger pore throats or enhanced fracturing in oil-producing areas. The depths of the shale units are midway between those of the Antrim Shale and the Barnett Shale; although the gas is thought to be thermogenic, there is some discussion on the presence or contribution, if any, of biogenic gas (C. Swezey, pers. comm., 2007).

In Alberta, there is no lack of black or grey shale at a similar depth and maturity; generally speaking, the most favourable areas for fracturing are well known in the WCSB (e.g., in the foothills and near basement arches and trenches; see Mossop and Shetsen, 1994). It is certainly true, however, that detailed fracture studies of our basin—especially ones that indicate the extent of fracturing within a specified formation or highlight basement fault rejuvenation—are relatively rare compared to other disciplines of geology and geophysics. More detailed studies of regional fracturing trends and magnitude are therefore warranted.

3.2 Antrim Shale and Analogues in the WCSB

The Late Devonian Antrim Shale Formation in the Michigan Basin of the United States is a unique shale gas play in that gas generation is largely biogenic (Martini et al., 2003, 2004). Therefore, the formation must be dewatered (i.e., ‘fresh water’) prior to gas production in a manner similar to many CBM plays. The Antrim comprises silty black shale with an aggregate thickness in the Lachine and Norwood members of up to 50 m (Curtis, 2002), with grey and green shale and carbonate beds of the Paxton member separating them. The black shale has a TOC content of up to 24 wt. %, is relatively immature (see Table 1), and is naturally well fractured due to regional and, perhaps, local tectonic events (Ryder,

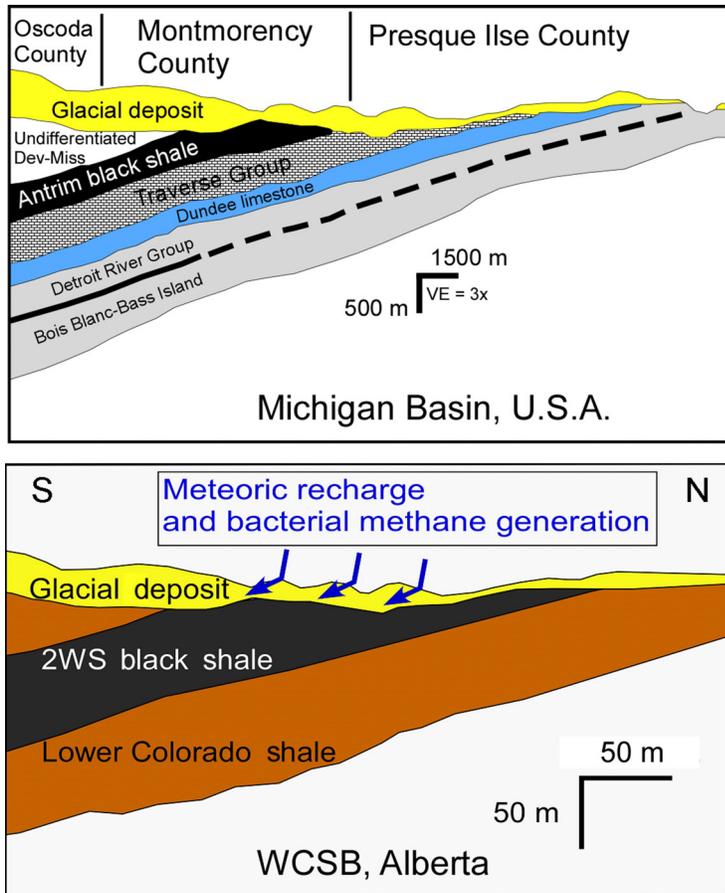


Figure 4. Stratigraphic analogy between the Antrim Shale Formation in the Michigan Basin and the Second White Speckled Shale in north-central Alberta (upper figure *modified after* Martini et al., 2004).

1996). According to Ryder (1996), an additional reason for enhanced fracturing is glacial isostatic rebound, as the Antrim subcrops immediately below surficial glacial till, a stratigraphic scenario common in the WCSB. An additional concern for Antrim production is that 10%–20% of the gas produced from this field is CO₂, whereas the remainder is dominated by methane (Wood, 2006). Hence, there is a need to dispose of fresh water and CO₂ during production.

W.B. Harrison, III of Western Michigan University recently summarized drilling and production data on the Antrim Shale in a gas shale committee report for the annual leadership meeting of the Energy and Minerals Division of the American Association of Petroleum Geologists (Cardott, 2008). His comments are paraphrased below:

Approximately 9600 wells have been drilled, with about 9400 wells still producing from depths ranging from about 107 m to 915 m. Wells are fractured using water and sand, although some have been fractured using nitrogen or foam. Cumulative production for the field exceeded 2.5 Tcf to the end of 2007, with approximately 136 Bcf produced during 2007 and an average production per well of 1104 m³/d. Initial production may be as high as 14 158 m³/d, but most wells begin production at less than 2832 m³/d. Water production is initially high and declines as gas production increases. The average gas to water production ratio during 2007 was ~41 m³/barrel, down from about 81 m³/barrel in 1998. Carbon dioxide (CO₂) production is initially low and increases through time. The

average CO₂ production during 2007 was about 14%, with some wells averaging as high as 30%.

