THE POTENTIAL FOR GEOLOGICAL STORAGE OF CARBON DIOXIDE IN NORTHEASTERN BRITISH COLUMBIA

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ABSTRACT

Carbon dioxide capture from large stationary sources and storage in geological media is a technologically-feasible mitigation measure for the reduction of emissions of anthropogenic CO_2 into the atmosphere in response to climate change as a result of human activity. Carbon dioxide can be sequestered underground in oil and gas reservoirs, in deep saline aquifers, in uneconomic coal beds and in salt caverns. The sedimentary succession in northeastern British Columbia has significant potential for CO_2 storage in gas reservoirs and deep saline aquifers. This is because geologically this region is located in a tectonically stable area, has significant, large gas reservoirs, and deep saline aquifers that are confined by thick, regional-scale shaly aquitards. In addition, there is significant infrastructure in place, there are several large CO_2-sources in the area, including high-purity sources (gas plants), and there is operational and regulatory experience with acid gas disposal in both depleted hydrocarbon reservoirs and deep saline aquifers. The CO_2 storage capacity in gas reservoirs is very large (>1,900 Mt CO_2), of which ~1,350 Mt CO_2 is in the largest 80 reservoirs. This capacity, just by itself, is likely sufficient to cover B.C.'s needs for this century. The CO_2 storage capacity in oil reservoirs is practically negligible at 5 Mt CO_2, and the only reason that this capacity would ever be realized is that additional oil may be produced in CO_2-EOR operations. Storage of CO_2 in coal beds does not have potential unless used in conjunction with coal gas recovery (technology that has yet to be proven), and even then it is questionable given the depth of the coal beds. Besides gas reservoirs, northeastern British Columbia has significant potential for CO_2 storage in deep saline aquifers. Carbon dioxide can be injected into almost all of the deep saline aquifers in the sedimentary succession. The only aquifers that are not suitable for CO_2 storage are the shallower Upper Cretaceous Dunvegan and Cardium formations, which crop out at river valleys as a result of Tertiary to Recent erosion. Cambrian to Lower Cretaceous aquifers are well confined by intervening and overlying shales. Geographically, Carboniferous to Triassic aquifers are the best targets for CO_2 storage in the southern part of northeastern British Columbia, while Devonian aquifers should be used for CO_2 storage in the northern part. Although there is great capacity and potential infrastructure for CO_2 storage in gas reservoirs, they will become available for CO_2 storage only after depletion, which, at current production rates, will occur in the next few decades. Until they become available, deep saline aquifers can be safely used for CO_2 storage in northeastern British Columbia.

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INTRODUCTION

Human activity since the industrial revolution has had the effect of increasing atmospheric concentrations of gases with a greenhouse effect, such as carbon dioxide (CO_2) and methane (CH_4). For example, atmospheric concentrations of CO_2 have risen from pre-industrial levels of 280 ppm to the current level of more than 370 ppm, primarily as a consequence of fossil-fuel combustion for energy production. Circumstantial evidence suggests that the increase in greenhouse-gas concentrations in the atmosphere leads to climate warming and weather changes, a fact that by now is generally accepted in the scientific community and by policy makers. Because of its relative abundance compared with the other greenhouse gases, CO_2 is responsible for about 64% of the enhanced 'greenhouse effect'. To address the effects of global climate change, scientific and policy efforts are focused in three major directions: 1) understanding better the science of climate change, 2) adaptation to predicted climate changes, and 3) mitigating the effects of climate change. As a result, reducing atmospheric emissions of anthropogenic CO_2 and methane is one of the main mitigating measures considered by the society, with most efforts being focused on reducing CO_2 emissions.

The 1992 United Nations Framework Convention on Climate Change (UNFCCC) states as an objective the "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system". The Kyoto Protocol, signed in 1997 and ratified in February 2005, set targets and timetables for emission reductions for Annex I Parties (developed and transition economies) at a level on average 5% below 1990 levels by 2008-2012 (the "Kyoto period"). Canada has committed to reduce CO_2 emissions at 6% below 1990 levels; however, economic development, population increase and lack of a clear policy resulted so far in an increase of ~24% over 1990 greenhouse gas emissions. Thus, in order to meet Canada's Kyoto commitments, the federal and provincial governments need to implement a very aggressive policy for reducing atmospheric emissions of anthropogenic greenhouse gases.

Reducing anthropogenic CO_2 emissions into the atmosphere involves basically three approaches: a) lowering the energy intensity of the economy (i.e., increase in conservation and efficiency of primary energy conversion and end use)[1]; b) lowering the carbon intensity of the energy system by substituting lower-carbon or carbon-free energy sources for the current sources[2]; and c) artificially increasing the capacity and capture rate of CO_2 sinks. Short of revolutionary, large-scale new technological advances and major expenditures, the energy intensity of the economy will continue to decrease at a lower rate than the rate of GDP increase and mitigation strategies will have a limited impact (Turkenburg, 1997). Similarly, fossil fuels, which currently provide more than 80% of the world's energy, will likely remain a major component of world's energy supply for at least the first half of this century (IEA, 2004) because of their inherent advantages, such as availability, competitive cost, ease of transport and storage, and large resources. Other forms of energy production are either insufficient or not acceptable to the public. Thus, the carbon intensity of the energy system is not likely to decrease in any significant way in the medium term. On the other hand, increasing carbon sinks and 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 (Turkenburg, 1997; IEA, 2004).

Large, natural CO_2 sinks are terrestrial ecosystems (soils and vegetation) and oceans with retention times of the order of tens to thousands of years, respectively. Terrestrial ecosystems and the ocean surface represent diffuse natural carbon sinks that capture CO_2 from the atmosphere after release from various sources. The capacity, but not the capture rate, of terrestrial ecosystems can be increased by changing forestry and agricultural practices[3]. On the other hand, CO_2 Capture and Storage (CCS) in geological media presents the opportunity of reducing significantly atmospheric CO_2 emissions from large, stationary sources such as thermal power plants (IEA, 2004; IPCC, 2005) by capturing the CO_2 prior to its release into the atmosphere and injecting it deep into geological formations that have a retention time of centuries to millions of years.

Geological storage of CO_2 is achieved through a combination of physical and chemical trapping mechanisms (IPCC, 2005). Physical trapping occurs when CO_2 is immobilized in free phase (static trapping and residual-gas trapping), or migrates in the subsurface with extremely low velocities such that it would take time on a geological scale to reach the surface (hydrodynamic trapping), by which time usually it is trapped by other mechanisms. Chemical trapping occurs when CO_2 first dissolves in subsurface fluids (solubility and ionic trapping) and then undergoes chemical reactions (geochemical trapping), or it is adsorbed onto the rock surface (adsorption trapping). In some cases, more than one single trapping mechanism is active, although they usually act on different time scales.

The physico-chemical mechanisms for CO_2 storage in underground geological media translate into the following means of trapping:

- Volumetric, whereby pure-phase, undissolved CO_2 is trapped in a rock volume and cannot rise to the surface due to physical and/or hydrodynamic barriers. The storage volume can be provided by:
  - Large man-made cavities, such as caverns and abandoned mines (cavern trapping); or
  - The pore space present in geological media. If trapped in the pore space, CO_2 can be at saturations less or greater than the irreducible saturation; if the former, the interfacial tension keeps the residual gas in place; if the later, pure CO_2 can be trapped:
    - in static accumulations in stratigraphic and structural traps in depleted oil and gas reservoirs and in deep saline aquifers, or
    - as a migrating plume in large-scale flow systems in deep aquifers.
- Dissolution, whereby CO_2 is dissolved into fluids that saturate the pore space in geological media, such as formation water and reservoir oil.
- Adsorption onto organic material in coal and shales rich in organic content.
- Chemical reaction to form a mineral precipitate.

[1]The Government of British Columbia has adopted in December 2004 a 40-points action plan to address climate change that promotes Sustainable Energy Production and Efficient Use, and Efficient Infrastructure, namely: energy conservation, energy efficiency; alternative energy (hydroelectric, wind and landfill gas); development of hydrogen and fuel cell technology; and use of alternative and hybrid fuels in transportation (Weather, Climate and the Future: B.C.'s Plan @ http://wlapwww.gov.bc.ca/air/climate/).

[2] Ibid.

[3] Similarly, in its climate change action plan (Weather, Climate and the Future: B.C.'s Plan @ http://wlapwww.gov.bc.ca/air/climate/), the Government of British Columbia has adopted measures for Sustainable Forest and Carbon Sink Management.

These means of CO_2 storage can occur in the following geological media (IPCC, 2005):

- oil and gas reservoirs
- deep saline aquifers, saturated with brackish water or brine
- coal seams (sorption is the only potentially practical technique in coal seams and is not a significant storage mechanism in the other classes of geological media)
- man-made underground cavities (i.e., salt caverns, in CO_2)

Any geological site for CO_2 storage must posses the following characteristics:

- capacity, for accepting the volumes of CO_2 that need to be stored;
- injectivity, to allow introduction of CO_2 into the subsurface at the desired rates; and
- confining ability, to retain the CO_2 for the desired period of time (i.e., avoidance of leakage).

These characteristics are largely met by geological media in sedimentary basins, where oil and gas reservoirs, coal beds and salt beds and domes are found. Igneous and metamorphic rocks are generally not suitable for CO_2 storage because they lack the permeability and porosity needed for CO_2 injection and storage, and/or because of their lack of confining properties due to their fractured nature. Volcanic areas and orogenic belts (mountains) are also unsuitable for CO_2 storage mainly because they lack capacity and are unsafe.

In the case of British Columbia, its landmass includes nine sedimentary basins and two geological troughs (Figure 1) that may have, to various degrees, potential for CO_2 geological storage. A previous analysis (Bachu, 2005) has identified the portion of the Western Canada Sedimentary Basin (WCSB) in northeastern British Columbia (Figure 1) as the most suitable sedimentary basin in B.C. for CO_2 geological storage and likely with the largest capacity. Most of the "large" stationary CO_2-sources have emissions less than 500 kt CO_2/yr, and very few sources emit more than 1 Mt CO_2/yr (Figure 1). The CO_2 sources are distributed according to the major industrial and population centers along the Pacific coast, in the B.C. interior, and in northeastern B.C., where gas plants produce a stream of high purity CO_2 and where a pipeline system is more developed locally.

The portion of the WCSB in northeastern B.C. is the most suited, and practically immediately accessible, basin for CO_2 geological storage in British Columbia. It meets all the general suitability criteria for CO_2 geological storage (Bachu and Stewart, 2002; Bachu, 2003):

- it is located in a tectonically stable region;

- has regional-scale flow systems confined by thick aquitards; - has significant oil and gas reservoirs;

- has coal beds; - has significant infrastructure in place;

- there are CO_2 sources in the area, including high-purity sources (gas plants); and

- there is experience with acid-gas injection operations.

Northeastern British Columbia has significant CO_2 storage capacity in oil and gas reservoirs, in deep saline aquifers, and possibly in coal beds if the technology will prove successful. The purpose of the work reported here is to evaluate the potential and capacity for CO_2 geological storage in northeastern British Columbia.

CAPACITY FOR CO_2 STORAGE IN OIL AND GAS RESERVOIRS

Worldwide, the largest CO_2-storage capacity is likely in deep saline aquifers, while the smallest is in coal beds (IPCC, 2005), and this is most probably true of northeastern British Columbia. On the other hand, it is recognized that, generally, CO_2 storage in geological media will occur first in oil and gas reservoirs because of the following reasons (IPCC, 2005): 1) their geology and trapping characteristics are better known as a result of exploration for and production of hydrocarbons, 2) there is already infrastructure in place (pipelines and wells), and 3) in the case of oil reservoirs that are suitable for CO_2-flood enhanced oil recovery (EOR), additional oil production will lower the cost of CO_2 storage, in some cases even realizing a profit, and will increase the stability and security of energy supplies. For this reason, this assessment starts with examining the CO_2 storage capacity in oil and gas reservoirs.

METHODOLOGY

The capacity for CO_2 storage in hydrocarbon reservoirs in any particular region is given by the sum of the capacities of all reservoirs in that area, calculated on the basis of reservoir properties, such as original oil or gas in place, recovery factor, temperature, pressure, rock volume and porosity, as well as in situ CO_2 characteristics, such as phase behaviour and density. The fundamental assumption being made in these calculations is that the volume previously occupied by the produced hydrocarbons becomes, by and large, available for CO_2 storage. This assumption is generally valid for reservoirs that are not in contact with an aquifer, or that are not flooded during secondary and tertiary oil recovery. In reservoirs that are in contact with an underlying aquifer, formation water invades the reservoir as the pressure declines because of production. However, CO_2 injection can reverse the aquifer influx, thus making pore space available for CO_2. However, not all the previously hydrocarbon-saturated pore space will become available for CO_2 because some residual water may be trapped in the pore space due to capillarity, viscous fingering and gravity effects (Stevens *et al.*, 2001).

Another important assumption is that CO_2 will be injected into depleted oil and gas reservoirs until the reservoir pressure is brought back to the original, or virgin, reservoir pressure. The results thus obtained represent a conservative estimate because the pressure can generally be raised beyond the original reservoir pressure as long as it remains safely below the threshold rock-

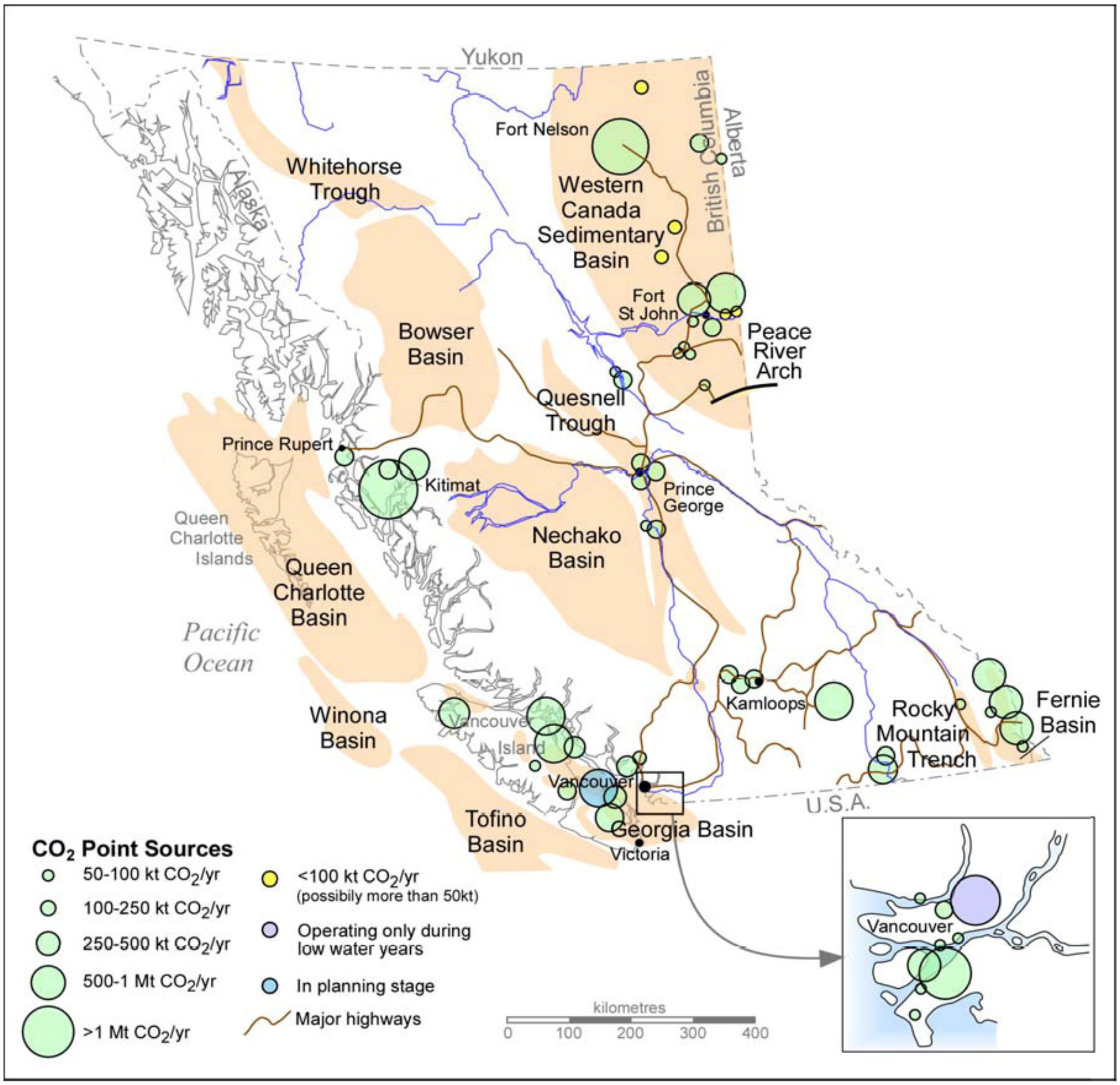


Figure 1. Location of sedimentary basins and major stationary CO_2-sources in British Columbia.

fracturing pressure. In this case, the CO_2 storage capacity would be higher due to CO_2 compression. However, the risk of raising the storage pressure beyond the original reservoir pressure requires a case-by-case reservoir analysis that is not practical for basin-scale evaluations.

Several capacity definitions are being introduced to clarify the meaning of various estimates and the relationships between them. The theoretical capacity assumes that all the pore space (volume) freed up by the production of all recoverable reserves will be replaced by CO_2 at in situ conditions. The effective capacity is the more realistic estimate obtained after water invasion, displacement, gravity, heterogeneity and water-saturation effects have been taken into account. Practical capacity is the storage capacity after consideration of technological limitations, safety, CO_2 sources and reservoir distributions, and current infrastructure, regulatory and economic factors. In the end, all the issues and factors relating to CO_2 capture, delivery and storage contribute to a reduction in the real capacity for CO_2 storage in hydrocarbon reservoirs. However, none of these capacity estimates is final, in the sense that these values evolve in time, most likely increasing as new oil and gas discoveries take place, or as better production technologies are developed.

Theoretical CO_2-Storage Capacity

Only non-associated and associated gas reservoirs are considered in CO_2-sequestration capacity calculations because solution gas is taken into account in oil reservoirs through the oil shrinkage factor. Since reserves databases indicate the volume of original gas in place (OGIP) at surface conditions, the mass-capacity for CO_2 storage in a reservoir at in situ conditions, MCO_2, is given by:

$$\mathbf{M_{CO2} = \rho_{CO2r} \cdot R_f \cdot (1 - F_{IG}) \cdot OGIP \cdot [(P_s \cdot Z_r \cdot T_r) / (P_r \cdot Z_s \cdot T_s)]} \quad \mathbf{(1)}$$

In the above equation, ρCO_2 is CO_2 density, Rf is the recovery factor, FIG is the fraction of injected gas, P, T and Z denote pressure, temperature and the compressibility factor, and the subscripts 'r' and 's' denote reservoir and surface conditions, respectively. The CO_2 density at reservoir conditions is calculated from equations of state (e.g., Span and Wagner, 1996).

The CO_2 storage capacity of single-drive oil reservoirs is calculated similarly to gas reservoirs on the basis of reservoir rock volume (area [A] times thickness [h]), porosity (φ) and oil saturation (1 – Sw), where Sw is the water saturation. For reservoirs flooded with or invaded by water, the volume available for CO_2 storage is reduced by the volume of injected and/or invading water (Viw). If water is produced with oil, then the volume available for CO_2 storage is augmented by the volume of produced water (Vpw). The same mass balance applies in the case of miscible flooding with solvent or gas. Thus:

$$\mathbf{M_{CO2} = \rho_{CO2res} \cdot [R_f \cdot A \cdot h \cdot \varphi \cdot (1 - S_w) - V_{iw} + V_{pw}]} \qquad \mathbf{(2)}$$

The volumes of injected and/or produced water, solvent or gas can be calculated from production records. However, the pore volume invaded by water from underlying aquifers cannot be estimated without detailed monitoring of the oil-water interface and detailed knowledge of reservoir characteristics.

Effective CO_2-Storage Capacity

In the case of reservoirs underlain by aquifers, the reservoir fluid (oil and/or gas) was originally in hydrodynamic equilibrium with the aquifer water. As hydrocarbons are produced and the pressure in the reservoir declines, a pressure differential is created that drives aquifer water up into the reservoir. The amount and rate of water influx is controlled by: 1) reservoir permeability and heterogeneity; 2) water expansion in the aquifer; 3) pore volume contraction due to the increase in effective stress caused by the pressure drop in the reservoir; 4) expansion of hydrocarbon accumulations linked to the common aquifer; and 5) artesian flow where the aquifer is recharged by surface water. As hydrocarbons are produced, some portions of the reservoir may be invaded by aquifer water, in addition to the initial water saturation. If CO_2 is then injected into the reservoir, the pore space invaded by water may not become available for CO_2 storage, resulting in a net reduction of reservoir capacity. The reduced storage volume may eventually become available if the reservoir pressure caused by CO_2 injection is allowed to increased beyond the original reservoir pressure, which may or may not always be allowed or possible. Furthermore, the hysteresis effect caused by various mechanisms may also prevent complete withdrawal of invaded water, leading to a permanent loss of storage space.

Analysis of the production history of close to 300 oil and gas pools in western Canada led to the establishment of a set of criteria for determining if an oil or gas reservoir has strong or weak aquifer support (Bachu and Shaw, 2003, 2005; Bachu *et al.*, 2004) on the basis of pressure history, water production, and cumulative water-gas ratio (WGR) or water-oil ratio (WOR). For oil reservoirs, the gas-oil ratio (GOR) was also included in the analysis because, typically, an oil pool with strong aquifer support tends to have a slow pressure decline and flat GOR profile close to solution GOR, and vice-versa. In addition, the production decline versus reservoir pressure was analyzed for these pools. For gas pools, P/Z plots were used to identify the presence of aquifer support, or lack thereof. The criteria and threshold values for identification of the strength of underlying aquifers are presented in Table 1.

The effect of the underlying aquifers was assessed using the Petroleum Expert's MBALTM (Material BALance) software for a limited number of oil and gas pools distributed across the Western Canada Sedimentary Basin that were considered to be reasonably representative for the range of conditions found in the basin (Bachu and Shaw, 2003; Bachu *et al.*, 2004). Injection of CO_2 was assumed to start immediately after reservoir depletion and to continue until the pool pressure exceeded the original pressure. Although the material balance reservoir model simulated by MBALTM is a tank model and does not account for reservoir geometry, drainage area and wells location, it is a very useful tool in matching the production history by determining the presence, type and size of an aquifer, and predicting reservoir pressure and performance for given production and/or injection scenarios.

TABLE 1. CRITERIA FOR ESTABLISHING THE STRENGTH AND EFFECT OF UNDERLYING AQUIFERS ON THE CO_2 STORAGE CAPACITY IN DEPLETED OIL AND GAS RESERVOIRS IN THE WESTERN CANADA SEDIMENTARY BASIN AND THE CORRESPONDING COEFFICIENT OF REDUCTION IN CO_2 STORAGE CAPACITY

Reservoir Type	WOR (m^3/m^3) or WGR (bbl/MMcf)	GOR (m^3/m^3)	Aquifer Strength	Capacity Reduction Coefficient
Oil	≥ 0.25		Strong	0.50
	≥0.15 and <0.25	<1000		
	≥0.15 and <0.25	≥1000	Weak	0.97
	<0.15			
Gas	≥5.6		Strong	0.70
	<5.6		Weak	0.97

Table 1 shows the reduction in CO_2 storage capacity for reservoirs with strong aquifer support. The storage capacity of reservoirs with weak or no aquifer support is not affected by the presence of the underlying aquifer. However, a very small effect needs to be considered in light of the fact that water is a wetting phase, as opposed to oil and gas, which are non-wetting, hence it should be expected that some irreducible water would be left behind in the pore space by the receding aquifer. To account for this effect it is assumed that the theoretical CO_2-storage capacity in oil and gas reservoirs with weak aquifer support is reduced by ~3%.

Notwithstanding the effect of an underlying aquifer, three factors, in particular, control the effectiveness of the CO_2 storage process: CO_2 mobility with respect to oil and water; the density contrast between CO_2 and reservoir oil and water, which leads to gravity segregation; and reservoir heterogeneity. Because of the very low CO_2 viscosity in liquid or supercritical phase, on the order of 10-5 Pa · s, the CO_2/oil and CO_2/water mobility ratios at reservoir conditions are on the order of 20 and higher. As a result, viscous fingering will develop and the CO_2 will tend to bypass the oil/water system in place in the reservoir, leading to a very unfavourable displacement process (Bondor, 1992).

Depending on reservoir temperature and pressure, the density of supercritical or liquid CO_2 may range between approximately 200 and 800 kg/m3. The density difference (buoyancy) between the lighter CO_2 and the reservoir oil and water leads to gravity override at the top of the reservoir, particularly if the reservoir is relatively homogeneous and has high permeability (Bondor, 1992; Stephenson *et al.*, 1993; Doughty and Preuss, 2004). This negatively affects the CO_2 storage, and the oil recovery in the case of EOR.

If the reservoir is heterogeneous, the injected CO_2 will flow along the path of less resistance, namely through regions of high permeability, bypassing regions of lesser permeability. This has a negative effect for oil recovery because whole regions of the reservoir may be left unswept by CO_2 before it breaks at the production well, thereby reducing the economic benefit. On the other hand, reservoir heterogeneity may have a positive effect because it may counteract the buoyancy effect by slowing down the rise of CO_2 to the top of the reservoir and forcing it to spread laterally, resulting in better vertical sweep efficiency (Doughty and Preuss, 2004).

