Carbon dioxide storage capacity in uneconomic coal beds in Alberta, Canada: Methodology, potential and site identification

Stefan Bachu*
Alberta Energy and Utilities Board, Edmonton, Alta. T6B 2X3, Canada

Abstract
Methodology is presented for a first-order regional-scale estimation of CO2 storage capacity in coals under sub-critical conditions, which is subsequently applied to Cretaceous-Tertiary coal beds in Alberta, Canada. Regions suitable for CO2 storage have been defined on the basis of groundwater depth and CO2 phase at in situ conditions. The theoretical CO2 storage capacity was estimated on the basis of CO2 adsorption isotherms measured on coal samples, and it varies between ~20 kt CO2/km2 and 1260 kt CO2/km2, for a total of approximately 20 Gt CO2. This represents the theoretical storage capacity limit that would be attained if there would be no other gases present in the coals or they would be 100% replaced by CO2, and if all the coals will be accessed by CO2. A recovery factor of less than 100% and a completion factor less than 50% reduce the theoretical storage capacity to an effective storage capacity of only 6.4 Gt CO2. Not all the effective CO2 storage capacity will be utilized because it is uneconomic to build the necessary infrastructure for areas with low storage capacity per unit surface. Assuming that the economic threshold to develop the necessary infrastructure is 200 kt CO2/km2, then the CO2 storage capacity in coal beds in Alberta is greatly reduced further to a practical capacity of only ~800 Mt CO2.

1. Introduction
Reducing atmospheric emissions of the main greenhouse gases, CO2 and methane, is one of the main climate-change mitigating measures considered by society, with most efforts being currently focused on reducing CO2 emissions. A significant increase in the capacity of carbon sinks and of their capture rate is the single major means of reducing net carbon emissions into the atmosphere in the short to medium term, although it is recognized that no single category of mitigation measures is sufficient (Socolow, 2005). Even for the long term, on the basis of scarcity of other forms of energy and abundance of fossil fuels, particularly coal in North America, China and India, which are already or are becoming the largest CO2 emitters in the world, the current thinking is that “clean coal”, coal-to-liquids (CTL) and coal-to-gas (coal gasification) will provide most of the energy needs for power generation and a significant portion of transportation fuels, with CO2 as a byproduct. Utilization of coal for energy production in various forms is also seen as a strategic approach to ensure energy security. However, CO2 is a major byproduct of energy production from coal, and the forecasted major increase in CO2 emissions has to be tackled sooner rather than later to forestall the increase in atmospheric concentrations of CO2 above acceptable limits (Hawkins and Bachu, 2006).

Carbon dioxide capture and geological storage (CCGS) presents the possibility of enhancing both the capacity and the capture rate of geological media (IEA, 2004; IPCC, 2005; Socolow, 2005). It can be achieved through a combination of physical and chemical trapping mechanisms (IPCC, 2005, and...
references quoted therein), including adsorption onto coal. This particular means of CO₂ storage, although technologically immature (IPCC, 2005), has two major advantages if proven successful: it is located in the vicinity of many current or future coal-fired power plants, thus reducing transportation costs, and will produce coalbed methane (CBM), which is a cleaner fossil fuel than coal (CBM should not be vented because it is also a stronger greenhouse gas than CO₂).

In Canada, Alberta’s CO₂ emissions are the highest in the country (Environment Canada, 2006) mainly as a result of coal-fired power generation and energy production. Fortunately, most of Alberta is underlain by the Alberta Basin, which, besides having many deep saline aquifers, is rich in oil and gas reservoirs and coal beds, thus providing many opportunities for CCGS (Bachu and Stewart, 2002; Bachu, 2003). Of the various CO₂ storage options, enhanced hydrocarbon recovery (EHR) presents the added benefit of producing additional energy resources (oil or CBM); thus it represents an attractive target for the initiation of large-scale CO₂ storage. The CO₂ storage capacity in oil and gas reservoirs in western Canada, including Alberta, has been studied recently (e.g., Bachu and Shaw, 2005). This study presents methodology for, and the results of, evaluating the theoretical, effective and practical CO₂ storage capacity (Bradshaw et al., 2007; Bachu et al., 2007) in coal beds in Alberta, with the aim of identifying the areas with large storage potential. Although the application is specific to Alberta, the methodology can be easily adapted and applied to other coal-rich regions around the world.

2. Methodology for CO₂ storage assessment and site selection

2.1. Identification of coal beds suitable for CO₂ storage

Any geological site for CO₂ storage, including coal beds, must possess the following characteristics:

(1) sufficient capacity, for accepting the large volumes of CO₂ that need to be stored;
(2) adequate injectivity, to allow introduction of CO₂ into the subsurface at the rates that CO₂ is delivered from large stationary CO₂ sources;
(3) containment, to retain the CO₂ for the desired period of time (i.e., avoidance of leakage);
(4) resource protection (i.e., even if a potential storage site meets the previous conditions, it may be unacceptable if in the process other resources are being jeopardized).