No Antrim-like fields have been discovered in the WCSB; however, there may be a stratigraphic analogue of this play in Alberta. The black shale of the Second White Specks Formation (2WS) and Fish Scales Zone directly underlies glacial sediment (Figure 4) along the south flank of the Peace River Arch. In this area, there are also indications of gas shows from water-well drilling data (Figure 5), although we stress that we have not determined that the gas is sourced from Colorado black shale. Many geochemical and geological parameters will differ from those of the Antrim Shale and very little of the Colorado shale is classified as ‘black shale.’ Strictly speaking, organic-rich shale, as opposed to ‘black shale,’ is a prerequisite in this type of play. Thus, any shallow, relatively organic-rich strata in an area of hydrogeological recharge may qualify. Nonetheless, we have a reasonable stratigraphic analogue that merits further work, including hydrogeological mapping to locate recharge zones. The area where the Colorado Group subcrops beneath glacial sediment is outlined in Figure 6. There may be other areas in Alberta that are prospective for biogenic gas, such as where Devonian shale subcrops beneath glacial till in northeastern Alberta (Hamilton et al., 1999).

3.3 Barnett Shale and Analogues in the WCSB

There does not appear to be an age equivalent of the Barnett Shale Formation in the Alberta portion of the WCSB. Hence, it is important to observe the characteristics of the Barnett to find a similar type of play in sediment of another age, as was done for the Muskwa shale in British Columbia (*see* Section 2.4). The Barnett is a highly radioactive, black shale of considerable depth (~2500 m), thickness (~350 m) and range of maturity (moderate to high, 0.6%–1.1% R_o; Pollastro et al., 2003). The formation is slightly overpressured and has an illite content of about 25% (Pollastro et al., 2003). The relative lack of smectite is an important factor for well completions. The shale is very silty, with much of the silt being authigenic (Papazis and Milliken, 2005); some of the silica may have originated from settling of planktonic skeletons (Schieber et al., 2000).

The keys to this play appears to be the elevated brittleness of the shale, which is due, in part, to a high silt content and the depth of the play, a high gas to oil ratio (GOR; Pollastro et al., 2003) and a high gas capacity (Curtis 2002). According to Humble Instruments and Services Inc. (2007), an important component in a thermogenic shale gas play may be the “reduction in the heavy components of the source system where the GOR increases dramatically” through the cracking of oil and heavy components. Secondary cracking can add substantial reserves to a shale gas play. Such a concept could certainly apply to mature to overmature formations in the WCSB.

Natural fractures are present in the Barnett, but the role of these fractures in gas production is somewhat contentious (Gale et al., 2007). Regional fractures that do not breach cap rock are preferred in order to retain, rather than expel, hydrocarbons. Natural fractures, if open and confined to the reservoir, will enhance gas production, so the timing of source generation versus regional fracturing may be an issue. Natural fractures that are mineralized may open during induced fracturing and enhance production. However, in some areas of the play, natural or induced fractures may be connected to an underlying aquifer. If induced fractures penetrate the aquifer, then water may enter the borehole and slow or stop the flow of gas. It is also worth mentioning that ‘fractures’ generally refers to meso and macro-sized fractures, since the role of microfractures in shale gas production is poorly understood.

According to the Texas Railroad Commission, there were 7170 Barnett Shale gas wells as of January 23, 2008. From 2004 to 2006, gas production increased from 380 Bcf/year to 698 Bcf/year (www.rrc.state.tx.us/data/fielddata/barnettshale.pdf). From January 2007 to November 2007, gas production was about 768 Bcf (Cardott, 2008), resulting in an average production per well for January to November 2007 (assuming all 7170 wells were in production) of roughly 320 mcf/d.