The presence of water in the reservoir also has the effect of reducing the CO_2 storage capacity, as discussed previously. Water may be present because of initial water saturation, because of water invasion as the reservoir is depleted, or because it was introduced during secondary and/or tertiary recovery. As a result of capillary forces, irreducible water (Swirr) will remain in the reservoir even if the water is 'pushed back' by the injected CO_2.

All the processes and reservoir characteristics that reduce the actual volume available for CO_2 storage can be expressed by capacity coefficients (C < 1) in the form (Doughty and Preuss, 2004):

$$\mathbf{M_{CO2eff} = C_m \cdot C_b \cdot C_h \cdot C_w \cdot C_a \cdot M_{CO2res}} \qquad \mathbf{(3)}$$

where MCO_2eff is the effective reservoir capacity for CO_2 storage, and the subscripts m, b, h, w and a stand for mobility, buoyancy, heterogeneity, water saturation, and aquifer strength, respectively, and refer to the phenomena discussed previously. These capacity coefficients likely vary over a wide range, depending on reservoir characteristics, and this explains the wide range of incremental oil recovery (7 to 23% of OOIP) and CO_2 utilization (0.7 to 4.7 m3 CO_2 / m3 recovered oil at reservoir conditions) observed for 25 CO_2-flood EOR operations in Texas (Holt *et al.*, 1995). Unfortunately, there are very few studies and methodologies for estimating the values of these capacity coefficients, mostly on the basis of numerical simulations, and generally there are no data or past experience for the specific case of CO_2 storage in depleted hydrocarbon reservoirs. The first four capacity coefficients can be captured in a single 'effective' coefficient:

$$\mathbf{C_{eff} = C_m \cdot C_b \cdot C_h \cdot C_w} \qquad \mathbf{(4)}$$

which can be estimated on the basis of experience with CO_2-flood EOR. A review of capacity coefficients for CO_2 storage in aquifers suggests that Ceff < 0.3. Conditions are more favourable in the case of oil reservoirs (for example the buoyancy contrast is much reduced), and a value of Ceff = 0.5 was considered in this study. For gas reservoirs, Cm ≈ 1 because fingering effects are very small to negligible. Because CO_2 density is greater than that of methane at reservoir conditions, the CO_2 injected in gas reservoirs will fill the reservoir from its bottom. Thus, it can be assumed that Cb ≈ 1 as well. The effect of initial water saturation was already implicitly taken into account in the estimates of theoretical ultimate CO_2-storage capacity, such that Cw ≈ 1 too. Although reservoir heterogeneity may reduce the CO_2 storage capacity by leaving pockets of original gas in place, Ch is probably high, approaching values close to unity. Thus, the reduction in CO_2 storage capacity for gas reservoirs is much less by comparison with oil reservoirs and a value of Ceff = 0.9 was used in this study.

CO_2 Storage Capacity in Enhanced Oil Recovery

Carbon dioxide can be used in tertiary enhanced oil recovery in miscible floods, if high purity CO_2 is available. To date, except for the Weyburn oil field in Saskatchewan, operated by Encana, and the Joffre Viking A oil reservoir in Alberta, currently operated by Penn West, no CO_2-EOR operations were implemented in western Canada because of the high cost of CO_2 capture and lack of pipeline infrastructure for CO_2 delivery at the well head. However, this situation may rapidly change if incentives for CO_2 geological storage are introduced and a market for carbon credits is created. For example, the Alberta Government introduced in 2004 a Royalty Credit Program to encourage the development of a CO_2-EOR industry in the province, and, as a result, currently four pilot operations started in Alberta in 2005. In a future carbon-constrained environment and sustained high oil prices, CO_2 flooding will probably become the preferred EOR option, leading to both CO_2 geological storage and additional oil recovery. In fact, it is most likely that this option will be implemented before any other. Thus, identification of reservoirs suitable for CO_2 flooding and estimation of their CO_2 storage capacity becomes essential.

Based on the experience gained in the United States where CO_2-EOR is being practiced for more than 30 years at close to 70 oil fields in the Permian Basin of west Texas, a series of technical criteria were developed for assessing the suitability of oil reservoirs for CO_2-EOR, reviewed and summarized in several publications (Taber *et al.*, 1997; Kovscek, 2002; Shaw and Bachu, 2002). In assessing the suitability of oil reservoirs in northeastern B.C. for CO_2-EOR, the following criteria were used (Shaw and Bachu, 2002):

- Oil gravity greater than 27ºAPI and less than 48ºAPI

- Initial reservoir pressure greater than 7580 kPa

- Reservoir temperature less than 121ºC (250ºF)

- Ratio of initial pressure to minimum miscibility pressure (MMP) greater than 0.95

An additional, quasi-economic criterion was also used in the screening, namely that the reservoir be sufficiently large to warrant the cost of implementing CO_2-EOR. Reservoir size was expressed either by original oil in place (OOIP) of at least 1 Mmbl (159,000 m3), or by area, with the requirement that it has to be at least one section in size (256 ha) to allow for a 5-spot pattern with current well spacing regulations.

The minimum miscibility pressure (MMP) was calculated with the relation (Mungan, 1981):

$$\mathbf{MMP = -329.558 + (7.727 \times MW \times 1.005T) - (4.377 \times MW)} \qquad \mathbf{(5)}$$

where T is temperature (ºF), and MW is the molecular weight of the oil C5+ components. In the absence of information in databases about oil composition, the following relation was used to estimate the molecular weight of the C5+ components as a function of oil gravity G expressed in ºAPI (Lasater, 1958):

$$\mathbf{MW = \left(\frac{7864.9}{G}\right)^{1/1.0386}} \qquad \mathbf{(6)}$$

Prediction of reservoir performance and incremental oil recovery on the basis of information contained in reserves databases was performed using an analytical model developed for this purpose (Shaw and Bachu, 2002). The CO_2 storage capacity in EOR operations at CO_2 breakthrough is a direct result of that model for predicting reservoir performance. Considering that, on average, 40% of the injected CO_2 is recovered at the surface after breakthrough (Hadlow, 1992) and assuming that it will be re-injected back into the reservoir, the CO_2 storage capacity for any fraction Fi of hydrocarbon pore volume (HCPV) of injected CO_2 was calculated using the following relations:

- At breakthrough (BT),

$$\mathbf{M_{CO2} = \rho_{CO2res} \cdot RF_{BT} \cdot OOIP/Sh} \qquad \mathbf{(7)}$$

- At any HCPV injection,

$$\mathbf{M_{CO2} = \rho_{CO2res} \cdot [RF_{BT} + 0.6 \times (RF_{\%HCPV} - RF_{BT})] \cdot OOIP/Sh} \qquad \mathbf{(8)}$$

where RFBT and RF%HCPV are, respectively, the recovery factor at breakthrough and at the assumed percentage of hydrocarbon pore volume (HCPV) of injected CO_2; OOIP is the volume of the original oil in place; Sh is the oil shrinkage factor (the inverse of the formation volume factor B0); and ρCO_2res is CO_2 density calculated at reservoir temperature and pressure conditions (Span and Wagner, 1996).

Practical CO_2-Storage Capacity

The theoretical CO_2-storage capacity represents the mass of CO_2 that can be stored in hydrocarbon reservoirs assuming that the volume occupied previously by the produced oil or gas will be occupied in its entirety by the injected CO_2. The effective CO_2-storage capacity represents the mass of CO_2 that can be stored in hydrocarbon reservoirs after taking into account intrinsic reservoir characteristics and flow processes, such heterogeneity, aquifer support, sweep efficiency, gravity override, and CO_2 mobility. However, there are also extrinsic criteria, discussed in the following, which need consideration when implementing CO_2 storage in oil and gas reservoirs on a large scale and that further reduce the CO_2 storage capacity in oil and gas reservoirs to practical levels.

The storage capacity of oil reservoirs undergoing water flooding is significantly reduced, making it very difficult to assess their CO_2 storage capacity in the absence of detailed, specific numerical simulations of reservoir performance. It is very unlikely that these oil pools, and generally commingled pools, will be used for CO_2 storage, at least not in the near future.

The low capacity of shallow reservoirs, where CO_2 would be in the gas phase, makes them uneconomic because of storage inefficiency (Winter and Bergman, 1993). On the other hand, CO_2 storage in very deep reservoirs could also become highly uneconomic because of the high cost of well drilling and of CO_2 compression, and the low 'net' CO_2 storage (CO_2 sequestered minus CO_2 produced during compression). Thus, the pressure window of 9 to 34.5 MPa is considered as being economic for CO_2 storage in depleted hydrocarbon reservoirs (Winter and Bergman, 1993), which roughly translates to a depth interval of 900 to 3,500 m.

In terms of CO_2 storage capacity, most reservoirs are relatively small in volume, and have a low capacity for CO_2 storage, rendering them uneconomic. On the other hand, associated oil and gas reservoirs (oil reservoirs with a gas cap) have a CO_2 storage capacity that is equal to the sum of the individual capacities of each reservoir. Considering the size of the major stationary CO_2-sources, it is most likely that only reservoirs with large CO_2-storage capacity will be considered in the short and medium term. Building the infrastructure for CO_2 capture, transportation and injection is less costly if the size of the sink is large enough, and if its lifespan is long enough, to justify the needed investment and reduce the cost per ton of sequestered CO_2. Thus, only reservoirs with individual CO_2-storage capacity greater than 1 Mt CO_2/year were selected at the end of the capacity assessment process. More detailed analysis, based on economic criteria, should be applied for the selection of top oil and gas reservoirs for CO_2 storage, but this is beyond the scope and resources of this study.

CAPACITY FOR CO_2 STORAGE IN HYDROCARBON RESERVOIRS IN NORTHEASTERN BRITISH COLUMBIA

The methodology described previously was applied to the 2004 B.C. oil and gas reserves databases to estimate the CO_2 storage capacity in oil and gas reservoirs and identify the pools with sufficiently large capacity to warrant further examination. The process consisted of three steps:

- checking for the existence of critical data needed in calculations,
- calculating the CO_2 storage capacity on a reservoir by reservoir basis, and
- identifying the oil pools with an associated gas cap.

Data Analysis

The B.C. oil reserves database contains 474 entries differentiated on the basis of field, pool, sequence and project unit. However, only the first three categories identify a physically distinct oil pool, the last one indicating only an administrative unit based on production type. The number of actual oil pools is 414, of which only 380 have all the data necessary to perform the calculations for determination of CO_2 storage capacity. A breakdown of these pools by production type and data existence is given in Table 2. All oil pools in northeastern B.C. contain light-medium oil (API gravity > 25).

Of the 34 oil reservoirs that lack critical data, 18 lack area (of these 8 lack thickness, 5 lack water saturation, 5 lack porosity, 2 lack the shrinkage factor and 2 lack oil density), and 16 lack just the shrinkage factor. The list of oil reservoirs lacking critical data for calculating the CO_2 storage capacity is given in Appendix A. The 34 oil pools that are lacking critical data are generally quite small (16 have OOIP < 1 Mmbl, 12 have OOIP between 1 and 2 Mmbl, 4 have OOIP between 4 and 7 Mmbl) and very likely with negligible CO_2-storage capacity, considering also the low recovery factor of oil reservoirs. Only two pools, Eagle Belloy-Kiskatinaw and Eagle West Belloy, have significant OOIP of ~54 and ~149 Mmbl, respectively, to be worth considering for potential CO_2-storage calculations, and the missing data for these pools should be retrieved in the future.

In regard to gas pools, there are 1832 gas pools in the 2004 reserves database, differentiated by field, pool and sequence, but only 1743 of them have the data needed for calculation of CO_2 storage capacity, as shown in Table 3. The list of gas reservoirs lacking critical data for calculating the CO_2 storage capacity is given in Appendix B. It is worth noting that all the gas reservoirs classified as “associated” are lacking fundamental data such as original gas in place (OGIP), pressure and temperature. The two non-associated gas reservoirs that are missing depth could not be located, but they are very small, with likely corresponding negligible CO_2-storage capacity.

Table 4 shows the range of variability in the data needed for calculating the CO_2 storage capacity for the 380 oil reservoirs and 1732 gas reservoirs in northeastern British Columbia that have the whole suite of required data. Regarding the gas reservoirs, it is worth noting that 97 have a recovery factor greater than unity, which means that these reservoirs have produced more gas than it was originally estimated to contain. Also, 49 gas reservoirs have a compressibility factor greater than unity, which is an artifact due to the way the Z factor is calculated for reservoirs that contain gas mixtures with a significant fraction of heavier gases.

Only 118 oil reservoirs are suitable for CO_2-EOR according to the criteria presented previously. These 118 reservoirs were selected through a process of successive screening in the order presented here, by which, if a reservoir did not meet a particular criterion, it was eliminated without further checking it against other criteria. Of the 262 rejected oil reservoirs, 18 are either too heavy (API < 27º) or too light (API > 48º), 13 have too low pressure (< 7580 kPa), 38 have initial pressure less than the minimum miscibility pressure, and 136 are too small (OOIP < 1 Mmbl, or 159,000 m3) to make them worth of consideration. The list of oil pools that are suitable for CO_2-EOR is given in Appendix C.

In regard to oil and gas pools in the same pool, data analysis by field, pool and sequence codes (or names) revealed 220 pairs of oil-gas pools among the initial 414 oil pools and 1832 gas pools. However, both the oil and corresponding gas reservoir are lacking critical data in the case of 7 pairs, in other 79 cases the oil reservoir has data but the corresponding gas reservoir does not (the gas pools are among the associated gas pools with no data, see Table 3), and in other 10 cases the oil reservoir is lacking critical data while the gas reservoir has them. Thus, in these 96 cases the combined CO_2-storage capacity in both the oil and corresponding gas reservoir could not be evaluated, leaving only 124 such pairs for which the calculations could be performed.

CO_2 Storage Capacity

The theoretical CO_2-storage capacity at depletion was calculated for all the 1743 gas reservoirs with data according to relation (1), and for all the 380 oil reservoirs in single drive with data according to relation (2). The effective storage capacity was then calculated for all of them according to relation (3) on the basis of aquifer support as determined according to the criteria presented in Table 1. Of the 49 water flooded oil reservoirs, only 29 have storage capacity left, and this is relatively small (negligible) for a total of approximately 1 Mt CO_2.

The additional CO_2-storage capacity in CO_2-EOR was calculated for the 118 oil reservoirs that are suitable according to the methodology presented previously for 50% HCPV (hydrocarbon pore volume) of injected CO_2. Generally the additional storage capacity is not large, varying between 13.5 and 800 kt CO_2, except for two reservoirs Buick Creek Lower Halfway and Stoddart West Belloy, whose additional CO_2-storage capacity is ~1.5 and ~1.8 Mt CO_2, respectively. The cumulative additional CO_2-storage capacity in these 118 oil reservoirs is in the order of 16.2 Mt CO_2. The incremental oil recovered through CO_2-EOR at these reservoirs varies between ~12,000 m3 and 515,000 m3, except again for the Buick Creek Lower Halfway and Stoddart West

TABLE 2. TYPE AND NUMBER OF OIL RESERVOIRS IN NORTHEASTERN BRITISH COLUMBIA AS PER B.C. 2004 RESERVES DATABASE, SHOWING ALSO THE AVAILABILITY OF CRITICAL DATA

Recovery	Production Type	Number	Number of Oil Pools with Data
Primary (single drive)	Depletion	255	229
	Gas Cap Expansion	97	93
	Gas Injection	6	6
	Gravity	1	1
	Combination	6	5
Secondary	Waterflood	44	43
	Waterflood and Gas Cap Expansion	5	3
	Total	**414**	**380**

TABLE 3. TYPE AND NUMBER OF GAS RESERVOIRS IN NORTHEASTERN BRITISH COLUMBIA AS PER B.C. 2004 RESERVES DATABASE, SHOWING ALSO THE AVAILABILITY OF CRITICAL DATA

Type of Gas Reservoir	Number	Number of Gas Pools with Data	Type of Missing Data
Non-associated	1618	1616	Depth
Gas Cap	127	127	-
Associated	87	87	OGIP, pressure, temperature
Total	**1832**	**1743**	

TABLE 4. RANGE OF CHARACTERISTICS OF OIL AND GAS POOLS IN NORTHEASTERN BRITISH COLUMBIA THAT HAVE THE WHOLE SUITE OF DATA NEEDED FOR CO_2 CAPACITY CALCULATIONS

Reservoir Type	Parameter	Minimum	Maximum
Oil	OOIP (10^3 m^3)	1.6	82,090
	Recovery Factor	0.001	0.629
	Depth (m)	407	3088
	Area (ha)	2.4	9728
	Net Pay (m)	0.3	28.0
	Water Saturation	0.026	0.617
	Porosity	0.02	0.28
	Shrinkage Factor	0.494	0.961
	Initial Pressure (kPa)	3481	39,580
	Temperature (ºC)	25	119
	Oil Density (kg/m^3)	699	926
	Oil Gravity (ºAPI)		
Gas	OGIP (10^6 m^3)	3	101,000
	Recovery Factor	0.008	43.17
	Depth (m)	340	4897
	Initial Pressure (kPa)	1,452	64,430
	Temperature (ºC)	13	175
	Compressibility (Z factor)	0.563	1.312
	CO_2 Content	0	0.3

Belloy reservoirs, whose estimated incremental oil production would be in the order of 1,050,000 and 1,345,000 m3 respectively (6.6 Mmbl and 8.46 Mmbl). The total incremental oil recovery from these 118 oil pools is estimated to be in the order of 12,192,000 m3 (76.68 Mmbl). Of course, these figures are only estimates, obtained with the methodology presented previously and on the basis of the data currently in the B.C. reserves database. However, they show the potential for CO_2-EOR in northeastern B.C. and identify the oil reservoirs with the largest potential. These reservoirs (e.g., Buick Creek Lower Halfway and Stoddart West Belloy) should be studied more in detail using specific reservoir simulations and production strategies to identify their real potential and economic value. The complete list of these reservoirs and their CO_2 storage capacity and incremental oil recovery is given in Appendix C.

For oil reservoirs, the total CO_2-storage capacity is the sum of the effective storage capacity at depletion and the additional storage capacity in CO_2-EOR if the oil reservoir is suitable for enhanced oil recovery. For the 124 pairs of oil and gas reservoirs in the same pool that both have data, the combined CO_2-storage capacity is the sum of the respective oil and gas capacities. The individual CO_2-storage capacity for the oil and gas pools in northeastern B.C. is listed in the CD associated with this report. The totals amount to 5.46 Mt CO_2 in 256 oil reservoirs, 2,162.53 Mt CO_2 in 1619 gas reservoirs, and 151.37 Mt CO_2 in the 124 pairs of oil and gas reservoirs (1999 different pools in total). The 79 oil pools for which the corresponding gas pool lacks critical data all have individual storage capacity of less than 0.5 Mt CO_2, hence likely of little or no significance. Similarly, of the 10 gas pools for which the corresponding oil pool is missing data, only Eagle West Belloy A has capacity of 1.8 Mt CO_2, all the other have capacity less than 1 Mt CO_2. However, the corresponding oil pool for the Eagle West Belloy A gas pool is water flooded with no CO_2 storage capacity, hence no error is introduced in the assessment and selection of oil and gas pools with large capacity.

The practical CO_2-storage capacity in oil and gas reservoirs in northeastern British Columbia was determined by applying the screening criteria of size (> 1 Mt CO_2) and depth (between 900 m and 3500 m) discussed previously. It should be mentioned here that 25 of the 1743 gas pools have no location given, but all except one have an effective CO_2-storage capacity less than 0.5 Mt CO_2, and only the Cutbank Falher B gas pool has a storage capacity of 830 kt CO_2. These are small gas pools that likely are not producing and are of no further interest anyway. Of the 1999 individual oil and gas pools in northeastern B.C., only 353 pools meet the criteria of size and depth, for a total CO_2-storage capacity of 1,935 Mt CO_2. The list of these reservoirs is given in Appendix D. Although these oil and gas pools represent 17.65% of the oil and gas pools in northeastern B.C. that were assessed, they possess 83.43% of the estimated CO_2-storage capacity in these oil and gas reservoirs.

Further analysis of these pools shows that the CO_2 storage capacity of ~5.3 Mt CO_2 in 31 oil reservoirs is negligible when compared to that in 352 gas reservoirs (~1,930 Mt CO_2). Note that 30 gas reservoirs have a corresponding oil reservoir. Of the 5.3 Mt CO_2 capacity in oil reservoirs, ~4.4 Mt CO_2 storage capacity will become available at reservoir depletion, and another 0.91 Mt CO_2 will be added through CO_2-EOR that will also produce close to 4 million m3 of additional oil (25 Mmbl) at 50% HCPV flooding. There is only one oil reservoir, Brassey Artex B, that has no corresponding gas reservoir and that, by itself, has a storage capacity of 1.26 Mt CO_2 at depletion (as it happens, this reservoir is not suitable for CO_2-EOR). All other 30 oil reservoirs in Appendix D have actually individual storage capacity of less than 1 Mt CO_2, but all are associated with a corresponding gas reservoir with large capacity. Five water flooded oil reservoirs have no CO_2 storage capacity. Fourteen oil reservoirs that are not suitable for CO_2-EOR, excluding the Brassey Artex B, have a cumulative CO_2-storage capacity at depletion of 1.67 Mt CO_2. Eleven oil reservoirs are suitable for CO_2-EOR, with an estimated cumulative storage capacity of 2.39 Mt CO_2, of which 1.48 Mt CO_2 at depletion and 0.91 Mt CO_2 in CO_2-EOR.

The CO_2 storage capacity in gas reservoirs ranges between 1 Mt CO_2 (Laprise Creek Baldonnel/Upper Charlie Lake F) and 118 Mt CO_2 (Helmet Jean Marie A), with an average of 5.47 Mt CO_2. Figure 2 shows a histogram of the CO_2 storage capacity in these gas pools. It is worth noting that 80 gas reservoirs have storage capacity greater than 5 Mt CO_2 each, but cumulatively they have a capacity of 1,355 Mt CO_2. Although they represent 3.6% of the oil and gas reservoirs in northeastern British Columbia, these reservoirs, whose location is shown in Figure 3 and that are listed in Table 5, should be the target of further studies because they constitute 58.42% of the CO_2 storage capacity in northeastern British Columbia. Furthermore, 21 of these 80 gas reservoirs are in the Foothills (Figure 3), with likely difficult access and maybe great depth and structural complexity. The other 59 large gas reservoirs in the undisturbed part of the basin, with a total capacity of 1,135 Mt CO_2 (~ 49% of the total), are much more accessible and likely with infrastructure in place, and these should form the object of further, detailed studies.

POTENTIAL FOR CO_2 STORAGE IN DEEP SALINE AQUIFERS AND COAL BEDS

As mentioned in the Introduction, deep saline aquifers and uneconomic coal beds are other geological media, besides hydrocarbon reservoirs, that can be used for storing CO_2. However, unlike the latter, estimating the CO_2 storage capacity for the former is much more difficult for a variety of reasons.

CHALLENGES IN ESTIMATING CO_2 STORAGE CAPACITY IN DEEP SALINE AQUIFERS AND UNECONOMIC COAL BEDS

The challenges in estimating the CO_2 storage capacity in deep saline aquifers and uneconomic coal beds fall into three categories:

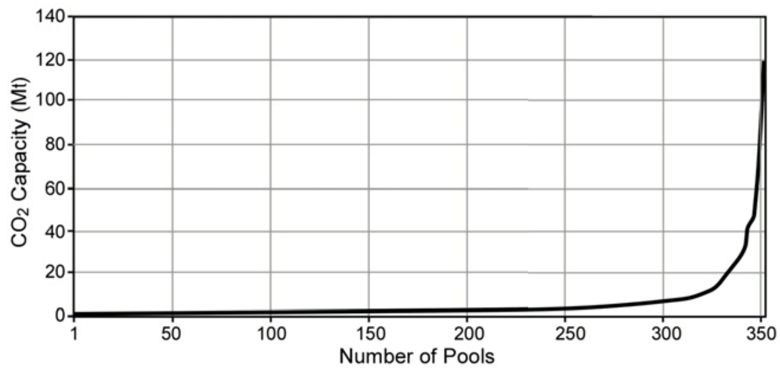


Figure 2. Histogram of the oil and gas pools in northeastern British Columbia with individual storage capacity greater than 1 Mt CO_2.