In addition, sites for CO₂ storage in coal beds and CBM recovery should (Gale and Freund, 2001):

• have low water saturation (coals with low water saturation are preferable because the coal seam has to be dewatered before it can be used for storage);
• have high gas saturation (from a methane-production perspective);
• have concentrated coal deposits (fewer, thick seams); however, more recently this criterion has been challenged because thick coals could be mined at some time in the future, thus, rather than sterilize a potential resource, multiple thin coal seams should be used (Frailey et al., 2006);
• be unmineable, now or in the future. Unmineable coals are coals that are too thin, too deep, or too unsafe to mine; they may be too high in sulphur or mineral matter, or be too low in heat value to be economically profitable (Byrer and Guthrie, 1998).

This set of criteria has been specifically applied in the identification of suitable CO₂ storage sites in Alberta’s coal beds. Shallow coals generally are not suitable for CO₂ storage because they may be mined in the future in open pits, or they may form shallow groundwater aquifers that are used for agricultural, industrial, and/or domestic purposes. Thus, only coals deeper than a few hundred metres should be considered for CO₂ storage.

Coal permeability is a determining factor in the viability of a CO₂ storage site. It varies widely and generally decreases with increasing depth as a result of cementation and increasing effective stress (McKee et al., 1988; Enever et al., 1994, 1999; Sparks et al., 1995; Bustin, 1997). Low permeability is likely to be a problem with deep coal seams, in that the permeability of coal beds deeper than 1500 m is generally below what is presently required for economic CBM production (Zuber et al., 1996) and CO₂ storage. Significantly, the economic cut-off for the production of CBM using standard dewatering for pressure reduction has been estimated as a permeability of 1 mD (Zuber et al., 1996) and most CBM-producing wells in the world are less than 1000 m deep. Thus, based on coal permeability alone, the depth limit for CO₂ storage in coal beds is somewhere in the 1000–1500 m window, depending on coal depositional history, stress regime and rock properties. However, CBM producibility could be enhanced through coal fracturing.

Coal permeability is further affected by the gas with which it is in contact (White et al., 2005), being reduced by up to two orders of magnitude in the presence of gaseous CO₂ as a result of swelling (Clarkson and Bustin, 1997; Palmer and Mansoori, 1998; Larsen, 2003; Shi and Durucan, 2005; Wo and Liang, 2005; Cui et al., in press). Furthermore, CO₂ is a “plasticizer” for coal, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure (“coal softening”; Larsen, 2003), destroying any pre-existing permeability that would have allowed CO₂ injection. The transition temperature may drop from ~400 °C at 3 MPa to <30 °C at 5.5 MPa (550 m water column equivalent) (Larsen, 2003). These effects likely depend on coal type, rank and characteristics, but, nevertheless, they negatively affect the CO₂ storage in coal beds. The process of CO₂ trapping in coals for temperatures and pressures above the critical point is much less understood and it seems that CO₂ absorption and dissolution in coal become significant (Larsen, 2003).
Coal swelling when CO$_2$ is injected, the current lack of understanding of adsorption or absorption processes for liquid and supercritical CO$_2$, and the potential for coal plasticization in the presence of CO$_2$ at high pressure and temperature, all indicate that, unless significant advances in science and technology are made, only coals at in situ temperature and pressure conditions where CO$_2$ is in gaseous phase should be considered for the time being as suitable for CO$_2$ storage. These constraints reduce the depth window for CO$_2$ storage in coal beds to a range of a few hundred metres to less than 1000 m depth. It should be noted that Burlington Resources ran a pilot project at the Allison field in the San Juan Basin in the USA from 1995 to 2001, where CO$_2$ was injected at 950 m depth (Reeves and Schoeling, 2001), and a pilot project in Canada has injected CO$_2$ at 1250 m depth (Gunter et al., 2005).

Once potential CO$_2$ storage sites are identified on the basis of the above technical and engineering criteria, the choice of a specific site involves a detailed assessment of source quality and quantity, transportation, and integration with economic and environmental factors. If the site is too distant from CO$_2$ sources or is associated with a high level of technical uncertainty, then its storage potential may never be realized. Thus, in addition to the previous intrinsic criteria, the selection of CO$_2$ storage sites and matching with CO$_2$ sources should consider the following extrinsic criteria (Kovscek, 2002): volume, purity and rate of the CO$_2$ stream; proximity of the source and storage/sites; level of infrastructure for CO$_2$ capture and delivery; existing wells, for injection and for leak prevention; injection and production strategies; terrain and right of way; proximity to population centres; and overall costs, and economics.

### 2.2 Estimation of CO$_2$ storage capacity

Two parameters are determinant in evaluating a CBM or a CO$_2$ storage prospect: the total gas in place and reservoir deliverability (White et al., 2005). Once suitable coal beds have been identified, the next step is to estimate the CO$_2$ storage capacity. In the case of a gas already adsorbed by the coal, like CBM, the initial gas in place (IGIP) is usually calculated with the relation (e.g., van Bergen et al., 2001; White et al., 2005):

$$ IGIP = AhCf GC\left(1 - f_a - f_m\right) $$

(1)

where $A$ and $h$ are the area and effective thickness of the coal zone, respectively, $C = C_b$ the bulk coal density, $f_a$ is the coal gas content, and $f_a$ and $f_m$ are the ash and moisture weight fraction of the coal, respectively.

