AER/AGS Special Report 132

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Foreword

This Special Report publication is a previously unpublished client report from 2004. No new data or interpretations have been included as part of its release.

The report provides regional-scale estimates of the CO_2 sequestration capacity in oil and gas reservoirs in the Western Canada Sedimentary Basin and highlights oil and gas pools with individual capacity greater than 1 Mt CO_2 based on available reservoir data at the time.

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Evaluation of CO_2 Sequestration Capacity in Oil and Gas Reservoirs in the Western Canada Sedimentary Basin

Stefan Bachu
Alberta Geological Survey
Alberta Energy and Utilities Board

March 2004

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Executive Summary

Geological sequestration of CO_2 is an immediately available means of reducing CO_2 emissions into the atmosphere from major point sources, such as thermal power plants and the petrochemical industry, which is particularly suited to the landlocked Western Canada Sedimentary Basin that extends from northeastern British Columbia to southwestern Manitoba. Sequestration of CO_2 in depleted hydrocarbon reservoirs and through enhanced oil recovery (EOR) will likely be implemented first because the geological conditions are already well known and infrastructure is already partially in place. In addition, an economic benefit may be realized through incremental oil production. Capacity calculations are based on the basic assumption that the volume occupied by the produced oil and gas can be backfilled with CO_2. Depending on the strength of the aquifer underlying a reservoir, water invasion has the effect of reducing the theoretical CO_2 sequestration capacity of depleted reservoirs by 50% on average for oil pools, and by 30% on average for gas pools, if the reservoir is allowed to be repressurized only back to its initial pressure. If the underlying aquifer is weak, then it has a very small effect on the reservoir CO_2 sequestration capacity. Other processes, such as reservoir heterogeneity, irreducible water saturation, and CO_2 mobility and buoyancy, further reduce the CO_2 sequestration capacity in reservoirs to effective capacity. On the other hand, if an oil reservoir is suitable for CO_2 miscible flooding, its sequestration capacity increases as a result of increased oil production that makes more space available for sequestration.

The reserves databases in the four western provinces record 37,033 gas pools and 10,552 oil pools. Commingled reservoirs, solution gas reservoirs and bitumen reservoirs were not considered in calculations of CO_2 sequestration capacity. The capacity of 695 oil reservoirs that are currently in secondary and tertiary production (water flood and miscible flood enhanced oil recovery) was estimated based on mass balance calculations at 362 Mt CO_2. However, this capacity decreases as flooding continues. The CO_2 sequestration capacity in the remaining 25,777 gas reservoirs and 8,454 oil reservoirs in single drive and primary production is estimated to be, respectively, 8,557 Mt CO_2 and 427 Mt CO_2. The CO_2 sequestration capacity in 4,748 oil pools that were identified as being suitable for CO_2-flood EOR is estimated to be 570 Mt CO_2 at 50% hydrocarbon pore volume of injected CO_2. The large difference in CO_2 sequestration capacity between oil and gas reservoirs is due mainly to the significantly smaller recovery factor for oil than for gas, but also to the fact that the number of oil pools is approximately one-third the number of gas pools.

Most reservoirs have a relatively small CO_2 sequestration capacity however (on average 330 kt CO_2 for gas reservoirs, 50 kt CO_2 for oil reservoirs, and 120 kt CO_2 in CO_2-flood EOR), rendering them largely uneconomic. In addition, shallow reservoirs are inefficient because of low CO_2 density, while very deep reservoirs may be too costly because of the high cost of CO_2 compression, and also inefficient in terms of net CO_2 sequestered. If only the largest reservoirs in the undeformed part of the basin and in the depth range of approximately 900 m to 3500 m are considered, each with an individual capacity greater than 1 Mt CO_2, then the number of reservoirs in the Western Canada Sedimentary Basin suitable for CO_2 sequestration in the short-to-medium term drops to 771 gas reservoirs and 98 oil reservoirs. These large reservoirs have, respectively, a practical CO_2 sequestration capacity of 3,180 Mt CO_2 and 522 Mt CO_2, of which 284 Mt CO_2 in miscible flood EOR. This practical capacity oil and gas reservoirs for CO_2 sequestration in the largest oil and gas pools in western Canada may provide a sink for CO_2 captured from major point sources that is estimated to last for three decades. Of the four western provinces, Alberta has by far the largest practical CO_2 sequestration capacity, estimated at 2,812 Mt CO_2, followed by northeastern British Columbia with 780 Mt CO_2. In both provinces gas reservoirs have by far more CO_2 sequestration capacity than oil reservoirs. Saskatchewan has a practical CO_2 sequestration capacity of only 79 Mt CO_2, of which more than 90% is in oil reservoirs, while Manitoba has a negligible practical CO_2 sequestration capacity of 1 Mt CO_2 in one oil reservoir only.

This regional-scale estimation of the CO_2 sequestration capacity in oil and gas reservoirs in the Western Canada Sedimentary Basin, and identification of those pools with very large individual capacity represent the first step in the selection of early candidates for CO_2 geological sequestration in Canada. To further advance the knowledge base and provide the information necessary for decision making regarding geological sequestration of CO_2 in oil and gas reservoirs in western Canada, it is recommended to:

1. evaluate the production history and the timing of availability (timing of depletion) for the oil and gas reservoirs with very large capacity (greater than 1 Mt CO_2 each) in western Canada;
2. evaluate the heterogeneity and permeability of these reservoirs because these characteristics affect injectivity, hence the number of wells that would be needed to deliver the CO_2 to the reservoir;
3. evaluate existing infrastructure for these reservoirs (e.g., wells, pipelines, gathering systems);
4. evaluate the age and conditions of existing wells;
5. evaluate the potential for incremental oil production and CO_2 sequestration in the top oil reservoirs (approximately 80) that are suitable for CO_2 miscible flooding, using more detailed and sophisticated reservoir models;
6. develop methodology and a model for matching major stationary CO_2 sources in western Canada with these large potential CO_2 sinks.

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Acknowledgments

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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). As a result of anthropogenic CO_2 emissions, atmospheric concentrations of CO_2 have risen from pre-industrial levels of 280 ppm to the current level of more than 360 ppm, primarily as a consequence of fossil-fuel combustion for energy production (Bryant, 1997). Circumstantial evidence suggests that the increase in greenhouse-gas concentrations in the atmosphere leads to climate warming and weather changes (Bryant, 1997; Jepma and Munasinghe, 1998). Because of its relative abundance compared with the other greenhouse gases, CO_2 is responsible for about 64% of the enhanced 'greenhouse effect' (Bryant, 1997). On a sectoral basis, the energy sector contributes globally the most (45%) to anthropogenic effects on climate change (Intergovernmental Panel on Climate Change, 1996). In a business-as-usual scenario, the Intergovernmental Panel on Climate Change predicts that global emissions of CO_2 to the atmosphere will increase from 7.4 billion tonnes of atmospheric carbon (Gt C) per year in 1997 to approximately 26 Gt C/yr by 2100 (Intergovernmental Panel on Climate Change, 1996).

Because of the uncertainty in predicting climate behaviour and the need to avoid irreversible climate changes and the associated risks resulting from greenhouse effects, most of the developed world has committed to reduce the release into the atmosphere of anthropogenic CO_2. Canada has recently ratified the Kyoto Protocol by which she has committed to reduce her CO_2 emissions in 2012 to 6% below the 1990 level of 460 Mt CO_2. However, Canada's emissions have increased steadily since then. Western Canada has also registered a significant increase in CO_2 emissions, such that by 1999 Alberta surpassed Ontario as the province with the largest emissions in Canada, while Saskatchewan has recorded the highest rate of increase in CO_2 emissions. The profile of CO_2 emissions in Alberta and Saskatchewan is different from the national profile and those of other regions because they are a major North American producer of fossil fuels. Because of the abundance of cheap fossil fuels (mainly coal), power generation in Alberta and Saskatchewan is thermally based, unlike the rest of Canada where it is mainly nuclear or hydroelectric. In addition, the majority of CO_2 emissions in the Western Canada Sedimentary Basin, which extends from northeastern British Columbia to southwestern Manitoba, are from large stationary sources, such as power plants, refineries, oil sand plants and cement plants, unlike in Ontario and Quebec where the majority of CO_2 emissions are from small, distributed and mobile transportation sources. Figure 1 shows the distribution in western Canada of stationary CO_2 sources with emissions greater than 100 kt CO_2/year. The histograms of these sources in Alberta (Figure 2a) and in the Western Canada Sedimentary Basin (Figure 2b) clearly show that Alberta produces by far most CO_2 in western Canada. The presence of large CO_2 stationary sources underlain by the Western Canada Sedimentary Basin provides the option and opportunity of reducing CO_2 emissions into the atmosphere by capturing CO_2 and injecting it into deep geological formations.

Reducing anthropogenic CO_2 emissions into the atmosphere involves basically three approaches, expressed best by examination of the following relation between carbon emissions (C), energy (E) and economic growth as indicated by the gross domestic product (GDP):

$$\text{Net C} = \text{GDP} \times (\text{E/GDP}) \times (\text{C/E}) - \text{S} \qquad (1)$$

where E/GDP is the 'energy intensity' of the economy, C/E is the 'carbon intensity' of the energy system, and S represents carbon removed from the atmosphere (carbon sinks). This relation represents a modification of the original identity for carbon emissions (Kaya, 1995) to account for carbon sinks.

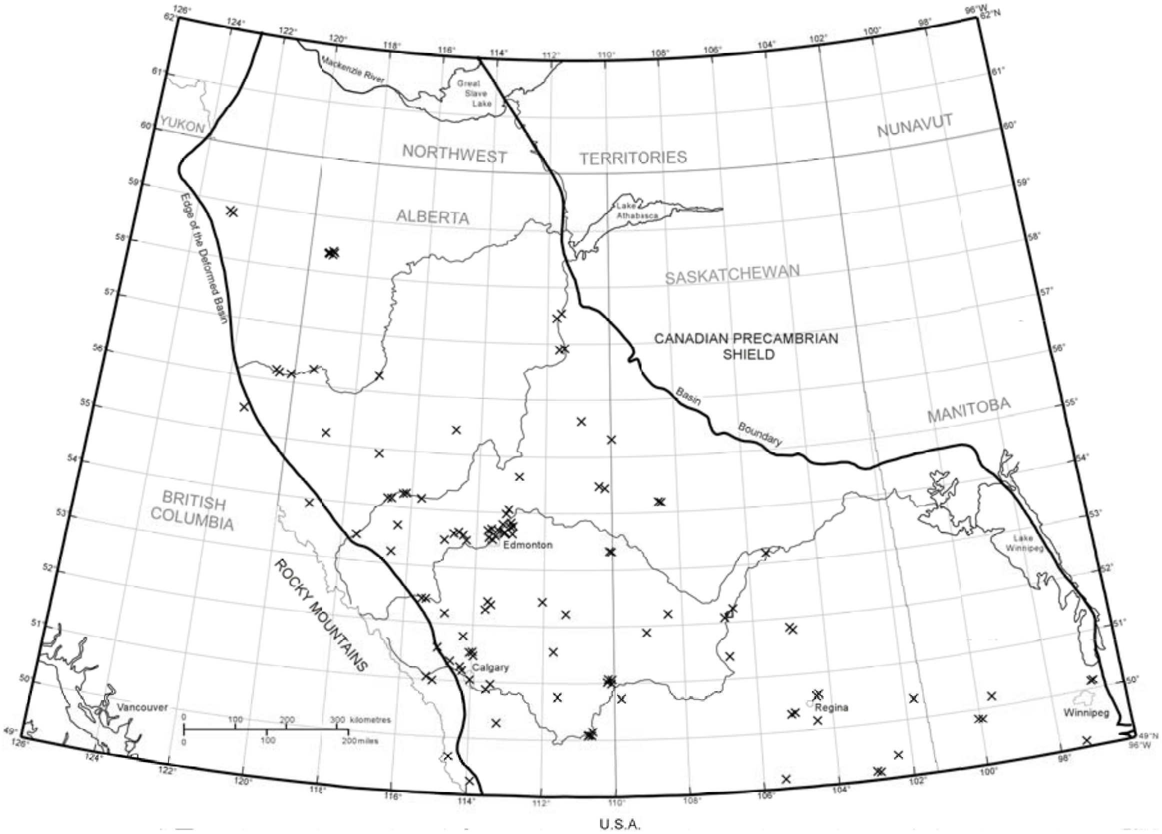
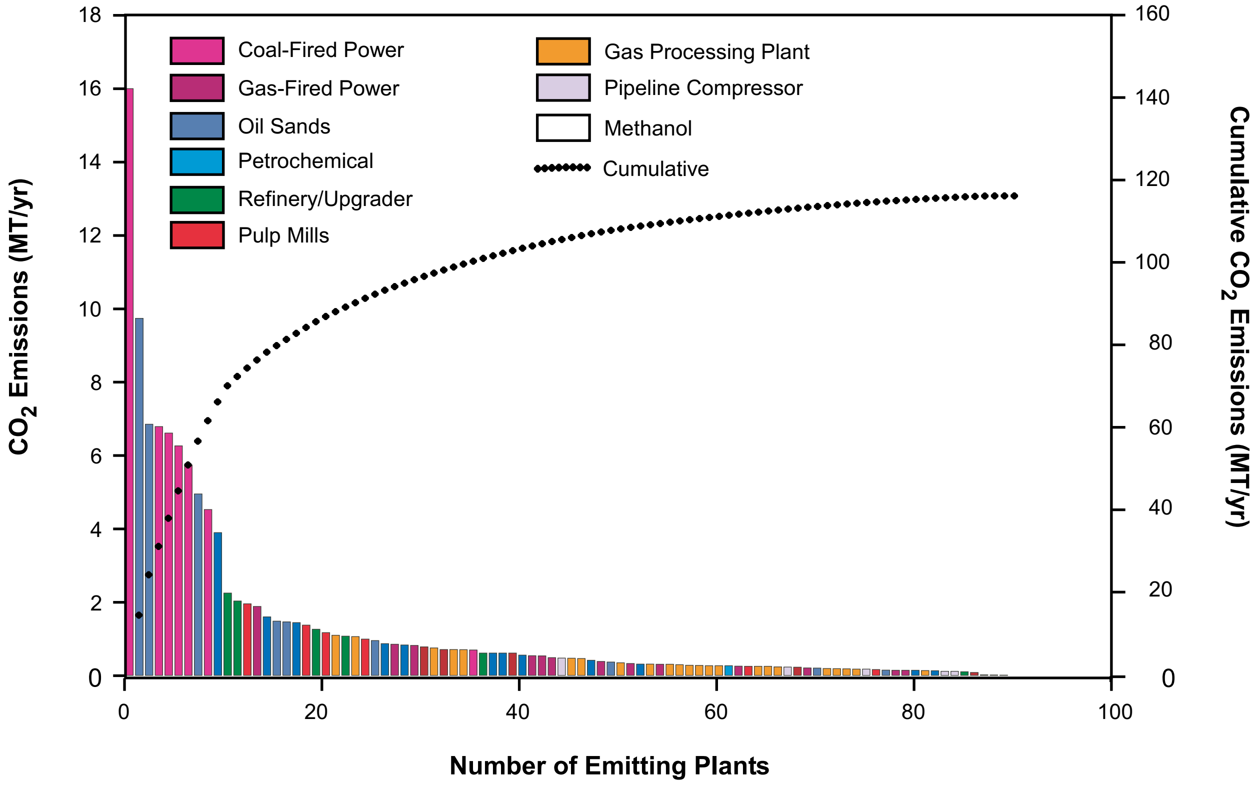


Figure 1. Distribution as of 2001 of major stationary sources of CO_2 (greater than 100 kt CO_2/year) in the Western Canada Sedimentary Basin.

Historical evidence shows that the emissions intensity (C/GDP) decreased continuously since the beginning of the industrial revolution; carbon removed from the atmosphere (S) decreased slightly as a result of deforestation and agricultural practices; but net carbon emissions (C) increased, mainly as a result of the economy (GDP) growing at a faster rate than the decrease in emissions intensity (Kaya, 1995). Since the GDP is increasing, a reduction in net CO_2 emissions into the atmosphere can be achieved by 1) lowering the energy intensity (E/GDP) of the economy (i.e., increasing the efficiency of primary energy conversion and end use); 2) lowering the carbon intensity (C/E) of the energy system by substituting lower carbon or carbon-free energy sources for the current sources; and 3) artificially increasing the capacity and capture rate of carbon sinks (S).

Short of revolutionary, large-scale, new technological advances and major expenditures, however, 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 (Kaya, 1995; Turkenburg, 1997). Given their inherent advantages, such as availability, competitive cost, ease of transport and storage, and large resources, fossil fuels will remain as a major, dominant component of the world's energy supply for at least this century (Jepma and Munasinghe, 1998; Bajura, 2001). Thus, the carbon intensity of the energy system is not likely to decrease in any significant way in the medium term. This leaves increasing the number of carbon sinks (S) and their capture rate in a significant way as the single major means of reducing net carbon emissions into the atmosphere in the short term, although it is recognized that no single category of mitigation measures is sufficient (Turkenburg, 1997). Any viable carbon sink must be safe, environmentally benign, effective, economic and acceptable to the public. Western Canada, which will continue to be a major North American energy supplier for the foreseeable future, needs to reduce CO_2 emissions into the atmosphere while, at the same time, ensuring sustainable economic development. This will most likely be achieved by increasing the capacity and rate of CO_2 sinks.

a.



b.