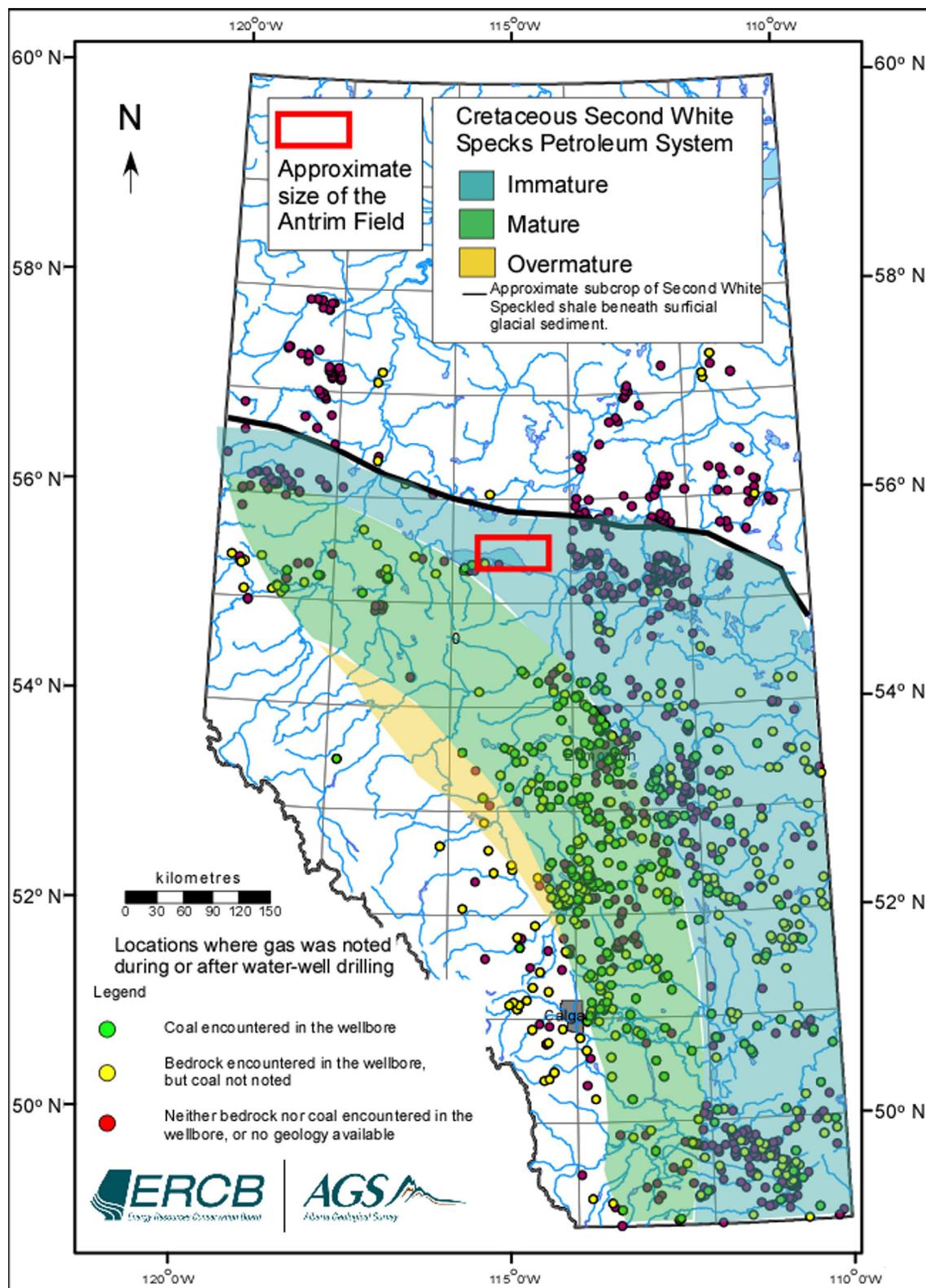


Figure 5. Water wells and gas shows in water wells in Alberta (modified after Lemay, 2003). The northern subcrop edge of the Second White Speckled Shale is also shown. The red box indicates the approximate present size of the Antrim shale gas field. Second White Specks maturity map after Creaney et al. (1994).