For a given temperature, the relation between pressure $P$ and gas content at saturation, $G_{CS}$, is generally assumed to follow a pressure-dependent Langmuir isotherm of the form:

$$ G_{CS} = V_L \frac{P}{P + P_L} $$

(2)

where $V_L$ and $P_L$ are Langmuir volume and pressure, respectively. The Langmuir isotherm expressed by Eq. (2) displays an increase in adsorption capacity with increasing pressure $P$ as the gas content $G_{CS}$ tends asymptotically toward $V_L$, the maximum gas adsorption capacity of a particular coal at the given temperature. This behavior reflects mono-layer adsorption on a surface, where the maximum represents the state of a completely covered surface that cannot adsorb any more gas molecules. On the other hand, the gas adsorption capacity decreases with increasing temperature (Bustin and Clarkson, 1998), and, since both pressure and temperature increase with depth, after a certain depth the gas adsorption capacity decreases. Inorganic matter (ash) and water present in the coal reduces its adsorption capacity (White et al., 2005), and this effect is taken into account in Eq. (1). If a coal seam is fully saturated with gas, then $G_C$ in Eq. (1) equals $G_{CS}$ in Eq. (2), otherwise $G_C < G_{CS}$.

In the case of CO$_2$ storage in coal beds, the basic assumption is that CO$_2$ will replace methane and other hydrocarbon gases present in the coal as a result of coal’s higher affinity for CO$_2$ than for these gases. Although, unlike methane, CO$_2$ dissolves in water, it is considered that the amount of CO$_2$ that may dissolve in the water contained in the coal cleats, if the coals are wet, can be neglected by comparison with the amount that can be stored through adsorption, since the coal microporosity is much higher than cleat porosity. Thus, Eq. (1) can be used in a reverse mode to estimate the maximum theoretical capacity for CO$_2$ storage of a coal bed if CO$_2$ Langmuir isotherms are known. To express the CO$_2$ storage capacity in mass rather than volume of CO$_2$, the result has to be multiplied by CO$_2$ density at standard conditions of 1.873 kg/m$^3$. This represents the theoretical storage capacity limit that would be attained if all the coals will be accessed by CO$_2$ and will adsorb CO$_2$ to 100% saturation. In reality these conditions will not be met, hence the need to reduce the theoretical storage potential to a more realistic estimate, which represents the effective storage capacity, that is similar to the reduction of initial gas in place (IGIP) to producible gas in place (PGIP) in the case of CBM production, according to (van Bergen et al., 2001):

$$ PGIP = R_C C G_{IGIP} $$

(3)

where $R_C$ is the recovery factor and $C$ is the completion factor, and together they express the reservoir gas deliverability. The completion factor $C$ represents an estimate of that part of the net cumulative coal thickness within the drilled coal zone that will contribute to gas production, it strongly depends on the individual thickness of the separate coal seams and on the distance between them, and is lower for thin coal seams than for thick ones. The recovery factor $R_C$ represents the fraction of gas that can be produced from the coal seams. In conventional CBM production, $R_C$ strongly depends on the pressure drop that can be realized by pumping out large volumes of water (coal dewatering) and ranges between 20% and 60% (van Bergen et al., 2001). Given the higher coal affinity for CO$_2$ than for methane, it is assumed that the recovery factor will increase significantly in CO$_2$ EBM operations and will be higher than 60%.

It is highly unlikely that all the effective CO$_2$ storage capacity in coal zones will be utilized because it is uneconomic to build the necessary infrastructure (pipelines, compressors and a high density of injection and production wells) for areas with low storage capacity. By identifying areas with CO$_2$
storage capacity per unit surface greater than a particular threshold limit, the effective storage capacity is reduced to practical CO2 storage capacity. Finally, case-by-case evaluations using economic considerations, location of CO2 sources, various regulatory requirements, and numerical and economic modelling, will identify specific CO2 storage sites that can be matched with specific CO2 sources, and their cumulative capacity constitutes the matched CO2 storage capacity.

This discussion about the identification of coal beds suitable for CO2 storage and estimating their storage capacity points out that, while the principles are straightforward, application to various basins and/or jurisdictions around the world depends on specific coal properties and characteristics and on a series of factors that have to be determined locally and through the application of specific economic and regulatory constraints, in conjunction with the estimation, based on experience and modelling, of various coefficients such as recovery and completion factors, and threshold storage capacity per unit surface that will make a project economic.

3. CO2 storage potential in coal beds in Alberta

Most of Alberta is underlain by the Alberta Basin, which was initiated during the late Proterozoic by rifting of the North American craton, and which comprises a wedge of sedimentary rocks that increases in thickness from zero at the edge of the Canadian Shield in the northeast to more than 6000 m at the edge of the Rocky Mountain Thrust and Fold Belt in the

Fig. 1 – Location of coal beds in Alberta, Canada: (a) areal extent of the three most important coal zones, including coalfields and (b) stratigraphic position in the sedimentary succession.
southwest. The basin consists of a passive-margin succession, dominated by carbonate and evaporite deposition with some intervening shale, followed by a foreland-basin succession dominated by clastic deposition since the middle Jurassic. Peat accumulated in the Alberta Basin during the Columbian and Laramide orogenies in the late Jurassic – early Cretaceous and the late Cretaceous – early Tertiary, respectively. Coal rank is the result of burial only, and ranges from lignite to high-volatile bituminous in rank, generally increasing in rank from east to west, consistent with increasing depth (Bustin, 1991). The coal seams dip to the west and occur at depths ranging from surface outcrop to more than 3000 m. The areal extent and stratigraphic location of various coal zones in Alberta are shown in Fig. 1. Lower Cretaceous Mannville coals are mined in surface mines in the Rocky Mountain Thrust and Fold Belt in Alberta and British Columbia where thrusting and folding brought them to the surface. Upper Cretaceous-Tertiary coals are or were mined in Alberta plains in open pit mines or shallow underground mines along the outcrop of the various coal zones (Fig. 1a).