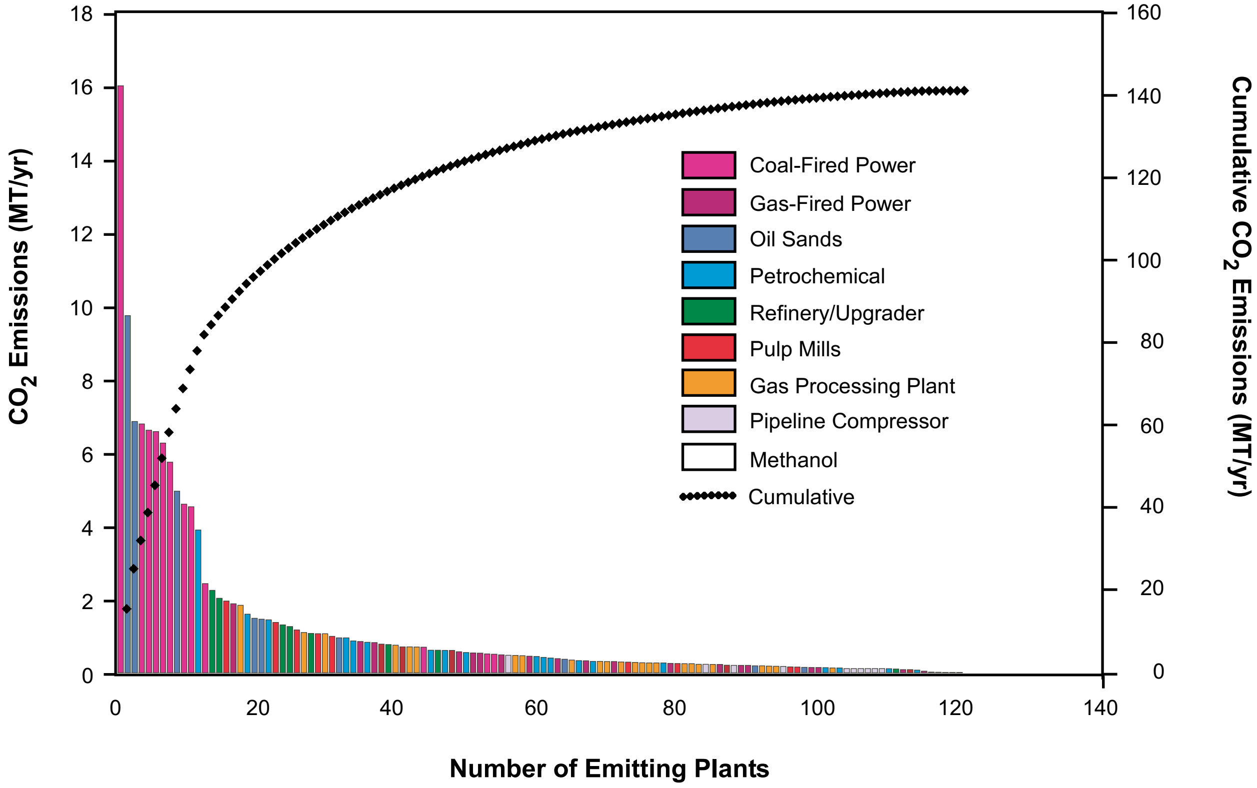


Figure 2. Size and type of major stationary anthropogenic sources of CO_2 as of 2001: a) in Alberta, and b) in the Western Canada Sedimentary Basin.

Large, natural CO_2 sinks are terrestrial ecosystems (soils and vegetation) and oceans with retention times on the order of 10 to 10^5 years (Gunter et al., 1998). Terrestrial ecosystems and the ocean surface represent a diffuse natural carbon sink that captures CO_2 from the atmosphere after its release from various sources. Population increase and other land uses, however, compete with expanding terrestrial natural CO_2 sinks through forestation. The natural, diffuse and slow exchange of CO_2 between the atmosphere and oceans can be artificially enhanced by injecting CO_2 at great depths, where it will form either hydrates or heavier-than-water plumes that will sink to the bottom of the ocean (Aya et al., 1999). Ocean disposal, however, involves issues of poorly understood physical and chemical processes, sequestration efficiency, cost, technical feasibility and environmental impact, and the technology for disposing of CO_2 from either ships or deep pipelines is only in the development stage. In addition, ocean circulation and processes may bring to the fore legal, political and international limitations to large-scale ocean disposal of CO_2. In contrast, the geological storage and/or sequestration of CO_2 currently represent the best short- to medium-term option for significantly enhancing CO_2 sinks, thus reducing net carbon emissions into the atmosphere. Geological sequestration and storage are defined as the **removal of CO_2 directly from anthropogenic sources (capture) and its disposal in geological media, either permanently (*sequestration*) or for significant time periods (*storage*)**. For landlocked regions located on foreland or intra-cratonic sedimentary basins such as in western Canada, sequestration in geological media is the best and only option currently available for increasing CO_2 sinks (Bachu and Gunter, 1999).

Carbon-dioxide disposal in geological media does not compete with agriculture, fishing, other industries and land use. The technology for the deep injection of CO_2, acid gases (CO_2 and H_2S) and industrial liquid waste is well developed and currently practiced mainly by the energy and petrochemical industries for enhanced oil recovery, acid gas (CO_2 and H_2S) disposal, and deep injection of various liquid wastes (e.g., Gale et al., 2001; Stevens et al., 2001a; Moritis, 2002; Tsang et al., 2002; Bachu et al., 2003). Generally, there are no associated environmental problems and the disposal can be safely undertaken within national boundaries, thus avoiding potential international issues. Fossil fuels and power generation are intrinsically and serendipitously linked with sedimentary basins (Hitchon et al., 1999), consequently lowering overall transportation costs. Thus, while CO_2 capture from anthropogenic sources still poses some technological challenges because of its high cost, the issues related to CO_2 disposal in geological media *strictu senso* are not technological, but rather fall into the following categories (Bachu, 2002):

1) geoscience (site selection, capacity and safety);

2) economic (cost, fiscal and taxation policy, credits); and

3) public (perception and acceptance).

Carbon dioxide can be sequestered in geological media by 1) geological trapping in depleted oil and gas reservoirs, 2) solubility trapping in reservoir oil and formation water, 3) adsorption trapping in uneconomic coal beds, 4) cavern trapping in salt structures, and 5) mineral immobilization (Hendriks and Blok, 1993; Blunt et al., 1993; Gunter et al., 1993, 1997; Dusseault et al., 2002). Use of CO_2 in enhanced oil and gas recovery (EOR and EGR; Blok et al., 1997; Holtz et al., 2001; Koide and Yamazaki, 2001) and in enhanced coalbed-methane recovery (ECBMR; Gunter et al., 1997; Gale and Freund, 2001), and hydrodynamic trapping in deep aquifers (Bachu et al., 1994) actually represent forms of CO_2 geological storage with retention times of a few months to potentially millions of years, depending on flow path and processes. In all cases of enhanced recovery of hydrocarbons, CO_2 ultimately breaks through at the producing well and has to be separated and recirculated back into the system. This reduces the sequestration capacity and efficiency of the operation, notwithstanding the additional CO_2 produced during the separation and compression stages. The economic benefits of incremental oil and gas production, however, make these operations most likely to be implemented first.

Carbon dioxide can be sequestered in a geological trap (structural or stratigraphic) under static conditions, similar to those under which hydrocarbons are trapped in reservoirs. The same seals (caprock) that impeded the escape and migration of hydrocarbons over geological time should retain CO_2 ‘permanently’, as long as pathways to the surface or adjacent formations are not created by fracturing the reservoir through overpressuring, or by improperly completed or abandoned wells (Celia and Bachu, 2002). Depleted gas reservoirs are primary candidates as geological traps for CO_2 because primary recovery removes as much as 95% of the original gas in place. Underpressured oil reservoirs that have not been invaded by water should also have good sequestration capacity. Oil and gas reservoirs in contact with underlying formation water (pressured by the water drive) are invaded by water as the reservoir is depleted. These reservoirs have less potential for CO_2 sequestration because CO_2 will have to displace (push back) the formation water.

Estimates of worldwide sequestration capacity in depleted oil reservoirs vary widely from 126 to 400 Gt CO_2 (Gunter et al., 1998; Holt et al., 2000; Freund, 2001). The capacity for CO_2 sequestration in depleted gas reservoirs is significantly higher than in oil reservoirs (e.g., tenfold in Texas; Bergman et al., 1997), estimated globally at 800 Gt CO_2 (Freund, 2001). Thus, we expect that the capacity for CO_2 sequestration in depleted oil and gas reservoirs in western Canada be significant and provide enough capacity for early implementation and reduction in Alberta’s CO_2 emissions into the atmosphere.

Theoretical Capacity of Depleted Hydrocarbon Reservoirs for CO_2 Sequestration

The capacity for CO_2 sequestration in hydrocarbon reservoirs in any specific area, western Canada in this case, is given by the sum of the capacities of all reservoirs in that area. After basin- and regional-scale evaluations (Bachu, 2000, 2002; Bachu and Stewart, 2002), the next step is the pool analysis based on 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. Earlier estimates of the capacity of oil and gas reservoirs for CO_2 sequestration assumed that the volume occupied by the produced hydrocarbons can be replaced by CO_2 (e.g., Winter and Bergman, 1993). Close to 95% of the original gas in place (OGIP) and between 5 and 21% of the original oil in place (OOIP) is usually recovered by primary production (Bondor, 1992; Holt et al., 1995), although the recovery factor for oil may be much higher in some cases. An additional 10 to 20% of OOIP is produced by secondary recovery, leaving some 60 to 70% of OOIP in the ground (Bondor, 1992). Various miscible agents, both hydrocarbon and non-hydrocarbon based, have been used for enhanced (tertiary) oil recovery, with various degrees of success and economic benefit (e.g., Stalkup, 1983).

The fundamental assumption being made is that the volume previously occupied by the produced hydrocarbons becomes, by and large, available for CO_2 sequestration. 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. 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., 2001a).

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-fracturing pressure. In this case, the CO_2 sequestration 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 sequestration 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 sequestration contribute to a reduction in the real capacity for CO_2 sequestration in hydrocarbon reservoirs. However, none of these capacity estimates is final, in the sense that values evolve in time, most likely increasing as new oil and gas discoveries take place, or as better production technologies are developed.

Theoretical Capacity of Depleted Gas Reservoirs

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. If enhanced-gas-recovery (EGR) methods are being used, the volume of the reservoir available for CO_2 sequestration is given by the volume of the initial producible gas minus the volume of the injected gas. However, this case can be neglected in large-scale capacity estimates because 1) EGR is currently applied in extremely few cases; and 2) the volume of the injected gas represents such a small percentage of the individual reservoir volume that accounting for gas injection is not warranted.

Since reserves databases indicate the volume of original gas in place (OGIP) at surface conditions, the mass-capacity for CO_2 sequestration in a reservoir at in situ conditions, M_{CO2}, is given by:

$$M_{CO2} = \rho_{CO2r} \cdot R_f \cdot (1 - F_{IG}) \cdot OGIP \cdot [(P_s \cdot Z_r \cdot T_r) / (P_r \cdot Z_s \cdot T_s)] \qquad (2)$$

In the above equation, ρ_{CO2} is CO_2 density, R_f is the recovery factor, F_{IG} 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).

Theoretical Capacity of Depleted Oil Reservoirs

The CO_2 sequestration capacity of oil reservoirs is calculated similarly to gas reservoirs; however, there are additional factors that must be taken into account because of the various methods for producing oil. Heavy oil and bitumen reservoirs (e.g., cyclic steam stimulation [CSS] and steam-assisted gravity drainage [SAGD]) will have a negligible reservoir volume available for CO_2 sequestration after thermal recovery, the rest being occupied by residual water, steam condensate and gas. These reservoirs are usually shallow, have low pressure and are hot for a significant period of time at the end of thermal recovery; hence, they have very low CO_2 sequestration capacity. Although these reservoirs are not taken into account in the present calculations for western Canada, they may considered in the future, being located in the eastern and northeastern part of Alberta where there are very few other options for CO_2 geological sequestration (Bachu and Stewart, 2002).

In the case of flooded reservoirs, the volume available for CO_2 sequestration is the reservoir volume of the produced oil minus the volume of the injected water, solvent or gas. These reservoirs have reduced CO_2 sequestration capacity, estimated at 2 to 4% of the pore volume (Stevens et al., 2001a). If a reservoir is subjected to CO_2 EOR after a flood, then the water, solvent or immiscible gas is displaced along with oil by CO_2 and the vacant volume becomes available for CO_2 sequestration (Holt et al., 1995).

The CO_2 sequestration capacity can be calculated using reserves databases (e.g., Winter and Bergman, 1993; Stevens et al., 2001a) on the basis of reservoir rock volume (area [A] times thickness [h]), porosity (ϕ) and oil saturation ($1 - S_w$), where S_w is the water saturation. For reservoirs flooded with or invaded by water, the volume available for CO_2 sequestration is reduced by the volume of injected and/or invading water (V_{iw}). If water is produced with oil, then the volume available for CO_2 sequestration is augmented by the volume of produced water (V_{pw}). The same mass balance applies in the case of miscible flooding with solvent or gas. Thus:

$$M_{CO2} = \rho_{CO2res} \cdot [R_f \cdot A \cdot h \cdot \phi \cdot (1 - S_w) - V_{iw} + V_{pw}] \qquad (3)$$

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.

Although more than 4000 reservoirs in Alberta meet the technical conditions for CO_2 flooding (Shaw and Bachu, 2002), currently there are no CO_2-EOR operations because of the high cost of CO_2 compared with solvent or natural gas, except for the Joffre Viking pool where a pure stream of CO_2 is obtained from Nova petrochemical plant (Stephenson et al., 1993). Similarly, in Saskatchewan there is only one CO_2-flood EOR operation at Weyburn, where Encana Corporation is injecting CO_2 that is the by-product of coal gasification in Beulah, North Dakota.

Effect of Underlying Aquifers

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.

At depletion of hydrocarbons, 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 be 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.

Individual determination of the effect of an underlying aquifer is a daunting task for the thousands of oil and gas pools in western Canada. For this study, 157 gas and 104 oil reservoirs in primary production that have very large theoretical CO_2 sequestration capacity (greater than 5 Mt CO_2 each) were selected for analysis. Assessing the strength of aquifer support was accomplished by examining these pools' water production, cumulative water-gas ratio (WGR) or water-oil ratio (WOR), and their pressure histories. 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. Based on the above analysis, reservoirs were divided into two categories: with strong, and weak or no aquifer support. It was initially assumed that a high recovery factor (R_f) would be indicative of strong aquifer support. However, no relation was found between R_f and the strength of the underlying aquifer.

The systematic review of the 261 oil and gas pools indicates that the aquifer support is generally weak if the cumulative WGR of these pools is less than 10 bbl/MMcf for gas reservoirs, and if the cumulative WOR is less than 0.2 for oil reservoirs (Bachu et al., 2004). The threshold value for oil reservoirs can be enhanced with cumulative producing GOR for reservoirs whose cumulative WOR is between 0.15 and 0.25. The analysis shows that pools that have low WOR tend to have high cumulative GOR. For pools that fall in this range, aquifer support is considered weak if the cumulative GOR>1,000 m^3/m^3 (5,600 scf/bbl). All other pools were determined to have relatively strong aquifer support.

Because of the significant resources needed for modeling reservoir performance, only 21 representative reservoirs were selected of the 261 examined oil and gas pools, and used for analysing the effect of the underlying aquifers using the Petroleum Expert's MBAL^{TM} (Material BALance) software (Bachu et al., 2004). These selected pools are distributed across the Western Canada Sedimentary Basin (WCSB) from northeastern British Columbia to southwestern Manitoba, and were considered to be reasonably representative for the range of conditions found in the basin. The analyzed pools include Bonnie Glen D-3 A, Harmattan-Elkton Rundle C, Nipisi Keg River Sand E, Suffield Mannville J, Blueridge Jurassic B, Sundance Viking A and Hanlan Beaverhill Lake A in Alberta, Clarke Lake, Roger and Siphon in British Columbia, and Arcola Frobisher, Tyvan Red River and Wapella in Saskatchewan. The pools have varying degrees of aquifer support and initial pressures that vary between 4,500 and 24,400 kPa. For these 21 oil and gas pools, pressure and production histories were matched first, leading to identification of aquifer properties and the production-driving mechanisms, such as fluid expansion, water influx and pore compressibility. Then, the program was used to forecast the expected future pressure decline by allowing the reservoir to produce the remaining recoverable reserves. 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 MBAL^{TM} 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.

For illustration, Figure 3 shows the history-matched and predicted pressure behaviour of two gas reservoirs, one with strong and the other with weak aquifer support. In the case of a strong underlying aquifer (Figure 3a), water continues to invade the reservoir (inflow) even after the start of CO_2 injection, albeit at a decreasing rate, and it reverses direction (outflow) only after the CO_2 pressure in the reservoir equals the pressure in the aquifer and continues to build up. A significant amount of water is still present in the reservoir by the time the CO_2 pressure reaches the initial reservoir pressure. To expel all the aquifer water and recover the initial reservoir volume, the reservoir pressure caused by CO_2 injection has to increase significantly beyond the initial pressure (in this case by ~30%), which may not be allowed by the current regulations for acid gas disposal. In the case illustrated, the aquifer invasion and retreat in the reservoir shows strong hysteresis behaviour.

The MBAL^{TM} model also allows simulating the same case without aquifer support (Bachu and Shaw, 2003), in which case the reservoir abandonment pressure is predicted to be much lower than the case with aquifer support in order to produce all the gas in the reservoir. In this scenario, the amount of injected CO_2 when pressure builds up to the initial reservoir pressure corresponds to the theoretical ultimate CO_2 sequestration capacity of this reservoir (Figure 3a). This example shows that, in the case of strong aquifer support, the ultimate theoretical CO_2 sequestration capacity of a reservoir is reduced significantly, in this case by ~22%. If the pressure is allowed to increase beyond the initial reservoir pressure, the reduction in CO_2 sequestration capacity diminishes. The two CO_2 capacity curves, with and without aquifer support, always cross at a pressure higher than the original reservoir pressure, indicating the eventual retreat of the aquifer given a sustained high CO_2 injection pressure. Beyond the crossover point, reservoirs with strong aquifer support predict even higher CO_2 sequestration capacities as a result of additional storage volume becoming available when the aquifer is receded beyond its original position.