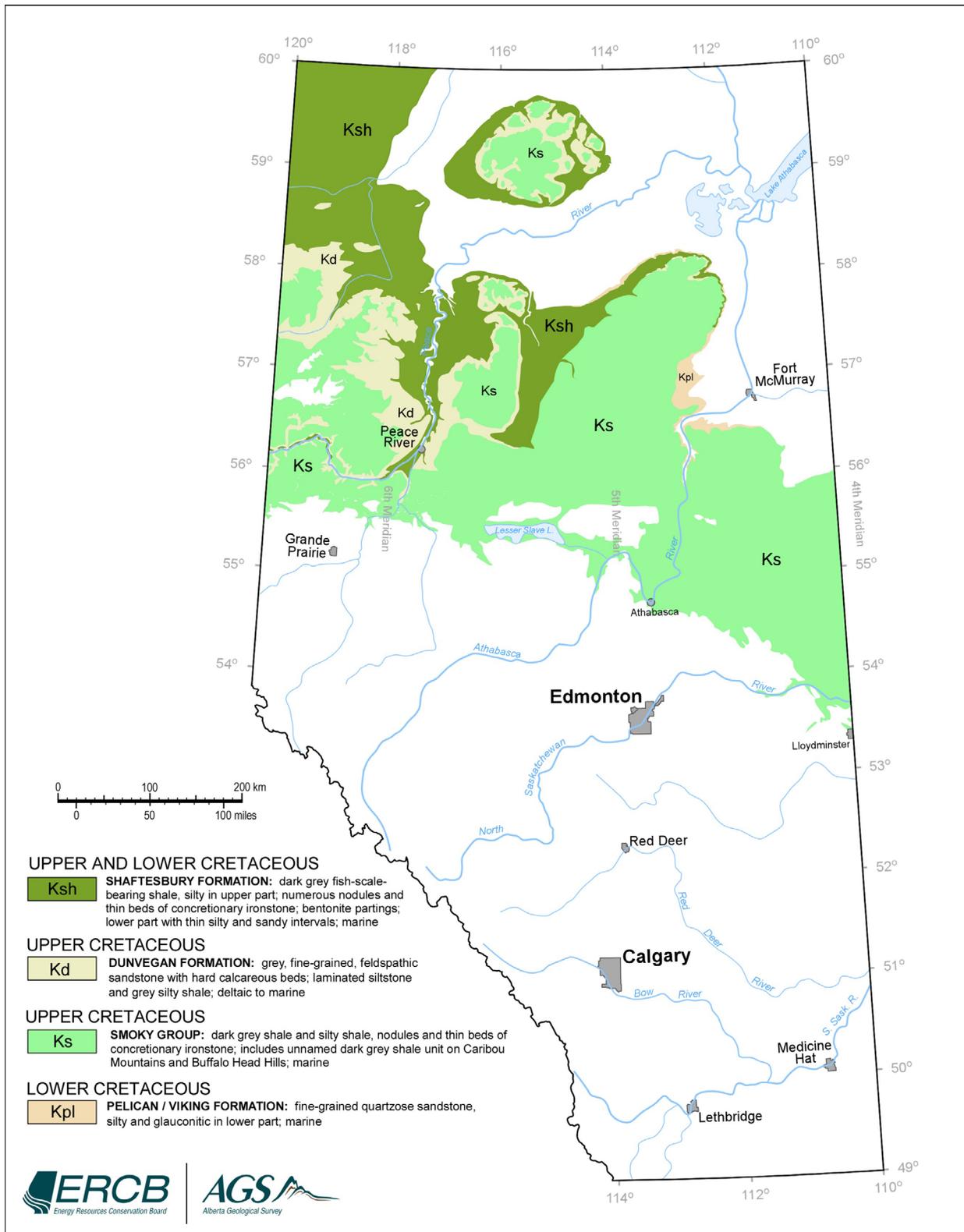


Figure 6. Areas where the Colorado Group bedrock subcrops beneath glacial sediment (*modified after* Hamilton et al., 1999).

Along the Foothills and in the Deep Basin of Alberta, there are numerous Cretaceous shale formations, along with Triassic, Jurassic and even Devonian strata, that may be in a favourable structural setting and are mature enough to qualify as potential for shale gas—although not all are necessarily silty ‘black’ shale. To a large degree, exploration along the Foothills for a Barnett equivalent is a ‘no-brainer,’ but the key is to find similar properties, as is being suggested for the Devonian Muskwa Formation in British Columbia (Duvernay is the approximate equivalent in southern Alberta), rather than locate a play of similar age. An Alberta-made play will have its own suite of characteristics that will make drilling and completion strategies equally unique. Furthermore, silty, organic-rich carbonate mudstone of Devonian and Mississippian age may be a future resource target, but we are not presently aware of a large body of research on organic-rich carbonate mudstone being a ‘shale gas’ target.

3.4 Lewis Shale and Analogues in the WCSB

The Late Cretaceous Lewis Shale Formation in the San Juan Basin has been described as a reservoir with characteristics between those of black shale and ‘tight gas’ sand, in that the productive ‘shale’ interval is dominated by shaly sandstone and siltstone laminations interbedded with silty shale (Dube, 2001). In this respect, Wipf and Party (2006) classified the play as a ‘hybrid’ thermogenic conventional-unconventional shale gas play. The quartz-rich laminations constitute much of the play; therefore, the free gas content may be higher than that of the other shale gas plays (*see* Table 1; Faraj et al., 2004). The shale has a TOC of about 0.5–1.3 wt. % (Dube et al., 2000), which is the lowest of the known major American shale gas plays. Unlike the Barnett, the Antrim or the Appalachian shale plays, the Lewis environment of deposition was probably farther upslope on the continental shelf, with perhaps a more oxygenated water column than the aforementioned classical black shale areas. The environment of deposition of the Lewis is described as “lower shoreface to offshore, open-marine sediment” (Shirley, 2001). The age of the Lewis Shale is Late Campanian to Early Maastrichtian, according to United States Geological Survey data (United States Geological Survey, 2006), and is roughly equivalent to Brazeau Group sedimentary rocks in Alberta, such as the Belly River and Bearpaw Formations.