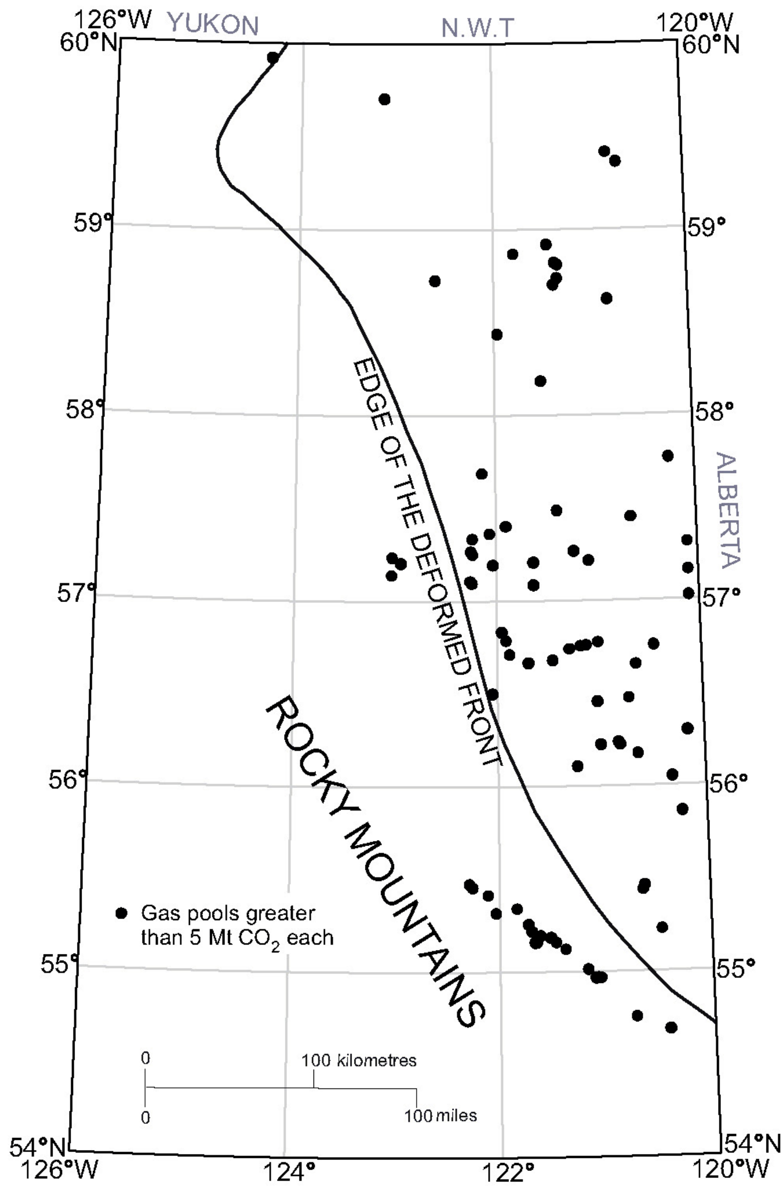


Figure 3. Location of the 80 gas pools in northeastern British Columbia with the largest CO_2-storage capacity (greater than 5 Mt CO_2 each).

TABLE 5. LIST AND CO_2 STORAGE CAPACITY OF THE LARGEST 80 OIL AND GAS RESERVOIRS IN NORTHEASTERN BRITISH COLUMBIA WITH INDIVIDUAL CAPACITY GREATER THAN 5 MT CO_2 EACH. FOR OIL RESERVOIRS, THE STORAGE CAPACITY IN EOR AT DEPLETION AND IN TOTAL IS GIVEN. IF AN OIL POOL IS ASSOCIATED WITH A GAS POOL, THEN THE TOTAL CAPACITY IS THE SUM OF THE TWO, OTHERWISE THE TOTAL CAPACITY IS EQUAL TO THE CAPACITY OF THE RESPECTIVE OIL OR GAS POOL

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	Mass CO2 @ EOR	Effective Mass CO2 (ton)	Oil CO2 Capacity	Gas CO2 Capacity	Combined Pool Capacity
740	8580	BEAVER RIVER	NAHANNI	A				8251410.437	8251410.437
800	4100	BEG	BALDONNEL	A				5903633.467	5903633.467
800	4800	BEG	HALFWAY	A				17898669.67	17898669.67
1400	2900	BLUEBERRY	DUNLEVY	A				11151657.46	11151657.46
1400	2900	BLUEBERRY	DUNLEVY	B				7307110.976	7307110.976
1400	4800	BLUEBERRY	HALFWAY	B				6326076.485	6326076.485
1950	4060	BOULDER	PARDONET-BALDONNEL	A				9776675.331	9776675.331
1950	4060	BOULDER	PARDONET-BALDONNEL	B				5592540.546	5592540.546
2000	6200	BOUNDARY LAKE	BELLOY	J				11671670.29	11671670.29
2150	4060	BRAZION	PARDONET-BALDONNEL	B				7525995.648	7525995.648
2200	4100	BUBBLES	BALDONNEL	A				7890510.267	7890510.267
2240	4150	BUBBLES NORTH	BALDONNEL/UPPER CHARLIE LAKE	A				7575459.584	7575459.584
2400	2600	BUICK CREEK	BLUESKY	C				10130019.19	10130019.19
2400	2900	BUICK CREEK	DUNLEVY	A	4122.442407	2014.671628	6137.114035	8464520.959	8470658.073
2400	2900	BUICK CREEK	DUNLEVY	B	0	786.3356989	786.3356989	7666411.534	7667197.869
2400	2900	BUICK CREEK	DUNLEVY	C	0	2133.676103	2133.676103	11072131.76	11074265.44
2800	2900	BUICK CREEK WEST	DUNLEVY	A	0	49.62855484	49.62855484	5351543.186	5351592.815
2860	4100	BULLMOOSE	BALDONNEL	A				7921424.741	7921424.741
2860	4100	BULLMOOSE	BALDONNEL	B				6807463.566	6807463.566
2860	4100	BULLMOOSE	BALDONNEL	C				6758089.11	6758089.11
2865	4060	BULLMOOSE WEST	PARDONET-BALDONNEL	C				6593968.151	6593968.151
2865	4060	BULLMOOSE WEST	PARDONET-BALDONNEL	D				6593251.452	6593251.452
2850	4060	BURNT RIVER	PARDONET-BALDONNEL	A				6946824.489	6946824.489
2920	4800	CACHE CREEK	HALFWAY	A				6238586.098	6238586.098
2985	4995	CHINCHAGA RIVER	LOWER CHARLIE LAKE/MONTNEY	A				6020139.021	6020139.021
3200	8400	CLARKE LAKE	SLAVE POINT	A				88553247.14	88553247.14
3380	2630	DAHL	BLUESKY-GETHING	A				16995537.11	16995537.11
3400	5000	DAWSON CREEK	MONTNEY	A				8513386.532	8513386.532
3430	2400	DRAKE	NOTIKEWIN	A				7232951.629	7232951.629
3450	8200	EKWAN	JEAN MARIE	A				5281233.359	5281233.359
3455	8200	ELLEH	JEAN MARIE	B				6802218.267	6802218.267
3600	4100	FORT ST JOHN	BALDONNEL	A				11773356.41	11773356.41
3600	4800	FORT ST JOHN	HALFWAY	A				6133278.104	6133278.104
4000	6200	FORT ST JOHN SOUTHEAST	BELLOY	A				7179477.321	7179477.321
4385	4100	GRIZZLY SOUTH	BALDONNEL	B				24894212.11	24894212.11
4470	8200	GUNNELL CREEK	JEAN MARIE	A				25631699.36	25631699.36
4700	8200	HELMET	JEAN MARIE	A				118066403.4	118066403.4
4700	8400	HELMET	SLAVE POINT	A				7501139.679	7501139.679

TABLE 5. CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	Mass CO_2 @ EOR	Effective Mass CO_2 (ton)	Oil CO_2 Capacity	Gas CO_2 Capacity	Combined Pool Capacity
4900	4575	INGA	INGA	A	0	0	0	12691634.91	12691634.91
5000	4150	JEDNEY	BALDONNEL/UPPER CHARLIE LAKE	A				36962850.42	36962850.42
5000	4800	JEDNEY	HALFWAY	A				16323309.44	16323309.44
5200	4800	KOBES	HALFWAY	A				11410651.73	11410651.73
5500	8400	LADYFERN	SLAVE POINT	A				30540369.15	30540369.15
5600	4150	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE	A				59792495.42	59792495.42
5600	4150	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE	B				12019955.53	12019955.53
5852	2805	MAXHAMISH LAKE	CHINKEH	A				22981632.25	22981632.25
6140	4800	MONIAS	HALFWAY	N/A				42853184.9	42853184.9
6220	4100	MURRAY	BALDONNEL	A				5143467.026	5143467.026
6220	4100	MURRAY	BALDONNEL	B				5813993.234	5813993.234
6220	4100	MURRAY	BALDONNEL	E				7766167.426	7766167.426
6220	4150	MURRAY	BALDONNEL/UPPER CHARLIE LAKE	A				21503666.81	21503666.81
6400	4100	NIG CREEK	BALDONNEL	A	1495.581537	2198.729638	3694.311176	27490336.92	27494031.23
6410	2600	NIG CREEK	BLUESKY	A				6963812.547	6963812.547
6430	2510	NOEL	FALHER B	C				5725211.813	5725211.813
6460	4800	OAK	HALFWAY	A	0	3192.63434	3192.63434	6374381.17	6377573.805
6480	4100	OJAY	BALDONNEL	A				22516110.32	22516110.32
9000	7400	OTHER AREAS	DEBOLT	C-053-J/094-G-03				5790890.102	5790890.102
6600	8100	PARKLAND	WABAMUN	A				14298530.01	14298530.01
7250	2400	PICKELL	NOTIKEWIN	A				6757579.467	6757579.467
7600	2900	RIGEL	DUNLEVY	F				41132614.98	41132614.98
7660	4990	RING	BLUESKY-GETHING-MONTNEY	A				45359322.45	45359322.45
7770	8200	SIERRA	JEAN MARIE	A				6162646.462	6162646.462
7770	8600	SIERRA	PINE POINT	A				58041889.53	58041889.53
7770	8600	SIERRA	PINE POINT	B				23953639.73	23953639.73
7770	8600	SIERRA	PINE POINT	D				8205766.58	8205766.58
7775	7400	SIKANNI	DEBOLT	C				9553961.083	9553961.083
7775	7400	SIKANNI	DEBOLT	G				5723020.652	5723020.652
7775	7400	SIKANNI	DEBOLT	H				10917177.69	10917177.69
7780	2600	SILVER	BLUESKY	A				7091702.016	7091702.016
8000	6200	STODDART	BELLOY	A				29214894.28	29214894.28
8110	4060	SUKUNKA	PARDONET-BALDONNEL	E				22431633.55	22431633.55
8110	4060	SUKUNKA	PARDONET-BALDONNEL	L				6049712.369	6049712.369
8110	4060	SUKUNKA	PARDONET-BALDONNEL	M				7171135.592	7171135.592
8110	4060	SUKUNKA	PARDONET-BALDONNEL	P				5739363.488	5739363.488
8115	2800	SUNDOWN	CADOMIN	B				12097243.51	12097243.51
8115	2200	SUNDOWN	CADOTTE	A				5797026.039	5797026.039
8150	4800	TOMMY LAKES	HALFWAY	A				46167148.17	46167148.17
8260	4100	WARGEN	BALDONNEL	B				6883745.846	6883745.846
8360	4800	WILDER	HALFWAY	A				5231576.855	5231576.855
8800	8600	YOYO	PINE POINT	A				72748677.05	72748677.05

- Knowledge and scientific gaps;
- Lack of a consistent and widely accepted methodology; and
- Lack of data.

Knowledge and Scientific Gaps

The processes leading to CO_2 storage in deep saline aquifers are more complex than in the case of either hydrocarbon reservoirs or coal beds. This is because, in the case of deep saline aquifers, several processes may act simultaneously but usually on different time scales: static trapping in stratigraphic and structural traps similarly to hydrocarbon reservoirs, hydrodynamic trapping in long-range flow systems, residual-gas trapping, dissolution and ionic trapping in formation water, and mineral precipitation. Not only that these processes act on different time scales, but also they interact with and affect each other. Figure 4 shows diagrammatically the relationship between various CO_2 storage processes in deep saline aquifers.

A significant gap in knowledge is the geochemistry of CO_2-brine-rock systems at elevated pressures and temperatures, and the speed of geochemical reactions. Most studies indicate that dissolution and geochemical reactions operate on time scales of centuries to millennia (Figure 4a; e.g., Xu *et al.*, 2003; Perkins *et al.*, 2005). Thus, to meet the CO_2 storage needs of this century, one can make the argument that these storage mechanisms should be disregarded. They would only add to the security of storage as time passes (Figure 4b), but do not contribute to capacity. On the other hand, some geochemists argue that some reactions occur very fast, and alter the mineral composition of the formation water and rock matrix.

Similarly, there is no quantitative understanding of the effect of mineral geochemical changes (dissolution and precipitation) on the flow characteristics (porosity and permeability) of the rock matrix. These, in turn, affect the spread and flow of the injected CO_2, hence hydrodynamic trapping, dissolution and mineral precipitation, since a plume of CO_2 that travels faster will encounter more undersaturated brine and new rock. In regard to residual-gas trapping, this process is activated only when the plume of injected CO_2 flows away, updip, from the injection site, and formation water invades back the pore space previously occupied by CO_2 (Kumar *et al.*, 2005). This process too is affected by the hydrodynamics of CO_2 flow, and by the displacement characteristics of CO_2-brine systems.

Finally, there are currently no comprehensive numerical models to simulate all the physico-chemical processes that take place when CO_2 is injected and stored in deep saline aquifers, neither is there computational power to solve such a complex system at the needed resolution.

In regard to CO_2 storage in uneconomic coal beds, there is disagreement in the scientific community about the effect of supercritical CO_2 on coal and about the storage process for liquid and supercritical CO_2. Is it adsorption, as in the case of gaseous CO_2, or it is absorption? It seems that adsorption is replaced by absorption and the CO_2 diffuses ("dissolves", Larsen, 2003) in coal. The transition from one process to the other is not sharp, but rather gradual. Carbon dioxide 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). The transition temperature may drop from ~ 400^{o}C at 3 MPa to < 30^{o}C at 5.5 MPa (Larsen, 2003). Coal plasticization, or softening, destroys any permeability that would allow CO_2 injection. In addition, some studies suggest that the injected CO_2 may react with the coal. However, CO_2 was successfully injected in coal beds in the San Juan Basin and in Alberta at depths that correspond to supercritical CO_2 phase.

Another issue relating to CO_2 storage in coal beds is coal permeability and how it is affected by CO_2. It is known that coal permeability decreases with increasing depth as a result of increasing stress that closes the cleats, but this relationship has not been quantified and it is highly dependent on local coal characteristics and depositional setting. Furthermore, coal swells as CO_2 is adsorbed and/or absorbed, which reduces permeability and injectivity (Clarkson and Bustin, 1997; Larsen, 2003). Also, the effect of other gases, either present in the coal matrix, or injected in an impure stream of CO_2, on CO_2 adsorption onto the coal matrix is not well understood and quantified. The lack of understanding regarding CO_2 effects on coal and the effect of other gases affects the ability to estimate the CO_2 capacity in coal beds.

Lack of Consistent Methodology

As pointed out in the IPCC Special Report on CO_2 Capture and Storage (IPCC, 2005), currently there is no consistent and accepted methodology for estimating the CO_2 storage capacity in deep saline aquifers. One school of thought considers that only stratigraphic and structural enclosures at the top of deep saline aquifers should be considered, these being similar to hydrocarbon reservoirs overlying an aquifer but being saturated with formation water rather than charged with oil and/or gas (e.g., Holloway *et al.*, 2006), all other trapping mechanisms being neglected. These estimates represent indeed a lower bound of storage capacity in deep saline aquifers. At the other end of the spectrum, dissolution and mineral precipitation are included in capacity estimates (e.g., Xu *et al.*, 2003), but these estimates do not consider the different time scales involved and the need for storage capacity this century rather than several centuries or thousand years from now.

Yet, other methods, used particularly in the past, estimate the CO_2 storage capacity for an aquifer or a basin based on area and pore space (e.g., Koide *et al.*, 1993), while others are based on numerical simulations (e.g., van der Meer, 1993; Kumar *et al.*, 2005). Each methodology has different data requirements and is based on different assumptions. The first method has been shown to be erroneous (Bradshaw and Dance, 2005), but the second one can produce estimates only at the local, site-specific scale, and it is not suitable for the whole of a sedimentary basin or at regional scale.

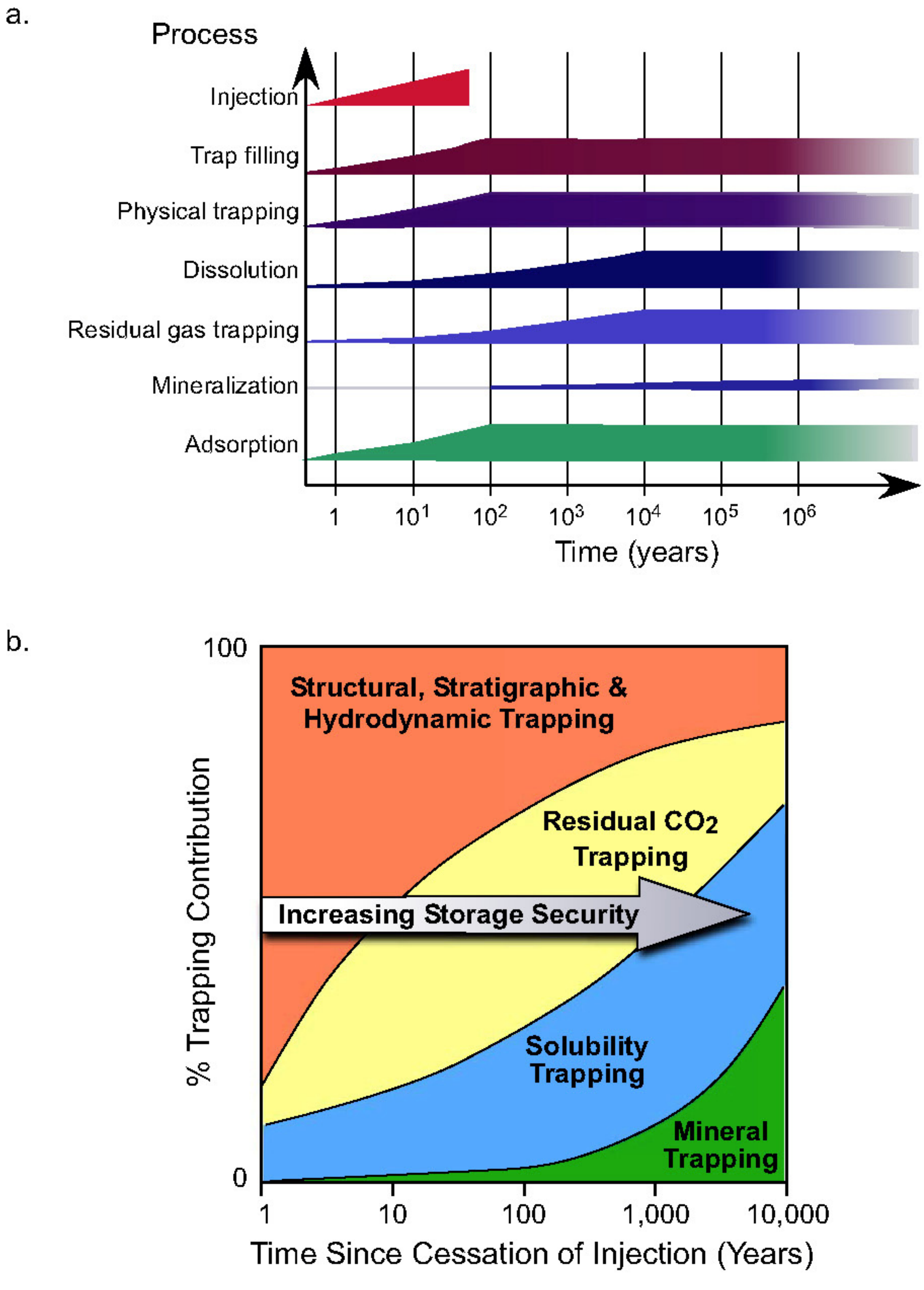


Figure 4. Relationship between various CO_2 storage processes in deep saline aquifers: a) time scales, and b) storage security.

In regard to CO_2 storage in coal beds, the lack of knowledge regarding the limits of applicability (permeability wise or from the point of view of CO_2 phase) shows only that it is very difficult to agree on and establish the deep depth-limit of a coal bed being considered for CO_2 storage. Is it the depth at which the very low permeability does not allow CO_2 injection unless the coal is fractured, jeopardizing the integrity of the storage site, or it is the depth that corresponds to the phase change of CO_2 from gaseous to liquid or supercritical? At the other end, the shallow depth-limit is equally difficult to establish, but for different reasons, the main criterion being protection from contamination of potable groundwater resources.

In addition, the very definition of “uneconomic coal beds” is open to debate and likely will evolve in time as technology advances and the need for stable and secure energy supplies increases. Shallow coal seams that are uneconomic to be mined today may be mined underground in the future, at which time any stored CO_2 will be released back into the atmosphere, notwithstanding that it may pose a safety hazard. Or, currently uneconomic coal seams may produce coal gas in the future or may be gasified in situ, as the price of gas increases. Finally, for any particular coal bed, the well density and recovery and completion factors will affect the CO_2-storage capacity estimates.

Lack of Data

The lack of data is a self-evident challenge. In the case of deep saline aquifers, there is need to know their geometry and internal architecture, pressure and temperature, and the composition, properties and characteristics of formation water and rocks. However, much less is known about these, and at a poorer, coarser resolution than in the case of oil and gas reservoirs because of the lack of an economic interest in obtaining, collecting and storing this information. Whatever is known is the result of drilling and testing when exploring for oil and gas (i.e., from dry holes). Furthermore, there are no data about the displacement characteristics of CO_2-brine systems, as opposed to CO_2-oil systems, and only very recently, a few laboratory measurements have been performed to quantify these (Bennion and Bachu, 2005).

In the case of uneconomic coal beds, there is need to know their geometry and thickness, composition, rank, ash and moisture content, adsorbed gases, and adsorption capacity for CO_2 at various temperatures and pressures and in the presence of other gases. This information is not collected usually, and when it is collected, it is generally at a very coarse resolution. The very definition of “uneconomic coal bed” precludes data collection since this represents a cost with no return on investment. Lately, with growing interest in producing coalbed methane (or coalbed gas) from coal beds, more data are being collected by industry to define and characterize this resource and associated reserves. Since CO_2 storage in coal beds may enhance coalbed methane recovery, additional relevant data are collected in places, but nowhere sufficiently for estimating CO_2 storage capacity.

To conclude, the CO_2 storage capacity in deep saline aquifers and coal beds in northeastern British Columbia cannot currently be estimated with any level of confidence with the existing knowledge and data. However, an evaluation of the potential for CO_2 storage and identification of strata and areas where this technology can be used are possible, and these will be addressed in the following.

THE POTENTIAL FOR CO_2 STORAGE IN DEEP SALINE AQUIFERS AND COAL BEDS IN NORTHEASTERN BRITISH COLUMBIA

Because the capacity for CO_2 storage in deep saline aquifers cannot be estimated for the reasons discussed previously, the potential for CO_2 storage will be assessed indirectly, on the basis of proxy characteristics. Deep saline aquifers posses by definition the porosity and permeability needed for CO_2 storage and injectivity, respectively. If fluids cannot be produced from or injected into a geological formation, then that formation is either an aquitard (e.g., shales) or an aquiclude (e.g., salt beds), otherwise it is an aquifer. Thus, the potential for CO_2 storage in deep saline aquifers is assessed here on the basis of the existence of a confining unit above each aquifer, a condition that is met by all but the shallowest drift aquifers in northeastern British Columbia, and by the pressure and temperature conditions at which CO_2 is a dense fluid (liquid or supercritical), to maximize storage efficiency. To illustrate this point, Figure 5 shows the dependence of CO_2 density on temperature and pressure, and Figure 6 shows the variation of CO_2 density with depth assuming a hydrostatic pressure gradient and various geothermal regimes. The geological space (defined by geological and lithological units, pressure and temperature) is transformed into the CO_2-phase space using the methodology described by Bachu (2002), and the region of CO_2-storage applicability is defined for each aquifer on the basis of the domain where the injected CO_2 will be in a dense phase.

Geology and Hydrostratigraphy

Only a very brief geological description is provided here for the sedimentary succession in northeastern British Columbia, for more detail the interested reader could consult the Geological Atlas of the Western Canada Sedimentary Basin (Mossop and Shetsen, 1994). The Cambrian to Lower Jurassic succession was deposited during the passive-margin stage of basin evolution and consists mainly of carbonate and evaporitic strata, with a few intervening shale units. The Upper Jurassic to Cretaceous strata consist of a succession of regional-scale thin sandstone and thick shale units deposited during the foreland stage of basin evolution. The stratigraphic and hydrostratigraphic nomenclature of the sedimentary succession in northeastern British Columbia is presented in Figure 7.

The basin was initiated during the Proterozoic by rifting of the North American craton. Due to extensive erosion in the Middle Ordovician and especially in the Early Devonian, only a small remnant of Cambrian strata is present in northeastern British Columbia. This

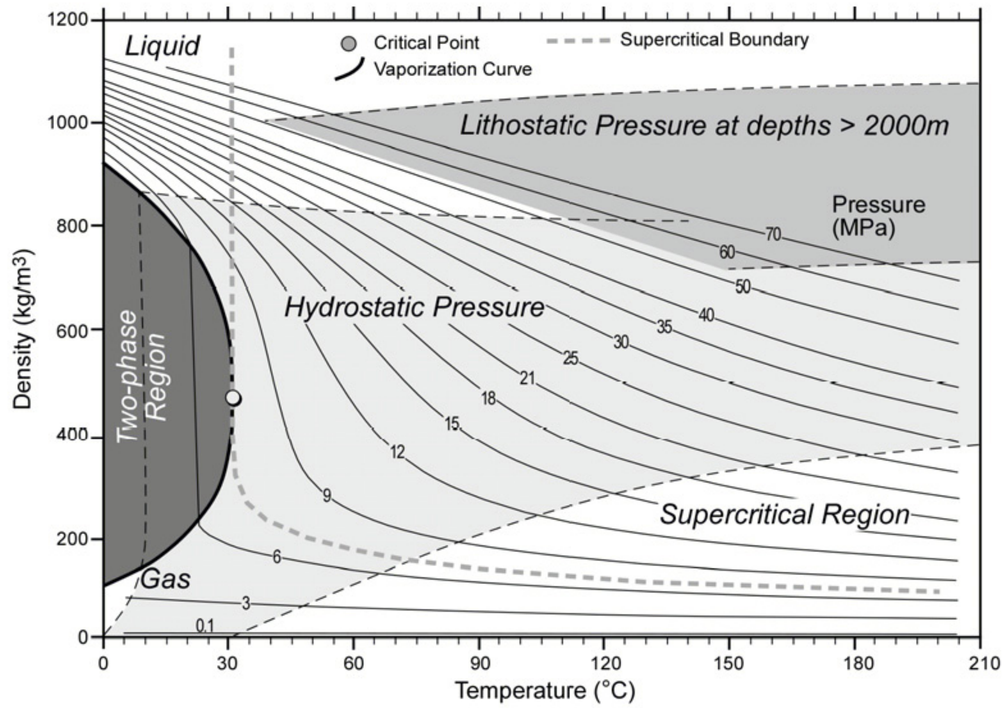


Figure 5. Variation of CO_2 density with temperature and pressure, and expected range of variation in sedimentary basins.