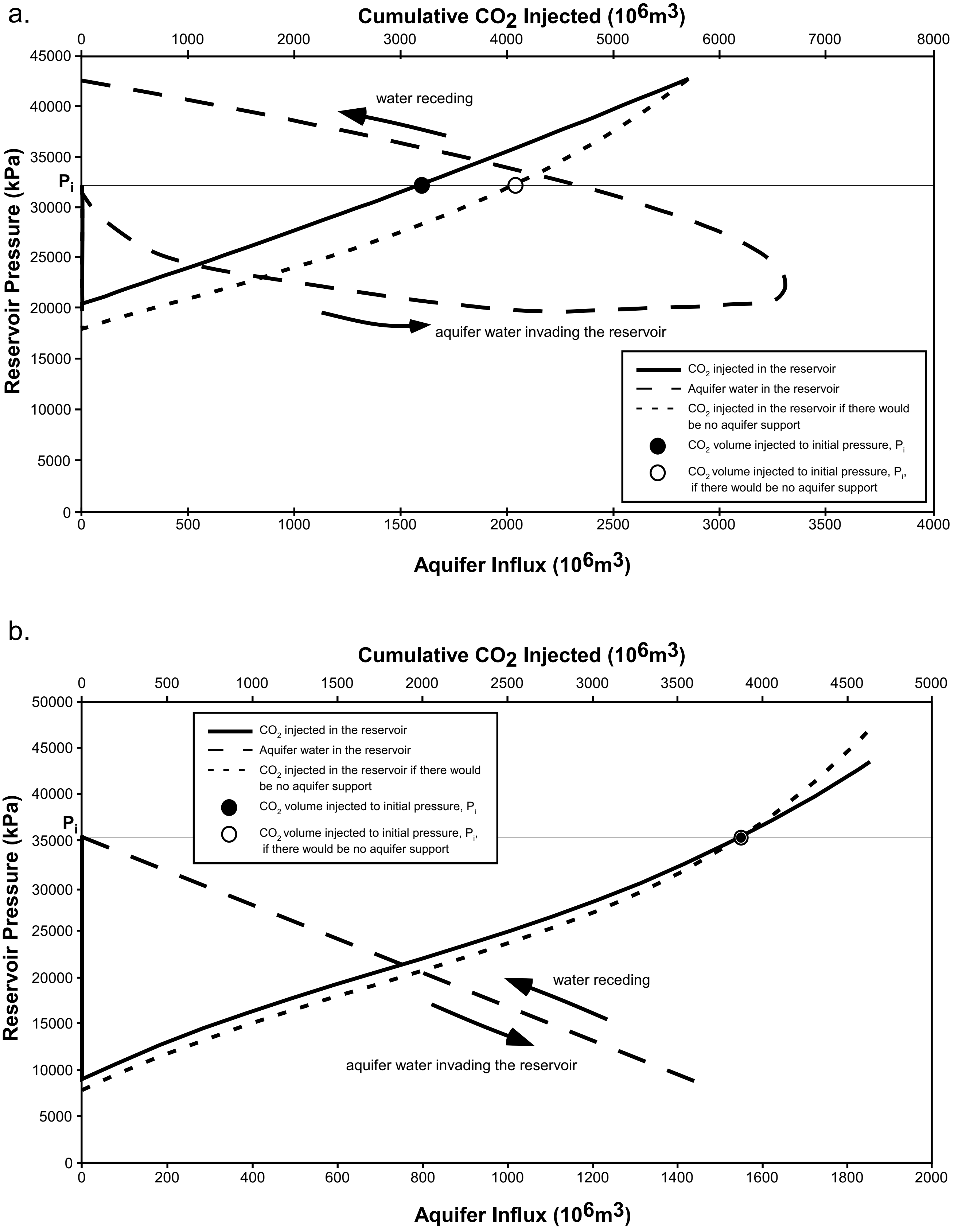


Figure 3. Past and predicted behaviour of gas reservoirs underlain by aquifers, with CO_2 injection after depletion: a) with strong aquifer support (Harmattan-Elkton D-3A in Alberta), and b) with weak aquifer support (Clearwater Rundle A in Alberta). Simulations were carried out using the model MBAL^{TM}.

In the case of a reservoir with weak or no aquifer support, the invading water recedes following the original pressure and aquifer influx path with very little or no hysteretic behaviour. All invading water is expelled from the reservoir by the time reservoir pressure builds up back to the initial pressure (Figure 3b). In this case, the underlying aquifer has almost no effect on the pool's theoretical ultimate CO_2 sequestration capacity. Similar behaviours are observed for the oil pools, as illustrated in Figure 4. In the case of a reservoir with weak or no aquifer support and limited gas drive ($WOR<0.15$), the invading water recedes as reservoir pressure is restored, with very little or no hysteretic behaviour, similarly with the case of gas reservoirs with weak aquifer support. The simplified tank models suggest that all invading water will be expelled from the reservoir by the time reservoir pressure builds up back to the initial pressure. The behaviour of oil pools with weak aquifer support and significant gas drive ($0.15<WOR<0.25$, $GOR>1{,}000\ m^3/m^3$) exhibits characteristics of oil pools with both weak and strong aquifer support, as illustrated in Figure 4b for the Wayne Rosedale Basal Quartz B pool in Alberta (Bachu et al., 2004). As with reservoirs with weak aquifer support, the underlying aquifer has a negligible effect on the theoretical CO_2 sequestration capacity. On the other hand, similarly to the case of reservoirs with strong aquifer support, the behaviour of the aquifer exhibits a strong hysteretic behaviour.

The CO_2 sequestration capacity of the 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 will be left behind in the pore space by the receding aquifer. To account for this effect it is assumed that the theoretical CO_2 sequestration capacity in oil and gas reservoirs with weak aquifer support is reduced by ~3%.

In the case of hydrocarbon reservoirs with strong aquifer support (gas and oil pools that have, respectively, cumulative WGR or WOR greater than the corresponding threshold values), the CO_2 sequestration capacity is significantly reduced by the presence of the aquifer. If the reservoir pressure resulting from CO_2 injection is limited to the initial reservoir pressure, then the reduction in CO_2 sequestration capacity based on MBAL analyzed cases varies between 0% and 48% for gas reservoirs (averaging 30%), and between 19% and 75% (averaging 50%) for oil reservoirs. The larger reduction in CO_2 sequestration capacity for oil reservoirs than for gas reservoirs is most likely due to the longer time needed to produce the oil reservoirs, which allows greater aquifer influx. In high-permeability gas reservoirs, it is possible to outrun the aquifer with very high depletion rates. If the CO_2 pressure is allowed to increase above the initial reservoir pressure, then ultimately all aquifer water will be repelled, providing additional CO_2 sequestration capacity as a result of increased pore space and CO_2 density. Table 1 shows the generalized criteria for establishing the strength and effect of underlying aquifers on the CO_2 sequestration capacity in depleted oil and gas reservoirs in western Canada.

Table 1. Criteria for establishing the strength and effect of underlying aquifers on the CO_2 sequestration capacity in depleted oil and gas reservoirs in the Western Canada Sedimentary Basin, and the corresponding coefficient of reduction in CO_2 sequestration 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	≥ 10		Strong	0.70
	<10		Weak	0.97

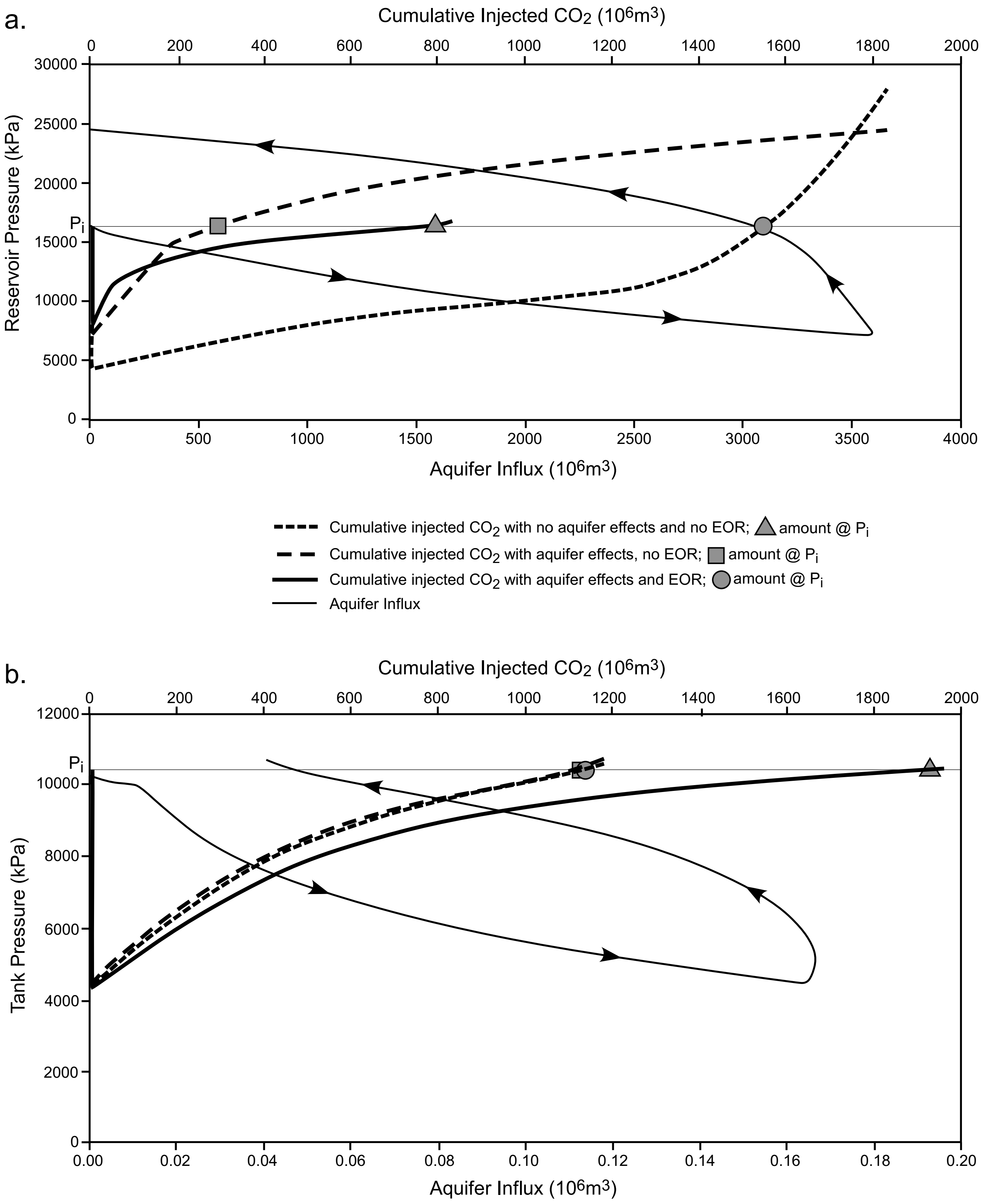


Figure 4. Predicted CO_2 sequestration capacity in oil pools with and without aquifer effects or CO_2-flood EOR for: a) a pool underlain by a strong aquifer (Otter Granite Wash in Alberta), and b) a pool underlain by a weak aquifer and with gas drive (Wayne Rosedale Basal Quartz B in Alberta). Simulations were carried out using the model MBAL™.

Effective CO_2 Sequestration Capacity

The nature of the displacement process and/or the geological complexity of a reservoir contribute to a reduction in the effective amount of CO_2 that can be stored in oil reservoirs (e.g., Bondor, 1992). Notwithstanding the effect of an underlying aquifer, three factors, in particular, control the effectiveness of the sequestration 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). To control CO_2 mobility in EOR operations, the injection of alternate slugs of water and CO_2 ('water alternating gas' process or WAG), simultaneous CO_2 and water injection, and surfactants that generate foams have been used (e.g., Martin and Taber, 1992; Bondor, 1992; Stephenson et al., 1993). All these methods for optimizing oil recovery do not necessarily maximize CO_2 sequestration. Thus, new strategies are needed that will optimize both oil recovery and CO_2 sequestration processes.

Depending on reservoir temperature and pressure, the density of supercritical or liquid CO_2 may range between approximately 200 and 800 kg/m^3. 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 et al., 2001). This negatively affects the CO_2 sequestration, 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 et al., 2001).

The presence of water in the reservoir also has the effect of reducing the CO_2 sequestration 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 (S_{wirr}) 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 sequestration can be expressed by capacity coefficients ($C < 1$) in the form (Doughty et al., 2001)

$$M_{CO2eff} = C_m \cdot C_b \cdot C_h \cdot C_w \cdot C_a \cdot M_{CO2res} \qquad (4)$$

where M_{CO2eff} is the effective reservoir capacity for CO_2 sequestration, 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 m^3 CO_2 / m^3 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

sequestration in depleted hydrocarbon reservoirs. The first four capacity coefficients can be captured in a single 'effective' coefficient

$$C_{eff} = C_m \cdot C_b \cdot C_h \cdot C_w \quad (5)$$

which can be estimated on the basis of experience with CO_2-flood EOR. A review of capacity coefficients for CO_2 sequestration in aquifers suggests that $C_{eff}<0.3$. Conditions are more favourable in the case of oil reservoirs (for example the buoyancy contrast is much reduced), and a value of $C_{eff}=0.5$ was considered in this study. For gas reservoirs, $C_m \approx 1$ 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 $C_b \approx 1$ as well. The effect of initial water saturation was already implicitly taken into account in the estimates of theoretical ultimate CO_2 sequestration capacity, such that $C_w \approx 1$ too. Although reservoir heterogeneity may reduce the CO_2 sequestration capacity by leaving pockets of original gas in place, C_h is probably high, approaching values close to unity. Thus, the reduction in CO_2 sequestration capacity for gas reservoirs is much less by comparison with oil reservoirs, and a value of $C_{eff}=0.9$ was used in this study.

Carbon Dioxide Sequestration in CO_2-Flood Enhanced Oil Recovery

Most of the CO_2-flood projects in the United States use inexpensive high-purity CO_2 from natural reservoirs in Colorado, New Mexico and Wyoming (Bondor, 1992; Moritis, 2002). Various gases, including natural gas, flue gas, nitrogen and CO_2 in supercritical state, have been used for EOR, with different degrees of success and economic benefit (Stalkup, 1983). The pressure needed for achieving dynamic miscibility with CO_2, generally above 10–15 MPa (Mathews, 1989), is much lower than those required for natural gas, flue gas or nitrogen. As a result, the number of potential target pools for CO_2 flood applications is much larger than for other gases. However, many oil reservoirs in western Canada have been miscibly flooded with hydrocarbon gases and not with CO_2 because the former are abundant, recoverable for resale and less expensive than CO_2 from anthropogenic sources. Without natural CO_2 sources and incentives to capture CO_2 emissions, the CO_2-flooding process has not gained wide acceptance in Canada. However, 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 sequestration and additional oil recovery. In fact, it is most likely that this option will be implemented before any other. Thus, the identification of reservoirs suitable for CO_2 flooding and estimation of their CO_2 sequestration capacity becomes essential.

The identification and inventory of oil reservoirs suitable for CO_2-flood EOR in western Canada, and determination of their oil recovery and capacity for CO_2 sequestration need to be performed on a reservoir-by-reservoir basis. However, the use of sophisticated and complex numerical models, such as those used in industry to evaluate reservoir performance, require a significant amount of data preparation and input, and significant computer resources for running each case. Thus, these methods and models are not suitable for a regional-scale, initial assessment and screening of oil pools in a sedimentary basin with respect to their suitability for CO_2-flood EOR, incremental recovered oil and sequestered CO_2. A method and procedures for screening oil reservoirs suitable for CO_2-flood EOR and for estimating their CO_2 sequestration capacity and incremental oil recovery have been specifically developed for using information usually available in reserves databases (Shaw and Bachu, 2002) and applied in this study to the reserves databases in British Columbia, Alberta, Saskatchewan and Manitoba.

Identification of Oil Reservoirs Suitable for CO_2-Flood Enhanced Oil Recovery

Various authors recommend criteria for the selection of oil reservoirs suitable for CO_2 flooding (Table 2), and most of these criteria are based on reservoir depth, temperature, pressure, and oil characteristics.

Table 2[1]. Selection criteria for application of CO_2- miscible flood EOR.

Reservoir Parameter	Geffen (1973)	Lewin et al. (1976)	NPC (1976)	McRee (1977)	Iyoho (1978)	OTA (1978)	Carcoana (1982)	Taber & Martin (1983)	Taber et al. (1997a)
Depth (ft)		>3000	>2300	>2000	>2500	i) >7200 ii) >5500 iii) >2500	<9800	>2000	i) >4000 ii) >3300 iii) >2800 iv) >2500
Temperature (°F)		NC	<250				<195	NC	
Initial Pressure (psia)	>1100	>1500					>1200		
Oil Gravity (°API)	>30	>30	>27	>35	30-45	i) <27 ii) 27-30 iii) >30	>40	>26	i) 22-27.9 ii) 28-31.9 iii) 32-39.9 iv) >40
Fraction of Remaining Oil	0.25	0.25		0.25	0.25		>30	0.30	0.20
Viscosity (cP)	<3	<12	<10	<5	<10	<12	<2	<15	<10
Permeability (mD)		NC		>5	>10		>1	NC	

Previous studies assumed that CO_2 reaches supercritical state (T>31.1°C and P>7.38 MPa), generally suitable for miscibility, at depths of approximately 800 m (Holloway and Savage, 1993; van der Meer, 1993). Others have considered various depths for which EOR is applicable (Table 2) that vary between 600 m and 3,000 m (2,000 and 9,800 ft.). However, depending on the geothermal and hydrodynamic regimes in a basin, the conditions for supercritical CO_2 are reached at various depths, from very shallow (a few hundred metres) to very deep (>1200 m) (Bachu, 2002; Bachu and Stewart, 2002). Thus, rather than applying a blanket depth threshold (i.e., 800 m, or the depths recommended in Table 2), the geological space can be transformed into the CO_2 P-T space (Bachu, 2002) for screening oil reservoirs unsuitable for CO_2 flooding because CO_2 is subcritical at the respective reservoir conditions. Accordingly, a lower temperature limit of 32°C can be used for reservoir screening. An upper limit of 121°C (250°F) is recommended by the National Petroleum Council (NPC, 1976).