Matrix porosity of the interbedded shale units in the Lewis Shale (Dube, 2001) is about 1%–2%, with permeability in the range of 10^{-4} millidarcies (mD) and some natural micro- and macrofractures evident. The reservoir is underpressured (0.22 psi/foot)—similar to Colorado Group shale in eastern Alberta (Katsube et al., 2000)—and has a storage capacity of about 22 Bcf per 160 acres. The Lewis Shale is also among the most mature of the American shale gas plays, as indicated by a vitrinite reflectance as high as 1.8%.

An example of a Lewis Shale–like area in Alberta may be the Colorado Group where siltstone/sandstone laminations interbedded with shale are relatively common. In eastern Alberta, for example, there is an interesting area where apparent Cardium-equivalent sediment, within the First White Speckled Shale Formation is producing. The Cardium-equivalent zone now covers about 20–25 townships, not unlike the present extent of the Lewis Shale play. The play is being developed about 200 km east of the Pembina Cardium Field. We suggest a comparable stratigraphic model or category of play to the Lewis Shale, although certainly not as an age equivalent because the Cardium Formation is slightly younger in geological time than the Lewis Shale.

4 Current Shale Gas Resource Estimates in Alberta

There have been a number of estimates of shale gas resources in the province, a few of which are provided here. We did not review the methodology of the estimates. Certainly, the variety of estimates proclaims the large potential for shale gas to add to the provincial resource base. To put these calculations in perspective, the Canadian Gas Potential Committee (2006) estimated Original Gas-in-Place (conventional) for the WCSB to be 464 Tcf, while a coalbed methane resource (CBM) appraisal by Beaton et al. (2002) estimated 506 Tcf of CBM resources in Alberta.

- Gas Technology Institute (Faraj et al., 2002): 86 Tcf gas-in-place using a few formations (Wilrich, Duvernay, Doig/Montney) in northern Alberta
- Canadian Institute Shale Gas Conference (Faraj, (2005): >10 000 Tcf in the Western Canada Sedimentary Basin (WCSB)
- Bustin (2005): >1000 Tcf in the WCSB
- Centre For Energy (2008): ~860 Tcf from a limited number of formations
- AJM Petroleum Consultants (Russum, 2005): ~100–900(?) Tcf in Canada.
- Oilweek (Cope, 2006): ~30,000 Tcf. in the WCSB (British Columbia, Alberta, Saskatchewan).

To date, AGS has released new geochemical and geological data pertaining to the Colorado Group (Figure 7; Table 3, 4) (Beaton et al., 2009a; Pawlowicz et al., 2009a; Rokosh et al. 2009a) and the Banff and Exshaw formations (Figure 8; Table 5, 6) (Beaton et al., 2009b; Pawlowicz et al., 2009b; Rokosh et al. 2009b) that will help in shale gas assessment.

5 Discussion and Conclusion

At present, the most notable areas drilled for shale gas in the WCSB are in northeast British Columbia (B.C.) where the Muskwa Formation in the Horn River Basin has gained considerable attention along with the Montney Formation in east-central British Columbia. Horizontal and vertical drilling is on-going in these formations and gas production testing has yielded considerable success. Initial gas flow rates announced in the Muskwa are comparable to the prolific Barnett shale gas field in the U.S.A., although production facilities in the area are being built so no extended production data is publically available. Horizontal drilling in the Montney Formation has resulted in numerous published examples of economic success with some fields literally abutting the B.C.-Alberta border. Reports on the shale gas potential of the Montney and Muskwa formations in B.C. can be found on the British Columbia Ministry of Energy, Mines and Petroleum Resources website (<http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalOilAndGas/Pages/Shale.aspx#studies>). In Alberta, there are Montney ‘shale’ gas wells drilled, but the number of wells drilled is not to the extent seen in British Columbia.

With respect to water resources, the Ground Water Protection Council (GWPC; www.gwpc.org) of the U.S.A. recently published a report entitled ‘Modern Shale Gas Development in the United States: A Primer’ (<http://www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf>). According to the authors, the primer discusses the “regulatory framework, policy issues, and technical aspects of developing unconventional shale gas resources,” including water use and environmental aspects related to horizontal drilling and hydraulic fracturing.

In conclusion, Alberta has numerous packages of thick shale that have characteristics suitable for shale gas generation and production. Although shale gas production in the U.S.A. is well established, preliminary results in Alberta suggest that shale gas has the potential to contribute to Alberta’s gas resource base.