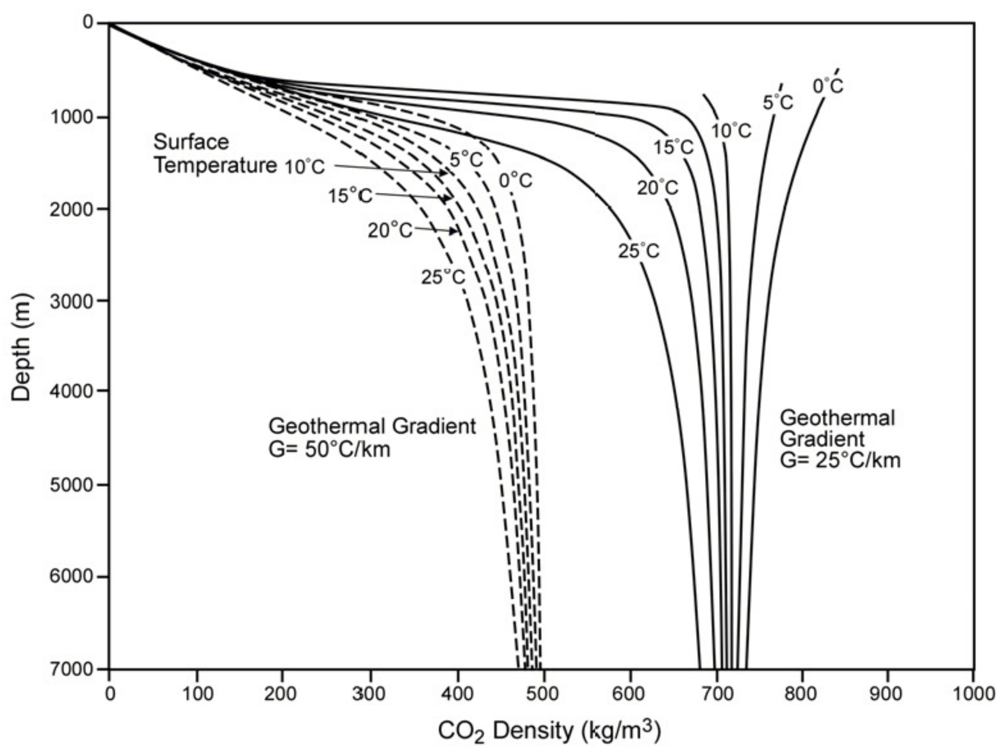


Figure 6. Variation with depth of CO_2 density assuming a hydrostatic pressure gradient and various geothermal conditions in a sedimentary basin (after Bachu, 2003).

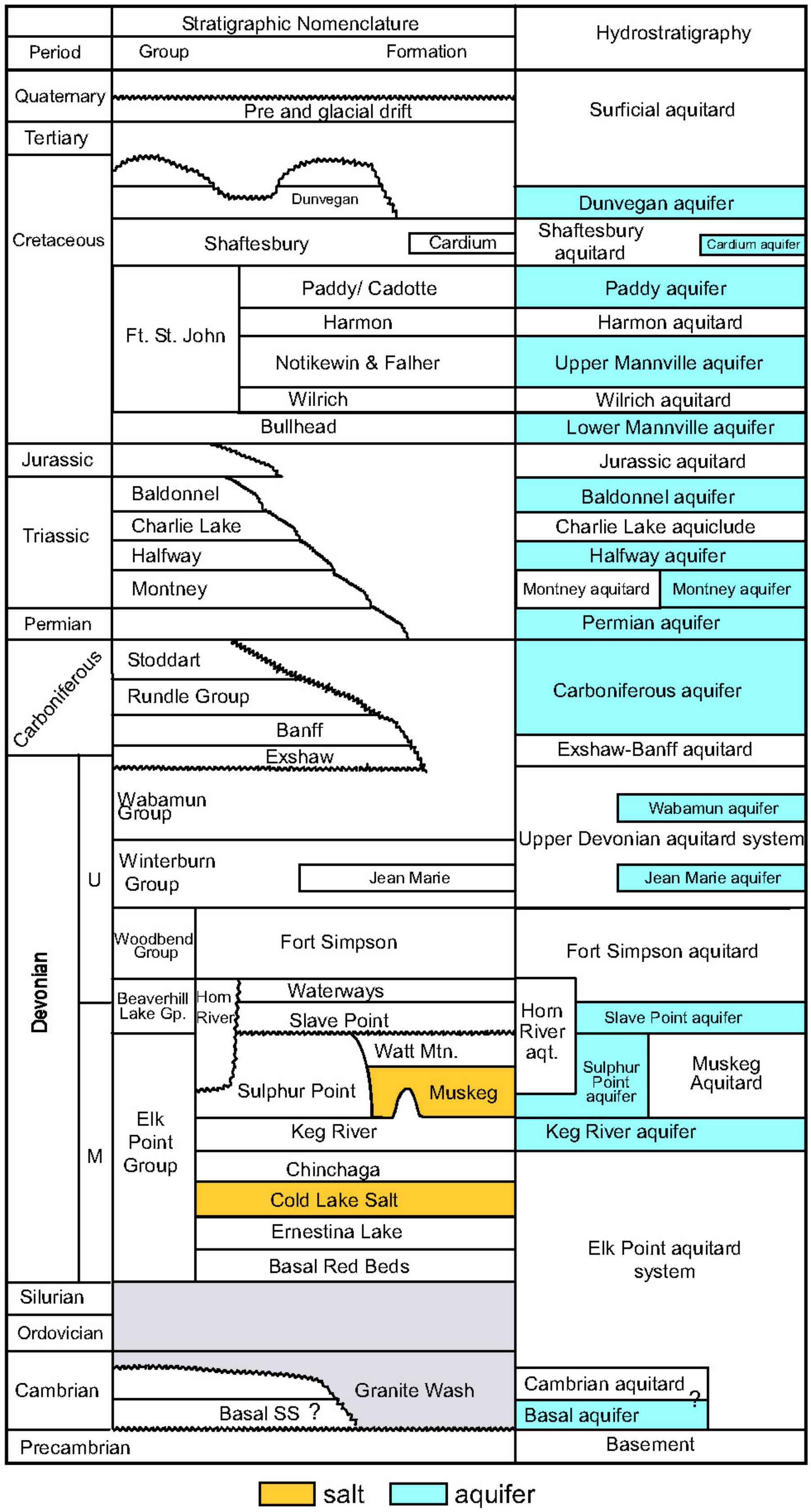


Figure 7. Stratigraphic and hydrostratigraphic nomenclature of the sedimentary succession in northeastern British Columbia.

succession, up to 200 m in thickness, comprises a thin basal sandstone unit, which forms an aquifer, overlain by dominantly silty shale that forms an aquitard. During most of the Devonian, the Peace River Arch was a land feature that slowly submerged in the surrounding sea. As a result, depositional boundaries of successively younger Middle and Late Devonian units advance southward against the Peace River landmass until its complete submersion during Late Devonian, when it was covered by the carbonate rocks of the Wabamun Group (Figure 8a). A Middle Devonian interbedded succession of low-permeability anhydritic red beds and carbonate, halite, and argillaceous carbonate (Basal Red Beds, and the Ernestina Lake, Cold Lake and Chinchaga formations) overlies the Cambrian or Granite Wash detritus at the top of the Precambrian and forms the Elk Point aquitard system (Bachu, 1997). The location of the thin Cold Lake salt beds in the northern part of the area is also shown in Figure 8a. The succession at the base of the Middle Devonian is overlain by the platform and reefal carbonate rocks of the Keg River Formation, which form an aquifer.

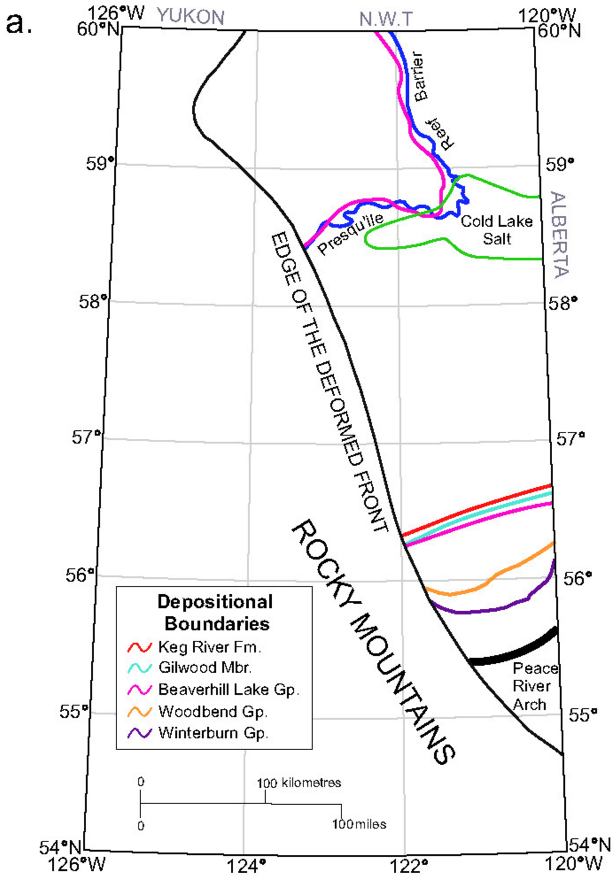
A major feature in northeastern British Columbia is the Presqu'ile reef barrier (Figure 8a), deposited during the late Middle Devonian. Shales of the Horn River Formation were deposited west of the barrier reef. The barrier limited the southward flow of seawater and led to deposition in the southern part of the area, toward the Peace River Arch landmass, of the evaporitic beds of the anhydrite-dominated Muskeg Formation, which forms an aquitard. Toward the Peace River Arch in the south, the evaporite beds of the Muskeg Formation change facies into the sandstone of the Gilwood Member, which is derived from clastic sediments eroded from the Peace River landmass. Subsequent reef growth along the seaward (northwest) edge of the Presqu'ile barrier reef formed the Sulphur Point Formation. Inside the barrier reef complex, the small inter-reef Cordova sub-basin was filled with shale coeval with the Horn River Formation. This complex lithological structure is disconformably overlain by the thin shale of the Watt Mountain Formation. Thus, the Keg River aquifer is overlain by a laterally complex, interlaced hydrostratigraphic structure consisting of the Horn River aquitard, the Sulphur Point aquifer and the Muskeg aquiclude (Figure 7). In the northern part of northeastern British Columbia, the Keg River and Sulphur Point aquifers are in contact, forming the Elk Point aquifer system (Bachu, 1997). In the south, abutting the Peace River Arch, the carbonate of the Keg River Formation and the overlying sandstone of the Gilwood Member also form the Elk Point aquifer system.

The Elk Point Group is overlain by the Beaverhill Lake Group, which can be subdivided into the open-marine platform carbonate of the Slave Point Formation, and the shale and argillaceous carbonate of the Waterways Formation. The seaward depositional margin of the Beaverhill Lake Group is roughly coincident with the underlying Elk Point Group reef barrier, with coeval shales of the Horn River Formation being deposited seaward. The Beaverhill Lake Group is overlain by the Woodbend Group, which consists mostly of a thick succession of shale-dominated strata (Fort Simpson Formation). Thus, the Slave Point aquifer is overlain by the Fort Simpson aquitard system (comprising the Waterways and Fort Simpson formations). The Woodbend Group is overlain by the Winterburn and Wabamun groups, which are dominated in northeastern British Columbia by shales, except for the carbonates of the Jean Marie Member in the Winterburn Group to the northeast and carbonates of the Wabamun Group to the southeast.

Carboniferous strata in northeastern British Columbia conformably overlie the Devonian rocks and consist of two major lithofacies associations. The lower one comprises the thin but competent shale of the Exshaw Formation and the overlying thick, shale-dominated Banff Formation, which together form the Exshaw–Banff aquitard. The top part of the Carboniferous succession consists of the carbonate rocks of the Rundle and Stoddart groups that form the Carboniferous aquifer (Bachu, 1997). A thin layer of Permian (Belloy Formation) interbedded siliciclastic and carbonate unconformably overlies the Carboniferous strata, and is overlain in turn by a Triassic succession that consists, in ascending order, of the shale and the sandstone of the Montney Formation, the sandstone-dominated Halfway Formation, the evaporites (halite) of the Charlie Lake Formation and the sandstone of the Baldonnel Formation (Figure 7). The Permian and Triassic strata form a succession of aquifers (Belloy, Montney, Halfway and Baldonnel) separated by intervening aquitards and aquicludes (Montney and Charlie Lake).

As a result of accretion of allochthonous terranes to the western margin of the North American protocontinent during the Columbian and Laramide orogenies of the Late Jurassic to Early Cretaceous and the Early Tertiary, respectively, the sedimentary strata were pushed eastward, being thrusted and folded into the Rocky Mountains and the foreland Thrust and Fold Belt, which today constitute the western boundary of the undeformed part of the basin. Because of lithostatic loading and isostatic flexure, the Precambrian basement tilted westward, such that progressively older Jurassic to Carboniferous strata subcrop in northeastern British Columbia at the sub-Cretaceous unconformity as a result of basement tilting and pre-Cretaceous erosion (Figure 8b). The foreland basin filled with synorogenic clastic sediments derived from the Cordillera.

The Upper Jurassic sandstone and shale strata of the Fernie Group represent the first influx of siliciclastic sediments from the west. The entire area is unconformably overlain by the Lower Cretaceous sediments of the Mines and Bullhead groups. As a result of peat deposition in a fluvial environment, these strata are rich in coal. The overlying Lower Cretaceous Fort St. John Group consists of a succession of sandstone-dominated strata (Falher, Notikewin and Paddy formations), deposited in a mainly fluvial and estuarine environment, alternating with shale-dominated strata, deposited in a mainly marine environment (Wilrich, Harmon and Shaftsbury formations). The deposition of the post- Notikewin strata corresponds to the post-Columbian orogeny lull in plate convergence, which was characterized by a widespread marine transgression. By analogy with the hydrostratigraphic succession in northern Alberta (Bachu, 1997), the entire Jurassic–Lower Cretaceous succession can be divided (Figure 7) into a



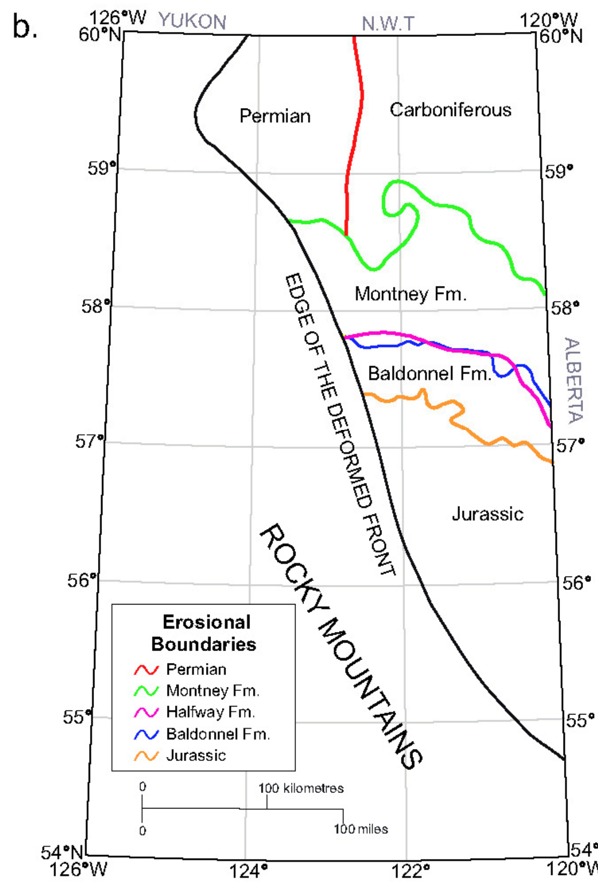


Figure 8. Depositional features in northeastern British Columbia: a) Devonian strata, and b) Carboniferous to Jurassic strata.

succession of aquifers (Bullhead, Falher and Paddy) separated by intervening aquitards (Wilrich, Harmon and Shaftsbury). The entire succession becomes shaly northward, such that the aquifers are present mostly in the southern part of northeastern British Columbia, whereas a single aquitard (Fort St. John) is present in the northern part.

Most of the Upper Cretaceous strata are eroded in northeastern British Columbia. The sandstone Dunvegan Formation, overlying the Fort St. John Group, is present in the subsurface in the south (south of latitude 56°N) and at the top of the bedrock further to the north, until it almost disappears north of 58°N. The sandstone Cardium Formation, isolated by underlying and overlying shale units, is present only at the southern tip of northeastern British Columbia. Finally, the sandstone-dominated Wapiti Group is similarly present at the top of the bedrock only at the southern tip. The Cretaceous strata that crop out at the top of the bedrock, with increasing age from south to north (Wapiti Group to Fort St. John Group), are covered by unconsolidated Quaternary sediments of pre- and postglacial origin.

Geothermal, Flow and Pressure Regimes

The multiyear ground-surface temperature in northeastern British Columbia is around 4°C and geothermal gradients increase from slightly less than 30°C/km in the south to more than 45°C/km in the north (Bachu and Burwash, 1991). With respect to geothermal effects on CO_2 storage, northeastern British Columbia displays the characteristics of a cold basin in the south and a warm basin in the north (Bachu, 2003). Carbon dioxide migrating upward will change phase from supercritical to liquid and then to gas in the south, but will undergo a direct phase-change from supercritical to gas in the north. Also, CO_2 will reach higher density in the south than in the north, resulting in greater storage capacity for the same pore space.

The flow of formation waters in pre-Cretaceous strata in the northern part of northeastern British Columbia is driven by topography in a regional-scale system that flows from recharge areas at the Thrust and Fold Belt to discharge areas in the northeast at the Slave River and Great Slave Lake (Bachu, 1997). In the south, toward the Peace River arch, flow in deep Devonian strata is driven in a regional-scale flow system by past tectonic compression (Hitchon *et al.*, 1989; Bachu, 1995). The flow in the Lower and Upper Mannville aquifers is generally driven by topography in an intermediate-scale flow system (Hitchon *et al.*, 1989). However, the Lower Cretaceous strata near the Thrust and Fold Belt at the southern tip of northeastern British Columbia are mostly saturated with gas and are abnormally pressured as a result of gas generation (Hitchon *et al.*, 1989; Michael and Bachu, 2001). The flow in Carboniferous to Triassic aquifers in the south is also driven in regional-scale systems. Finally, the flow in the shallow Paddy, Dunvegan and Cardium aquifers is driven by topography in local-scale flow systems that discharge at outcrop along river valleys throughout northeastern British Columbia or to the east in Alberta.

The sedimentary strata in northeastern British Columbia are normally pressured or slightly subhydrostatic. At these conditions, CO_2 will always be lighter than formation waters (Figure 5), and lighter than reservoir oil in most cases. Carbon dioxide injected into aquifers in the sedimentary succession of northeastern British Columbia will migrate updip to the northeast, driven by buoyancy. Its migration will be enhanced by the concurrent, northeastward flow of formation waters. Because the flow in the shallow post-Mannville aquifers is in local-scale systems, CO_2 storage in these strata should generally not be considered because of the high buoyancy of the CO_2, unless depleted oil or gas reservoirs are being used for storage (stratigraphic trapping).

Suitability of Deep Saline Aquifers for CO_2 Storage

The Middle Devonian and Cambrian strata in northeastern British Columbia are found at depths greater than 1500 m, with corresponding pressures and temperatures greater than 14 MPa and 50ºC, respectively. This means that CO_2 injected into and stored in the Cambrian Basal Sandstone aquifer, if present, and in the carbonate Keg River, Sulphur Point and Slave Point aquifers (Figure 7) will always be in dense supercritical phase. These aquifers underlie most of northeastern British Columbia, except for its northwest corner (Figure 8a), and are overlain by the thick Fort Simpson aquitard. Thus, there is likely good potential for CO_2 storage in these aquifers in both stratigraphic and structural traps that have to be identified, and hydrodynamically in the regional-scale flow system that operates below the Ft. Simpson aquitard (Bachu, 1997). Carbon dioxide dissolution will probably be limited because of the high salinity of formation water in these aquifers. The Jean Marie aquifer in the Winterburn Group, of limited areal extent, is the lowermost aquifer in the succession where, depending on location, the injected CO_2 will be in gaseous phase or in a dense, liquid or supercritical phase (Figure 9a). This is because pressures in the northeast are below the CO_2 critical pressure of 7.38 MPa. Because most of the Wabamun Group consists of shale over most of the area, particularly in the north, and carbonate rocks, which form an aquifer, are present only in the south, where temperatures and pressures are greater than 80ºC and 20 MPa, respectively, CO_2 injected into the Wabamun aquifer in the south will be in dense supercritical phase.

The lower part of the Carboniferous, comprising the shales and shale-dominated Exshaw and Lower Banff formations, forms a strong aquitard that separates the overlying Carboniferous aquifer (Rundle and Stoddart groups) from the underlying Devonian units. Depths to the top of the aquifer vary from less than 400 m in the north to more than 4400 m in the south, with temperatures and pressures varying accordingly from less than 20°C in the northeast to approximately 160°C in the south, and from less than 4 MPa in the northeast to greater than 26 MPa in the south, respectively. Thus, depending on location, CO_2 injected into the Carboniferous aquifer will be in all three phases, from supercritical in the south to gaseous in the north and northeast (Figure 9b). This pattern reoccurs for all shallower, stratigraphically younger aquifers in the sedimentary succession, and its distribution is either limited by aquifer extent or uncertain due to lack of data.

The Permian (Belloy Formation) is present only in the southern part of northeastern B.C. and in the Liard subbasin in the northwest, having been eroded during the Late Jurassic and Early Cretaceous. Depths range from less than 200 m to more than 3200 m in the northwest (Liard subbasin), and from less than 600 m in the northeast to more than 4200 m in the south. Temperatures vary accordingly from less than 10°C to approximately 150°C in the south. There are no pressure data for the northern and southwestern parts of the Permian, but the existing data indicate that pressures vary from less than 8 MPa to greater than 26 MPa. As in the case of the underlying Carboniferous aquifer, CO_2 injected into the Permian will be in all three phases, depending on location (Figure 9c), although one can only speculate about the Liard subbasin.

Like the underlying Permian and Carboniferous strata, the Triassic has been eroded by late Jurassic to early Cretaceous erosion, and is present only in the southern two thirds of northeastern British Columbia. Successively younger formations, the Montney, Halfway, Charlie Lake and Baldonnel, subcrop from south to north (Figure 8b). The oldest Triassic unit, the Montney Formation, is dominated by shale in the western part, and by sandstone in the eastern part; it is therefore an aquitard in the west and an aquifer in the east. Depths to the Montney Formation vary between approximately 600 m at its northern end to more than 4000 m at its southern end. Temperatures vary from less than 30°C to approximately 150°C. The very few existing pressure data for the Montney aquifer indicate that pressures vary from less than 4 MPa to more than 12 MPa. Therefore, CO_2 injected in the Montney aquifer would be in all three phases, depending on location (Figure 9d).

The overlying Halfway aquifer is found at depths varying from less than 1000 m in the north to 4000 m in the south. Temperatures range from approximately 40°C in the north to approximately 140°C in the south. Pressures in this aquifer vary from less than 6 MPa to greater than 34 MPa. Consequently, CO_2 injected into the Halfway aquifer will be in all three phases, but mostly in supercritical phase, depending on location (Figure 9e). The Baldonnel aquifer is separated from the underlying Halfway aquifer by the evaporitic rocks of the Charlie Lake Formation. Depths to the top of the Baldonnel aquifer vary from approximately 1000 m in the north to approximately 3700 m in the south. Temperatures at the top of the aquifer vary from less than 40°C in the northeast to approximately 130°C in the south. Although there are no pressure data in the north and southwest, pressures vary likely from less than 8 MPa in the north to greater than 14 MPa in the south. Thus, CO_2 injected into this aquifer will be in supercritical phase in the southern area, and likely in liquid and gas phase in the northern part.

The Triassic strata are partially overlain by Jurassic siliciclastic rocks (Figure 8b), which are dominated by shale in northeastern British Columbia. Thus, the Jurassic, where present, forms an aquitard between the underlying Baldonnel aquifer and the overlying Lower Cretaceous Bullhead aquifer, which disconformably overlies the Carboniferous to Jurassic strata that subcrop at the sub-Cretaceous unconformity (Figure 8b). The entire succession becomes shaly in the northern part of northeastern British Columbia, such that the Bullhead and Falher aquifers are present only in the southern part. Both aquifers are gas-saturated at their southern tip (Figures 9f and 9g), where gas generation probably still takes place (Masters, 1979). Thus, this region should not be used for CO_2 storage while there is still potential for gas production. Depth to the Bullhead aquifer varies from less than 400 m in the north to more than 2800 m in the south, and to the Falher aquifer varies from less than 200 m in the north to more than 2600 m in the south. Temperature at the top varies from less than 20°C in the north to approximately 110°C in the south for the Bullhead aquifer, and from less than 20°C in the north to more than 90°C in the south for the Falher aquifer. Pressures in these aquifers vary from less than 4 MPa in the northeast to approximately 20 MPa in the south. Thus, CO_2 injected into these aquifers will be in supercritical, liquid and gas phases, depending on location (Figures 9f and 9g).