Reservoir pressure at the start of CO_2 flooding is recommended to be greater than 7.58 MPa (1100 psia) and even greater than 10.3 MPa (1500 psia), which exceeds the CO_2 critical pressure of 7.38 MPa (Lewin

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[1] The values presented in this table and Table 3 are in imperial units, as reported in the original papers by the respective authors. NC stands for 'Not a Criterion'. The conversion factors into SI units are:

Foot	=0.3048 m
°F	=(-32)/1.8°C
psi	=6895 Pa
mD	$=10^{-12}$ m^2
cP	=0.001 Pa·s

and Associates, 1976). An additional screening criterion is that the reservoir pressure at the start of a CO_2 flood should be at least 1.38 MPa (200 psi) above the minimum miscibility pressure (MMP) to achieve miscibility between CO_2 and reservoir oil (Rivas et al., 1994). The MMP depends on the oil composition and gravity, and reservoir temperature (Cronquist, 1978; Yellig and Metcalfe, 1980; Johnston and Pollin, 1981; Holm and Josendal, 1982; Alston et al., 1983). For example, the Weyburn reservoir oil has gravities that range from 25 to 33°API, and MMPs that vary accordingly from 14.5 to 11.5 MPa (Srivastava et al., 2000). The Joffre Viking oil has a gravity of 42°API, with a correspondingly lower MMP of approximately 10.3 MPa (Ko et al., 1985). In the absence of specific reservoir information, the MMP can be estimated on the basis of oil gravity and reservoir temperature (NPC, 1976; Table 3). The minimum reservoir pressure requirement means that the ratio between reservoir pressure and minimum miscible pressure (P/MMP) should normally be greater than 1. In reality, CO_2-flood EOR is still possible for P/MMP=0.95. Thus, P/MMP>0.95 is another screening criterion for reservoirs suitability for CO_2 flooding.

Table 3. Estimates of CO_2-crude oil minimum miscibility pressure (NPC, 1976).

Oil Gravity (°API)	MMP (psia)	Temperature (°F)	Additional Pressure (psia)
<27	4000	120	None
27-30	3000	120-150	200
>30	1200	150-200	350
		200-250	500

A very important screening criterion is oil gravity, generally recommended to be greater than 27°API (light oils with density <900 kg/m^3) but less than 48°API, because extremely light oil such as condensate is not conducive to the development of multi-contact miscibility for miscible flooding (Table 2). Oil viscosity is not a necessary screening parameter, since it is dependent on the oil gravity and reservoir temperature.

To ensure an economic outcome for CO_2 EOR, the fraction of remaining oil before CO_2 flooding ($S_o > 0.25$) should be a limiting factor (Table 2). However, this criterion becomes irrelevant if the main objective is CO_2 sequestration rather than oil recovery. Finally, reservoir permeability, recommended by some to be greater than 5×10^{-15} m^2 (5 mD; Table 2), is not a critical screening criterion because most oil reservoirs that have sufficient production should also have adequate CO_2 injectivity.

The various criteria recommended previously for the identification of reservoirs suitable for CO_2-flood EOR are based on optimizing reservoir performance. However, the criteria of reservoir depth and oil viscosity can be ignored because two other parameters, oil gravity and reservoir temperature, either affect or are affected by the former two (i.e., temperature is affected by reservoir depth, and oil viscosity is affected by oil gravity). Thus, depth and oil viscosity do not necessarily need to be explicitly considered in reservoir screening for CO_2-flood EOR.

Prediction of Reservoir Performance and Incremental Oil Recovery

The main purpose of conducting CO_2-flooding performance prediction is to estimate the oil-recovery efficiency and the volume of sequestered CO_2 for various operating scenarios. The recovery efficiency of the CO_2-flood EOR is controlled mainly by the mobility ratio (relative permeability to viscosity) of the CO_2 and oil; by gravity segregation (buoyancy or override) between the two; and by reservoir heterogeneity. The injected CO_2 will not contact all the remaining oil in place in a reservoir for several reasons (Bondor, 1992), causing premature breakthrough of CO_2 at production wells. The produced CO_2 is usually reinjected (recirculated) back into the reservoir, reducing the amount of net CO_2 sequestered in the reservoir. Generally, only 25–50% of the total CO_2 injected volume is acquired, and the produced CO_2 is recycled from one to three times (Bondor, 1992).

Based on the United States experience, the incremental oil recovery from CO_2 flooding is estimated to increase the ultimate oil recovery by 7–23% (average 13.2%) of the original oil in place (OOIP) (Martin and Taber, 1992; Holt et al., 2000). The recovery of 13% of OOIP obtained to 1993 for the Joffre Viking miscible CO_2 flood in Alberta, predicted to reach 18% by the end of the operation (Stephenson et al., 1993), falls within the estimated range. For the Weyburn reservoir in Saskatchewan, an additional 25% OOIP is estimated to be recoverable by CO_2 flooding, over and above the 31% additional recovery by primary and water flooding (Srivastava et al., 2000). Other studies consider that the miscible flood displacement achieves an incremental oil recovery of 22% OOIP (Martin and Taber, 1992; Taber at al., 1997; Bergman et al., 1997; Todd and Grand, 1993).

Current methods for analyzing reservoir performance use extensive numerical modeling based on detailed knowledge of the oil reservoir, streamtube models and scaled physical models. Such detailed methods are not suitable for the massive processing involved in analyzing thousands of oil pools based on limited and broad information as that found in reserves databases. An analytical method was developed and implemented (Shaw and Bachu, 2002), based on the original work of Koval as modified by Claridge for areal sweep and further modified to include Hawthorne's gravity-stabilization effect and trapped-oil saturation (Koval, 1963; Claridge, 1972; Hawthorne, 1960; Paul, 1983)). This method was found to be the most suitable for the case of an extremely large number of oil reservoirs with minimal information, as is the case with reserves databases, and can be used to calculate oil recovery for a series of assumed slug sizes (hydrocarbon pore volume, or HCPV) in a five-spot water-alternating gas (WAG) miscible flood. The Koval method for predicting solvent-flood efficiency assumes that solvent-enhanced oil recovery is applied immediately after primary recovery, and that the reservoir has no aquifer support. The latter assumption may lead to an overestimate of oil production and CO_2 storage; however, reservoir-by-reservoir analysis is needed to account for water influx, which is beyond the scope of this study.

The following equation is used for estimating the fraction of oil produced (N_P) from the miscible CO_2 injection (Claridge, 1972):

$$\left(\frac{N_P - V_{piBT}}{1.0 - N_P}\right) = \left(\frac{1.6}{K^{0.61}}\right)\left(\frac{F_i - V_{piBT}}{1.0 - V_{piBT}}\right)^{\left(\frac{1.28}{K^{0.26}}\right)} \tag{6}$$

where the subscript BT stands for breakthrough, V_{pi} is the actual fraction of pore volume of injected solvent, F_i is the fraction of hydrocarbon pore volume (HCPV) of solvent injected in a reservoir of unit thickness in an ideal five-spot EOR operation, and K is the Koval factor (Koval, 1963). In the above equation, N_p represents HCPV of additional produced oil, in units of volume/volume (fraction). The volumetric value of N_P is obtained by multiplying it by the pore volume $V_{P.}$

The actual fraction of pore volume of CO_2 injected at breakthrough (V_{piBT}) is given by

$$V_{piBT} = E_{ABT} \cdot V_{pvdBT} \tag{7}$$

where V_{pdv} is the invaded pore volume. The areal sweep efficiency at breakthrough (E_{ABT}) and the invaded pore volume injected at breakthrough (V_{pvdBT}) are given by

$$E_{ABT} = 1 + \frac{0.4M}{1+M} \tag{8}$$

and

$$V_{pvdBT} = \frac{1}{K} \tag{9}$$

In equations 8 and 9, M is the mobility ratio

$$\mathrm{M} = \frac{\mu_o}{\mu_s} \tag{10}$$

and the Koval factor K is defined as

$$\mathrm{K} = \mathrm{H}\cdot\mathrm{F}\cdot\left[0.78 + 0.22\left(\frac{\mu_o}{\mu_s}\right)^{1/4}\right]^4 \tag{11}$$

where μ_o and μ_s are oil and solvent (CO_2) viscosities, respectively; H is the heterogeneity factor (1 for homogeneous reservoirs); and F is the gravity override factor (1 if no gravity override is assumed). The Koval factor K is 1 in the idealized case of a homogeneous reservoir with oil and solvent of the same density and viscosity; for all other, real cases, K is greater than 1.

For heterogeneous reservoirs, the heterogeneity factor H is given by the equation

$$\log_{10}\mathrm{H} = \left[\frac{V_{DP}}{(1 - V_{DP})^{0.2}}\right] \tag{12}$$

where V_{DP} is the Dykstra-Parsons coefficient that indicates reservoir heterogeneity. Willhite (1986) summarized literature values that show a range of 0.5 to 0.9 for V_{DP}, with an average of 0.7 for most reservoir rocks.

The gravity override factor (F) is given by the equation (Hawthorne, 1960; Paul et al., 1984)

$$\mathrm{F} = 0.565\,\log_{10}\left[Ck_vA\frac{\Delta\rho}{Q\mu_s}\right] + 0.870 \tag{13}$$

where k_v is vertical permeability (mD), A is pattern size (acre), $\Delta\rho$ is the density difference between oil and CO_2 (g/cm^3), Q is the injection rate (reservoir bbl/d), μ_s is solvent (CO_2) viscosity (cp), and C is the pattern constant (2.5271 for five-spot, and 2.1257 for line drive). The injection rate and pattern size are operating parameters that are established for each reservoir on a case-by-case basis after appropriate engineering studies. Thickness and vertical permeability are reservoir specific and need to be established for each reservoir; $\Delta\rho$ must also be established for each reservoir, based on the oil and CO_2 densities at reservoir pressure and temperature.

For calculation of the mobility ratio (M), the viscosity of CO_2 is estimated based on reservoir pressure and temperature (Fenghour et al., 1998) and the oil viscosity (in cp) can be estimated using the following equations (Beggs and Robinson, 1975).

For dead oils

$$\mu_{od} = 10^x - 1 \tag{14}$$

$$x = 10^{2.1646 - 0.033580(API)} T^{-0.601} \qquad (15)$$

where API is the oil gravity (°), and T is temperature (^{o}C).

For live oils

$$\mu_o = A \mu_{od}^{B} \qquad (16)$$

$$\text{A}=12.589\,(R_S + 200)^{-0.482} \qquad \text{and} \qquad \text{B}=1.276\,(R_S + 15)^{-0.090} \qquad (17)$$

where R_S is the solution gas/oil ratio (scf/STB), given in reserves databases.

Figure 5 shows a nomogram (Claridge, 1972) for estimating the fractional volume of additional produced oil for a five-spot miscible flood of a homogeneous reservoir of unit thickness for different values of the mobility ratio (M) and of the fraction (F_i) of injected solvent (CO_2) relative to the hydrocarbon pore volume (HCPV).

The presented analytical method allows the preliminary prediction of the amount of incremental oil that will be produced and the amount of CO_2 that must be injected into an oil reservoir for various fractions of hydrocarbon pore volume (HCPV) of injected CO_2, when using limited information about a large number of reservoirs. Application of the method permits the rapid evaluation, ranking and further screening of reservoirs suitable for CO_2 flooding, prior to detailed, case-by-case reservoir studies.

CO_2 Sequestration Capacity in Enhanced Oil Recovery

The United States experience shows that approximately 40% of the originally injected CO_2 is being produced at the pump and re-injected (Hadlow, 1992). This suggests a 'gross' CO_2-retention efficiency of approximately 60%, similar to the value that was reported for the Joffre Viking miscible CO_2 flood in Alberta (Stephenson et al., 1993). This also matches 66% CO_2 retention obtained in numerical simulations, or approximately 63% hydrocarbon pore volume (HCPV) (Todd and Grand, 1993; Holt et al., 1995).

The CO_2 sequestration capacity in EOR operations at CO_2 breakthrough is a direct by-product of Koval's method for predicting reservoir performance (V_{piBT} given by equation 7). Considering that, on average, 40% of the injected CO_2 is recovered at the surface after breakthrough and assuming that it will be re-injected back into the reservoir, the CO_2 sequestration capacity for any fraction F_i of hydrocarbon pore volume (HCPV) of injected CO_2 can be calculated using the following equations:

- At breakthrough (BT),

$$M_{CO2} = \rho_{CO2res} \cdot RF_{BT} \cdot OOIP/Sh \qquad (18)$$

- At any HCPV injection,

$$M_{CO2} = \rho_{CO2res} \cdot [RF_{BT} + 0.6 \text{ x } (RF_{\%HCPV} - RF_{BT})] \cdot OOIP/Sh \qquad (19)$$

where RF_{BT} 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

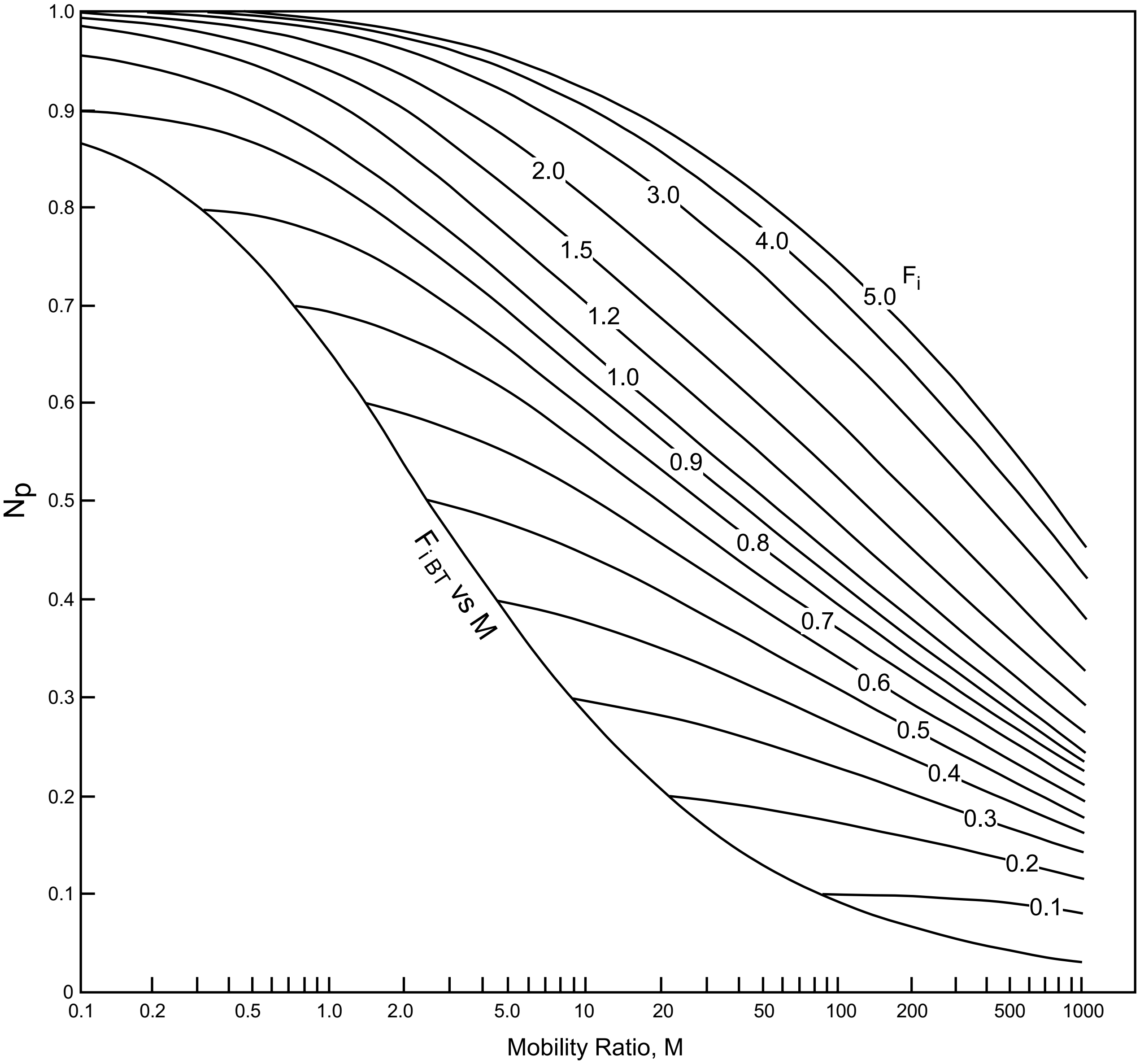

Figure 5. Nomogram for estimating the fraction volume of additional produced oil, N_p, for a five-spot miscible flood of a homogeneous reservoir of unit thickness. F_i is the fraction of injected solvent, F_{iBT} is the fraction at break-through, and M is mobility ratio.

in place; Sh is the oil shrinkage factor (the inverse of the formation volume factor B_0); and ρ_{CO2res} is CO_2 density calculated at reservoir temperature and pressure conditions (Span and Wagner, 1996).

Practical CO_2 Sequestration Capacity

The theoretical CO_2 sequestration 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 sequestration capacity represents the mass of CO_2 that can be stored in hydrocarbon reservoirs after taking into account reservoir characteristics and flow processes, such heterogeneity, aquifer support, sweep efficiency, gravity override, and CO_2 mobility. However, there are other criteria, discussed in the following, which need consideration when implementing CO_2 sequestration in oil and gas reservoirs on a large scale.