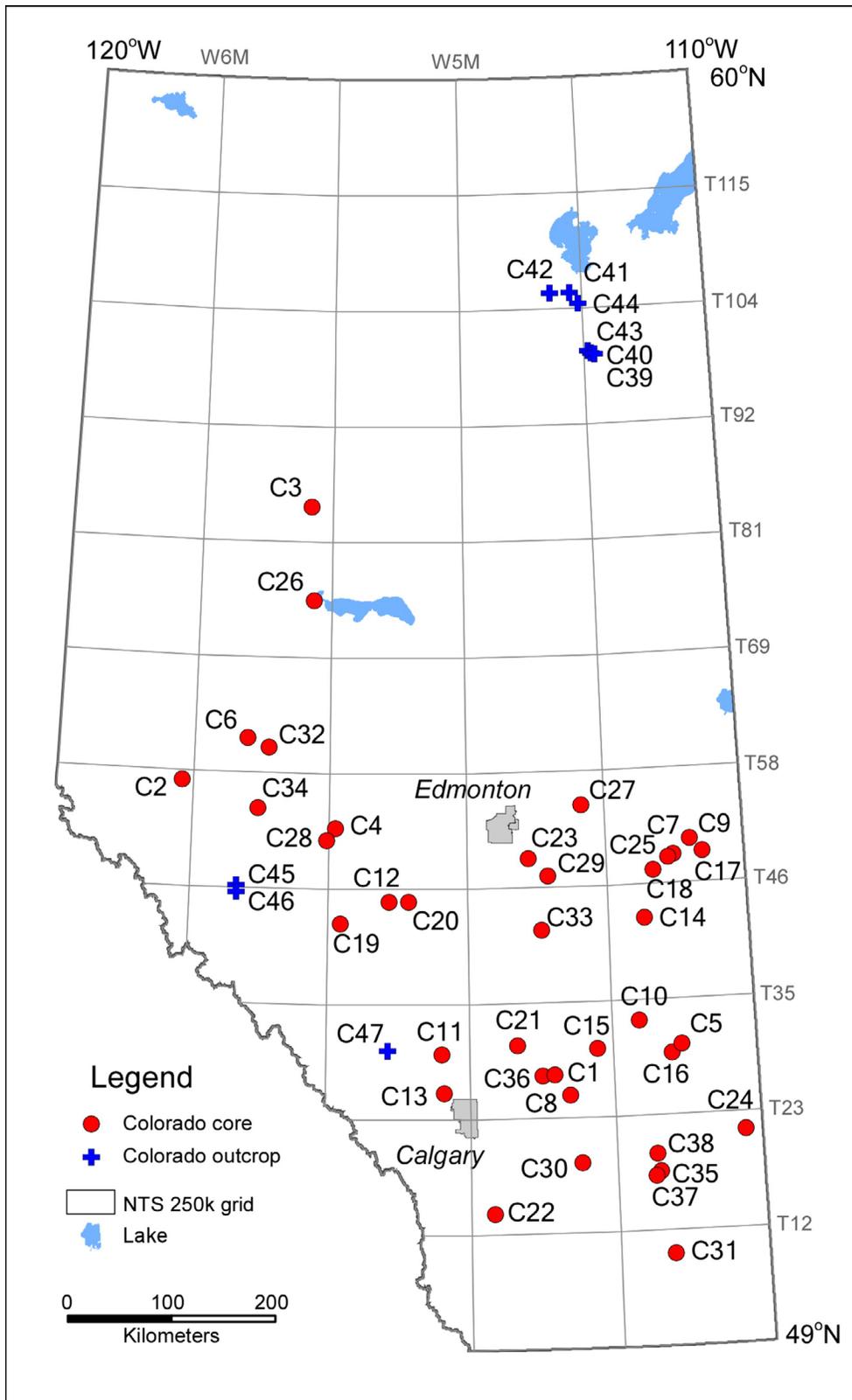


Figure 7. Location of sample sites for Colorado Group shale. See Tables 3 and 4 for locations.

Table 3. Colorado Group core locations. See also Figure 7.