The Paddy Formation is found everywhere in northeastern British Columbia, at depths ranging from less than 200 m in the northwest to more than 2600 m at the southern tip, and with temperatures varying accordingly between less than 20°C and approximately 90°C. However, it is mostly shaly, and therefore an aquitard, over most of the region, except where it is deepest in the southern part (approx. south of latitude 56°N). Pressures in this area vary from less than 4 MPa to greater than 14 MPa. Consequently, CO_2 injected into the Paddy aquifer in northeastern British Columbia will be in all three phases, depending on location (Figure 9h). Like the underlying Falher and Bullhead aquifers, the Paddy aquifer is saturated with gas at its southern tip (Figure 9h), hence this region should not be used for CO_2 storage.

Shallower aquifers such as Dunvegan and Cardium, which are present only in the southern part of northeastern British Columbia as the result of Tertiary to Recent erosion, are not suitable for CO_2 injection for the following reasons. First, pressures are less than 7.38 MPa (the CO_2 critical pressure), thus injected CO_2 will be in gaseous phase. Second, these aquifers crop out along river valleys to the north, and CO_2 will migrate updip, driven by a very strong buoyancy, and will escape back into the atmosphere at outcrop.

Suitability of Coal Beds for CO_2 Storage

Coals are found in northeastern British Columbia in the Lower Cretaceous Bullhead Group, having been deposited in a fluvial environment, and probably contain coalbed gas that could be produced. Consequently, CO_2 could be stored in these coal beds by adsorption, thereby producing methane concurrently. Because methane is a much cleaner fossil fuel than coal, substituting it for coal also contributes to lowering CO_2 emissions into the atmosphere. However, these coals are found at great depths that vary from ~ 600 m to more than 2800 m, with most of them being at depths greater than 1000 m (Figure 10a). As discussed previously in the section on

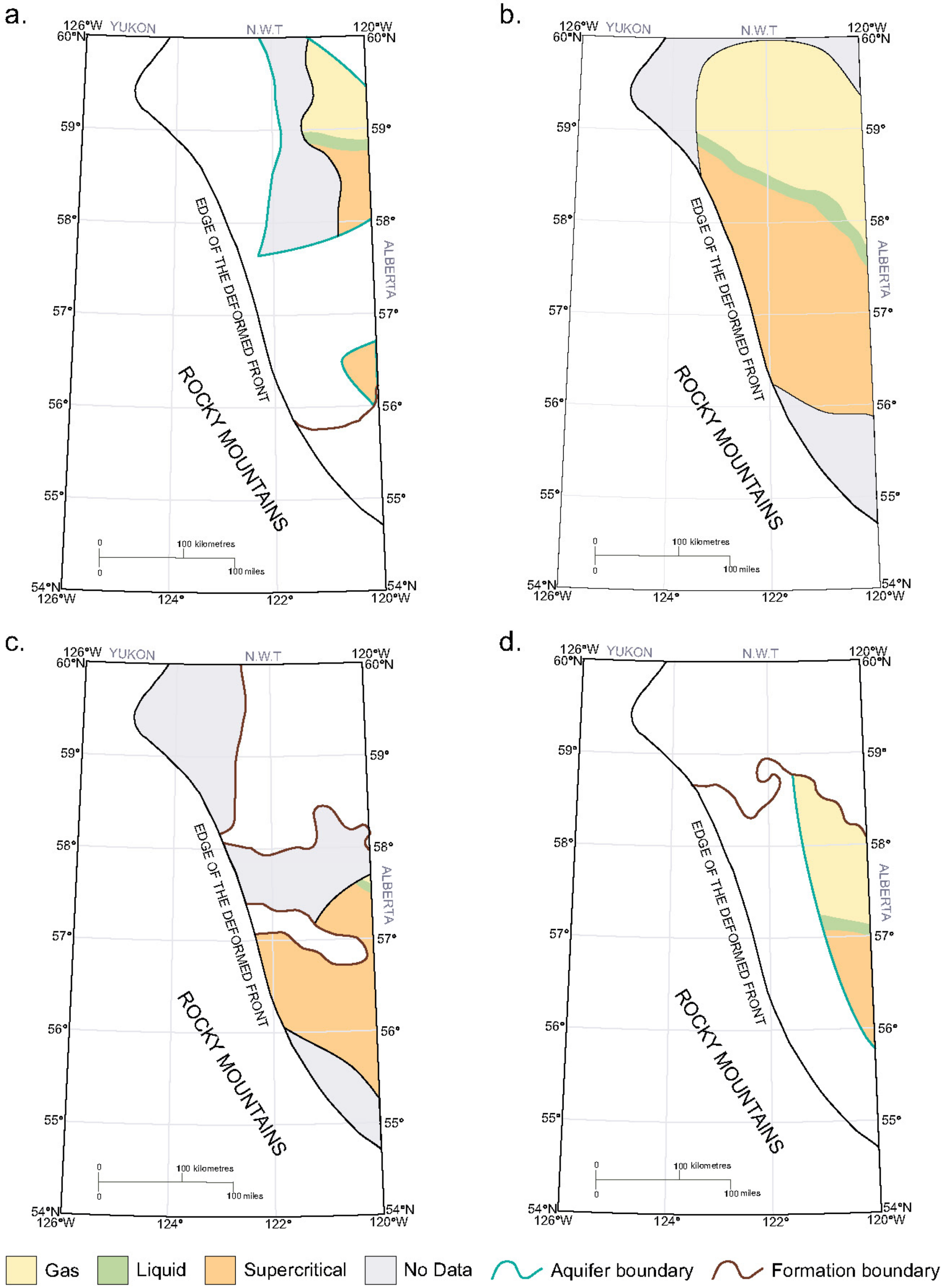


Figure 9. Phase distribution of CO_2 at the top of various aquifers in northeastern British Columbia: a) Jean Marie, b) Carboniferous, c) Permian, and d) Montney.

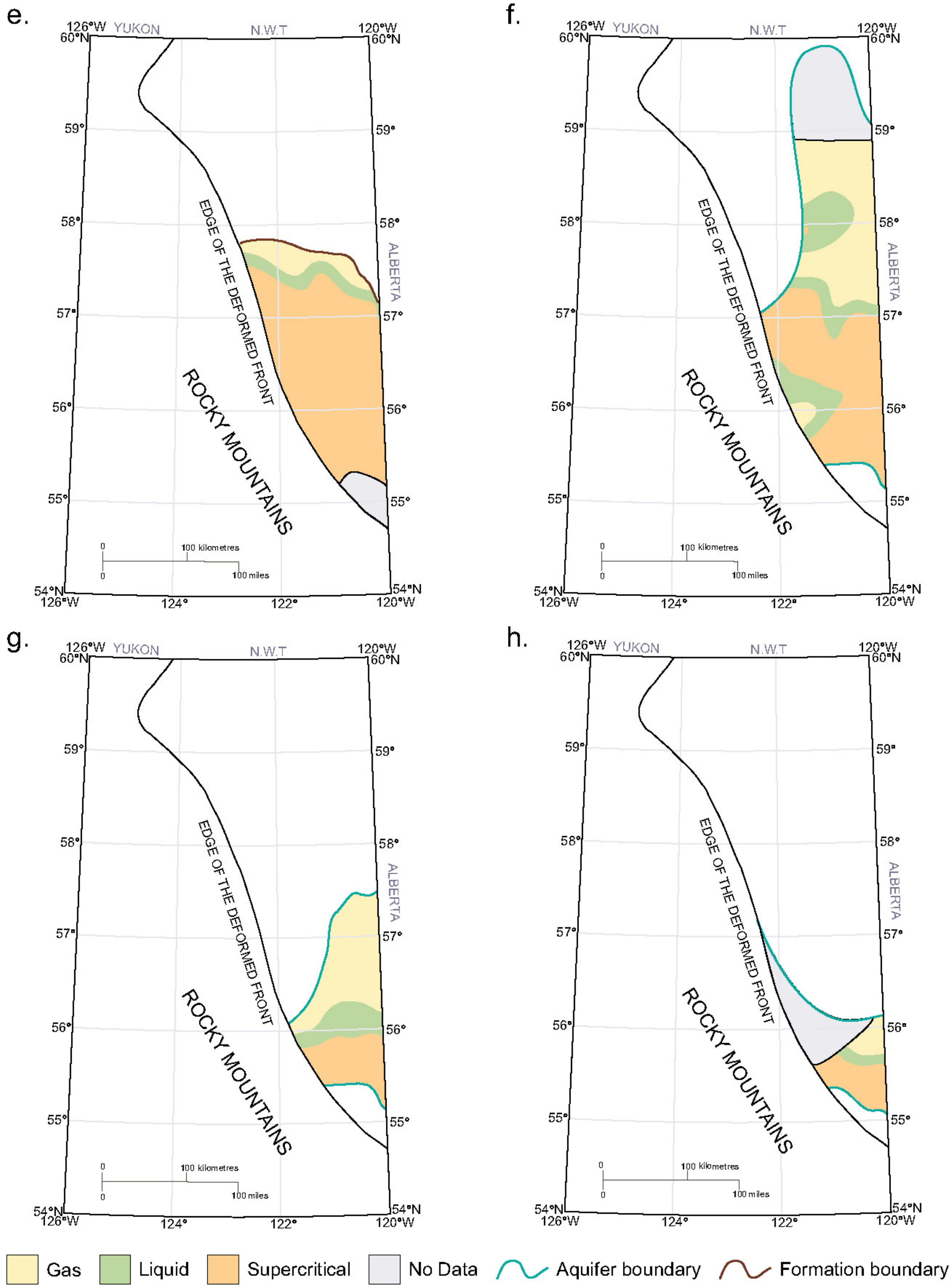


Figure 9 continued. Phase distribution of CO_2 at the top of various aquifers in northeastern British Columbia: e) Halfway, f) Lower Mannville (Bullhead), g) Upper Mannville, and h) Paddy.

Challenges in Estimating CO_2 Storage Capacity in Deep Saline Aquifers and Uneconomic Coal Beds, serious challenges handicap the evaluation of the potential for CO_2 storage in coals in northeastern B.C.

One challenge is that coal permeability decreases with depth such that, generally, the coals have to be fractured at depths greater than ~ 1500 m in order to produce coalbed gas or inject CO_2, operation that inherently would affect the integrity of the storage site; however, the precise depth of coal gas producibility without fracturing is not known. On the other hand, even if these coals are fractured, the thick Fort St. John and Shaftsbury shales above the coals will ensure CO_2 containment. Previous studies (e.g., Voormeij and Simandl, 2005) have considered 2000 m as the maximum coal depth for which CO_2 storage in northeastern B.C. would be possible. Adopting this depth as the deep limit for CO_2 storage in coals of the Bullhead Group will also avoid targeting the deep, gas-saturated region at the southern tip of this unit (Figure 9f).

More serious challenges in estimating the potential for CO_2 storage in coal beds in northeastern B.C. are the general lack of proper understanding of the storage mechanism for non-gaseous CO_2 (see discussion in Section 3.1.1) and the specific lack of data (adsorption isotherms in particular). As a proxy for permeability, it is worth noting that a micro pilot project for CO_2 injection and methane production from Lower Cretaceous Mannville Group coal beds at Fenn Big Valley in central Alberta reported permeabilities in the order of a few millidarcies at ~ 1250 m depth (Gunter *et al.*, 2005).

Based on the above considerations, three categories of potential areas for CO_2 storage in coals in northeastern B.C. are defined here (Figure 10b):

- high potential, in relatively shallow areas where injected CO_2 will be in gaseous phase;
- moderate potential at greater depths but shallower than 1400 m, where CO_2 will be in dense liquid or supercritical phase but where permeability, hopefully is sufficient to allow CO_2 injection and coal gas production; and
- low potential at depths between 1400 m and 2000 m, where CO_2 will be in dense, liquid or supercritical phase and permeability will likely be very low such that the coals may have to be fractured for CO_2 injection and coal gas production.

Further studies of coal permeability, gas content and CO_2 adsorption capacity are needed to improve on this assessment of the potential for CO_2 storage in coal beds in northeastern British Columbia.

STRATIGRAPHIC SUITABILITY FOR CO_2 STORAGE IN NORTHEASTERN BRITISH COLUMBIA

The stratigraphic and geographic assessment of the suitability for CO_2 storage of the sedimentary succession in northeastern British Columbia is based on a unit-by-unit evaluation on the basis of geology, geothermal and pressure regimes, and would-be phase of injected CO_2 in these units, and the presence and location of hydrocarbon reservoirs and coal beds.

Northeastern British Columbia is rich in oil and gas, particularly the latter, as organic material was generally buried deeply and underwent maturation well beyond the oil window. The Cambrian contains no hydrocarbons and the Devonian contains only gas. Oil reservoirs occur in Carboniferous and younger strata that have not been buried as deeply as the Devonian. Major gas pools are found in Middle Devonian reefal carbonate reservoirs in the north along the Presqu'ile reef barrier in the Elk Point Group (e.g., Yoyo, Sierra and Klua) and along the Sulphur Point reef barrier in the Beaverhill Lake Group (e.g., Clarke Lake). Large gas reservoirs in the Upper Devonian are also found in the northern part of the region in the Jean Marie Formation of the Winterburn Group (e.g., Helmet North). Major gas pools in the Carboniferous are found in the southern part of the region, and oil reservoirs are present in the north. The Permian contains large oil pools at Eagle, Eagle West and Stoddart West, and gas pools at Stoddart, Stoddart West, Boundary Lake and Fort St. John. Major oil pools are found in the Triassic, mainly in the Halfway Formation, at Boundary Lake, Peejay, Mulligan Creek and Weasel, and major gas pools are found at Laprise, Monias, Jedney, Ring, Nig Creek and Tommy Lakes. The Bullhead Group in the southern part of northeastern British Columbia contains coal beds, particularly in the Gething Formation, and oil and gas pools, such as Rigel and Buick Creek. Major gas pools are found in the Paddy Formation in the deep basin toward the southern tip of the region.

Other than oil and gas reservoirs, and potentially coal beds, CO_2 can be stored in aquifers mostly in the pre-Cretaceous sedimentary succession in northeastern British Columbia. All of the Cambrian and Devonian aquifers (Basal Cambrian Sandstone, Keg River, Sulphur Point, Gilwood, Slave Point, Jean Marie and Wabamun) are well confined by successive intervening aquitards (Cambrian, Elk Point, Muskeg, Waterways, Fort Simpson, Wabamun, Exshaw–Lower Banff). The solubility of CO_2 in the formation water of these aquifers is likely to be reduced as a result of high salinity and temperatures. Except for the northern part of the Jean Marie aquifer in the Winterburn Group, CO_2 will be in supercritical phase if injected into Devonian and Cambrian aquifers. Because of the high temperatures encountered in these strata, the CO_2 density will probably be relatively low, on the order of several hundred kg/m3. Thus, buoyancy forces will be strong and CO_2 will migrate updip, although with very small velocities. In the south, depositional features around the Peace River Arch, such as Granite Wash detritus and reef buildup, create hydraulic communication between the Keg River, Gilwood, Slave Point and Woodbend (Leduc reefs) aquifers. However, this succession is confined by the thick shale units of the Winterburn and Wabamun groups. In the northern part of the Jean Marie aquifer, CO_2 will be in gaseous phase, but this aquifer is well confined by the shale units of the overlying Wabamun and Exshaw–Banff aquitards.

The Carboniferous to Triassic aquifers (Carboniferous, Permian, Montney, Halfway, and Baldonnel) are partially confined by eroded intervening aquitards (Montney, Charlie Lake, Jurassic) and subcrop

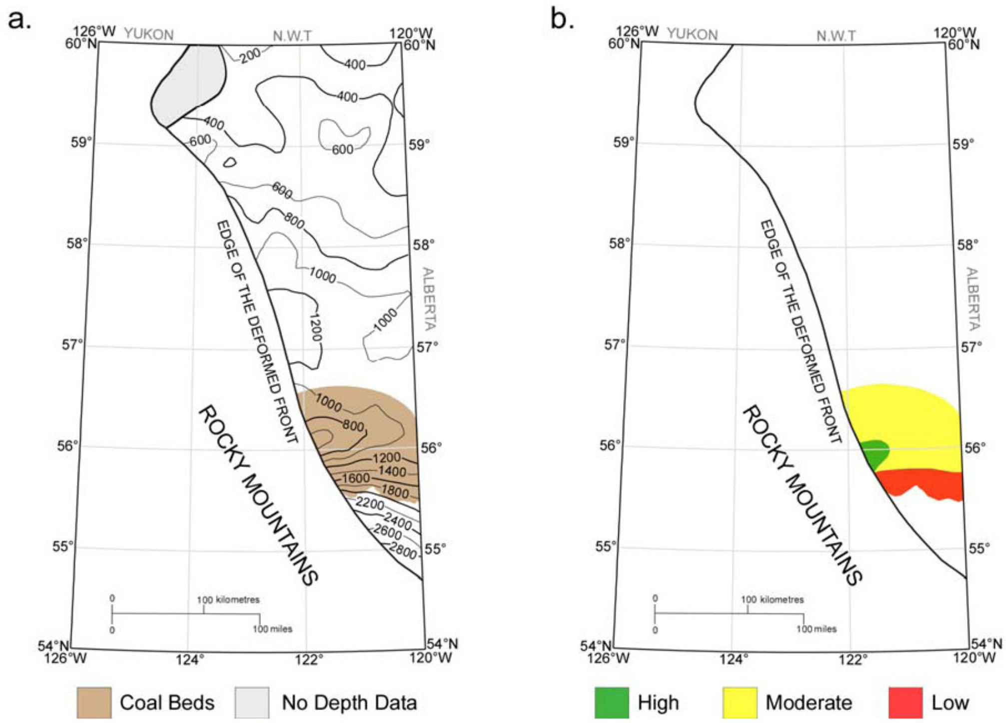


Figure 10. Area in northeastern British Columbia with potential for CO_2 storage in coal beds: a) coal distribution and depth to the top of the Bullhead Group that contains the coal beds; and b) regions of high, moderate and low storage potential based on CO_2 phase and likely coal permeability.

beneath Lower Cretaceous Bullhead Group strata in the north and northeast. However, since the entire Lower Cretaceous succession is shaly in the northern part of northeastern British Columbia, practically all these aquifers are confined, either by intervening aquitards or by thick Cretaceous shale. Carbon dioxide injected into aquifers in this succession in the southern part of northeastern British Columbia will be in dense liquid or supercritical phase. However, if injected into the Carboniferous in the northeast, or if it migrates there driven by buoyancy, it will change phase and become gaseous, with ever-increasing buoyancy as it moves updip. The time scale of this process is likely to be very large unless the CO_2 finds paths of high permeability.

The Lower Cretaceous aquifers (Bullhead, Falher and Paddy) are only partially present in northeastern British Columbia, mostly in the south. The intervening and overlying aquitards (Wilrich, Harmon, Fort St. John), and their own lithofacies change into shale to the north, provide good confinement for CO_2 injected into these aquifers. Because of expected relatively low density of CO_2, the storage capacity of these aquifers is likely to be reduced. The Upper Cretaceous aquifers (Dunvegan and Cardium) are not suitable for CO_2 storage because of relatively shallow depth, low temperatures and outcrop of these units along river valleys.

In terms of storage strategy, although northeastern British Columbia has the potential for CO_2 storage in most of the sedimentary succession, attention should be paid to optimizing capacity. Because temperature and pressure have opposite effects on CO_2 density (Figure 6), the effect of increasing pressure is cancelled by increasing temperature beyond certain depths (usually around 1000–1300 m), so that the CO_2 density increases very little with increasing depth (Figure 11). Thus, no gains in capacity are being realized by injecting CO_2 at greater depths, whereas the cost increases as a result of higher drilling and compression costs. From this point of view, CO_2 storage in Carboniferous to Lower Cretaceous strata in the south should be pursued first, before Devonian strata are considered. In the north, CO_2 storage should be considered only for Devonian strata.

In addition, care should be taken to avoid contamination of existing and potential energy resources, such as oil and gas reservoirs. Carbon dioxide injected close to and downdip from hydrocarbon reservoirs will migrate updip, driven by buoyancy, and will accumulate in these reservoirs, thus contaminating the reservoir's oil or gas. Thus, while most of the permeable strata in northeastern British Columbia, be they hydrocarbon reservoirs or deep saline aquifers, are suitable for CO_2 storage, a strategy must be developed and implemented regarding the timing and location of CO_2 injection. This strategy should take into account the distribution of CO_2 sources and hydrocarbon reservoirs, and the local-scale characteristics of the sedimentary strata in the succession. In this respect, the experience of acid gas injection in northeastern British Columbia provides a good example of application of this strategy. Injection of acid gas, a combination of H_2S and CO_2 produced by gas plants in the process of sour gas desulphurization, currently occurs in the southern part of British Columbia (Figure 12) and takes place in Carboniferous to Triassic strata, which are

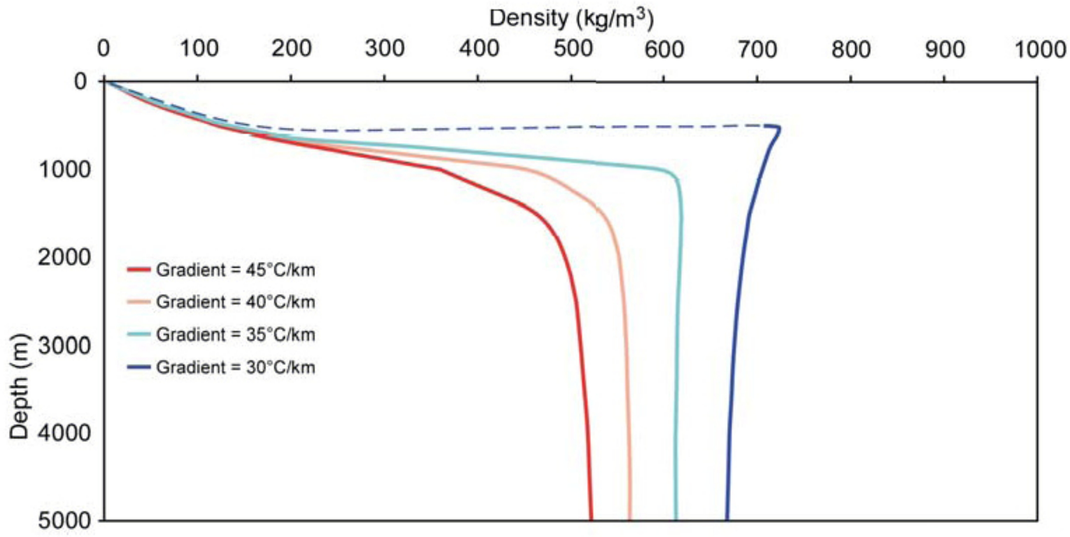


Figure 11. Variation of CO_2 density with depth assuming hydrostatic pressures and geothermal conditions characteristic of northeastern British Columbia.

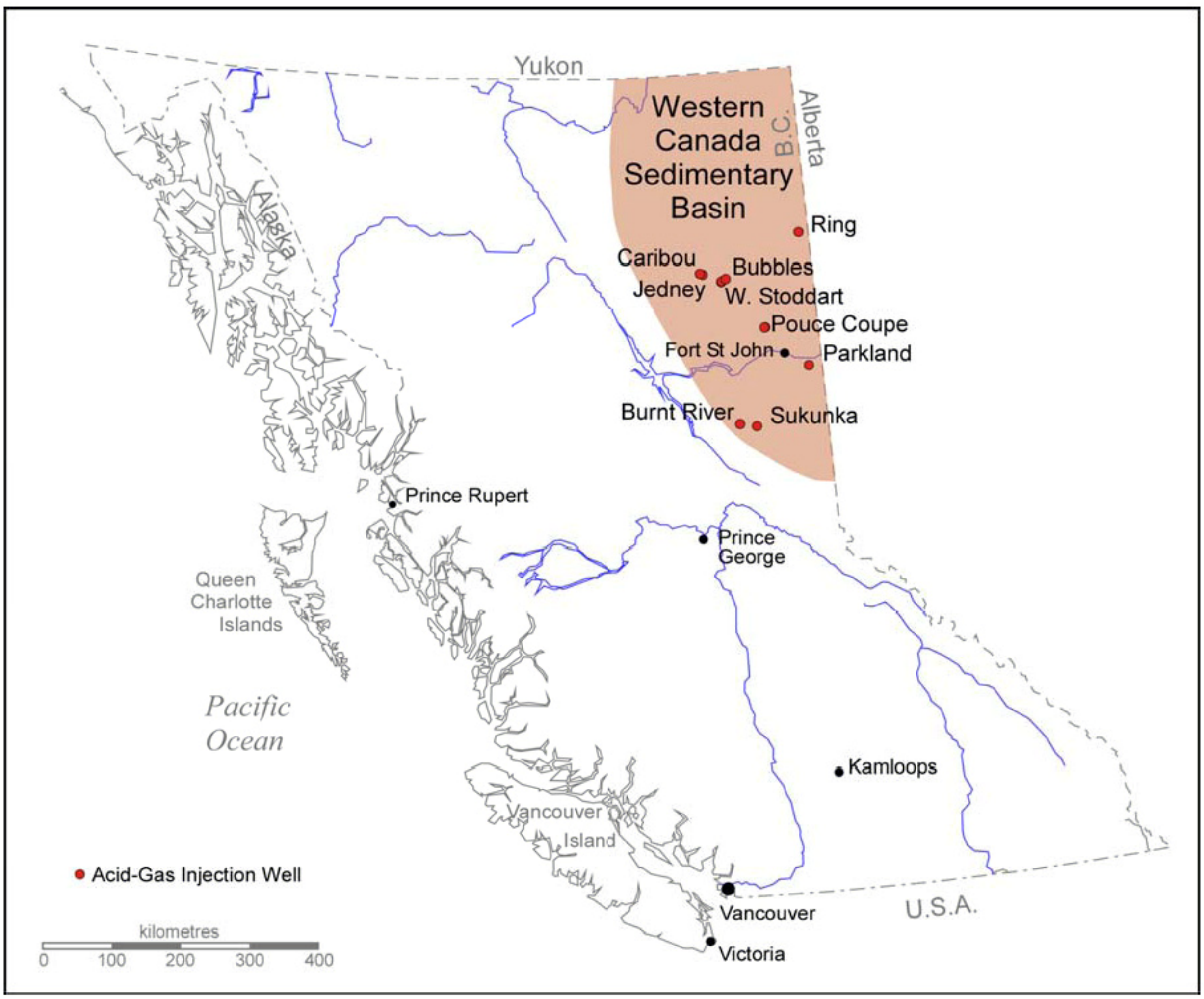


Figure 12. Location of acid-gas injection operations in northeastern British Columbia.

the most optimal strata in terms of confinement, acid-gas phase and density, and cost of injection.