The CBM potential was estimated for the Upper Cretaceous-Tertiary coal zones (Table 1) (Beaton et al., 2002). The estimated CBM potential of the Lower Cretaceous Mannville coals is by far the largest of all coal zones in Alberta’s plains at 320 Tcf (> 9 x 10^12 m^3) (Beaton, 2003). However, this figure encompasses the entire areal extent of the Upper Mannville Coal Zone (Fig. 1a) down to depths close to 3500 m. If only coals at depths less than 1500 m are considered because the permeability of deeper coals is too low to allow production, then the estimate of potential gas in place drops to 144 Tcf (> 4 x 10^12 m^3). Since coal thickness and gas content are an indicator for the potential for CO2 storage, the data suggest that the only coal beds that may possess CO2 storage capacity worth of consideration are the coals of the Ardley, Drumheller and Mannville coal zones. The other coal zones, larger in area but with smaller CBM potential, are thin, discontinuous and with limited and very localized CO2 storage potential. This is reflected also in the fact that more than 99% of the ~7000 CBM wells drilled in Alberta to date are in these three coal zones. Consequently, only the Ardley, Drumheller and Mannville coal zones were assessed for CO2 storage potential. Application will be illustrated for the Ardley coal beds only, the other being similar but less representative.

### Table 1 – Summary of coal and gas potential for Upper Cretaceous-Tertiary coals in the Alberta plains region, Canada (from Beaton et al., 2002)

<table>
<thead>
<tr>
<th>Coal zone</th>
<th>Area (10^3 km^2)</th>
<th>Coal tonnage (Gt)</th>
<th>GIP (Tcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ardley</td>
<td>59</td>
<td>596</td>
<td>50.6</td>
</tr>
<tr>
<td>Carbon-Thompson</td>
<td>76</td>
<td>183</td>
<td>12.8</td>
</tr>
<tr>
<td>(CRB-THM)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Daly-Weaver</td>
<td>76</td>
<td>178</td>
<td>12.4</td>
</tr>
<tr>
<td>Drumheller</td>
<td>128</td>
<td>564</td>
<td>33.0</td>
</tr>
<tr>
<td>Lethbridge</td>
<td>170</td>
<td>277</td>
<td>8.7</td>
</tr>
<tr>
<td>Taber</td>
<td>190</td>
<td>335</td>
<td>11.0</td>
</tr>
<tr>
<td>McKay</td>
<td>212</td>
<td>403</td>
<td>18.7</td>
</tr>
</tbody>
</table>

GIP: gas-in-place, Gt: giga tonnes, Tcf: trillion cubic feet (1 Tcf = 28.316 x 10^9 m^3).

3.1. Coal characteristics

#### 3.1.1. Ardley Coal Zone

The coal zone dips southwestward, like all the strata in the Alberta basin. The depth to the top of the Ardley Coal Zone (Fig. 2a) reflects the combined effect of topography and of southwestward dipping strata. Depth varies between a few metres under the Quaternary drift at outcrop at the top of the bedrock in the east, to more than 1000 m in the west at the eastern limit of the thrust and Fold Belt. The coal zone comprises 8–34 individual coal seams that vary in thickness between less than 0.5 and 11.0 m. The cumulative coal thickness varies between 0.5 m and more than 20 m (Fig. 2b). The total thickness of the Ardley Coal Zone, comprising the coal seams and intervening layers, varies between 0.5 m at outcrop and 265 m. The geometry and thickness of the Ardley Coal Zone is based on data from 2365 wells that penetrate and record it.

Coal rank within the Ardley Coal Zone ranges from subbituminous C near outcrop in the east (reflectance less than 0.5%) to high-volatile bituminous B in the west at its deepest, but most of the Ardley coals are high-volatile bituminous C in rank (reflectance 0.5–0.65%). Ardley coals are mined in open-pit mines for power generation in west-central Alberta.

The Scollard–Paskapoo sandstones that host the Ardley Coal Zone form an unconfined aquifer, with the flow of formation water being driven by topography (Bachu and Michael, 2003). Given the meteoric origin of formation water, salinity in these areas is low, less than 2000 mg/L. Water in these strata is defined as potable groundwater and, as such, is protected under provincial regulations. The coals are “wet”, i.e., water-saturated, and low-salinity fresh water will be produced concurrent with CBM production and CO2 storage. Given the low salinity of this water, it may be possible to dispose of it at the surface. Pressures in the Ardley Coal Zone are generally hydrostatic, increasing linearly with depth from the water table with a gradient of ~9.8 kPa/m. The distribution of pressures at the base of the Ardley coals (Fig. 2c) reflects the depth of the Ardley Coal Zone from the water table and its total thickness. Pressures reach more than 7380 kPa (CO2 critical pressure) only in its deepest part close to the Rocky Mountain deformation front (Fig. 2c).