Site No.	Unique Well ID	Latitude (NAD 83)	Longitude (NAD 83)	Year Drilled	No. of Samples	Group
C01	100/04-11-028-22W4/00	51.375371	-113.000011	2002	6	Colorado
C02	100/04-13-057-02W6/00	53.921709	-118.170803	1962	4	Colorado
C03	100/04-29-084-15W5/00	56.306578	-116.343167	1952	6	Colorado
C04	100/04-31-052-13W5/00	53.530131	-115.912450	2002	2	Colorado
C05	100/05-03-030-09W4/00	51.537186	-111.196063	1946	4	Colorado
C06	100/05-27-061-22W5/00	54.301586	-117.223691	1997	4	Colorado
C07	100/05-30-049-07W4/00	53.252497	-111.024094	2005	2	Colorado
C08	100/06-08-026-19W4/00	51.202794	-112.626775	1980	15	Colorado
C09	100/06-11-051-06W4/00	53.385156	-110.785097	2006	2	Colorado
C10	100/06-15-033-12W4/00	51.827959	-111.624249	1980	6	Colorado
C11	100/06-17-030-03W5/00	51.568035	-114.390524	1982	7	Colorado
C12	100/06-20-045-08W5/00	52.892068	-115.129927	1979	2	Colorado
C13	100/06-21-026-03W5/00	51.233362	-114.365477	1983	6	Colorado
C14	100/06-23-043-11W4/00	52.716098	-111.492145	2004	8	Colorado
C15	100/06-29-030-16W4/00	51.595231	-112.225340	1969	5	Colorado
C16	100/06-34-030-08W4/00	51.609735	-111.052456	1969	6	Colorado
C17	100/06-36-049-05W4/00	53.268492	-110.606221	2004	3	Colorado
C18	100/07-12-048-10W4/00	53.124039	-111.332969	2004	7	Colorado
C19	100/07-16-043-13W5/00	52.703956	-115.824539	2006	3	Colorado
C20	100/07-19-045-06W5/00	52.892373	-114.854086	1979	16	Colorado
C21	100/08-09-031-24W4/00	51.639470	-113.338736	1952	2	Colorado
C22	100/08-24-014-28W4/00	50.184105	-113.687534	1998	4	Colorado
C23	100/08-27-049-22W4/00	53.254931	-113.128424	2004	4	Colorado
C24	100/09-05-022-02W4/00	50.844880	-110.240286	2004	1	Colorado
C25	100/09-16-049-08W4/00	53.229438	-111.107681	2005	6	Colorado
C26	100/12-16-075-15W5/00	55.499583	-116.274312	1950	7	Colorado
C27	100/12-32-054-16W4/00	53.709219	-112.332668	2004	9	Colorado
C28	100/13-20-051-14W5/00	53.421052	-116.035361	2003	6	Colorado
C29	100/13-34-047-20W4/00	53.102458	-112.853229	2005	4	Colorado
C30	100/14-18-019-18W4/00	50.612334	-112.488539	2004	6	Colorado
C31	100/15-03-010-10W4/00	49.798865	-111.277533	1949	3	Colorado
C32	100/15-27-060-20W5/00	54.221784	-116.911727	1982	4	Colorado
C33	100/16-21-042-21W4/00	52.634819	-112.960441	1979	10	Colorado
C34	100/16-29-054-21W5/00	53.697805	-117.053719	1980	5	Colorado
C35	102/03-14-018-11W4/00	50.515811	-111.418574	2004	4	Colorado
C36	102/10-12-028-21W4/00	51.381280	-112.830199	2004	2	Colorado
C37	102/11-32-017-11W4/00	50.480595	-111.484723	2003	8	Colorado
C38	102/13-03-020-11W4/00	50.670811	-111.457734	2004	4	Colorado

Table 4. Colorado Group outcrop locations. See also Figure 7.

Site No.	Datum	UTM Zone	Easting	Northing	Site Location Name	No. of Samples	Group
C39	NAD83	12	446778	6385401	Birch Mtns. (NTS 84I)	1	Colorado
C40	NAD83	12	449178	6384521	Birch Mtns. (NTS 84I)	1	Colorado
C41	NAD83	12	429162	6444821	Birch Mtns. (NTS 84I)	1	Colorado
C42	NAD83	12	410496	6444999	Birch Mtns. (NTS 84I)	3	Colorado
C43	NAD83	12	443512	6387776	Birch Mtns. (Asphalt Creek)	16	Colorado
C44	NAD83	12	436680	6434329	Birch Mtns. (Greystone Creek)	22	Colorado - Shaftesbury
C45	NAD83	11	478167	5875014	Cadomin (railroad section)	30	Colorado - Blackstone

Table 5. Banff and Exshaw formations core locations. See also Figure 8.

Site No.	Unique Well ID	Latitude (NAD 83)	Longitude (NAD 83)	Year Drilled	No. of Samples	Formation
B01	100/01-20-001-24W4/00	49.045566	-113.165460	1981	3	Banff
B02	100/02-14-082-02W6/00	56.103477	-118.193028	1950	6	Banff
B03	100/02-28-094-09W6/00	57.179218	-119.376578	1952	6	Banff
B04	100/04-23-072-10W6/00	55.245950	-119.431068	1972	4	Banff
B05	100/06-04-084-07W6/00	56.252096	-119.047260	1974	2	Banff
B06	100/07-08-074-14W5/00	55.394566	-116.113837	1949	8	Banff
B07	100/08-08-076-07W6/00	55.568451	-119.040018	2002	2	Banff
B08	100/08-27-039-11W5/00	52.383168	-115.491096	1955	14	Banff
B09	100/08-30-082-02W6/00	56.135519	-118.293350	1985	3	Banff
B10	100/09-06-052-11W5/00	53.463004	-115.601615	1954	8	Banff
B11	100/12-36-030-22W4/00	51.614422	-112.978894	1950	4	Banff
B12	100/15-05-107-08W6/00	58.264601	-119.290939	2001	4	Banff
B13	100/15-27-098-25W5/00	57.539368	-117.965423	2002	1	Banff
B14	100/16-18-107-06W6/00	58.296137	-118.982929	1954	2	Banff
B15	100/16-24-077-06W6/00	55.693279	-118.777249	1986	3	Banff
B16	102/06-02-079-22W5/00	55.817907	-117.332954	1984	2	Banff

Table 6. Banff and Exshaw formations outcrop locations. See also Figure 8.