CONCLUSIONS

The sedimentary succession in northeastern British Columbia has significant potential for CO_2 storage in gas reservoirs and deep saline aquifers. This portion of the Western Canada Sedimentary Basin is the most suited, and practically immediately accessible, basin for CO_2 geological storage in British Columbia. This is because geologically this region is located in a tectonically stable area, has significant, large gas reservoirs and deep saline aquifers that are confined by thick, regional-scale shaly aquitards. In addition, there is significant infrastructure in place, there are several large CO_2-sources in the area, including high-purity sources (gas plants), and there is operational and regulatory experience with acid-gas disposal in both depleted hydrocarbon reservoirs and deep saline aquifers.

Northeastern British Columbia has significant CO_2-storage capacity in gas reservoirs (>1,900 Mt CO_2), of which ~ 1,350 Mt CO_2 is in the largest 80 reservoirs. This capacity, just by itself, is likely sufficient to cover B.C.'s needs for this century when considering that annual CO_2 emissions in British Columbia are currently less than 70 Mt/year (Environment Canada, 2002), of which only about a third are from large stationary sources that are suitable for CO_2 capture and storage (CCS). If only local CO_2 sources (energy producers and paper mills) are considered, which currently are in the order of 4-5 Mt CO_2/year, then this storage capacity will still be available long after these sources will exhaust themselves. The CO_2 storage capacity in oil reservoirs is practically negligible at 5 Mt CO_2, and the only reason that this capacity would ever be realized is that additional oil may be produced in CO_2-EOR operations. Storage of CO_2 in coal beds does not have potential unless used in conjunction with coal gas recovery (technology that has yet to be proven), and even then it is questionable given the depth of the coal beds.

Besides gas reservoirs, northeastern British Columbia has significant potential for CO_2 storage in deep saline aquifers. Although the storage capacity has not been numerically evaluated for a variety of reasons, a stratigraphic assessment by aquifers in the sedimentary succession, based on temperatures and pressures, indicates that the storage potential is very large. Carbon dioxide can be injected into almost all of the deep saline aquifers in the sedimentary succession. All aquifers in the Cambrian to Lower Cretaceous succession are confined by intervening and overlying aquitards. The only aquifers that are not suitable for CO_2 storage are the shallower Upper Cretaceous Dunvegan and Cardium formations, which crop out at river valleys as a result of Tertiary to Recent erosion. Carbon dioxide injected into Cambrian and Devonian strata will be mostly in supercritical state, thus achieving conditions necessary for increased storage capacity. However, the high cost of injection into these very deep strata may delay their use for CO_2 storage. Carboniferous to Triassic aquifers, although they are eroded and subcrop beneath the Cretaceous strata, are well confined and are currently used for acid gas injection in the south. Carbon dioxide injected into these strata will be in supercritical phase except for the northern part, where it will be gaseous and therefore have increased buoyancy with respect with formation water. Lower Cretaceous aquifers, present in the southern part of northeastern British Columbia, are also suitable for CO_2 injection. Geographically, Carboniferous to Triassic aquifers are the best targets for CO_2 storage in the southern part of northeastern British Columbia, while Devonian aquifers should be used for CO_2 storage in the northern part.

Carbon dioxide emissions in northeastern B.C. are likely to increase in the future as more and deeper wells are drilled; hence, more sour-gas reservoirs are discovered and brought into production. In the absence of economic, fiscal or regulatory drivers, no CO_2 storage is likely to occur, but, if such drivers are introduced by the provincial and/or federal governments, it is very likely that the industry will implement CO_2 geological storage in this region. Although there is great capacity and potential infrastructure for CO_2 storage in gas reservoirs, they will become available for CO_2 storage only after depletion, which, at current production rates, will occur in the next few decades. Until they become available, deep saline aquifers can be safely used for CO_2 storage in northeastern British Columbia.

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APPENDIX A
OIL RESERVOIRS IN NORTHEASTERN B.C. THAT LACK CRITICAL DATA NEEDED FOR CALCULATING CO_2 STORAGE CAPACITY

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	Area (ha)	Net Pay (m)	Water Saturation	Porosity	Shrinkage
3560	4800	FLATROCK	HALFWAY	F			0.441000015	0.114	0.787401557
3580	4520	FLATROCK WEST	CECIL	C		0.800000012	0.324000001	0.134000003	0.843881845
3600	2700	FORT ST JOHN	GETHING	A					0.875656724
2020	4540	BOUNDARY LAKE NORTH	COPLIN	F	378	0.300000012	0.326999992	0.093999997	
380	4582	BEAR FLAT	BEAR FLAT	A			0.138999999	0.149000004	0.832639456
380	4582	BEAR FLAT	BEAR FLAT	D		1.600000024	0.368000001	0.064000003	0.832639456
1400	4500	BLUEBERRY	CHARLIE LAKE	A	71	2	0.224999994	0.119999997	
1400	4900	BLUEBERRY	DOIG	A	71	4	0.300000012	0.059999999	
2820	4800	BULRUSH	HALFWAY	B					0.807102501
2920	2600	CACHE CREEK	BLUESKY	C	66	4.699999809	0.479999989	0.090999998	
2985	4800	CHINCHAGA RIVER	HALFWAY	A	70	2.299999952	0.230000004	0.181999996	
3440	6250	EAGLE	BELLOY-KISKATINAW			4.949999809	0.218500003	0.120000005	0.77519381
3445	6200	EAGLE WEST	BELLOY	A		5	0.286500007	0.122499995	0.774593353
4925	4575	INGA SOUTH	INGA	A					0.74850297
5150	8200	JUNIOR	JEAN MARIE	A	68	4.400000095	0.017999999	0.057	
5600	4540	LAPRISE CREEK	COPLIN	A		0.699999988	0.192000002	0.105999999	
5600	4540	LAPRISE CREEK	COPLIN	B		0.600000024	0.123999998	0.108999997	
6490	2700	OSBORN	GETHING	C	74	2	0.305999994	0.209000006	
6500	4800	OSPREY	HALFWAY	G	71	1.200000048	0.514999986	0.174999997	
6530	4520	OWL	CECIL	A		1.400000095	0.289499998	0.142499998	0.802568197
7275	4520	PLUTO	CECIL	A	66	1.5	0.25	0.123000003	
7600	2900	RIGEL	DUNLEVY	A					0.870322049
7600	2900	RIGEL	DUNLEVY	B			0.180000007	0.109999999	0.870322049
7860	4100	SIPHON EAST	BALDONNEL	B	66	4.900000095	0.317999989	0.144999996	
8060	7250	STODDART SOUTH	KISKATINAW	A	65	6.800000191	0.349999994	0.050999999	
8100	4100	STODDART WEST	BALDONNEL	C	66	9.100000381	0.398999989	0.090999998	
8100	4582	STODDART WEST	BEAR FLAT	C	66	1	0.165999994	0.074000001	
8200	4800	TWO RIVERS	HALFWAY	D	65	4	0.361999989	0.177000001	
8240	2630	VELMA	BLUESKY-GETHING			1.5	0.432000011	0.135000005	0.89445436
8300	4520	WEASEL	CECIL	C	70	1	0.432999998	0.126000002	
8300	4805	WEASEL	LOWER HALFWAY	A					0.83822298
8360	4535	WILDER	BOUNDARY LAKE	B	65	0.899999976	0.349999994	0.119999997	
9000	4535	OTHER AREAS	BOUNDARY LAKE	09-22-083-14-W6M		3	0.310000002	0.090000004	0.802568197
9000	4535	OTHER AREAS	BOUNDARY LAKE	16-35-083-15-W6M		3	0.310000002	0.090000004	0.802568197

APPENDIX B
GAS RESERVOIRS IN NORTHEASTERN B.C. THAT LACK ORIGINAL GAS IN PLACE (OGIP), PRESSURE AND TEMPERATURE DATA NEEDED FOR CALCULATING CO_2 STORAGE CAPACITY

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Drive Mechanism
380	4582	BEAR FLAT	BEAR FLAT	B	ASSOCIATED
380	4582	BEAR FLAT	BEAR FLAT	D	ASSOCIATED
700	4805	BEAVERDAM	LOWER HALFWAY	A	ASSOCIATED
760	4800	BEAVERTAIL	HALFWAY	K	ASSOCIATED
1260	4100	BIRCH	BALDONNEL	C	ASSOCIATED
1280	4800	BIRLEY CREEK	HALFWAY	F	ASSOCIATED
1280	4800	BIRLEY CREEK	HALFWAY	H	ASSOCIATED
1400	4900	BLUEBERRY	DOIG	A	ASSOCIATED
1880	6200	BOUDREAU	BELLOY	B	ASSOCIATED
1880	6200	BOUDREAU	BELLOY	C	ASSOCIATED
2000	4535	BOUNDARY LAKE	BOUNDARY LAKE	A	ASSOCIATED
2000	4805	BOUNDARY LAKE	LOWER HALFWAY	A	ASSOCIATED
2000	4805	BOUNDARY LAKE	LOWER HALFWAY	B	ASSOCIATED
2000	6300	BOUNDARY LAKE	TAYLOR FLAT	A	ASSOCIATED
2020	4900	BOUNDARY LAKE NORTH	DOIG	A	ASSOCIATED
2020	4900	BOUNDARY LAKE NORTH	DOIG	D	ASSOCIATED
2020	4900	BOUNDARY LAKE NORTH	DOIG	E	ASSOCIATED
2240	4540	BUBBLES NORTH	COPLIN	A	ASSOCIATED
2400	2900	BUICK CREEK	DUNLEVY	L	ASSOCIATED
2400	2900	BUICK CREEK	DUNLEVY	P	ASSOCIATED
2400	4580	BUICK CREEK	NORTH PINE	D	ASSOCIATED
2400	4805	BUICK CREEK	LOWER HALFWAY	N	ASSOCIATED
2400	4805	BUICK CREEK	LOWER HALFWAY	O	ASSOCIATED
2400	4805	BUICK CREEK	LOWER HALFWAY	S	ASSOCIATED
2400	4805	BUICK CREEK	LOWER HALFWAY	T	ASSOCIATED
2400	4805	BUICK CREEK	LOWER HALFWAY	U	ASSOCIATED
2700	2900	BUICK CREEK NORTH	DUNLEVY	U	ASSOCIATED
2920	4900	CACHE CREEK	DOIG	C	ASSOCIATED
2920	4900	CACHE CREEK	DOIG	E	ASSOCIATED
2920	4900	CACHE CREEK	DOIG	F	ASSOCIATED
2920	4900	CACHE CREEK	DOIG	H	ASSOCIATED
2960	4510	CECIL LAKE	SIPHON	A	ASSOCIATED
2960	4520	CECIL LAKE	CECIL	A	ASSOCIATED
2960	4580	CECIL LAKE	NORTH PINE	B	ASSOCIATED
3300	4800	CURRANT	HALFWAY	D	ASSOCIATED
3440	2700	EAGLE	GETHING	A	ASSOCIATED
3445	6200	EAGLE WEST	BELLOY	C	ASSOCIATED
3520	2600	FIREBIRD	BLUESKY	F	ASSOCIATED
3540	4900	FIREWEED	DOIG	A	ASSOCIATED
3540	4900	FIREWEED	DOIG	B	ASSOCIATED
3560	6200	FLATROCK	BELLOY	A	ASSOCIATED
3580	4520	FLATROCK WEST	CECIL	B	ASSOCIATED
3600	6200	FORT ST JOHN	BELLOY	B	ASSOCIATED
4390	4520	GROUNDBIRCH	CECIL	A	ASSOCIATED
4600	4575	HALFWAY	INGA	A	ASSOCIATED
4600	4800	HALFWAY	HALFWAY	B	ASSOCIATED

APPENDIX B CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Drive Mechanism
4600	7400	HALFWAY	DEBOLT	A	ASSOCIATED
4650	2600	HAY RIVER	BLUESKY	B	ASSOCIATED
5600	4540	LAPRISE CREEK	COPLIN	A	ASSOCIATED
5600	4540	LAPRISE CREEK	COPLIN	B	ASSOCIATED
5860	4545	MICA	MICA	A	ASSOCIATED
6200	4520	MONTNEY	CECIL	B	ASSOCIATED
6230	4800	MUSKRAT	HALFWAY	E	ASSOCIATED
6230	4805	MUSKRAT	LOWER HALFWAY	A	ASSOCIATED
6460	4520	OAK	CECIL	B	ASSOCIATED
6460	4520	OAK	CECIL	I	ASSOCIATED
6460	4520	OAK	CECIL	K	ASSOCIATED
6530	4520	OWL	CECIL	A	ASSOCIATED
6800	4800	PEEJAY	HALFWAY	R	ASSOCIATED
7000	4800	PEEJAY WEST	HALFWAY	D	ASSOCIATED
7400	4900	RED CREEK	DOIG	C	ASSOCIATED
7600	2900	RIGEL	DUNLEVY	B	ASSOCIATED
7600	2900	RIGEL	DUNLEVY	D	ASSOCIATED
7600	4520	RIGEL	CECIL	B	ASSOCIATED
7600	4520	RIGEL	CECIL	G	ASSOCIATED
7600	4520	RIGEL	CECIL	I	ASSOCIATED
8000	4520	STODDART	CECIL	B	ASSOCIATED
8000	4520	STODDART	CECIL	J	ASSOCIATED
8000	4580	STODDART	NORTH PINE	E	ASSOCIATED
8000	4580	STODDART	NORTH PINE	G	ASSOCIATED
8000	6200	STODDART	BELLOY	C	ASSOCIATED
8060	6200	STODDART SOUTH	BELLOY	A	ASSOCIATED
8060	6200	STODDART SOUTH	BELLOY	C	ASSOCIATED
8100	4100	STODDART WEST	BALDONNEL	C	ASSOCIATED
8100	4520	STODDART WEST	CECIL	B	ASSOCIATED
8100	4582	STODDART WEST	BEAR FLAT	D	ASSOCIATED
8100	4900	STODDART WEST	DOIG	B	ASSOCIATED
8100	6200	STODDART WEST	BELLOY	L	ASSOCIATED
8130	4520	SUNSET PRAIRIE	CECIL	A	ASSOCIATED
8130	4520	SUNSET PRAIRIE	CECIL	C	ASSOCIATED
8240	2630	VELMA	BLUESKY-GETHING	N/A	ASSOCIATED
8300	2700	WEASEL	GETHING	B	ASSOCIATED
8300	4800	WEASEL	HALFWAY	K	ASSOCIATED
8400	4800	WILDMINT	HALFWAY	I	ASSOCIATED
8900	4610	ZAREMBA	A MARKER/BASE OF LIME	K	ASSOCIATED
8900	4610	ZAREMBA	A MARKER/BASE OF LIME	M	ASSOCIATED
8900	4610	ZAREMBA	A MARKER/BASE OF LIME	N	ASSOCIATED

APPENDIX C
LIST OF OIL RESERVOIRS IN NORTHEASTERN B.C. THAT ARE SUITABLE FOR CO_2-ENHANCED OIL RECOVERY, SHOWING ALSO THE ESTIMATED ADDITIONAL RECOVERABLE OIL AND CO_2 STORAGE CAPACITY

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	OOIP (1000 m^3)	Recovery Factor	OOIP * Oil Recovery @ 0.50 PV CO_2 Injection (1000 m^3)	CO_2 Storage Mass (tonnes) at @ 0.50 PV CO_2 Injection
200	2700	AITKEN CREEK	GETHING	A	2233.5	0.600	356.708	277549.1
380	4582	BEAR FLAT	BEAR FLAT	B	159.8	0.150	16.406	27239.3
1260	4100	BIRCH	BALDONNEL	C	3666.9	0.200	397.716	461208.4
1260	4100	BIRCH	BALDONNEL	G	185.6	0.040	17.969	25758.6
1280	4800	BIRLEY CREEK	HALFWAY	F	193.0	0.100	19.040	18093.3
1400	7400	BLUEBERRY	DEBOLT	E	1334.0	0.246	175.490	293459.9
1800	7400	BLUEBERRY WEST	DEBOLT	B	195.4	0.200	27.929	44510.2
1800	7400	BLUEBERRY WEST	DEBOLT	C	643.6	0.200	91.018	158816.5
1880	6200	BOUDREAU	BELLOY	A	387.8	0.100	70.032	100260.5
1880	6200	BOUDREAU	BELLOY	B	206.2	0.100	38.606	51810.3
1880	6200	BOUDREAU	BELLOY	C	386.5	0.100	66.937	95334.8
2000	6200	BOUNDARY LAKE	BELLOY	L	764.1	0.063	127.049	176753.2
2000	4800	BOUNDARY LAKE	HALFWAY	H	220.5	0.100	33.519	43092.8
2000	4800	BOUNDARY LAKE	HALFWAY	K	237.0	0.200	32.226	27866.7
2000	4800	BOUNDARY LAKE	HALFWAY		2939.2	0.211	430.435	535488.4
2000	4805	BOUNDARY LAKE	LOWER HALFWAY	B	362.3	0.200	49.395	42532.6
2000	6300	BOUNDARY LAKE	TAYLOR FLAT	A	190.0	0.200	19.397	43227.4
2020	4900	BOUNDARY LAKE NORTH	DOIG	A	720.8	0.200	125.378	94396.8
2020	4900	BOUNDARY LAKE NORTH	DOIG	C	204.5	0.150	33.913	26518.4
2020	4900	BOUNDARY LAKE NORTH	DOIG	D	263.4	0.200	49.535	28686.0
2020	4900	BOUNDARY LAKE NORTH	DOIG	F	204.9	0.150	31.501	37470.5
2020	4800	BOUNDARY LAKE NORTH	HALFWAY	D	424.7	0.150	49.120	46244.3
2020	4800	BOUNDARY LAKE NORTH	HALFWAY	I	941.7	0.200	108.954	87167.8
2400	4100	BUICK CREEK	BALDONNEL	A	253.6	0.200	19.690	30862.3
2400	2900	BUICK CREEK	DUNLEVY	A	464.4	0.050	50.171	42468.3
2400	2900	BUICK CREEK	DUNLEVY	P	184.6	0.200	19.527	28152.2
2400	4805	BUICK CREEK	LOWER HALFWAY	A	542.0	0.150	84.378	135287.4

APPENDIX C CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	OOIP (1000 m^3)	Recovery Factor	OOIP * Oil Recovery @ 0.50 PV CO_2 Injection (1000 m^3)	CO_2 Storage Mass (tonnes) at @ 0.50 PV CO_2 Injection
2400	4805	BUICK CREEK	LOWER HALFWAY	B	1080.1	0.150	168.319	270699.6
2400	4805	BUICK CREEK	LOWER HALFWAY	C	6821.5	0.150	1050.055	1516171.2
2400	4805	BUICK CREEK	LOWER HALFWAY	D	3393.5	0.150	514.750	802503.7
2400	4805	BUICK CREEK	LOWER HALFWAY	E	1844.0	0.100	294.778	425776.4
2400	4805	BUICK CREEK	LOWER HALFWAY	I	1636.8	0.125	245.591	355709.8
2400	4805	BUICK CREEK	LOWER HALFWAY	J	2701.3	0.150	414.232	632467.8
2400	4805	BUICK CREEK	LOWER HALFWAY	L	561.4	0.200	82.205	112928.4
2400	4805	BUICK CREEK	LOWER HALFWAY	N	508.7	0.050	74.852	107395.2
2400	4805	BUICK CREEK	LOWER HALFWAY	O	901.5	0.150	136.678	198179.0
2400	4805	BUICK CREEK	LOWER HALFWAY	S	273.9	0.200	42.501	63898.6
2400	4805	BUICK CREEK	LOWER HALFWAY	U	1038.1	0.150	153.895	222467.0
2920	4900	CACHE CREEK	DOIG	C	820.1	0.050	196.379	295316.2
2960	4520	CECIL LAKE	CECIL	B	266.3	0.087	26.758	52431.5
2960	4520	CECIL LAKE	CECIL	E	278.5	0.200	25.054	44465.9
2960	4580	CECIL LAKE	NORTH PINE	A	732.2	0.254	84.720	148344.4
2960	4580	CECIL LAKE	NORTH PINE	C	605.9	0.200	63.691	120625.0
2960	4510	CECIL LAKE	SIPHON	A	358.3	0.360	34.826	48721.5
3425	4100	DOE	BALDONNEL	B	411.6	0.200	41.680	82179.0
3426	4800	DOIG RAPIDS	HALFWAY	C	343.9	0.100	40.532	30180.2
3426	4040	DOIG RAPIDS	NORDEGG-BALDONNEL	F	194.3	0.100	15.761	13543.1
3440	6200	EAGLE	BELLOY	A	188.0	0.050	31.656	37700.6
3440	2700	EAGLE	GETHING	A	186.3	0.110	27.310	39829.0
3445	6200	EAGLE WEST	BELLOY	C	354.9	0.200	57.564	65638.1
3445	6200	EAGLE WEST	BELLOY	D	308.4	0.200	54.300	76274.8
3445	5000	EAGLE WEST	MONTNEY	A	333.8	0.200	85.038	98420.1
3540	4805	FIREWEED	LOWER HALFWAY	A	978.2	0.200	152.130	187071.1
3560	6200	FLATROCK	BELLOY	A	311.9	0.200	53.504	75272.9
3560	4535	FLATROCK	BOUNDARY LAKE	B	494.3	0.135	34.043	87584.4
3560	4800	FLATROCK	HALFWAY	E	1159.9	0.140	164.136	207393.9
3560	4800	FLATROCK	HALFWAY	J	412.1	0.200	50.303	47096.8

APPENDIX C CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	OOIP (1000 m^3)	Recovery Factor	OOIP * Oil Recovery @ 0.50 PV CO_2 Injection (1000 m^3)	CO_2 Storage Mass (tonnes) at @ 0.50 PV CO_2 Injection
3580	4533	FLATROCK WEST	FLATROCK	A	187.7	0.005	17.991	26228.5
3580	4800	FLATROCK WEST	HALFWAY	D	2007.2	0.175	270.196	280612.0
3580	4580	FLATROCK WEST	NORTH PINE	A	175.1	0.050	16.681	24781.1
3600	6200	FORT ST JOHN	BELLOY	B	229.3	0.023	39.321	57771.5
3600	6200	FORT ST JOHN	BELLOY	G	205.5	0.175	36.619	60683.2
3600	4580	FORT ST JOHN	NORTH PINE	A	663.1	0.501	84.166	141507.6
3600	4580	FORT ST JOHN	NORTH PINE	C	165.1	0.350	18.070	30175.7
4100	2600	GOOSE	BLUESKY	A	226.3	0.200	25.641	53279.0
4600	4800	HALFWAY	HALFWAY	B	800.4	0.200	130.277	202172.5
5860	4545	MICA	MICA	A	1026.0	0.300	107.051	238843.1
5880	2600	MIKE	BLUESKY	A	974.0	0.075	85.247	86737.6
6020	4800	MILLIGAN CREEK WEST	HALFWAY	I	579.0	0.100	62.329	36935.9
6200	4800	MONTNEY	HALFWAY	C	214.1	0.013	29.464	38408.0
6230	4800	MUSKRAT	HALFWAY	D	239.8	0.090	29.153	35550.4
6230	4800	MUSKRAT	HALFWAY	E	377.9	0.070	46.153	56164.0
6230	4800	MUSKRAT	HALFWAY		584.4	0.149	74.350	65701.1
6230	4805	MUSKRAT	LOWER HALFWAY	B	370.1	0.200	49.183	58088.6
6230	4805	MUSKRAT	LOWER HALFWAY	C	359.4	0.200	45.246	46576.8
6400	4100	NIG CREEK	BALDONNEL	A	220.7	0.100	19.092	22830.6
6400	4100	NIG CREEK	BALDONNEL	D	1056.6	0.100	86.213	108716.3
6460	4100	OAK	BALDONNEL	E	186.0	0.150	11.984	21488.3
6460	4100	OAK	BALDONNEL	H	309.2	0.200	24.540	33972.0
6460	4800	OAK	HALFWAY	B	1883.1	0.200	256.615	345879.9
6460	4800	OAK	HALFWAY	C	341.4	0.002	40.268	45502.1
6460	4805	OAK	LOWER HALFWAY	A	245.8	0.020	28.892	42289.2
6500	4800	OSPREY	HALFWAY	A	201.0	0.400	20.374	18988.5
6500	4800	OSPREY	HALFWAY	D	691.7	0.100	74.906	59873.1
6500	4800	OSPREY	HALFWAY	E	305.6	0.200	30.480	28184.0
6500	4800	OSPREY	HALFWAY	H	188.7	0.002	22.239	14994.8
6500	4800	OSPREY	HALFWAY	K	512.6	0.150	52.953	46602.6