It is very unlikely that gas pools associated with oil reservoirs, oil pools currently in secondary and tertiary production, and generally commingled pools will be used for CO_2 sequestration, at least not in the near future. Also, 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 sequestration in very deep reservoirs could also become highly uneconomic because of the prohibitive cost of compression and the low 'net' CO_2 sequestration (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 sequestration 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 sequestration capacity, the great majority of reservoirs are relatively small in volume, and have a low capacity for CO_2 sequestration, rendering them uneconomic. Considering the size of the major stationary CO_2 sources in the Western Canada Sedimentary Basin, it is most likely that only reservoirs with large CO_2 sequestration 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, most likely only large reservoirs with significant individual CO_2 sequestration capacity will be considered in the short-to-medium term. Application of screening criteria based on reservoir depth and CO_2 sequestration capacity reduces the total CO_2 sequestration capacity in the Western Canada Sedimentary Basin from effective to practical values.

Capacity for CO_2 Sequestration in Hydrocarbon Reservoirs in the Western Canada Sedimentary Basin

The distribution of oil and gas reservoirs and reserves in the Western Canada Sedimentary Basin reflects the basin structure (actually the foreland Alberta basin in northeastern British Columbia and Alberta, and the intra-cratonic Williston basin in Saskatchewan and southwestern Manitoba) and history of hydrocarbon generation, migration and accumulation. The Alberta basin has significantly more gas than oil reservoirs, many of them quite large in size. The Williston basin has few gas reservoirs, mostly in the western part (western Saskatchewan), where gas migrated in place from downdip in the Alberta basin.

The ultimate theoretical capacity for CO_2 sequestration in hydrocarbon reservoirs in the Western Canada Sedimentary Basin has been estimated using the most recently available reserves databases in each province. The system of reserves classification is different from province to province. For the purpose of this study and to ensure consistency, all the reservoirs have been classified according to the classification used for Alberta by the Alberta Energy and Utilities Board (EUB), because Alberta has by far most reservoirs and the largest CO_2 sequestration capacity, as will be seen in the following. Besides different classifications, the data provided in the various databases are quite different from province to province. Furthermore, the level of completeness and accuracy is variable, decreasing in quality from Alberta, to British Columbia, to Saskatchewan and to Manitoba. Thus, significant effort and resources have been expended to clean up and correct the data. However, data for some small and generally old reservoirs could not be found, and these reservoirs could not be used in the analysis. Because it is highly unlikely that oil or gas reservoirs with significant reserves, hence potential CO_2 sequestration capacity, are not properly accounted for and characterized in reserves databases, these reservoirs lacking critical data would most likely have dropped from the analysis at a later step in the analysis. Thus, their omission from the analysis is not affecting the final estimates of practical CO_2 sequestration capacity in the Western Canada Sedimentary Basin.

Capacity for CO_2 Sequestration in Gas Reservoirs

The gas reserves are categorized into non-associated (i.e., independent gas pools), associated (i.e., gas cap at the top of an oil reservoir), and solution gas (i.e., gas dissolved in oil in an oil reservoir). Solution gas is not considered in the calculations of CO_2 sequestration capacity in hydrocarbon reservoirs because, from a CO_2 capacity point of view, the respective pore space is occupied by the oil that contains the gas in solution. Table 4 shows, by province, the number of gas reservoirs booked in provincial reserves databases and the number of reservoirs that have been considered further in the CO_2 sequestration capacity calculations. Reservoirs with solution gas, commingled reservoirs, and a few reservoirs in British Columbia used for gas storage have been excluded from further consideration. Of the remaining gas reservoirs (non-associated and associated), reservoirs lacking critical data such as pressure, temperature and/or compressibility (see eq. 2) were not considered further in capacity calculations.

Table 4. Breakdown of gas reservoirs that are booked in provincial reserves databases and of those used in calculations of CO_2 sequestration capacity in the Western Canada Sedimentary Basin.

Province	Gas Reservoirs in Reserves Databases	Excluded Reservoirs	Non-Associated and Associated Reservoirs	Reservoirs Lacking Critical Data	Reservoirs Considered in CO_2 Capacity Calculations
NE B.C.	1,271	110	1,161	156	1,005
Alberta	35,589	10,126	25,463	806	24,657
Sask.	173	33	140	25	115
Manitoba	0	0	0	0	0
Total	37,033	10,269	26,764	987	25,777

The gas reservoirs considered for CO_2 sequestration capacity calculations are located at depths ranging between 33 and 5243 m. Accordingly, temperature and initial pressure vary from approximately 6°C and 120 kPa to 185°C and ~100 MPa, respectively. Table 5 shows a breakdown by province of the CO_2 sequestration capacity in gas pools in the Western Canada Sedimentary Basin.

Table 5. CO_2 sequestration capacity in non-associated gas reservoirs in the Western Canada Sedimentary Basin.

Province	Number of Gas Reservoirs	Theoretical Capacity (Mt CO_2)	Reservoirs with Strong Aquifer Support	Reduced Capacity Due to Aquifer Effects (Mt CO_2)	Effective Capacity (Mt CO_2)
NE B.C.	1,005	1,756.7	202	1,589.1	1,430.2
Alberta	24,657	7,958.4	6,562	7,334.4	6,600.9
Sask.	115	615.8	42	584.3	525.5
Manitoba	0	0	0	0	0
Total	25,777	10,330.9	6,806	9,507.8	8,556.6

Examination of Table 5 reveals that the gas pools in northeastern British Columbia have significant CO_2 storage capacity relative to their number, and so do gas pools in Saskatchewan. This could reflect both reality and a different way of pool administration and booking practiced by the various provinces. Figure 6 shows the frequency distribution of CO_2 sequestration capacity in gas reservoirs in the Western Canada Sedimentary Basin. Both Table 5 and Figure 6 indicate that the great majority of gas reservoirs have low capacity (~332 ktCO_2 on average), which would make them impractical and uneconomic for CO_2 sequestration. If criteria of size (>1 MtCO_2) and depth are applied, the practical CO_2 sequestration capacity in gas reservoirs in the Western Canada Sedimentary Basin reduces to ~4 Gt CO_2 (Table 6).

Table 6. Practical CO_2 sequestration capacity in gas reservoirs in the Western Canada Sedimentary Basin.

Province	Number of Gas Reservoirs	Depth Range (m)	Initial Pressure Range (kPa)	Temperature Range (°C)	Capacity (Mt CO_2)
NE B.C.	237	944 – 3,500	5,971 – 40,818	28 – 130	1,107.7
Alberta	655	900 – 3,490	3,350 – 55,360	18 – 117	2,913.7
Sask.	3	972 – 1,057	6,241 – 9,650	29 – 46	5.6
Manitoba	0				0
Total	895				4,027.0

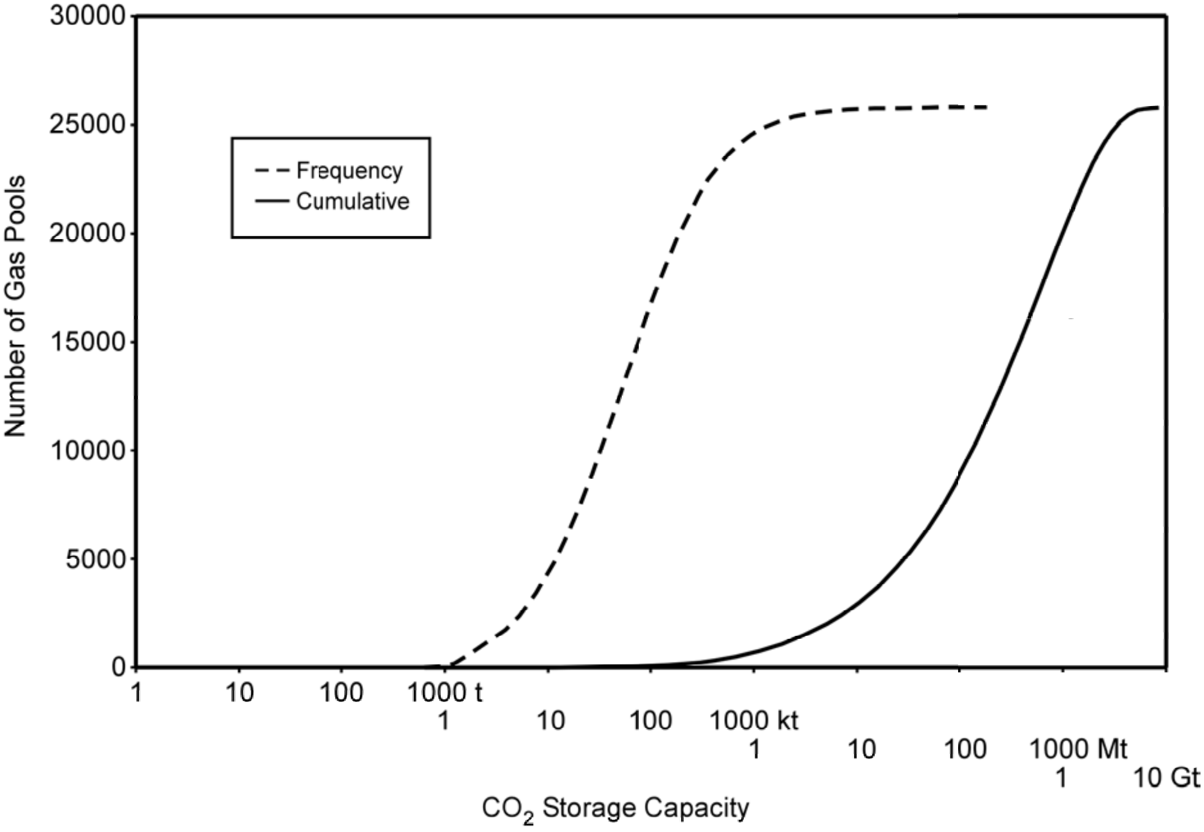

Figure 6. Frequency and cumulative distributions of CO_2 sequestration capacity in gas pools in the Western Canada Sedimentary Basin.

These gas reservoirs have sufficient individual capacity (4.5 Mt CO_2 on average) to make them economic in terms of developing the necessary infrastructure for CO_2 sequestration. Figure 7 shows the frequency distribution of these 895 gas reservoirs, and Figure 8 shows their location. Of these, 38 are gas reservoirs associated with oil reservoirs (gas cap). Because the oil has to be produced first from these reservoirs, and then the gas, these gas reservoirs will become available for CO_2 sequestration at a later time. The geographic distribution of gas reservoirs with large CO_2 sequestration capacity shows that they are all in the Alberta basin, and none in the Williston basin (Figure 8).

A significant number of the non-associated gas reservoirs are in the Foothills of the Rocky Mountains (Figure 8), relatively far from major CO_2 sources and posing additional challenges in terms of CO_2 transport and injection. If only the large non-associated gas reservoirs in the undisturbed portion of the Alberta basin are considered as primary candidates, then the number of gas reservoirs suitable for CO_2 sequestration in the Western Canada Sedimentary Basin drops further to 771, with a practical CO_2 sequestration capacity of 3,180 Mt CO_2. The list of these 771gas reservoirs is provided in Appendix A. Notwithstanding their large size, the 124 gas pools in the foothills that have large CO_2 sequestration capacity will likely not constitute primary targets for CO_2 sequestration because of geological complexity, difficult access, remoteness and distance from CO_2 sources.

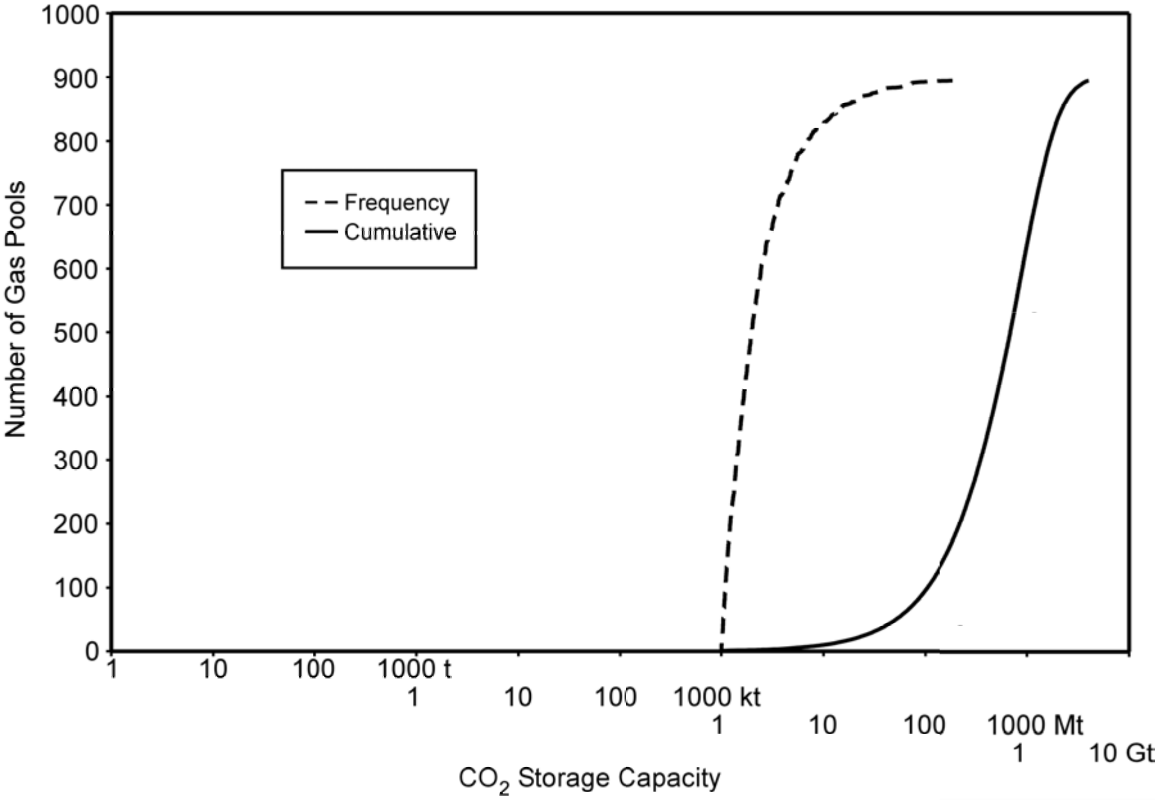

Figure 7. Frequency and cumulative distributions of CO_2 sequestration capacity in the largest 895 gas pools in the Western Canada Sedimentary Basin with individual storage capacity greater than 1 Mt CO_2 each.

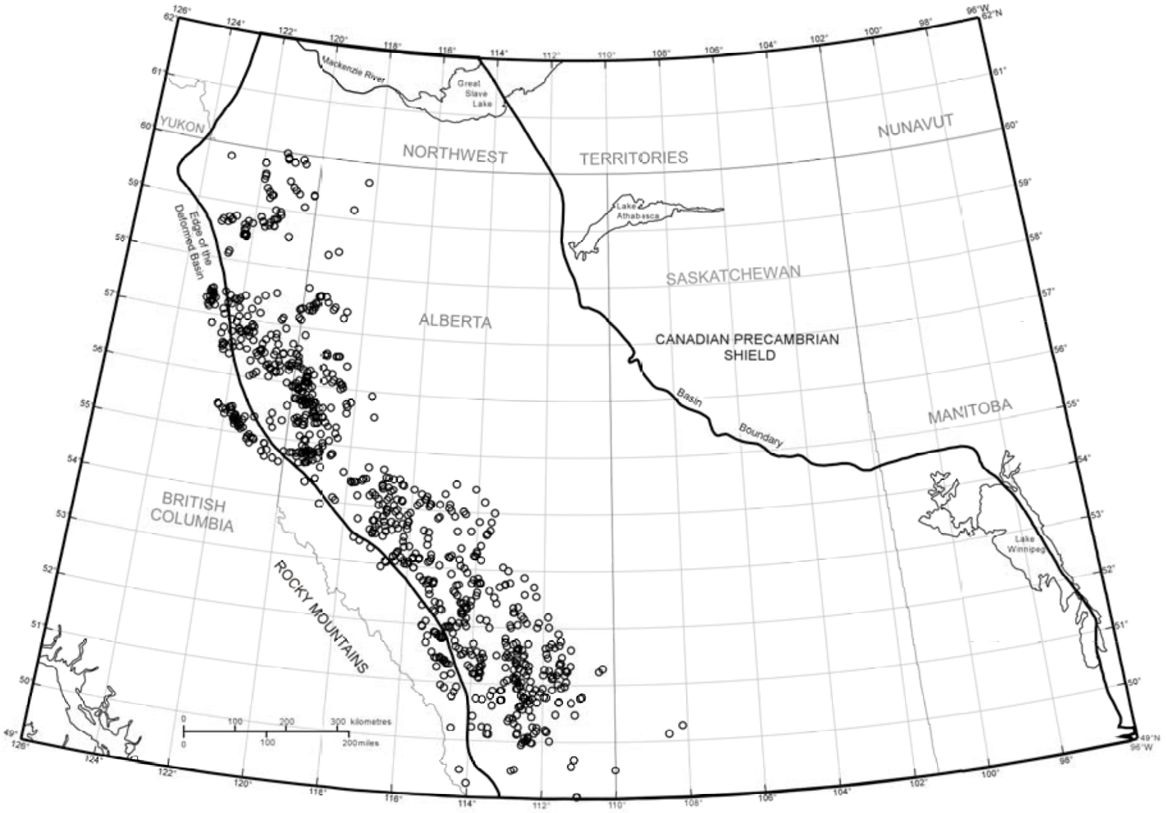

Figure 8. Location of the 895 largest gas pools in the Western Canada Sedimentary Basin with CO_2 sequestration capacity greater than 1 Mt CO_2 each.