Temperatures (T) at the base of the Ardley Coal Zone were determined on the basis of multi-annual ground surface temperatures in the 5–7°C range, distribution of average geothermal gradients in the area (Bachu and Burwash, 1991), and depth, according to the relation:

\[ T = T_S + GD \]

where \( T_S \) is the multi-annual ground surface temperature, \( G \) is geothermal gradient, and \( D \) is depth. Temperatures at the base of the Ardley Coal Zone barely reach 31.1°C in the west adjacent to the Rocky Mountain deformation front (Fig. 2d).

#### 3.1.2. Drumheller Coal Zone

Depth to this coal zone varies from less than 41.3 m at outcrop under Quaternary sediments in the east to ~1900 m in the west at the Rocky Mountain deformation front. Cumulative
coal thickness varies from less than 1 m in the west and northwest to more than 35 m in the east close to outcrop. The total thickness of the Drumheller Coal Zone, comprising the coal seams and intervening layers, varies between less than 1 m at outcrop and 288 m. Coal rank reflects depth of burial and varies from subbituminous C in the east to high-volatile C in the west. These coals are mined at shallow depths for power generation (Fig. 1a) and also are currently the main target for CBM exploration and production in Alberta. However, certain shallow porous and permeable sandstone and coal aquifers, many of which are fractured, represent a prime source of groundwater.

The flow of formation water in the deep parts of the Horseshoe Canyon Formation, which hosts the Drumheller Coal Zone, is driven downdip, inward toward the Rocky Mountain deformation front by erosional and post-glacial rebound (Bachu and Michael, 2003). This flow system is severely undepressed, with undepressing increasing toward the Rocky Mountains. Capillary sealing between downdip gas-saturated sandstones and updip water-saturated sandstones, and low permeability depositional barriers create flow barriers that impede the inward flow of meteoric water from outcrop areas in the east that would equilibrate pressures with current basin topography (Bachu and Michael,
2003). Because fresh meteoric water did not penetrate the deep portion of this aquifer to dilute the original connate water, the salinity of formation waters in this area is relatively high (between 5000 and 18,000 mg/L) compared to outcrop areas where it is less than 2000 mg/L. Thus, formation water in the recharge and outcrop areas of this aquifer qualifies as protected potable groundwater (salinity <4000 mg/L), while formation water in the deep central areas of the aquifer does not.

Pressures at the base of the Drumheller Coal Zone vary from less than 500 kPa at the eastern edge of the coal zone, to ~17,000 kPa near the Rocky Mountain deformation front at ~1900 m depth. Underpressuring, however, is not uniform, reaching more than 6000 kPa in western Alberta. As a result of underpressuring and of the permeability and capillarity barriers to recharge by meteoric water, the coals in the Drumheller Coal Zone are gas-saturated, such that no water is produced with CBM, obviating the need for water disposal. Only in outcrop areas these coals are water wet, forming shallow aquifers. The underpressuring reduces the gas content of the coal seams because less gas is adsorbed onto the coal at lower pressures, hence lower than normal CO2 storage capacity should be expected in the Drumheller Coal Zone than for identical coals under hydrostatic conditions. Temperatures at the base of the Drumheller Coal Zone vary from 8 °C in the east to ~60 °C in the west near the Rocky Mountain deformation front.

3.1.3. Mannville Coal Zone

Depth to the top of the Upper Mannville Coal Zone varies from less than ~475 m in the northeast to ~3600 m in the southwest at the Rocky Mountain deformation front. Coal seams, varying in number from 1 to 15, have a cumulative thickness that ranges from 0.2 to 16.5 m, with the thickest coals found in west-central Alberta. The total thickness of the Upper Mannville Coal Zone, comprising the coal seams and inter-vening layers, varies between 0.2 and 72.2 m. Coal rank reflects the depth of burial and ranges from lignitic and sub-bituminous C in the northeast (reflectance 0.3–0.4%) to low-volatile bituminous in the west at its deepest point (reflectance >1.5%), but most of the Mannville coals are subbituminous to high-volatile bituminous.

Flow in the Mannville aquifer system is the most complex of all coal-bearing strata in the Alberta basin. A basin-scale, long-range flow system is present in the eastern part of the area where coal seams occur, driven north-northwestward long-range flow system is present in the eastern part of the Alberta basin. A basin-scale, long-range flow system is present in the Mannville Group strata. Gradients of the minimum horizontal stress are mostly in the 16–18 kPa/m range (Bell and Bachu, 2003). The effective stress, \( \sigma_{ef} \), which controls cleat aperture and coal permeability, is given by:

\[
\sigma_{ef} = \sigma - P
\]

where \( \sigma \) is stress, and increases with depth with a gradient of 6–8 kPa/m in hydrostatically pressured strata, closing coal cleats (fractures) and decreasing permeability. If the pore space is underpressured, as is the case of most of the Drumheller and Mannville coal zones, then the coals take on, correspondingly, more effective stress, closing further the cleats, with a net effect of even lower permeability.

Although coal permeability is one of the most critical parameters for CBM production, there is very little information regarding the permeability of the deeper coal beds in the Alberta basin, but the available data generally indicate indeed low permeability (Dawson, 1995). Fig. 3a shows the variation with depth of coal permeability data that are currently available in the public domain, variation that can be expressed by the empirical relationship:

\[
\ln(k) = 83.065D^{-0.686}
\]

where \( k \) is permeability. In the depth range of interest, coal permeability is low, in the order of a few millidarcies, and only shallow coals, less than 100 m deep, have higher permeability, in the order of darcies, but these coals are fractured and generally they constitute shallow groundwater aquifers.