APPENDIX C CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Sequence	OOIP (1000 m^3)	Recovery Factor	OOIP * Oil Recovery @ 0.50 PV CO_2 Injection (1000 m^3)	CO_2 Storage Mass (tonnes) at @ 0.50 PV CO_2 Injection
9000	4100	OTHER AREAS	BALDONNEL	D-060-D/094-A-16	310.8	0.002	24.861	24088.0
6800	4800	PEEJAY	HALFWAY	L	201.7	0.060	20.965	24810.3
6800	4800	PEEJAY	HALFWAY	R	290.4	0.150	28.993	24747.6
7400	4900	RED CREEK	DOIG	B	300.9	0.150	63.565	86498.5
7410	4900	RED CREEK NORTH	DOIG	B	575.3	0.200	122.141	130011.8
7600	2900	RIGEL	DUNLEVY	E	290.6	0.200	34.030	26600.6
7600	4800	RIGEL	HALFWAY	DD	333.3	0.200	38.457	32341.2
7600	4800	RIGEL	HALFWAY	F	365.3	0.200	45.085	33508.5
7600	4800	RIGEL	HALFWAY	H	702.9	0.150	85.402	114079.6
7600	4800	RIGEL	HALFWAY	I	265.8	0.200	30.538	33872.7
7600	4800	RIGEL	HALFWAY	O	411.0	0.200	48.801	42484.5
7600	4800	RIGEL	HALFWAY	T	236.5	0.200	29.177	28945.7
7620	2700	RIGEL EAST	GETHING	A	173.4	0.115	20.834	14611.5
7750	4800	SEPTIMUS	HALFWAY	C	189.2	0.200	31.154	39014.9
7900	4580	SQUIRREL	NORTH PINE	A	174.5	0.250	17.930	26316.5
8000	6200	STODDART	BELLOY	C	1169.5	0.150	189.542	254101.8
8000	4520	STODDART	CECIL	A	187.2	0.065	12.022	33428.0
8000	4520	STODDART	CECIL	B	183.5	0.200	14.002	35631.0
8000	4580	STODDART	NORTH PINE	F	528.3	0.201	55.273	75062.5
8000	4580	STODDART	NORTH PINE	G	192.0	0.200	21.032	28478.5
8060	6200	STODDART SOUTH	BELLOY	A	980.1	0.154	162.517	211944.8
8060	6200	STODDART SOUTH	BELLOY	C	305.1	0.049	54.352	68602.6
8100	6200	STODDART WEST	BELLOY	C	8865.2	0.234	1345.867	1771182.2
8100	6200	STODDART WEST	BELLOY	E	190.5	0.100	31.865	38968.9
8100	6200	STODDART WEST	BELLOY	L	1272.0	0.100	186.571	252716.1
8100	4900	STODDART WEST	DOIG	A	663.3	0.200	148.595	165640.1
8100	4900	STODDART WEST	DOIG	B	548.7	0.200	119.759	155161.4
8100	4805	STODDART WEST	LOWER HALFWAY	A	172.2	0.180	26.492	41255.5
8100	4805	STODDART WEST	LOWER HALFWAY	B	1606.5	0.200	182.737	392423.6
8200	4800	TWO RIVERS	HALFWAY	B	406.1	0.025	60.037	84149.7
8700	4800	WOLF	HALFWAY	A	1241.0	0.300	144.498	120452.5

APPENDIX D

OIL AND GAS RESERVOIRS IN NORTHEASTERN B.C. THAT HAVE AN ESTIMATED CO_2- STORAGE CAPACITY GREATER THAN 1 MT CO_2. FOR OIL RESERVOIRS, THE STORAGE CAPACITY IN EOR AT DEPLETION AND IN TOTAL IS GIVEN. IF AN OIL POOL IS ASSOCIATED WITH A GAS POOL, THEN THE TOTAL CAPACITY IS THE SUM OF THE TWO, OTHERWISE THE TOTAL CAPACITY IS EQUAL TO THE CAPACITY OF THE RESPECTIVE OIL OR GAS POOL

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs			Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
								Mass CO_2 @ EOR (tonnes)	Effective Mass CO_2 (tonnes)	Total CO_2 capacity (tonnes)		
50	8400	ADSETT	SLAVE POINT	A	-122.690620	58.110417	2497.2				3,590,369	3,590,369
50	8400	ADSETT	SLAVE POINT	B	-122.630476	58.166799	2550.6				2,393,105	2,393,105
210	2600	AITKEN CREEK NORTH	BLUESKY	A	-122.008487	57.035382	1272.5				3,149,322	3,149,322
320	2600	ALTARES	BLUESKY	A	-122.029607	56.335368	899.8				1,370,348	1,370,348
320	2600	ALTARES	BLUESKY	B	-122.152527	56.384763	1009.2				1,151,589	1,151,589
350	7340	ATTACHIE	BASAL KISKATINAW	A	-121.442128	56.310703	2056.5				2,460,889	2,460,889
380	4800	BEAR FLAT	HALFWAY	B	-121.091729	56.318201	1618.9				1,850,753	1,850,753
740	8580	BEAVER RIVER	NAHANNI	A	-124.359374	59.926890	3830.4				8,251,410	8,251,410
700	4798	BEAVERDAM	UPPER HALFWAY	A	-120.453120	56.947917	1123.3				1,195,482	1,195,482
760	2600	BEAVERTAIL	BLUESKY	A	-120.863504	56.833882	1017.0				4,288,802	4,288,802
760	4800	BEAVERTAIL	HALFWAY	E	-120.725520	56.828757	1233.6				1,112,678	1,112,678
800	4100	BEG	BALDONNEL	A	-122.252229	57.100311	1342.5				5,903,633	5,903,633
800	4100	BEG	BALDONNEL	C	-122.419275	57.254051	1454.8				2,648,988	2,648,988
800	4800	BEG	HALFWAY	A	-122.240620	57.089583	1572.0				17,898,670	17,898,670
1280	2630	BIRLEY CREEK	BLUESKY-GETHING	A	-121.196880	57.135417	1021.8				1,258,911	1,258,911
1300	8200	BIVOUAC	JEAN MARIE	A	-120.080112	58.454249	1205.5				1,349,117	1,349,117
1400	4100	BLUEBERRY	BALDONNEL	B	-121.956469	56.823819	1422.3				1,308,276	1,308,276
1400	7400	BLUEBERRY	DEBOLT	A	-121.858760	56.690867	2031.5	0	561,924	561,924	497,372	1,059,296
1400	7400	BLUEBERRY	DEBOLT	B	-121.940675	56.789429	2184.0	0	253,970	253,970	1,932,224	2,186,194
1400	2900	BLUEBERRY	DUNLEVY	A	-121.865741	56.706063	1221.4				11,151,657	11,151,657
1400	2900	BLUEBERRY	DUNLEVY	B	-121.899272	56.781609	1257.5				7,307,111	7,307,111
1400	4800	BLUEBERRY	HALFWAY	B	-121.954747	56.829478	1685.2				6,326,076	6,326,076
1800	4100	BLUEBERRY WEST	BALDONNEL	A	-121.977555	56.680866	1239.3				1,159,023	1,159,023
1950	4060	BOULDER	PARDONET-BALDONNEL	A	-122.263884	55.467562	2497.2				9,776,675	9,776,675
1950	4060	BOULDER	PARDONET-BALDONNEL	B	-122.235220	55.448738	2517.4				5,592,541	5,592,541
2000	4100	BOUNDARY LAKE	BALDONNEL	B	-120.110000	56.369270	1211.0				2,975,872	2,975,872
2000	7340	BOUNDARY LAKE	BASAL KISKATINAW	N	-120.027324	56.370599	1944.5				1,415,922	1,415,922
2000	7340	BOUNDARY LAKE	BASAL KISKATINAW	N/A	-120.232478	56.266849	2133.4				2,287,010	2,287,010
2000	6200	BOUNDARY LAKE	BELLOY	B	-120.206890	56.314487	1782.7				3,561,080	3,561,080
2000	6200	BOUNDARY LAKE	BELLOY	G	-120.202038	56.314711	1786.7				2,766,893	2,766,893

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs			Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
								Mass CO_2 @ EOR (tonnes)	Effective Mass CO_2 (tonnes)	Total CO_2 capacity (tonnes)		
2000	6200	BOUNDARY LAKE	BELLOY	J	-120.145788	56.295667	1746.2				11,671,670	11,671,670
2000	6200	BOUNDARY LAKE	BELLOY	K	-120.122926	56.308677	1733.5				3,637,718	3,637,718
2000	6200	BOUNDARY LAKE	BELLOY	O	-120.225073	56.309919	1058.5				1,019,100	1,019,100
2000	4540	BOUNDARY LAKE	COPLIN	A	-120.029720	56.518091	1380.0				1,176,649	1,176,649
2000	4800	BOUNDARY LAKE	HALFWAY	B	-120.012777	56.528281	1465.0				1,563,911	1,563,911
2000	4800	BOUNDARY LAKE	HALFWAY		-120.100005	56.382633	1324.5	87,778	22,545	110,323	957,984	1,068,308
2000	7300	BOUNDARY LAKE	LOWER KISKATINAW	B	-120.039223	56.294652	2023.2				1,728,838	1,728,838
2020	4800	BOUNDARY LAKE NORTH	HALFWAY	B	-120.198949	56.528646	1342.2				1,734,727	1,734,727
2020	4800	BOUNDARY LAKE NORTH	HALFWAY	L	-120.152605	56.601705	1342.6				1,355,140	1,355,140
2100	4700	BRASSEY	ARTEX	B	-120.797422	55.613089	2921.8	0	1,259,767	1,259,767		1,259,767
2150	4060	BRAZION	PARDONET-BALDONNEL	A	-121.991368	55.383576	2511.7				3,361,046	3,361,046
2150	4060	BRAZION	PARDONET-BALDONNEL	B	-122.091810	55.402430	2353.6				7,525,996	7,525,996
2200	4100	BUBBLES	BALDONNEL	A	-122.035434	57.193315	1468.0				7,890,510	7,890,510
2200	8400	BUBBLES	SLAVE POINT	A	-122.080698	57.287989	1886.0				4,387,956	4,387,956
2200	8400	BUBBLES	SLAVE POINT	B	-122.120502	57.281875	3274.0				1,881,975	1,881,975
2240	4150	BUBBLES NORTH	BALDONNEL/UPPER CHARLIE LAKE	A	-122.229458	57.331668	1443.1				7,575,460	7,575,460
2240	4800	BUBBLES NORTH	HALFWAY	A	-122.179012	57.331863	1648.0				1,927,244	1,927,244
2240	4800	BUBBLES NORTH	HALFWAY	C	-122.109301	57.314035	1516.8				1,363,995	1,363,995
2400	2600	BUICK CREEK	BLUESKY	C	-120.453120	56.756250	981.4				10,130,019	10,130,019
2400	2900	BUICK CREEK	DUNLEVY	A	-121.122618	56.756520	1093.8	4,122	2,015	6,137	8,464,521	8,470,658
2400	2900	BUICK CREEK	DUNLEVY	B	-121.001563	56.775114	1112.2	0	786	786	7,666,412	7,667,198
2400	2900	BUICK CREEK	DUNLEVY	C	-121.172983	56.751831	1137.6	0	2,134	2,134	11,072,132	11,074,265
2400	2900	BUICK CREEK	DUNLEVY	H	-120.898390	56.781162	1086.5				1,098,562	1,098,562
2400	2900	BUICK CREEK	DUNLEVY	K	-121.097536	56.835103	1056.0				1,494,852	1,494,852
2400	4805	BUICK CREEK	LOWER HALFWAY	C	-121.066992	56.738850	1213.2	270,836	468,807	739,643	1,321,126	2,060,769
2400	4805	BUICK CREEK	LOWER HALFWAY	D	-121.055626	56.782090	1356.9	139,864	210,193	350,057	923,626	1,273,683
2400	4580	BUICK CREEK	NORTH PINE	A	-121.046880	56.702083	1285.3				1,816,984	1,816,984
2400	8400	BUICK CREEK	SLAVE POINT	B	-121.096456	56.848341	3150.7				1,416,634	1,416,634
2400	8400	BUICK CREEK	SLAVE POINT	C	-121.006822	56.896075	3132.0				1,678,628	1,678,628
2700	2600	BUICK CREEK NORTH	BLUESKY	A	-121.271870	56.856250	1113.5				1,716,761	1,716,761
2700	2900	BUICK CREEK NORTH	DUNLEVY	A	-121.254642	56.818649	1098.9				2,116,786	2,116,786
2800	2600	BUICK CREEK WEST	BLUESKY	A	-121.479585	56.902062	1097.5				2,121,038	2,121,038
2800	2900	BUICK CREEK WEST	DUNLEVY	A	-121.285970	56.739950	1170.2	0	50	50	5,351,543	5,351,593

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
2800	2900	BUICK CREEK WEST	DUNLEVY	B	-121.322531	56.811738	1193.9	0	60	60	4,385,226	4,385,286
2800	2900	BUICK CREEK WEST	DUNLEVY	G	-121.499840	56.884054	1205.7				1,743,429	1,743,429
2800	2900	BUICK CREEK WEST	DUNLEVY	J	-121.440620	56.947917	1198.3				1,253,916	1,253,916
2860	4100	BULLMOOSE	BALDONNEL	A	-121.451909	55.148902	2440.2				7,921,425	7,921,425
2860	4100	BULLMOOSE	BALDONNEL	B	-121.498270	55.179456	2939.9				6,807,464	6,807,464
2860	4100	BULLMOOSE	BALDONNEL	C	-121.358544	55.114138	2958.1				6,758,089	6,758,089
2860	4100	BULLMOOSE	BALDONNEL	D	-121.158720	55.084610	3013.0				1,087,215	1,087,215
2860	4060	BULLMOOSE	PARDONET-BALDONNEL	A	-121.473286	55.142595	2720.4				2,079,822	2,079,822
2865	4060	BULLMOOSE WEST	PARDONET-BALDONNEL	B	-121.527845	55.113943	2795.7				1,480,735	1,480,735
2865	4060	BULLMOOSE WEST	PARDONET-BALDONNEL	C	-121.626035	55.150648	2425.9				6,593,968	6,593,968
2865	4060	BULLMOOSE WEST	PARDONET-BALDONNEL	D	-121.651747	55.154730	2714.4				6,593,251	6,593,251
2865	4060	BULLMOOSE WEST	PARDONET-BALDONNEL	E	-121.454361	55.089936	2943.4				1,504,200	1,504,200
2850	4060	BURNT RIVER	PARDONET-BALDONNEL	A	-122.012452	55.306289	2537.4				6,946,824	6,946,824
2900	8400	CABIN	SLAVE POINT	B	-121.727687	59.341880	2171.1				1,968,273	1,968,273
2920	4100	CACHE CREEK	BALDONNEL	A	-121.418757	56.645270	1227.7				2,218,899	2,218,899
2920	2600	CACHE CREEK	BLUESKY	A	-121.425321	56.641657	1082.4				1,146,608	1,146,608
2920	4540	CACHE CREEK	COPLIN	A	-121.445343	56.659903	1380.2				2,717,433	2,717,433
2920	4540	CACHE CREEK	COPLIN	B	-121.603961	56.732683	1453.5				1,193,615	1,193,615
2920	4800	CACHE CREEK	HALFWAY	A	-121.447535	56.681091	1584.9				6,238,586	6,238,586
2960	2700	CECIL LAKE	GETHING	A	-120.645584	56.288865	1000.5				1,153,584	1,153,584
2960	4580	CECIL LAKE	NORTH PINE	A	-120.712487	56.291824	1346.8	16,140	18,496	34,636	3,778,971	3,813,607
2985	2640	CHINCHAGA RIVER	BLUESKY-GETHING-DETRITAL	A	-120.009206	57.339109	940.9				1,510,601	1,510,601
2985	4995	CHINCHAGA RIVER	LOWER CHARLIE LAKE/MONTNEY	A	-120.090630	57.310417	962.6				6,020,139	6,020,139
2985	8400	CHINCHAGA RIVER	SLAVE POINT	A	-120.046048	57.338037	2630.7				1,438,412	1,438,412
2985	8400	CHINCHAGA RIVER	SLAVE POINT	B	-120.012928	57.255970	2667.9				2,104,443	2,104,443
2990	4100	CHOWADE	BALDONNEL	A	-122.484380	56.702083	1684.4				2,342,274	2,342,274
3200	8600	CLARKE LAKE	PINE POINT	C	-122.754093	58.698601	2191.0				2,276,916	2,276,916
3200	8600	CLARKE LAKE	PINE POINT	D	-122.741561	58.713921	2219.6				1,119,964	1,119,964
3200	8400	CLARKE LAKE	SLAVE POINT	A	-122.600366	58.730490	1918.7				88,553,247	88,553,247
3230	4060	COMMOTION	PARDONET-BALDONNEL	A	-121.901468	55.517044	3728.6				1,412,147	1,412,147
3230	4060	COMMOTION	PARDONET-BALDONNEL	B	-121.852228	55.531163	3622.1				1,550,248	1,550,248
3300	4800	CURRANT	HALFWAY	A	-120.317124	56.764510	1199.5	0	0	0	1,168,095	1,168,095
3340	2000	CUTBANK	PADDY	B	-120.211391	55.325324	1768.0				1,163,647	1,163,647

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
3340	2000	CUTBANK	PADDY	H	-120.227228	55.287732	1765.4				1,238,324	1,238,324
3360	4100	CYPRESS	BALDONNEL	A	-122.840514	56.852097	1358.2				1,943,388	1,943,388
3380	2630	DAHL	BLUESKY-GETHING	A	-120.655420	57.448034	1148.1				16,995,537	16,995,537
3380	8400	DAHL	SLAVE POINT	A	-120.510931	57.390262	2854.0				1,355,106	1,355,106
3390	4100	DAIBER	BALDONNEL	A	-122.448342	56.814224	1358.7				1,536,177	1,536,177
3400	5000	DAWSON CREEK	MONTNEY	A	-120.223563	55.862205	2047.3				8,513,387	8,513,387
3425	4100	DOE	BALDONNEL	A	-120.014836	55.966308	1420.9				1,641,172	1,641,172
3425	2700	DOE	GETHING	A	-120.008736	55.939912	1239.5				1,355,816	1,355,816
3425	2700	DOE	GETHING	B	-120.014836	55.966308	1239.9				1,506,335	1,506,335
3425	2330	DOE	PEACE RIVER	A	-120.255774	55.920947	778.3				3,247,746	3,247,746
3425	8100	DOE	WABAMUN	A	-120.208657	55.994451	3283.8				3,301,561	3,301,561
3426	4040	DOIG RAPIDS	NORDEGG-BALDONNEL	A	-120.340630	56.960417	1018.4				1,213,630	1,213,630
3430	2400	DRAKE	NOTIKEWIN	A	-120.088364	57.021502	1167.5				7,232,952	7,232,952
3445	6200	EAGLE WEST	BELLOY	A	-120.809565	56.312715	1634.7				1,807,042	1,807,042
3450	8200	EKWAN	JEAN MARIE	A	-120.834827	58.630816	1237.6				5,281,233	5,281,233
3453	7400	ELBOW CREEK	DEBOLT	C	-122.905043	57.097706	2580.0				1,236,041	1,236,041
3455	8200	ELLEH	JEAN MARIE	B	-121.972323	58.442121	1544.0				6,802,218	6,802,218
3540	2600	FIREWEED	BLUESKY	B	-121.471870	56.802083	1172.1				2,075,748	2,075,748
3540	2900	FIREWEED	DUNLEVY	A	-121.579469	56.834470	1251.2	0	552	552	4,445,250	4,445,802
3540	2900	FIREWEED	DUNLEVY	B	-121.553120	56.881250	1109.1				1,430,412	1,430,412
3540	2900	FIREWEED	DUNLEVY	D	-121.505809	56.818669	1232.1	0	354	354	2,180,093	2,180,447
3540	2900	FIREWEED	DUNLEVY	H	-121.672011	56.836784	1279.5				2,801,192	2,801,192
3560	4800	FLATROCK	HALFWAY	E	-120.547903	56.280890	1429.6	32,086	26,790	58,876	1,747,949	1,806,824
3560	4800	FLATROCK	HALFWAY	G	-120.494184	56.284614	1442.9				1,481,041	1,481,041
3580	4800	FLATROCK WEST	HALFWAY	C	-120.548803	56.353091	1459.7				2,098,525	2,098,525
3580	4800	FLATROCK WEST	HALFWAY	D	-120.602557	56.324149	1288.2	39,867	51,827	91,693	1,170,992	1,262,686
3600	4100	FORT ST JOHN	BALDONNEL	A	-120.819483	56.232754	1185.4				11,773,356	11,773,356
3600	6200	FORT ST JOHN	BELLOY	A	-120.811060	56.218398	1928.8				1,459,860	1,459,860
3600	4800	FORT ST JOHN	HALFWAY	A	-120.811737	56.217846	1486.6				6,133,278	6,133,278
3600	6222	FORT ST JOHN	LOWER BELLOY	A	-120.814899	56.220378	1987.2				1,483,907	1,483,907
4000	4100	FORT ST JOHN SOUTHEAST	BALDONNEL	A	-120.581208	56.173010	1186.8				3,081,931	3,081,931
4000	6200	FORT ST JOHN SOUTHEAST	BELLOY	A	-120.634325	56.174530	1924.2				7,179,477	7,179,477
4000	4800	FORT ST JOHN SOUTHEAST	HALFWAY	A	-120.594730	56.164457	1489.2				4,550,536	4,550,536

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
4200	8500	GOTE	SULPHUR POINT	A	-121.953852	59.533149	2321.7				3,682,954	3,682,954
4300	4100	GRAHAM	BALDONNEL	A	-122.327038	56.517851	1437.4				2,581,155	2,581,155
4300	4100	GRAHAM	BALDONNEL	C	-122.400139	56.480430	1588.6				1,914,608	1,914,608
4300	4100	GRAHAM	BALDONNEL	D	-122.299348	56.419567	1451.0				4,330,528	4,330,528
4300	4100	GRAHAM	BALDONNEL	E	-122.409370	56.547917	1489.0				1,289,344	1,289,344
4300	4100	GRAHAM	BALDONNEL	F	-122.388205	56.508707	1512.2				1,737,349	1,737,349
4350	7400	GRASSY	DEBOLT	A	-122.929922	57.310333	1878.5				4,369,251	4,369,251
4370	4800	GREEN CREEK	HALFWAY	A	-122.554603	57.435605	1371.0				4,776,225	4,776,225
4380	4100	GRIZZLY NORTH	BALDONNEL	A	-120.659370	54.889583	3500.0				2,669,737	2,669,737
4380	2900	GRIZZLY NORTH	DUNLEVY	A	-120.648288	54.885355	2590.4				3,779,561	3,779,561
4385	4100	GRIZZLY SOUTH	BALDONNEL	B	-120.708967	54.745795	1559.8				24,894,212	24,894,212
4385	2900	GRIZZLY SOUTH	DUNLEVY	A	-120.561535	54.774623	2544.9				2,366,653	2,366,653
4385	6300	GRIZZLY SOUTH	TAYLOR FLAT	A	-120.530656	54.750976	4219.0				1,902,113	1,902,113
4400	4800	GUNDY CREEK	HALFWAY	A	-122.055747	56.799175	1602.4				1,094,419	1,094,419
4460	4100	GUNDY CREEK WEST	BALDONNEL	A	-122.153478	56.751663	1281.1				1,166,164	1,166,164
4460	2900	GUNDY CREEK WEST	DUNLEVY	A	-122.159370	56.760417	1123.1				1,828,263	1,828,263
4470	8200	GUNNELL CREEK	JEAN MARIE	A	-121.794153	58.874530	1451.4				25,631,699	25,631,699
4500	4100	GWILLIM	BALDONNEL	A	-121.458789	55.357192	3575.3				1,781,054	1,781,054
4500	4060	GWILLIM	PARDONET-BALDONNEL	A	-121.360138	55.309390	3377.7				2,038,070	2,038,070
4500	4060	GWILLIM	PARDONET-BALDONNEL	B	-121.503120	55.381250	3663.9				2,488,064	2,488,064
4600	4100	HALFWAY	BALDONNEL	A	-121.851772	56.515652	1139.5				1,030,900	1,030,900
4700	8200	HELMET	JEAN MARIE	A	-120.817424	59.417185	1294.9				118,066,403	118,066,403
4700	8200	HELMET	JEAN MARIE	N/A	-121.180002	59.640120	1098.3				1,538,798	1,538,798
4700	8400	HELMET	SLAVE POINT	A	-120.702616	59.366786	1873.3				7,501,140	7,501,140
4780	2515	HIDING CREEK	FALHER C	B	-120.034033	54.794431	2893.0				1,691,630	1,691,630
4780	2520	HIDING CREEK	FALHER D	A	-120.026339	54.903739	2757.8				1,323,911	1,323,911
4800	4060	HIGHHAT MOUNTAIN	PARDONET-BALDONNEL	B	-121.883868	55.426838	3474.4				1,450,861	1,450,861
4800	4060	HIGHHAT MOUNTAIN	PARDONET-BALDONNEL	C	-121.846431	55.424713	3460.2				2,456,406	2,456,406
4800	4060	HIGHHAT MOUNTAIN	PARDONET-BALDONNEL	D	-121.959059	55.456009	3676.3				1,224,563	1,224,563
4800	4060	HIGHHAT MOUNTAIN	PARDONET-BALDONNEL	E	-121.776217	55.454964	3301.4				1,802,840	1,802,840
4850	8400	HOFFARD	SLAVE POINT	D	-122.181301	58.720273	1961.6				1,062,830	1,062,830
4900	4575	INGA	INGA	A	-121.683418	56.662279	1413.1	0	0	0	12,691,635	12,691,635
5000	4150	JEDNEY	BALDONNEL/UPPER CHARLIE LAKE	A	-122.248211	57.267997	1316.6				36,962,850	36,962,850