Site No.	Datum	UTM Zone	Easting	Northing	Site Location Name	No. of Samples	Formation
B17	NAD 83	11	567642	5816426	Nordegg – railroad section	30	Banff, Exshaw
B18	NAD 83	11	539339	5769916	Kootenay Plains – mountain section	1	Banff
B19	NAD 83	11	628902	5661581	Jura Creek – Exshaw type section	28	Banff, Exshaw

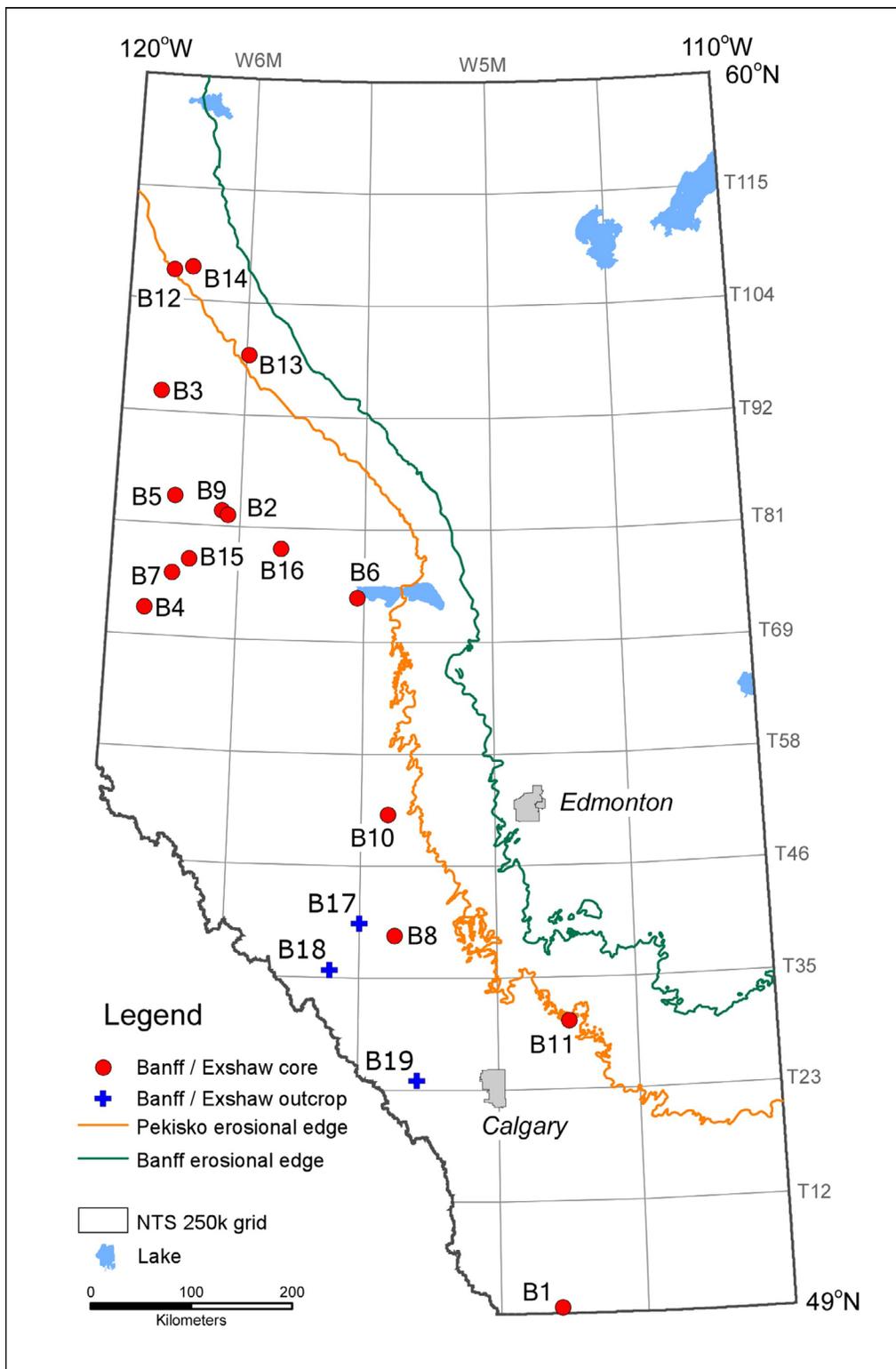


Figure 8. Location of Banff-Exshaw outcrop sample sites and subsurface core well locations. See also Tables 5 and 6 for locations.

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