The maximum and minimum horizontal-stress orientations have a direction generally perpendicular and parallel to
the Rocky Mountain deformation front, respectively (Bell and Bachu, 2003), as indicated also by the direction of face cleats identified in coal mines (Campbell, 1979). These cleats will tend to be open and provide preferred flow paths for water and/or gas (methane or CO2). The orientation of stress trajectories is an excellent indicator of the direction of coal cleat directions in a southwest-northeast direction and of similar permeability anisotropy in the coal bedding planes.

There is a scarcity of CO2 adsorption isotherm data for coals in Alberta. The very few existing analyses in the public domain, summarized in Table 2, were performed in the last several years, spurred by the interest in the potential for CO2 enhanced CBM recovery. The coal samples were preserved in the field at the time of drilling and the measurements were performed at in situ temperature conditions on the samples as received (including ash and moisture), and dry, ash free (Table 2), using the methodology described in Clarkson and Bustin (2000). The variability in Langmuir volumes is most likely due to coal petrology. The presence of inorganic matter (ash; average of 14%) and water (average 13.6%) in the coal reduces its adsorption capacity by 28.5% on average (compare “as received” values with “dry, ash free” values in Table 2). The CO2 adsorption capacity of these relatively low-rank coals is 5–6 times greater than for methane, as illustrated in Fig. 3b for representative CO2 and methane adsorption isotherms run on the same coal samples.

### 3.3. CO2 storage capacity

The CO2 storage capacity in coal beds in Alberta was determined in three steps:

1. identification of the areas suitable for CO2 storage;
2. estimation of the theoretical and effective CO2 storage capacity in these areas;
3. identification of areas with CO2 storage greater than 200 kt CO2/km², considered for the purpose of this study.

<table>
<thead>
<tr>
<th>Well location</th>
<th>Depth (m)</th>
<th>Temperature (°C)</th>
<th>Ash (wt%)</th>
<th>Moisture (wt%)</th>
<th>Langmuir pressure (MPa)</th>
<th>Langmuir volume, as received</th>
<th>Langmuir volume dry, ash free (DAF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>8-16-45-7 W5Mer</td>
<td>412.8</td>
<td>26.0</td>
<td>10.0</td>
<td>11.01</td>
<td>3.05</td>
<td>36.20</td>
</tr>
<tr>
<td>2</td>
<td>8-16-45-7 W5Mer</td>
<td>411.6</td>
<td>37.0</td>
<td>21.0</td>
<td>8.65</td>
<td>3.55</td>
<td>32.84</td>
</tr>
<tr>
<td>3</td>
<td>8-16-45-7 W5Mer</td>
<td>405.8</td>
<td>27.0</td>
<td>18.6</td>
<td>9.40</td>
<td>3.66</td>
<td>35.71</td>
</tr>
<tr>
<td>4</td>
<td>6-23-52-5 W5Mer</td>
<td>91.2</td>
<td>10.0</td>
<td>9.9</td>
<td>19.00</td>
<td>2.13</td>
<td>24.84</td>
</tr>
<tr>
<td>5</td>
<td>13-2-37-28 W4Mer</td>
<td>262.0</td>
<td>15.0</td>
<td>42.7</td>
<td>15.64</td>
<td>2.14</td>
<td>18.00</td>
</tr>
<tr>
<td>6</td>
<td>9-34-38-28 W4Mer</td>
<td>287.0</td>
<td>20.0</td>
<td>7.4</td>
<td>13.46</td>
<td>3.59</td>
<td>36.81</td>
</tr>
<tr>
<td>7</td>
<td>11-1-56-19 W5Mer</td>
<td>592.5</td>
<td>19.6</td>
<td>5.6</td>
<td>13.94</td>
<td>2.12</td>
<td>30.55</td>
</tr>
<tr>
<td>8</td>
<td>6-9-36-25 W4Mer</td>
<td>236.0</td>
<td>12.0</td>
<td>6.7</td>
<td>14.59</td>
<td>2.83</td>
<td>37.20</td>
</tr>
<tr>
<td>9</td>
<td>8-22-47-26 W4Mer</td>
<td>390.0</td>
<td>?</td>
<td>16.0</td>
<td>10.26</td>
<td>3.41</td>
<td>39.52</td>
</tr>
<tr>
<td>10</td>
<td>16-32-34-21 W4Mer</td>
<td>334.5</td>
<td>17.5</td>
<td>7.6</td>
<td>18.36</td>
<td>2.80</td>
<td>34.02</td>
</tr>
<tr>
<td>11</td>
<td>9-10-36-19 W4Mer</td>
<td>232.0</td>
<td>18.5</td>
<td>11.24</td>
<td>20.88</td>
<td>3.84</td>
<td>32.20</td>
</tr>
<tr>
<td>12</td>
<td>4-23-36-20 W4Mer</td>
<td>1252.0</td>
<td>n.a</td>
<td>n.a</td>
<td>n.a</td>
<td>n.a</td>
<td>n.a</td>
</tr>
<tr>
<td>13</td>
<td>9-1-36-19 W4Mer</td>
<td>1290.0</td>
<td>35.5</td>
<td>19.72</td>
<td>7.83</td>
<td>2.95</td>
<td>27.20</td>
</tr>
<tr>
<td>14</td>
<td>6-14-44-15 W4Mer</td>
<td>902.0</td>
<td>36.1</td>
<td>4.46</td>
<td>13.96</td>
<td>4.94</td>
<td>40.02</td>
</tr>
</tbody>
</table>

Langmuir volume units are in cm³/g, or m³/t. Measurements were performed at in situ temperature conditions. ?: unknown.