Capacity for CO_2 Sequestration in Oil Reservoirs

Oil reserves are categorized first into light-medium and heavy, and then they are further subdivided by production method into single drive, primary production in a multi-mechanism production pool, water flood, solvent flood and gas flood, and commingled. Similarly with gas reservoirs, commingled oil reservoirs were excluded from consideration for CO_2 storage. Bitumen reservoirs were also excluded for the reasons explained previously. Table 7 shows, by province, the number of oil reservoirs booked in reserves databases, and the number of reservoirs that have been considered further in capacity calculations for CO_2 storage.

Table 7. Breakdown of oil reservoirs that are booked in provincial reserves databases and of those used in calculations of CO_2 sequestration capacity in the Western Canada Sedimentary Basin.

Province	Oil Reservoirs in Reserves Databases	Excluded Reservoirs	Single Drive, Primary Production and Flooded Reservoirs	Reservoirs Lacking Critical Data	Reservoirs Considered in CO_2 Capacity Calculations
NE B.C.	367	0	367	8	359
Alberta	9,355	592	8,763	604	8,159
Sask.	588	58	530	0	530
Manitoba	242	141	101	0	101
Total	10,552	791	9,761	612	9,149

A significant number of oil reservoirs in the Western Canada Sedimentary Basin are currently in secondary (water flood) and tertiary production (gas or solvent miscible flood). The CO_2 sequestration capacity of these reservoirs is greatly reduced by the injected water, gas or solvent. Their capacity was calculated according to eq. (3) using data from production databases regarding the injected and produced amounts of water, gas or solvent. The effect of the underlying aquifers on the potentially available pore space was also taken into account for these reservoirs. Table 8 shows the estimated CO_2 sequestration capacity in flooded oil reservoirs in the Western Canada Sedimentary Basin.

The flooded reservoirs are very large, with significant original oil in place (~44% of the OOIP and ~56% of the recoverable oil in the 9,149 oil reservoirs) and corresponding pore space. Water and gas or solvent flooding has reduced the CO_2 sequestration capacity of these reservoirs from an original estimated 972 Mt CO_2 to the current 362 Mt CO_2. As flooding continues, the remaining capacity will be further reduced. However, a good portion of the original sequestration capacity of these reservoirs can be retrieved if CO_2 is injected in these oil reservoirs to recover the injected gas or solvent, which both have economic value, or just to recover additional oil in the water flooded reservoirs (CO_2 flood tertiary recovery).

Table 8. CO_2 sequestration capacity in flooded oil reservoirs in the Western Canada Sedimentary Basin.

Province	Oil Reservoirs Considered in CO_2 Capacity Calculations	Water Flooded Reservoirs	CO_2 Sequestration Capacity (Mt CO_2)	Gas and Solvent Flooded Reservoirs	CO_2 Sequestration Capacity (Mt CO_2)	Reservoirs in Single Drive or Primary Production
NE B.C.	359	31	1.0	5	4.3	323
Alberta	8,159	384	82.0	64	176.5	7,711
Sask.	530	194	88.2	2	0.1	334
Manitoba	101	14	9.8	1	0.1	86
Total	9,149	623	181.0	72	181.0	8,454

For the 8,454 oil reservoirs in single drive or primary production, their CO_2 sequestration capacity at depletion, summarized in Table 9, was calculated according to the methodology described previously, assuming that CO_2 will be injected immediately after primary production. This is currently not the process used by industry, where secondary production (water flood and/or a water-alternating-gas [WAG] process) usually follows primary production. Immediate CO_2 injection would, nevertheless, maximize CO_2 sequestration because more pore space would be available for CO_2, which would otherwise be occupied by water.

Table 9. CO_2 sequestration capacity at depletion in oil reservoirs in the Western Canada Sedimentary Basin.

Province	Oil Reservoirs in Single Drive or Primary Production	Theoretical Capacity (Mt CO_2)	Reservoirs with Strong Aquifer Support	Reduced Capacity Due to Aquifer Effects (Mt CO_2)	Effective Capacity (Mt CO_2)
NE B.C.	323	71.8	140	63.1	31.5
Alberta	7,711	614.4	4,676	481.3	240.6
Sask.	334	623.9	288	352.3	176.1
Manitoba	86	14.3	65	9.0	4.5
Total	8,454	1,324.4	5,169	905.7	452.7

Although the number of oil reservoirs in single drive and primary production is much larger (by one order of magnitude) than the number of flooded reservoirs, most of these reservoirs are quite small (average capacity of 53.5 Mt CO_2), such that their cumulative capacity is only approximately 25% greater than that of flooded reservoirs (~453 Mt CO_2 versus 362 Mt CO_2) because the latter are much larger. The discrepancy in CO_2 sequestration capacity in oil reservoirs in the various provinces relative to the number of reservoirs is most likely due to different booking and procedures in reservoirs administration. Figure 9 shows the frequency and cumulative distributions of CO_2 sequestration capacity at depletion in oil reservoirs in the Western Canada Sedimentary Basin.

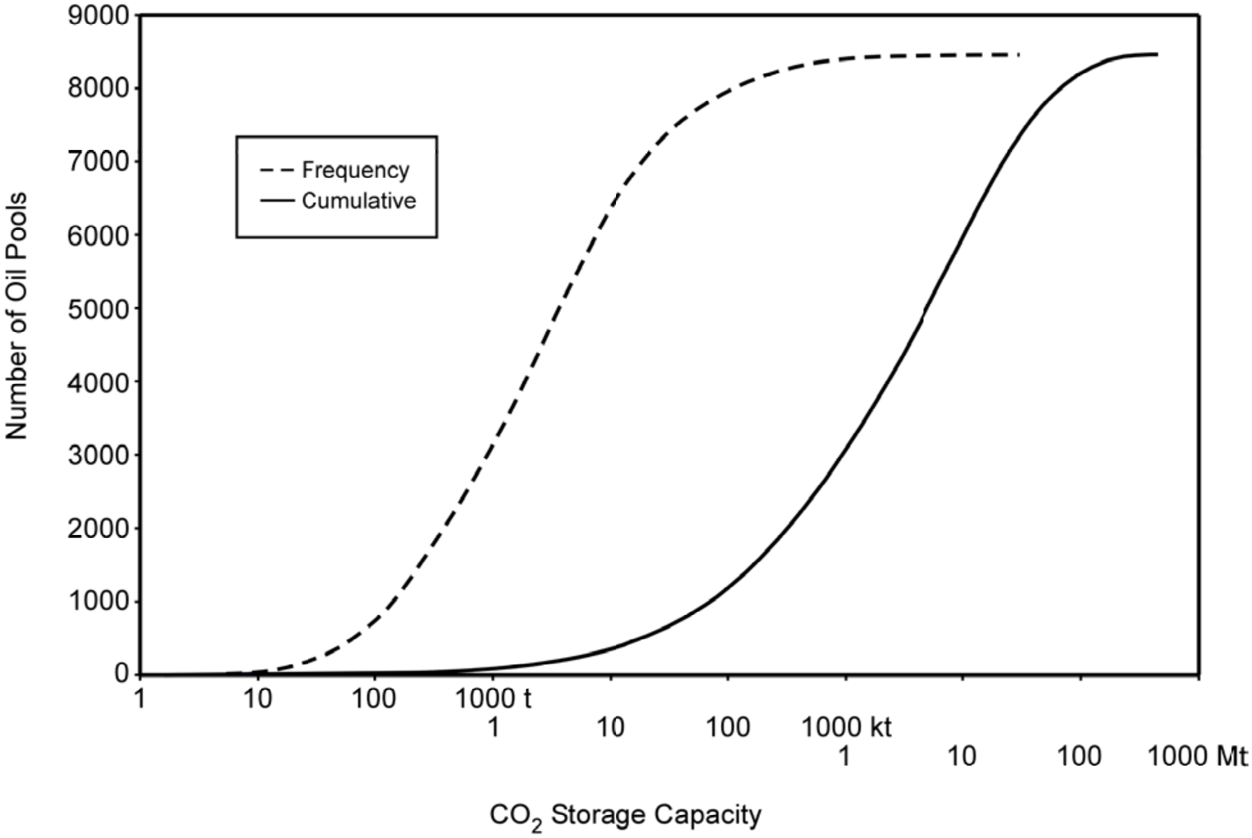

Figure 9. Frequency and cumulative distributions of CO_2 sequestration capacity at depletion in oil pools in the Western Canada Sedimentary Basin currently in single drive and primary production.

A significant number of the reservoirs in single drive and primary production meet the technical criteria for CO_2 flooding, in which case their CO_2 sequestration capacity would increase. Table 10 shows the estimated CO_2 sequestration capacity in CO_2-flood EOR in oil reservoirs in the Western Canada Sedimentary Basin that are suitable for CO_2 miscible flooding, and the corresponding estimates of incremental recoverable oil. The estimates were calculated for 50% pore volume of CO_2 using the analytical model described previously. The CO_2 sequestration capacity and recoverable oil will change accordingly if other amounts of CO_2 will be injected.

The results in Table 10 show that the oil reservoirs that are suitable for miscible CO_2 flooding have an added capacity comparable to that at depletion for all oil pools (~570 Mt CO_2 versus ~453 Mt CO_2). However, their individual CO_2 sequestration capacity and incremental oil recovery are quite small (120 kt CO_2 and 73,647 m^3 oil on average) to make them economic. Furthermore, the great majority of these oil reservoirs are in Alberta, and the very small capacity of oil reservoirs in Saskatchewan and Manitoba (~1 kt CO_2 on average) makes these very uneconomic. Figures 10 and 11 show the frequency and cumulative distributions for, respectively, CO_2 sequestration capacity and incremental oil recovery at 50% HCPV injected CO_2 for the oil reservoirs in the Western Canada Sedimentary Basin that are suitable for miscible CO_2 flooding.

Table 10. CO_2 sequestration capacity in CO_2-flood EOR in oil reservoirs in the Western Canada Sedimentary Basin.

Province	Oil Reservoirs Suitable for CO_2-Flood EOR	Incremental Oil Recovery @ 50% HCPV (1000 m^3)	CO_2 Capacity @ 50% HCPV (Mt CO_2)
NE British Columbia	213	17,996	24.5
Alberta	4,371	331,493	545.0
Saskatchewan	129	42	0.1
Manitoba	35	147	0.1
Total	4,748	349,678	569.7

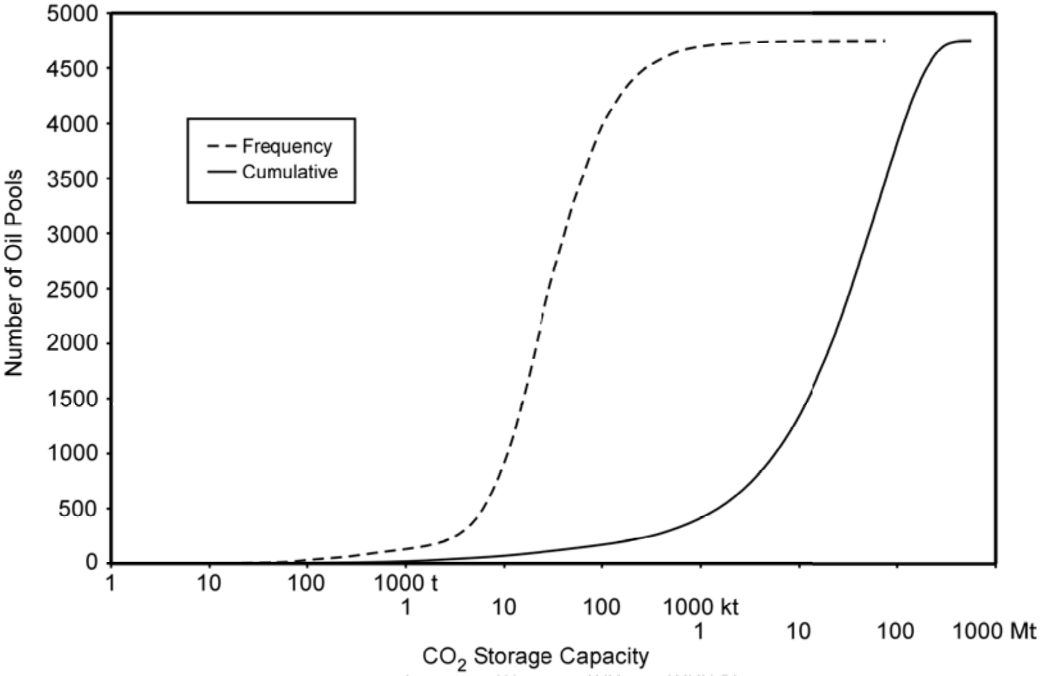

Figure 10. Frequency and cumulative distributions of additional CO_2 sequestration capacity through EOR in oil pools in the Western Canada Sedimentary Basin that are technically suitable for CO_2-flood EOR.

If criteria of size (>1 Mt CO_2) and depth are applied, the practical CO_2 sequestration capacity in oil reservoirs in the Western Canada Sedimentary Basin that are currently in single drive and primary production reduces to ~0.5 Gt CO_2 (Table 11). However, these 98 oil pools have significant capacity (~5.2 Mt CO_2 on average) to make them primary targets for CO_2 sequestration. The incremental oil production from the 81 oil reservoirs that are also suitable for miscible CO_2 flooding is estimated at ~146x10^6 m^3 oil (918 Mmbbl). Figures 12, 13 and 14 show the frequency and cumulative distributions for CO_2 sequestration capacity in the largest 98 oil reservoirs in the Western Canada Sedimentary Basin at depletion, in CO_2-flood EOR and total, respectively. Figure 15 shows the frequency and cumulative distributions for incremental oil recovery at 50% HCPV injected CO_2 from these oil reservoirs in the Western Canada Sedimentary Basin that are suitable for miscible CO_2 flooding, and Figure 16 shows their location. Appendices B and C provide, respectively, the list of these 81 oil reservoirs that are suitable for CO_2-flood EOR and of the 17 oil reservoirs that are not.

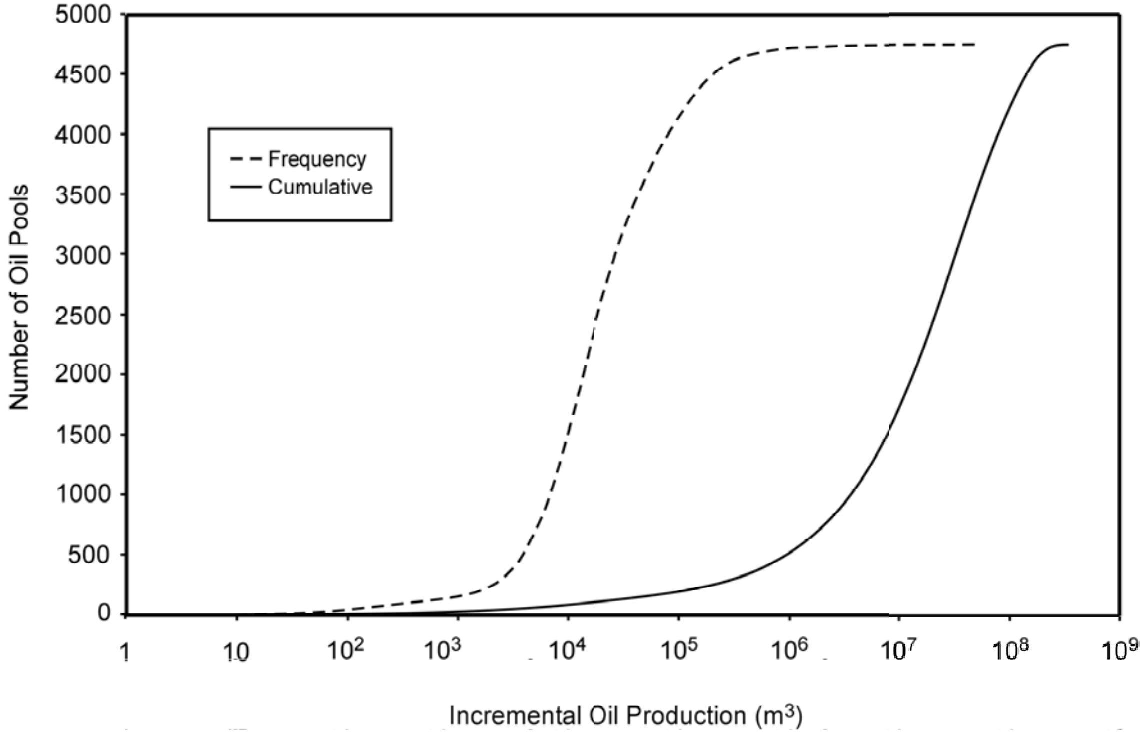

Figure 11. Estimated incremental oil production at 50% HCPV flooding from oil reservoirs in the Western Canada Sedimentary Basin that are technically suitable for CO_2-flood EOR.