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
5000	4800	JEDNEY	HALFWAY	A	-122.228830	57.247937	1593.1				16,323,309	16,323,309
5160	4990	KAHNTAH RIVER	BLUESKY-GETHING-MONTNEY	A	-120.678953	57.843860	803.1				2,275,201	2,275,201
5160	5000	KAHNTAH RIVER	MONTNEY	A	-121.027109	58.087235	667.0				1,328,679	1,328,679
5170	2800	KELLY	CADOMIN	D	-120.028310	55.168824	2475.0				3,797,884	3,797,884
5170	2505	KELLY	FALHER A	A	-120.030022	55.197306	1457.0				1,485,945	1,485,945
5170	2505	KELLY	FALHER A	B	-120.098357	55.081165	2407.6				2,595,692	2,595,692
5170	2510	KELLY	FALHER B	A	-120.371880	55.114583	2256.8				2,568,733	2,568,733
5170	2510	KELLY	FALHER B	C	-120.271824	55.146075	2251.1				1,188,793	1,188,793
5180	8600	KLUA	PINE POINT	D	-122.234362	58.486469	2331.9				1,268,651	1,268,651
5180	8600	KLUA	PINE POINT	F	-122.212789	58.495280	2330.7				1,133,024	1,133,024
5180	8600	KLUA	PINE POINT	H	-122.276294	58.486732	2378.0				1,009,870	1,009,870
5180	8600	KLUA	PINE POINT	L	-122.202589	58.441202	2190.7				1,627,073	1,627,073
5180	8600	KLUA	PINE POINT	M	-122.231588	58.452782	2302.2				1,197,744	1,197,744
5180	8600	KLUA	PINE POINT	Q	-122.203565	58.595364	2285.1				3,547,224	3,547,224
5180	8600	KLUA	PINE POINT	R	-122.079042	58.562285	2302.9				1,740,216	1,740,216
5180	8400	KLUA	SLAVE POINT	B	-122.306235	58.645910	1956.3				2,627,291	2,627,291
5180	8400	KLUA	SLAVE POINT	D	-122.293081	58.565081	2046.8				1,725,422	1,725,422
5200	4100	KOBES	BALDONNEL	A	-122.209370	56.664583	1397.0				2,233,000	2,233,000
5200	4500	KOBES	CHARLIE LAKE	B	-122.061176	56.526284	1560.4				1,943,112	1,943,112
5200	7400	KOBES	DEBOLT	C	-122.103130	56.577083	2262.7				2,315,718	2,315,718
5200	2900	KOBES	DUNLEVY	A	-122.029243	56.500003	848.3				3,094,003	3,094,003
5200	4800	KOBES	HALFWAY	A	-122.040630	56.497917	1777.4				11,410,652	11,410,652
5400	8400	KOTCHO LAKE	SLAVE POINT	A	-121.299627	59.034468	2054.3				3,677,501	3,677,501
5420	8400	KOTCHO LAKE EAST	SLAVE POINT	C	-121.202882	58.924207	1994.2				1,624,805	1,624,805
5500	8400	LADYFERN	SLAVE POINT	A	-120.081270	57.161167	2764.6				30,540,369	30,540,369
5500	8400	LADYFERN	SLAVE POINT	B	-120.004499	57.135120	2802.5				2,673,264	2,673,264
5560	4800	LAPP	HALFWAY	A	-120.872901	57.518831	1029.8				1,238,292	1,238,292
5600	4150	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE	A	-122.053387	57.360889	1362.2				59,792,495	59,792,495
5600	4150	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE	B	-121.900548	57.397226	1162.1				12,019,956	12,019,956
5600	4150	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE	D	-122.046880	57.314583	1349.7				2,548,993	2,548,993
5600	4150	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE	F	-122.027604	57.493081	1285.5				1,004,208	1,004,208
5800	4100	LAPRISE CREEK WEST	BALDONNEL	B	-122.171880	57.431250	1316.8				1,302,454	1,302,454
5810	6200	LILY LAKE	BELLOY	A	-122.848389	57.167021	2111.4				1,583,735	1,583,735

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
5850	4100	MARTIN	BALDONNEL	A	-121.469337	57.348098	1168.0				1,968,862	1,968,862
5850	4100	MARTIN	BALDONNEL	E	-121.378120	57.414583	1167.2				1,292,963	1,292,963
5852	2805	MAXHAMISH LAKE	CHINKEH	A	-123.157247	59.710795	1427.7				22,981,632	22,981,632
5854	4060	MEIKLE CREEK	PARDONET-BALDONNEL	A	-121.412749	55.244141	3200.9				1,389,622	1,389,622
5855	8600	MEL	PINE POINT	B	-121.725575	59.214888	2265.7				1,218,844	1,218,844
5855	8400	MEL	SLAVE POINT	A	-121.592569	59.173861	2237.0				4,522,061	4,522,061
6000	8400	MILLIGAN CREEK	SLAVE POINT	A	-120.725461	57.114241	2904.5				3,221,953	3,221,953
6030	8600	MILO	PINE POINT	A	-123.084557	58.643784	2418.9				1,336,210	1,336,210
6030	8600	MILO	PINE POINT	B	-123.032894	58.695449	2343.9				1,949,173	1,949,173
6030	8600	MILO	PINE POINT	D	-123.243156	58.513985	3070.9				1,727,034	1,727,034
6140	4800	MONIAS	HALFWAY	N/A	-121.226168	56.107041	1449.1				42,853,185	42,853,185
6140	4800	MONIAS	HALFWAY	T	-121.293704	56.060579	1519.2				4,921,878	4,921,878
6140	4800	MONIAS	HALFWAY	U	-121.396315	56.027085	1697.3				1,925,017	1,925,017
6140	4800	MONIAS	HALFWAY	V	-121.447566	56.100863	1519.1				4,627,935	4,627,935
6210	2200	MOOSE	CADOTTE	A	-121.133656	55.331392	1854.2				1,430,094	1,430,094
6220	4100	MURRAY	BALDONNEL	A	-121.084370	54.960417	1773.3				5,143,467	5,143,467
6220	4100	MURRAY	BALDONNEL	B	-121.149821	55.005494	2727.3				5,813,993	5,813,993
6220	4100	MURRAY	BALDONNEL	E	-121.034141	54.957162	2291.7				7,766,167	7,766,167
6220	4150	MURRAY	BALDONNEL/UPPER CHARLIE LAKE	A	-121.060963	54.963652	1561.6				21,503,667	21,503,667
6220	4060	MURRAY	PARDONET-BALDONNEL	A	-121.204222	54.963557	1725.0				2,614,899	2,614,899
6400	4100	NIG CREEK	BALDONNEL	A	-121.629583	57.085325	1213.0	1,496	2,199	3,694	27,490,337	27,494,031
6410	2600	NIG CREEK NORTH	BLUESKY	A	-121.628120	57.206250	1203.4				6,963,813	6,963,813
6430	2200	NOEL	CADOTTE	A	-120.430131	55.264522	2043.0				3,236,669	3,236,669
6430	2200	NOEL	CADOTTE	M	-120.640620	55.222917	2151.7				1,998,044	1,998,044
6430	2510	NOEL	FALHER B	C	-120.448349	55.219956	2257.9				5,725,212	5,725,212
6440	4580	NORTH PINE	NORTH PINE	B	-120.707051	56.381901	1319.2	0	6,831	6,831	1,147,220	1,154,051
6460	4100	OAK	BALDONNEL	C	-120.804559	56.488229	1179.4				1,441,860	1,441,860
6460	4800	OAK	HALFWAY	A	-120.705973	56.473678	1246.2	0	3,193	3,193	6,374,381	6,377,574
6480	4100	OJAY	BALDONNEL	A	-120.397282	54.681303	3579.9				22,516,110	22,516,110
6480	4100	OJAY	BALDONNEL	B	-120.507808	54.677651	2813.9				1,681,101	1,681,101
6480	4100	OJAY	BALDONNEL	C	-120.590794	54.658425	1605.9				1,166,131	1,166,131
6480	7400	OJAY	DEBOLT	A	-120.155149	54.596371	4445.9				1,638,400	1,638,400
6480	2850	OJAY	NIKANASSIN	A	-120.390183	54.813529	3371.0				1,216,518	1,216,518

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
6480	2850	OJAY	NIKANASSIN	B	-120.207900	54.629125	2894.2				1,180,335	1,180,335
6480	2850	OJAY	NIKANASSIN	C	-120.332426	54.795965	3398.9				1,240,612	1,240,612
6480	6300	OJAY	TAYLOR FLAT	A	-120.208051	54.629095	4249.1				1,998,863	1,998,863
6480	6300	OJAY	TAYLOR FLAT	C	-120.216732	54.566024	3698.1				3,091,653	3,091,653
6490	2700	OSBORN	GETHING	A	-120.157463	56.694305	1084.7				1,852,567	1,852,567
9000	4100	OTHER AREAS	BALDONNEL	06-35-087-15-W6M	-120.492138	56.797829	1122.3				1,848,170	1,848,170
9000	4100	OTHER AREAS	BALDONNEL	A-067-F/094-G-07	-120.492138	56.797829	989.3				2,109,349	2,109,349
9000	4100	OTHER AREAS	BALDONNEL	B-043-B/094-G-07	-120.492138	56.797829	1025.3				2,218,710	2,218,710
9000	4100	OTHER AREAS	BALDONNEL	C-018-G/093-O-09	-120.492138	56.797829	2706.3				1,300,101	1,300,101
9000	4100	OTHER AREAS	BALDONNEL	C-032-F/093-O-09	-120.492138	56.797829	3044.3				1,204,652	1,204,652
9000	4100	OTHER AREAS	BALDONNEL	C-055-J/094-B-10	-120.492138	56.797829	1634.3				2,152,595	2,152,595
9000	4100	OTHER AREAS	BALDONNEL	D-030-C/093-O-09	-120.492138	56.797829	2200.3				1,785,794	1,785,794
9000	4100	OTHER AREAS	BALDONNEL	D-033-K/094-A-11	-120.492138	56.797829	1176.3				1,937,004	1,937,004
9000	4100	OTHER AREAS	BALDONNEL	D-051-C/094-A-16	-120.492138	56.797829	1038.3				1,618,243	1,618,243
9000	2600	OTHER AREAS	BLUESKY	C-027-A/094-H-01	-120.848388	57.002001	899.3				1,430,960	1,430,960
9000	2600	OTHER AREAS	BLUESKY	C-055-J/094-B-10	-120.848388	57.002001	1596.3				1,479,503	1,479,503
9000	2600	OTHER AREAS	BLUESKY	D-049-B/094-A-16	-120.848388	57.002001	963.3				2,333,890	2,333,890
9000	2800	OTHER AREAS	CADOMIN	07-28-083-15-W6M	-121.894221	56.574076	1089.7				1,111,916	1,111,916
9000	7400	OTHER AREAS	DEBOLT	07-26-084-22-W6M	-121.529590	58.183388	1869.0				3,699,934	3,699,934
9000	7400	OTHER AREAS	DEBOLT	A-023-I/094-I-04	-121.529590	58.183388	783.0				3,629,816	3,629,816
9000	7400	OTHER AREAS	DEBOLT	A-051-H/094-B-10	-121.529590	58.183388	2657.0				2,993,815	2,993,815
9000	7400	OTHER AREAS	DEBOLT	A-063-G/094-I-01	-121.529590	58.183388	524.0				2,628,114	2,628,114
9000	7400	OTHER AREAS	DEBOLT	B-024-B/094-P-11	-121.529590	58.183388	471.0				2,433,289	2,433,289
9000	7400	OTHER AREAS	DEBOLT	B-030-E/094-B-08	-121.529590	58.183388	471.7				3,276,642	3,276,642
9000	7400	OTHER AREAS	DEBOLT	B-041-K/094-I-01	-121.529590	58.183388	525.0				2,719,559	2,719,559
9000	7400	OTHER AREAS	DEBOLT	B-064-E/094-G-15	-121.529590	58.183388	471.7				3,495,726	3,495,726
9000	7400	OTHER AREAS	DEBOLT	B-085-E/094-G-02	-121.529590	58.183388	471.7				4,988,907	4,988,907
9000	7400	OTHER AREAS	DEBOLT	C-053-D/094-P-06	-121.529590	58.183388	470.0				2,449,652	2,449,652
9000	7400	OTHER AREAS	DEBOLT	C-053-J/094-G-03	-121.529590	58.183388	471.7				5,790,890	5,790,890
9000	7400	OTHER AREAS	DEBOLT	C-074-L/094-A-14	-121.529590	58.183388	1390.0				3,914,604	3,914,604
9000	7400	OTHER AREAS	DEBOLT	C-097-D/094-G-15	-121.529590	58.183388	1190.0				4,182,374	4,182,374
9000	7400	OTHER AREAS	DEBOLT	D-019-E/094-G-15	-121.529590	58.183388	1299.0				3,718,180	3,718,180
9000	7400	OTHER AREAS	DEBOLT	D-027-H/094-G-10	-121.529590	58.183388	1326.0				3,449,588	3,449,588

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs			Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
								Mass CO_2 @ EOR (tonnes)	Effective Mass CO_2 (tonnes)	Total CO_2 capacity (tonnes)		
9000	7400	OTHER AREAS	DEBOLT	D-055-L/094-P-11	-121.529590	58.183388	472.0				2,427,075	2,427,075
9000	7400	OTHER AREAS	DEBOLT	D-057-H/094-B-09	-121.529590	58.183388	2000.0				3,472,751	3,472,751
9000	7400	OTHER AREAS	DEBOLT	D-059-I/094-B-09	-121.529590	58.183388	1896.0				3,665,107	3,665,107
9000	7400	OTHER AREAS	DEBOLT	D-095-K/094-B-07	-121.529590	58.183388	2675.0				3,049,374	3,049,374
9000	7400	OTHER AREAS	DEBOLT	D-097-A/094-B-07	-121.529590	58.183388	2033.0				3,590,968	3,590,968
9000	4060	OTHER AREAS	PARDONET-BALDONNEL	A-050-H/093-I-14	-121.121941	54.866188	1801.6				2,080,951	2,080,951
9000	4060	OTHER AREAS	PARDONET-BALDONNEL	D-023-E/093-I-15	-121.121941	54.866188	1810.6				1,726,426	1,726,426
9000	7500	OTHER AREAS	SHUNDA	D-075-E/094-B-16	-122.604339	57.950708	2734.2				1,215,518	1,215,518
6600	4800	PARKLAND	HALFWAY	A	-120.333479	56.048706	1727.8				1,345,327	1,345,327
6600	8100	PARKLAND	WABAMUN	A	-120.313557	56.048992	3317.0				14,298,530	14,298,530
6800	4800	PEEJAY	HALFWAY		-120.479166	56.864488	1107.3	0	0	0	1,713,760	1,713,760
7000	4800	PEEJAY WEST	HALFWAY	A	-120.667121	56.872833	1191.7	0	35,884	35,884	1,106,082	1,141,965
7250	2400	PICKELL	NOTIKEWIN	A	-121.077284	57.216415	885.8				6,757,579	6,757,579
7300	7400	POCKETKNIFE	DEBOLT	A	-123.045186	57.473323	1727.9				1,450,143	1,450,143
7300	7400	POCKETKNIFE	DEBOLT	C	-123.004961	57.402439	1741.8				4,273,936	4,273,936
7340	4100	PRESPATOU	BALDONNEL	A	-121.218915	57.027596	1203.9				1,213,325	1,213,325
7400	4582	RED CREEK	BEAR FLAT	A	-121.235920	56.398357	1515.9				1,124,601	1,124,601
7410	4800	RED CREEK NORTH	HALFWAY	A	-121.282102	56.445510	1667.2				1,273,738	1,273,738
7600	4520	RIGEL	CECIL	A	-120.734380	56.756250	1162.0				1,473,356	1,473,356
7600	2900	RIGEL	DUNLEVY	F	-120.631095	56.655379	884.8				41,132,615	41,132,615
7600	4800	RIGEL	HALFWAY	I	-120.562574	56.614271	1310.7	3,650	6,375	10,025	1,428,753	1,438,778
7620	2700	RIGEL EAST	GETHING	A	-120.438310	56.644498	1062.2	1,708	1,574	3,281	2,817,457	2,820,739
7660	4990	RING	BLUESKY-GETHING-MONTNEY	A	-120.252960	57.769322	838.5				45,359,322	45,359,322
7660	4990	RING	BLUESKY-GETHING-MONTNEY	E	-120.103539	57.918535	804.9				4,586,292	4,586,292
7720	8600	ROGER	PINE POINT	A	-122.616142	58.769011	2100.5				3,497,291	3,497,291
7740	8200	SAHTANEH	JEAN MARIE	A	-121.711948	58.745381	1428.8				1,055,990	1,055,990
7740	8400	SAHTANEH	SLAVE POINT	B	-121.690201	58.738135	1977.2				1,549,807	1,549,807
7745	5000	SATURN	MONTNEY	A	-120.912304	55.907625	2408.9				1,121,167	1,121,167
7750	4800	SEPTIMUS	HALFWAY	A	-120.809042	56.063346	1707.0				1,791,022	1,791,022
7755	8400	SEXTET	SLAVE POINT	D	-121.625619	58.660597	1897.8				2,957,713	2,957,713
7770	8200	SIERRA	JEAN MARIE	A	-121.367734	58.828738	1458.7				6,162,646	6,162,646
7770	8600	SIERRA	PINE POINT	A	-121.347619	58.814306	2164.8				58,041,890	58,041,890
7770	8600	SIERRA	PINE POINT	B	-121.344058	58.742344	2142.3				23,953,640	23,953,640

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
7770	8600	SIERRA	PINE POINT	D	-121.381888	58.712224	2120.6				8,205,767	8,205,767
7770	8600	SIERRA	PINE POINT	E	-121.282709	58.827038	2209.9				3,253,073	3,253,073
7770	8600	SIERRA	PINE POINT	F	-121.231697	58.729359	2050.5				2,989,701	2,989,701
7770	8600	SIERRA	PINE POINT	G	-121.223327	58.831176	2205.3				2,036,297	2,036,297
7770	8600	SIERRA	PINE POINT	J	-121.460577	58.748161	2245.2				3,313,980	3,313,980
7775	7400	SIKANNI	DEBOLT	C	-123.030034	57.232110	1822.6				9,553,961	9,553,961
7775	7400	SIKANNI	DEBOLT	G	-122.948705	57.202528	1800.9				5,723,021	5,723,021
7775	7400	SIKANNI	DEBOLT	H	-123.030681	57.136235	2247.6				10,917,178	10,917,178
7775	7400	SIKANNI	DEBOLT	I	-122.953685	57.253209	2022.8				1,994,944	1,994,944
7775	7400	SIKANNI	DEBOLT	K	-123.162285	57.278452	1420.9				4,423,356	4,423,356
7780	2600	SILVER	BLUESKY	A	-121.378575	57.488151	1095.0				7,091,702	7,091,702
7820	4580	SILVERBERRY	NORTH PINE	A	-121.129630	56.630642	1408.1				1,078,745	1,078,745
7840	2900	SIPHON	DUNLEVY	A	-120.435988	56.498964	1131.3				3,152,973	3,152,973
7840	4800	SIPHON	HALFWAY	A	-120.439125	56.489230	1405.1				1,712,827	1,712,827
7860	2600	SIPHON EAST	BLUESKY	A	-120.329454	56.502418	1098.0	0	252	252	1,948,298	1,948,549
8000	6200	STODDART	BELLOY	A	-121.014613	56.452081	1936.4				29,214,894	29,214,894
8100	6200	STODDART WEST	BELLOY	A	-121.153960	56.488088	1976.7				2,820,277	2,820,277
8100	6200	STODDART WEST	BELLOY	C	-121.075252	56.425788	1447.1	310,999	668,660	979,659	740,431	1,720,089
8100	6200	STODDART WEST	BELLOY	H	-121.149530	56.513421	1962.2				1,758,458	1,758,458
8100	6200	STODDART WEST	BELLOY	I	-121.182748	56.513446	1935.2				1,143,500	1,143,500
8100	4900	STODDART WEST	DOIG	E	-121.325870	56.583487	1639.6	0	803,677	803,677	1,507,968	2,311,645
8100	4800	STODDART WEST	HALFWAY	B	-121.198158	56.489087	1626.2				1,201,234	1,201,234
8105	4060	STONE CREEK	PARDONET-BALDONNEL	A	-121.861886	55.640423	3585.7				1,191,979	1,191,979
8110	4060	SUKUNKA	PARDONET-BALDONNEL	A	-121.686544	55.302940	2657.6				1,651,100	1,651,100
8110	4060	SUKUNKA	PARDONET-BALDONNEL	B	-121.579240	55.282730	3386.8				1,411,111	1,411,111
8110	4060	SUKUNKA	PARDONET-BALDONNEL	C	-121.612779	55.260637	2969.7				1,987,211	1,987,211
8110	4060	SUKUNKA	PARDONET-BALDONNEL	E	-121.678120	55.210417	2018.0				22,431,634	22,431,634
8110	4060	SUKUNKA	PARDONET-BALDONNEL	G	-121.899031	55.305654	2884.0				2,325,446	2,325,446
8110	4060	SUKUNKA	PARDONET-BALDONNEL	H	-121.618660	55.223326	3235.7				2,294,302	2,294,302
8110	4060	SUKUNKA	PARDONET-BALDONNEL	I	-121.576201	55.234190	3258.2				1,374,237	1,374,237
8110	4060	SUKUNKA	PARDONET-BALDONNEL	J	-121.653526	55.283754	2642.0				3,635,286	3,635,286
8110	4060	SUKUNKA	PARDONET-BALDONNEL	L	-121.818749	55.333958	2942.5				6,049,712	6,049,712
8110	4060	SUKUNKA	PARDONET-BALDONNEL	M	-121.716196	55.247327	2535.5				7,171,136	7,171,136

APPENDIX D CONTINUED

Field Code	Pool Code	Field Name	Pool Name	Pool Seq.	Longitude	Latitude	Depth (m)	Oil Reservoirs: Mass CO_2 @ EOR (tonnes)	Oil Reservoirs: Effective Mass CO_2 (tonnes)	Oil Reservoirs: Total CO_2 capacity (tonnes)	Gas Reservoirs CO_2 Capacity (tonnes)	Combined Pool Capacity (tonnes)
8110	4060	SUKUNKA	PARDONET-BALDONNEL	P	-121.594674	55.189800	2807.3				5,739,363	5,739,363
8110	4060	SUKUNKA	PARDONET-BALDONNEL	Q	-121.803301	55.377945	3418.7				1,144,877	1,144,877
8110	4060	SUKUNKA	PARDONET-BALDONNEL	U	-121.712104	55.272462	2692.1				1,258,436	1,258,436
8110	4060	SUKUNKA	PARDONET-BALDONNEL	X	-121.786149	55.241410	3008.3				1,218,518	1,218,518
8110	6300	SUKUNKA	TAYLOR FLAT	A	-121.737014	55.225242	4226.2				1,616,555	1,616,555
8115	2800	SUNDOWN	CADOMIN	B	-120.609234	55.457533	2374.6				12,097,244	12,097,244
8115	2200	SUNDOWN	CADOTTE	A	-120.627890	55.434920	1819.5				5,797,026	5,797,026
8115	2200	SUNDOWN	CADOTTE	C	-120.632981	55.406880	1883.9				1,394,640	1,394,640
8140	7400	THETLAANDOA	DEBOLT	A	-121.359474	59.443973	635.7				4,719,797	4,719,797
8150	4800	TOMMY LAKES	HALFWAY	A	-122.127888	57.685193	1066.5				46,167,148	46,167,148
8160	4800	TOWN	HALFWAY	A	-122.234380	56.972917	1694.4				2,119,205	2,119,205
8180	8400	TSEA	SLAVE POINT	C	-121.861476	59.553057	2102.0				1,985,548	1,985,548
8200	4800	TWO RIVERS	HALFWAY	A	-120.469952	56.179704	1492.9				1,816,737	1,816,737
8220	2600	UMBACH	BLUESKY	A	-121.371957	57.136953	1059.4				1,139,415	1,139,415
8240	2630	VELMA	BLUESKY-GETHING	A	-120.579579	57.306140	1108.2				4,343,934	4,343,934
8260	4100	WARGEN	BALDONNEL	B	-121.228130	57.264583	1154.5				6,883,746	6,883,746
8260	2700	WARGEN	GETHING	A	-121.342102	57.289492	1112.7	0	714	714	1,377,572	1,378,286
8300	4800	WEASEL	HALFWAY		-120.679628	57.031158	1271.9	0	0	0	3,055,234	3,055,234
8360	4800	WILDER	HALFWAY	A	-120.988972	56.222423	1333.3				5,231,577	5,231,577
8360	4800	WILDER	HALFWAY	D	-120.936015	56.254260	1544.3				1,888,992	1,888,992
8400	4800	WILDMINT	HALFWAY	A	-120.567136	57.039489	1125.5	0	0	0	3,260,905	3,260,905
8600	4800	WILLOW	HALFWAY	A	-120.623350	57.085297	1114.5				1,634,633	1,634,633
8600	4800	WILLOW	HALFWAY	B	-120.579635	57.122832	1095.2				1,160,492	1,160,492
8800	8600	YOYO	PINE POINT	A	-121.453126	58.923699	2218.8				72,748,677	72,748,677