Fig. 3 – Relevant coal characteristics in Alberta, Canada: (a) variation of coal permeability with depth and (b) representative methane and CO2 adsorption isotherms.
as a substitute (proxy) threshold for the economic application of CO₂ storage in coal beds.

The areas suitable for CO₂ storage were determined for each of the three coal zones by identifying a shallow depth limit, based on groundwater and coal resource protection, and a deep depth limit, based on the CO₂ phase at the respective in situ pressure and temperature conditions.

Shallow coals in the Ardley and Drumheller coal zones along their outcrop (Fig. 1a) have an economic value, being currently mined in places at outcrop for power generation, and may have an economic value in the future. In addition, the shallow coals are water-saturated, have relatively high permeability and constitute shallow groundwater aquifers, as shown by numerous hydraulic tests performed in the past on shallow coals; hence they are a protected source of potable water. A search of 184,271 water wells in central and southern Alberta has shown that 90% of the water wells are less than 100 m deep, and that 98% are shallower than 300 m. Thus, for the purpose of this study the depth of 300 m has been selected as the upper (shallowest) depth limit for CO₂ storage. Given the west-southwestward dip of the strata in the basin, including the coal beds, the 300-m depth limit represents the eastward boundary of the regions that could potentially be considered for CO₂ storage. These considerations do not apply to the Mannville Coal Zone, which is found at depths greater than 300 m and is saturated with saline formation water.

The deep limit of the regions suitable for CO₂ storage in each coal zone was determined on the basis of CO₂ phase-change at the respective in situ pressure and temperature conditions. Only the regions deeper than 300 m where CO₂ is still in gaseous phase were considered in this study for CO₂ storage. These considerations do not apply to the Mannville Coal Zone, which is found at depths greater than 300 m and is saturated with saline formation water.

The theoretical CO₂ storage capacity in the three coal zones in Alberta was calculated for the respective suitable regions using relations (1)–(3), a coal density value of n₇ = 1.4 t/m³, the adsorption capacity data for dry, ash-free (daf) coal samples (Table 2) according to their distribution in each region, and average moisture and ash content. The theoretical CO₂ storage capacity varies between 20 and 420 kt/km² in the Mannville coal beds, between 7 and 860 kt/km² in the Drumheller coal beds, and between 21 and 1260 kt/km² in the Ardley coal beds. Completion and recovery factors of 40% and 80%, respectively, were assumed in calculating the effective CO₂ storage capacity, resulting in a reduction to 32% of the initially-computed storage capacity. The completion and recovery factors, while realistic, are somewhat arbitrary and on the optimistic side. As experience is gained with CO₂ storage operations, these numbers can be easily modified and applied anew to improve the capacity estimates and identify the regions with the highest potential. For illustration, Fig. 4 presents the region identified as suitable for CO₂ storage and the distribution of theoretical and effective CO₂ storage capacities for the Ardley Coal Zone.

The distributions of theoretical CO₂ storage capacity in the coal zones mimic the respective coal distributions (net thickness). The total theoretical CO₂ storage capacity in these three coal zones is in the order of 20 Gt CO₂ (with 45% of this capacity in the Ardley coals) and the total effective storage capacity is 6.4 Gt CO₂. Considering that it is economic to develop the necessary infrastructure of pipelines, compressors and wells for both CO₂ injection and CBM production only for areas with sufficient CO₂ storage capacity, assumed to be greater than 200 kt CO₂/km², then the CO₂ storage capacity in coal beds in Alberta is greatly reduced further to a practical capacity of only ~850 Mt CO₂, of which 94% is in the Ardley Coal Zone in western Alberta, and the remainder is in the Drumheller Coal Zone in several small areas southeast and northeast of Calgary (Fig. 5). The Mannville Coal Zone has no practical CO₂ storage capacity if this threshold is applied.
Notwithstanding the low CO₂ storage capacity of the Mannville coals, this coal zone is generally not a good candidate for CO₂ storage because: (1) the formation water that saturates these coals is very saline, thus requiring treatment when produced with methane and/or deep injection for disposal; (2) the Mannville Group is a major oil- and gas-producing stratigraphic interval in Alberta, and CO₂ injected into Mannville coals may leak and locally contaminate these resources; and (3) there are no major CO₂ sources in the region where the Mannville coals would be suitable, albeit at low capacity, for CO₂ storage.

The small areas suitable for CO₂ storage in the Drumheller Coal Zone are located in the agricultural heartland of Alberta and CO₂ storage with concurrent CBM production may raise conflicts with other land use and public opposition. An additional disadvantage of the Drumheller coals is that the thick coals that would be good candidates for CO₂ storage are comparatively shallow and concentrated in a relatively narrow band around 300 m depth, i.e., close to shallow groundwater and to coals that may be mined in the future. Thus, CO₂ storage in these coals is less recommended.