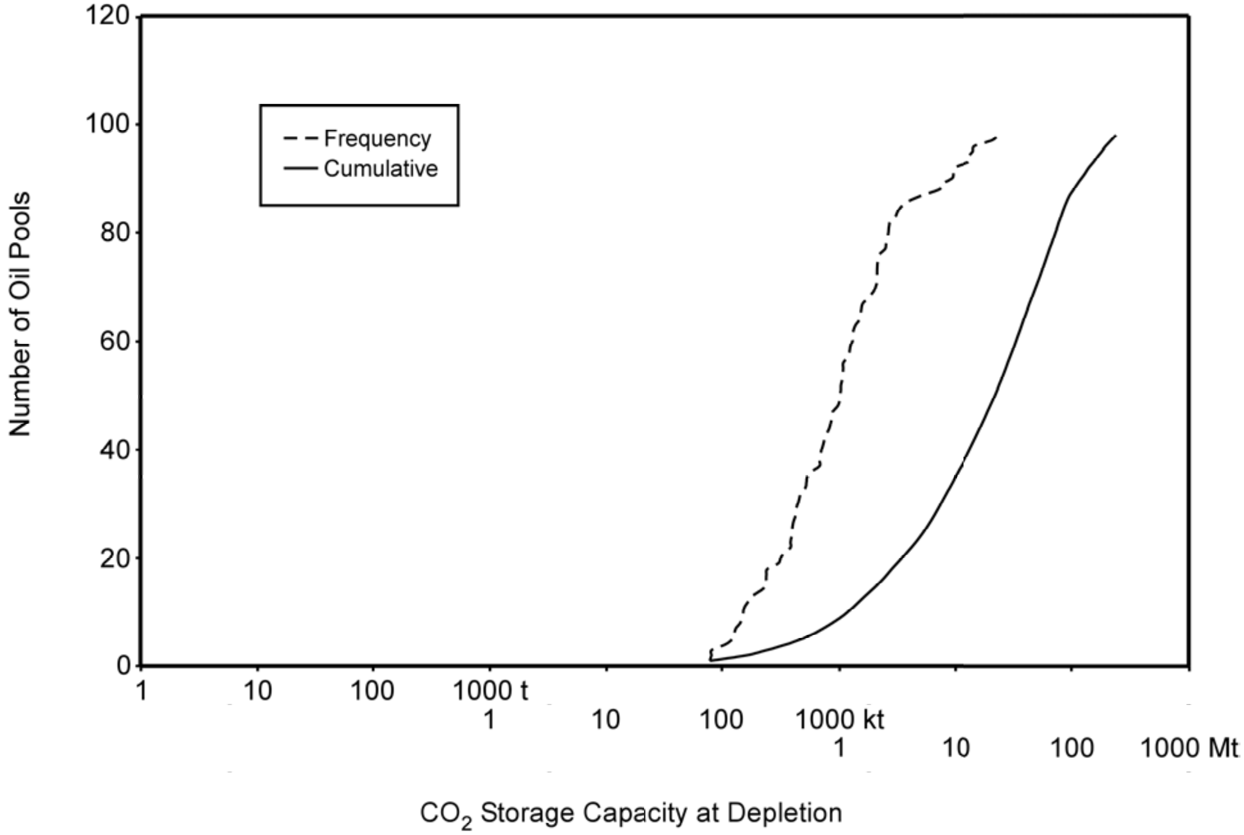

Figure 12. Frequency and cumulative distribution of CO_2 sequestration capacity at depletion in the largest 98 oil pools in the Western Canada Sedimentary Basin with individual total storage capacity greater than 1 Mt CO_2 each.

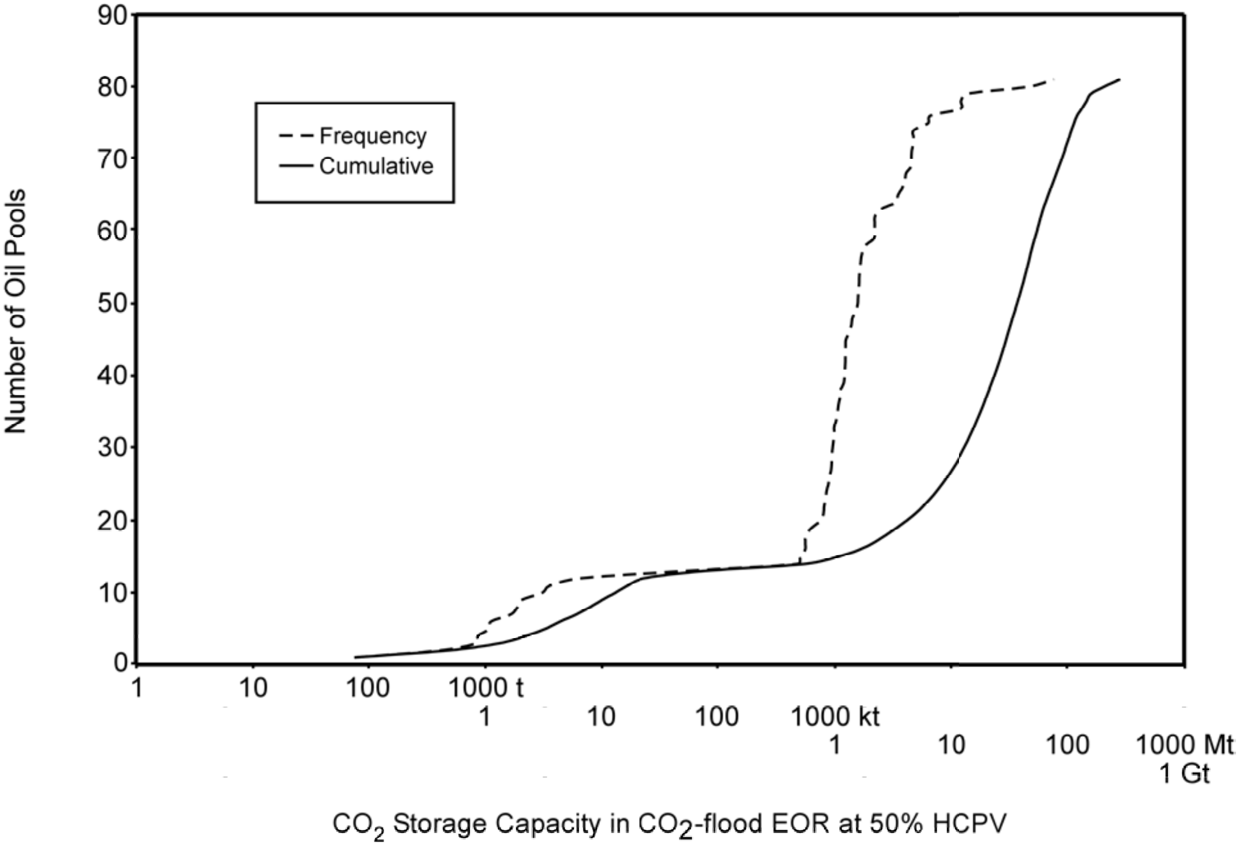

Figure 13. Frequency and cumulative distribution of CO_2 sequestration capacity in CO_2-flood EOR in the 81 oil pools in the Western Canada Sedimentary Basin with individual total storage capacity greater than 1 Mt CO_2 each that are suitable for CO_2-flood EOR.

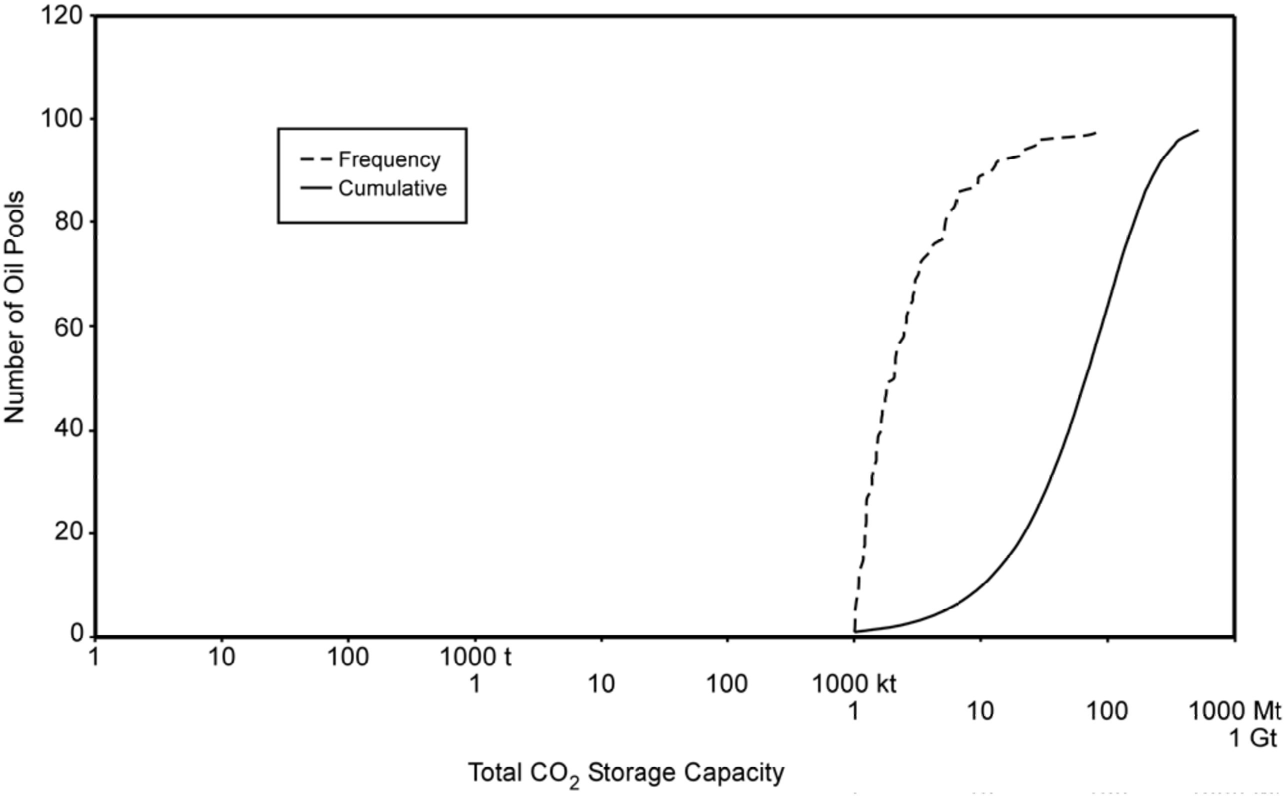

Figure 14. Frequency and cumulative distribution of total CO_2 sequestration capacity in the largest 98 oil pools in the Western Canada Sedimentary Basin with individual total storage capacity greater than 1 Mt CO_2 each.

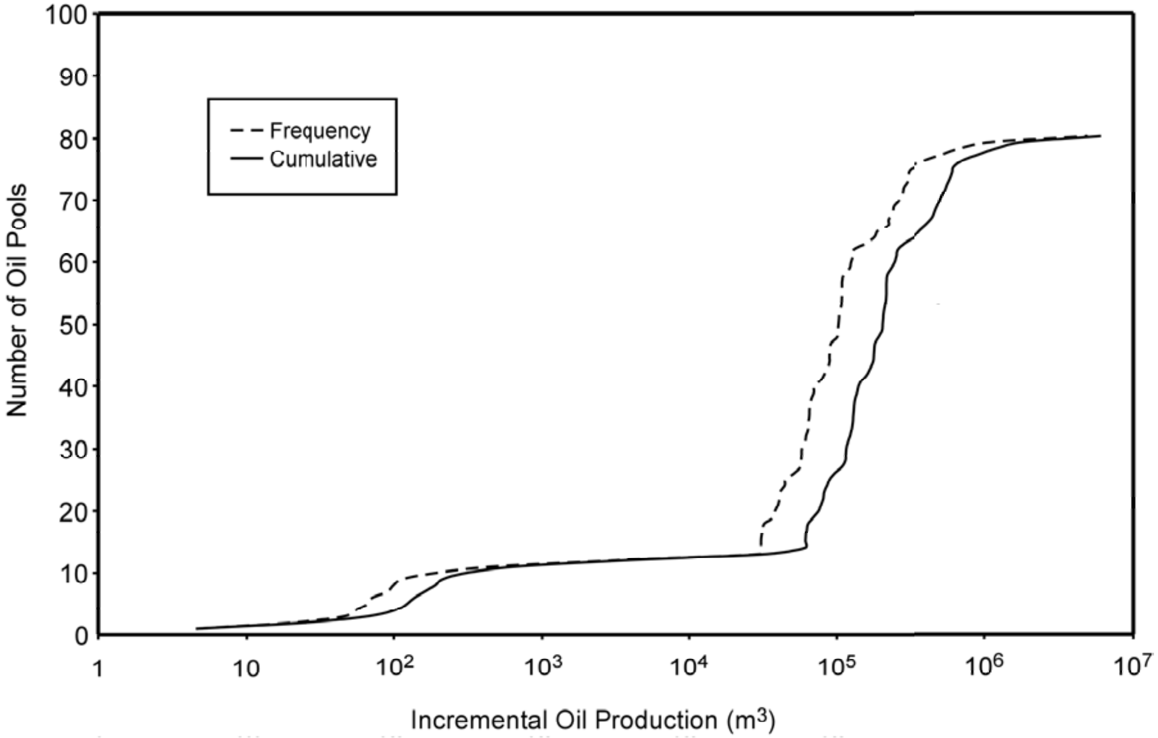

Figure 15. Estimated incremental oil production at 50% HCPV flooding from the 81 oil reservoirs in the Western Canada Sedimentary Basin that have individual total CO_2 storage capacity greater than 1 Mt CO_2 each and are suitable for CO_2-flood EOR.

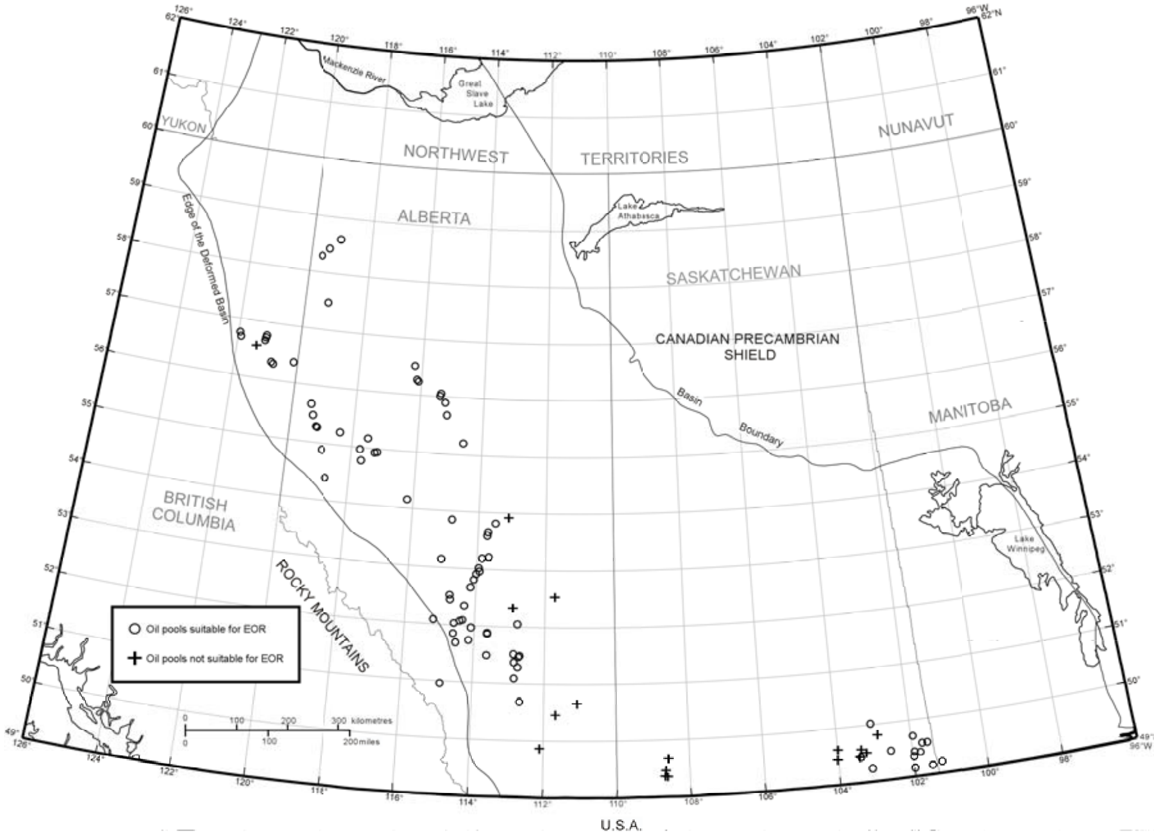

Figure 16. Location of the 98 largest oil pools in the Western Canada Sedimentary Basin with CO_2 sequestration capacity greater than 1 Mt CO_2 each.

It is worth noting that most of the gas reservoirs in the Western Canada Sedimentary Basin have weak or no aquifer support, such that application of the aquifer reduction coefficients identified previously lead to an overall reduction in the estimates of CO_2 sequestration capacity of only 8%. Aquifer invasion can be neglected for flooded oil reservoir because reservoir pressure is maintained with injection, but in the case of oil reservoirs in single-drive and primary production it is sufficiently important, reducing their CO_2 sequestration capacity by 35%. The effective CO_2 storage capacity at depletion in oil reservoirs (~453 Mt CO_2) is ~5% of the storage capacity in depleted gas reservoirs (8,557 Mt CO_2), confirming previous general assessments that gas reservoirs have significantly higher CO_2 sequestration capacity than oil reservoirs. If only the large reservoirs are considered, then the CO_2 sequestration capacity in oil reservoirs (both at depletion and in CO_2 miscible flooding) represents approximately 13% of that in gas reservoirs.

Table 11. Practical CO_2 sequestration capacity in oil reservoirs in the Western Canada Sedimentary Basin.

Province	Type	Number of Oil Reservoirs	Depth Range (m)	Initial Pressure Range (kPa)	Temperature Range (°C)	Effective Capacity at Depletion (Mt CO_2)	Capacity in EOR @50% HCPV (Mt CO_2)	Total Capacity (Mt CO_2)
NE B.C.	Non-EOR	1	1,644	18,479	62	2.1		2.1
	CO_2 EOR	8	1,362 – 2,113	11,822 – 19,181	52 – 75	15.4	12.2	27.6
Alberta	Non-EOR	6	917 – 1,642	6,531 – 15,332	28 – 61	30.3		30.3
	CO_2 EOR	60	1,180 – 2,784	8,705 – 32,135	38 – 104	117.1	270.9	388.0
Sask.	Non-EOR	10	1,306 – 1,478	12,450 – 15,700	40 – 62	40.0		40.0
	CO_2 EOR	12	974 – 2,485	8,912 – 26,601	35 – 92	33.4	.02	33.4
Manitoba	Non-EOR	0						0
	CO_2 EOR	1	985	9,197	40	0.9	0.05	1.0
Total		98				239.2	283.2	522.4

Limiting Factors and Operational Issues

Carbon dioxide separated from flue gases and effluents, and during fuel-decarbonization processes, could be captured and concentrated into a liquid or gas stream that could be transported to the injection site over large distances, as in Colorado and Texas where CO_2 from natural reservoirs is pipelined several hundred kilometres to EOR operations in the Permian basin (Stevens et al., 2001b). Although the technology is readily available, issues to be addressed include uncertainties regarding the volumes available for sequestration; identification of specific sequestration sites; long-term integrity of sequestration; the fate of injected CO_2 over long periods of time; liability and cost associated with CO_2 capture, transport and injection; and public acceptance (Bachu, 2001; Lenstra and van Engelenburg, 2001). As a result, several factors and operational challenges reduce even further the capacity of hydrocarbon reservoirs for CO_2 sequestration as previously determined, but they need to be evaluated on a case-by-case basis.