In contrast to the Mannville and Drumheller coal zones, the Ardley Coal Zone has a significant practical capacity for CO₂ storage, in the order of ~800 Mt CO₂, located in a forested area of ~3300 km² where the potential for land use conflicts is much smaller (Fig. 5). Because of low salinity and meteoric origin, water that would be produced with methane in CO₂ storage operations will not have to be treated, and it may even be possible to discharge it at surface. There are no oil or gas resources in the formations adjacent to Ardley coals that otherwise would need protection, like in the case of Mannville coals. Furthermore, a significant number of major CO₂ sources in Alberta (coal-fired power plants, pulp mills, gas plants and petrochemical plants) are located in close vicinity or at acceptable distance (200–300 km) from the suitable areas (Fig. 5). Deeper oil and gas reservoirs in western Alberta have significant CO₂ storage capacity (Bachu and Shaw, 2005), such that infrastructure built for bringing CO₂ to this region would be used for a long period of time considering the large potential for CO₂ storage in oil and gas reservoirs and coal seams in this area. Thus, this analysis indicates that the Ardley Coal Zone in the west-central Alberta should be the primary target for CO₂ storage in uneconomic coal beds.

4. Conclusions

Storage of CO₂ in coal seams, concurrent with methane production, is one of the possible means of CO₂ geological storage, although currently it is still an immature technology. Application of this technology requires identification at a regional scale of coal beds suitable for CO₂ storage, estimation of their storage capacity, and selection of areas with good potential. It is proposed, based on the current status of knowledge, to consider for CO₂ storage only coal beds located at depths for which, under the respective in situ pressure and geothermal regimes, the injected CO₂ is in gaseous phase (subcritical). On the other hand, the coal beds considered for CO₂ storage should be deeper than coals that are, or that potentially will be mined, and should be deeper than shallow groundwater aquifers. Application of these criteria reduces the potential coal beds suitable to CO₂ storage to a depth window of approximately 300 to 800–900 m. Coal thickness and permeability are also major factors in identification of coal beds suitable for CO₂ storage.

Estimation of the theoretical and effective storage capacities of the coal beds identified for CO₂ storage is based on CO₂ adsorption isotherms, coal volume, and completion and recovery factors that, in the absence of field experience and detailed numerical simulations, have to be estimated by analogy with CBM production. While some of the coefficients and parameters used in the storage capacity estimation and site identification have no real basis because of the lack of field experience, the proposed methodology can be easily applied for any set of criteria and coefficients that may be selected in the future as the technology matures.

The proposed methodology has been applied to Cretaceous-Tertiary coal beds in Alberta, some of them with potential for CBM production and CO₂ storage. Based on their thickness and potential for CBM, three coal zones, Mannville, Drumheller and Ardley, have been identified for assessing their capacity for CO₂ storage. For each coal zone, a region of intermediate depth, greater than 300 m but less than 800–900 m, has been identified that, theoretically, is suitable for CO₂ storage. The theoretical CO₂ storage capacity in the respective suitable region of each coal zone was estimated on the basis of CO₂ adsorption isotherms measured on coal samples, taking into account the moisture and ash content of these coals. The theoretical CO₂ storage capacity varies from ~20 kt CO₂/km² in the areas of thin coals to 1260 kt CO₂/km² in areas of thick coals with high adsorption capacity, for a total of...
approximately 20 Gt CO₂. A recovery factor of 80% and a completion factor of 40% reduce the theoretical storage capacity to an effective storage capacity of 6.4 Gt CO₂ for the three coal zones. Considering that it is economic to build the necessary infrastructure only in areas with effective CO₂ storage capacity greater than 200 kt CO₂/km², then the CO₂ storage capacity in coal beds in Alberta is further reduced to a practical capacity of only ~850 Mt CO₂.

There are no suitable target areas with high CO₂ storage capacity in the Mannville Coal Zone, which is also a poor candidate for CO₂ storage because of its depth, low permeability, elevated salinity of formation water that would be produced, and presence of oil and gas reservoirs in this stratigraphic interval that could be contaminated by leaked CO₂. In regard to the Drumheller Coal Zone, there are a few very small areas with high capacity located in the agricultural heartland of Alberta, with a total practical CO₂ storage capacity of 50 Mt CO₂. The coal beds in these regions are relatively shallow (close to 300 m depth), and CO₂ stored in these coals will likely sterilize shallow coal resources that may become economic for mining at some time in the future, while any leaked CO₂ from these coals will likely contaminate groundwater resources in these agricultural regions. In addition, CO₂ storage with CBM production may raise conflicts with land use and public opposition. In contrast, the Ardley Coal Zone has a much larger practical capacity for CO₂ storage of ~800 Mt CO₂ in a forested area of ~3300 km² that is less likely to become the object of land-use conflicts. In addition, the low salinity of water in the Ardley coals has the advantage that produced water does not have to be treated, and it is possible that it could even be discharged at surface if provincial regulations are being met. Large stationary CO₂ emitters are located within close distance of these areas, thus, the identified region of the Ardley Coal Zone should be the primary target for CO₂ storage in coals in Alberta.

REFERENCES