Carbon Dioxide Purity

Carbon dioxide purity is an important element in developing the infrastructure for large-scale CO_2 sequestration. The properties of CO_2, which in turn affect CO_2 mobility, buoyancy and reservoir sequestration capacity, are strongly dependent on the purity and quality of the CO_2 stream (amount and type of other gases present). The negative effects of impurities must be weighed against the high cost of purifying some CO_2 streams (e.g., flue gases from power plants). The presence of contaminants in the CO_2 stream (e.g., SO_x, NO_x, H_2S) may require its classification as hazardous, imposing different requirements for injection and disposal than if the stream were pure (Bergman et al., 1997).

Pure, dry CO_2 is essentially non-corrosive. In the presence of water, however, CO_2 forms carbonic acid, whose corrosiveness increases with increasing CO_2 partial pressure. The presence of impurities, particularly H_2S, increases the CO_2 corrosivity. The key to eliminating corrosion in the CO_2 delivery system is to ensure that no water is present (Bondor, 1992; Davison et al., 1999). Nevertheless, the experience of the EOR and acid-gas disposal operations indicates that these technological problems have been successfully overcome, and the increased cost of corrosion-prevention measures seems to be relatively insignificant (McIntyre, 1986). Corrosion may also be a problem for old, abandoned wells that penetrate the injection reservoir, particularly if the cement used was not designed to resist acidic agents.

Safety and Regulatory Issues

Safety is a major concern in the delivery, injection and production of CO_2 for EOR and sequestration. The long-term fate of the sequestered CO_2 is not known; however, natural reservoirs, such as the McElmo and Bravo domes, and the Sheep Mountain accumulations in the United States indicate that CO_2 can be safely stored for geological periods of time (Stevens et al., 2001b). Aside from the fact that the requirements for CO_2 geological sequestration would probably be as stringent as those for natural gas storage, all past and present wells into a reservoir must be located and plugged (Winter and Bergman, 1993). In some cases, not all past wells can be located; in others, there might be tens or hundreds of wells. The potential for CO_2 leakage along improperly completed and/or abandoned wells or through wells damaged by the corrosive effect of CO_2 (reservoir ‘puncturing’) may also exclude some reservoirs from being considered for CO_2 sequestration (Celia and Bachu, 2002). Reservoir integrity must be confirmed by pressure and tracer monitoring over significant periods of time, which may increase significantly the cost of the operation. Other safety issues that may preclude CO_2 sequestration in a particular reservoir are the presence of natural conduits, such as open faults and fractures, and lack of integrity of the cap rock.

Reservoir ownership is another issue that needs to be addressed. Currently, companies get mineral rights for producing the hydrocarbons that saturate the pore space. However, pore-space ownership for disposal purposes is unclear in most, if not all, jurisdictions and requires clarification for several reasons: 1) ownership and leasing, 2) access, and 3) future liability (i.e., container versus mineral rights; Bergman et al., 1997).

Infrastructure and Economic Factors

Infrastructure and other economic factors play an important role in estimating the capacity for CO_2 sequestration in hydrocarbon reservoirs, particularly in the near term (immediate capacity). Although the technology exists and hydrocarbon reservoirs have a 'geological' track record for sequestering fluids, the success of these operations depends on a number of factors (e.g., Edwards, 2000; Kovscek, 2002):

- well-developed infrastructure for the capture and delivery of CO_2
- high-quality, high-productivity CO_2 sources
- large number of hydrocarbon reservoirs suitable for CO_2-flood EOR and/or sequestration
- local expertise

The economic success of EOR operations in west Texas is due mainly to the availability of large quantities of pure CO_2 from natural sources, such as the McElmo and Bravo domes (Bondor, 1992; Stevens et al., 2001a, b). In other regions, where CO_2 must be captured from anthropogenic sources, the cost of capturing renders most CO_2-flood EOR operations uneconomic and becomes a net cost for pure CO_2 sequestration. An adequate system of CO_2 delivery (trunk line CO_2 collector, distribution pipelines and compression stations) must be put in place, which also adds to the cost of CO_2 utilization and sequestration, and will delay implementation until construction is completed. However, transportation seems not to be an issue, as demonstrated by the pipeline system in Colorado, New Mexico and west Texas and by the 300 km pipeline from the North Dakota coal gasification plant in Beulah that delivers CO_2 to Encana's EOR project at Weyburn in southeastern Saskatchewan.

In western Canada, the location of the major CO_2 sources in the Joffre-Wabamun-Edmonton-Redwater triangle (Figure 1) and of the oil and gas reservoirs with the largest CO_2 sequestration capacity along a trend that parallels the Rocky Mountains (Figures 8 and 16) suggests a major northwest-southeast trunk line with collectors and distributors along the way, as proposed previously for future CO_2 EOR operations (Edwards, 2000). Such a trunk line could link with sources and sinks in Northeastern British Columbia and continue in southern Saskatchewan, and have lateral collectors from major CO_2 sources and distributors to various oil and gas fields. Issues relating to the implementation of such a delivery system are terrain, right of way and population centres (Winter and Bergman, 1993). Reservoir characteristics and production strategies, which affect the number of injection wells and their spacing, also contribute to the economic aspects of CO_2 sequestration in hydrocarbon reservoirs (Bergman et al., 1997).

Finally, general economic conditions, mainly the oil price but also the fiscal and royalty regime, directly affect the implementation of CO_2-flood EOR operations. Sequestration of CO_2 in depleted hydrocarbon reservoirs is uneconomic in terms of realizing a profit, but it may become attractive in the case of a penalty or cost avoidance and/or in a CO_2 credit-trading system (Freund, 2001; Stevens et al., 2001a). Some barriers to the wide implementation of CO_2 sequestration in oil and gas fields are (Stevens et al., 2001a): 1) the high cost of capturing, processing and transporting anthropogenic CO_2; 2) incomplete understanding of reservoir processes; 3) underdeveloped monitoring and verification technologies; and 4) potential conflicts between CO_2 sequestration and hydrocarbon recovery (maximization of one does not necessarily mean maximization of the other).

All these factors, particularly safety and regulatory ones, may reduce further the practical capacity for CO_2 sequestration in depleted oil and gas reservoirs.

Time of Availability and Duration

Another issue in the implementation of CO_2 sequestration in oil and gas reservoirs in western Canada is their timing of availability and duration. The reservoirs with large capacity are not yet depleted and they will become available for sequestration at some time into the future, when further production becomes uneconomic. However, in the case of oil reservoirs, advanced recovery techniques (e.g., horizontal wells) and/or a rise in oil prices may make it economic to resume production later, so they may not be used for CO_2 sequestration right away after production of the current booked reserves. Thus, the availability of reservoirs for CO_2 sequestration will be primarily determined by the economics of oil and gas production. Therefore, it will take several years until significant capacity CO_2 sequestration capacity will be added.

The duration of CO_2 sequestration in oil and gas pools, once large-scale implementation starts, can be estimated using the relationship:

$$\sum_{k}^{N}(B \cdot A^{k-1} - L) = C_s \tag{20}$$

where B is the base level of annual CO_2 emissions at the start of implementation, A is the annual increase in CO_2 emissions, L is the emission limit imposed by policy and/or regulations, C_s is the available sequestration capacity, and N is duration, in years (Bachu and Shaw, 2003).

In Alberta's case, the total CO_2 emissions increased between 1990 and 2000 at a rate of ~4%/yr, from approximately 140 Mt/yr to some 210 Mt/yr, as a result of population increase and economic development. Since Alberta is by far the largest emitter of CO_2 in the Western Canada Sedimentary Basin, these rates can be used as indicative for the entire basin. Assuming that large-scale implementation of CO_2 sequestration in geological media will start in western Canada from a base emission level of 200 Mt CO_2/yr for large stationary CO_2 sources, with a target of reducing emissions to meet commitments made under the Kyoto protocol, and considering an annual increase at a lower rate of 2.5%/year, then the CO_2 sequestration capacity in the largest oil and gas reservoirs in the Western Canada Sedimentary Basin (with capacity greater than 1 Mt CO_2 each), estimated currently to be of the order of 3.7 Gt, will last for less than 25 years. These estimates show that large oil and gas pools in the Western Canada Sedimentary Basin may provide enough practical capacity for CO_2 geological sequestration for at least two decades during which, hopefully, technological breakthroughs and new energy sources would provide other means for reducing CO_2 emissions into the atmosphere. Because the oil and gas pools will become available for CO_2 sequestration over a period of time spread out during the next three decades, additional means and sites for geological sequestration should be found and implemented concomitantly, such as unmineable coal seams and deep brine-saturated formations.

Conclusions

Geological sequestration of CO_2 is an immediately available means of reducing CO_2 emissions into the atmosphere from major point sources, such as thermal power plants and the petrochemical industry, which is particularly suited to landlocked Alberta. Trapping of CO_2 in depleted hydrocarbon reservoirs and through enhanced oil recovery (EOR) will likely be implemented first because the geological conditions are already well known and infrastructure is already partially in place. In addition, use of CO_2 in EOR operations leads to incremental oil recovery, thus realizing an economic benefit that will lower the cost of CO_2 sequestration.

The basic assumption used in estimating the theoretical ultimate capacity for CO_2 sequestration in hydrocarbon reservoirs is that the volume occupied by the produced oil and gas can be backfilled with CO_2. Depending on the strength of the underlying aquifer, water invasion has the effect of reducing the theoretical CO_2 sequestration capacity of depleted reservoirs by up to 50% on average for oil pools and by up to 30% on average for gas pools, if the reservoir is allowed to be repressurized only back to its initial pressure. If the underlying aquifer is weak, then its effect on the reservoir CO_2 sequestration capacity is very small. The estimates obtained in this way do not consider secondary effects of water invasion, gravity segregation, viscous fingering and reservoir heterogeneity. Consideration of these effects reduces further the estimates to effective estimates, but generally they require a much more detailed knowledge of reservoir properties.

The effective CO_2 sequestration capacity in more than 25,000 gas reservoirs in the Western Canada Sedimentary Basin is ~8.5 Gt CO_2. In contrast to gas reservoirs, the effective sequestration capacity at depletion in more than 8,400 oil pools in single drive and primary production is only ~453 Mt CO_2. The difference in capacity between oil and gas reservoirs is due mainly to the significantly smaller recovery factor for oil than for gas, but also to the fact that the number of oil pools is approximately one-third the number of gas pools. In addition, 695 oil pools that are currently in secondary or tertiary recovery (water, solvent or gas flooded) have an estimated CO_2 sequestration capacity of 362 Mt CO_2. The capacity of these reservoirs, however, is continuously decreasing as water, solvent or gas is injected to enhance oil production. These reservoirs are therefore not likely to be primary candidates for CO_2 sequestration unless CO_2 is used to recover the injected gas or solvent, which have economic value, or just for sequestration, in which case the water that currently occupies the pore space will have to be disposed of in an environmentally safe manner.

Notwithstanding their very large number, most reservoirs have a relatively small CO_2-sequestration capacity, rendering them largely uneconomic. In addition, shallow reservoirs are inefficient because of low CO_2 density, while very deep reservoirs may be too costly because of the high cost of CO_2 compression, and also inefficient in terms of net CO_2 sequestered. If only the largest reservoirs in the undeformed part of the basin and in the depth range of approximately 900 m to 3500 m are considered, each with an individual capacity greater than 1 Mt CO_2, then the number of reservoirs in the Western Canada Sedimentary Basin suitable for CO_2 sequestration in the short-to-medium term drops to 771 gas reservoirs and 98 oil reservoirs currently in single drive or primary production, with an estimated practical CO_2 sequestration capacity of 3,180 Mt CO_2 and 522 Mt CO_2, respectively.

Of the four western provinces, Alberta has by far the largest practical CO_2 sequestration capacity, estimated at 2,812 Mt CO_2, followed by northeastern British Columbia with 810 Mt CO_2. In both provinces gas reservoirs have by far more CO_2 sequestration capacity than oil reservoirs. Saskatchewan has a practical CO_2 sequestration capacity of only 79 Mt CO_2, of which more than 90% is in oil reservoirs, while Manitoba has a negligible practical CO_2 sequestration capacity of 1 Mt CO_2 in one oil reservoir only.

More than 140 Mt CO_2 in 2000 were emitted by major CO_2 stationary sources in the Western Canada Sedimentary Basin with individual CO_2 emissions greater than 100 kt/yr, such as power plants, oil-sands plants, petrochemical plants, cement plants, refineries and pipelines, which facilitates CO_2 capture and sequestration. The practical capacity for CO_2 sequestration in oil and gas reservoirs in the Western Canada Sedimentary Basin, estimated to be of the order of 3.7 Gt in large pools, may provide a sink for CO_2 captured from these major point sources that is estimated to last for three decades. Some additional economic benefits could be realized at the same time by producing additional oil and gas in CO_2-based EOR and EGR operations. A major pipeline system with a trunk line and collectors and distributors could be built in western Canada to carry CO_2 from major sources to large sinks.

Recommendations

Regional-scale estimation of the CO_2 sequestration capacity in oil and gas reservoirs in the Western Canada Sedimentary Basin, and identification of those pools with very large individual capacity represent the first step in the development of the geoscience infrastructure needed for the selection of early candidates for CO_2 geological sequestration in Canada. To further advance the geoscience knowledge base and provide the information necessary for the development of proper policy regarding geological sequestration of CO_2, it is recommended to:

1. evaluate the production history and the timing of availability (timing of depletion) for the oil and gas reservoirs with very large capacity (greater than 1 Mt CO_2 each) in western Canada;
2. evaluate the heterogeneity and permeability of these reservoirs because these characteristics affect injectivity, hence the number of wells that would be needed to deliver the CO_2 to the reservoir;
3. evaluate existing infrastructure for these reservoirs (e.g., wells, pipelines, gathering systems);
4. evaluate the age and conditions of existing wells;
5. evaluate the potential for incremental oil production and CO_2 sequestration in the top oil reservoirs (approximately 80) that are suitable for CO_2 miscible flooding, using more detailed and sophisticated reservoir models;
6. develop methodology and a model for matching major stationary CO_2 sources in western Canada with these large potential CO_2 sinks.

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Appendix A - List of gas pools in the undeformed part of the Western Canada Sedimentary Basin that have an estimated effective CO_2 sequestration capacity greater than 1 Mt CO_2 each.

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	AERIAL	MANNVILLE G	-112.53894778	51.51348873	1,092,322
AB	ALDERSON	UPPER MANNVILLE EEE	-111.92647558	50.20813833	1,891,880
AB	ALDERSON	UPPER MANNVILLE LLL	-111.89616434	50.17649871	4,385,482
AB	ALDERSON	UPPER MANNVILLE OOO	-111.88103455	50.18625381	1,346,233
AB	ALEXANDER	BASAL QUARTZ A	-113.95304893	53.83703745	15,300,980
AB	ANSELL	CARDIUM G	-116.80155200	53.49513066	21,814,536
AB	ANTE CREEK	DUNVEGAN B	-117.39186083	54.67455219	2,294,958
AB	ARDENODE	BELLY RIVER OO	-113.76081762	51.17604120	1,332,728
AB	ATLEE-BUFFALO	UPPER MANNVILLE Z	-110.91646563	50.77613319	2,727,149
AB	ATLEE-BUFFALO	GLAUCONITIC R	-110.96263141	50.75416496	1,002,046
AB	BALSAM	BLUESKY B	-119.58268026	56.22472817	1,637,704
AB	BALSAM	BALDONNEL FM Undefined	-119.62043750	56.14347740	1,099,946
AB	BALSAM	KISKATINAW A	-119.55321521	56.14883091	1,362,483
AB	BALSAM	KISKATINAW D	-119.57946840	56.12340339	1,925,098
AB	BALSAM	KISKATINAW N	-119.59601612	56.22448444	1,328,206
AB	BALSAM	KISKATINAW P	-119.60549925	56.13796665	1,298,957
AB	BANTRY	MANNVILLE A	-111.63960332	50.47531240	1,014,056
AB	BANTRY	MANNVILLE VVV	-111.90895845	50.77573653	1,291,035
AB	BASSANO	UPPER MANNVILLE D	-112.60153222	50.79762821	1,211,383
AB	BASSANO	UPPER MANNVILLE Y	-112.54390698	50.76481376	1,672,122
AB	BASSANO	UPPER MANNVILLE CC	-112.51129890	50.74839230	2,146,172
AB	BASSANO	UPPER MANNVILLE LL	-112.50161008	50.76358193	1,683,364
AB	BASSANO	GLAUCONITIC III	-112.36757290	50.94141430	2,841,850
AB	BELLOY	MONTNEY A	-118.12326779	55.77228164	1,511,682
AB	BERRY	UPPER MANNVILLE RR	-111.54042113	51.35053452	1,563,317
AB	BEZANSON	CHARLIE LAKE B	-118.42752102	55.13187817	1,058,491
AB	BIGSTONE	DUNVEGAN A	-117.12403092	54.19599038	22,021,912
AB	BIGSTONE	DUNVEGAN B	-117.28871899	54.18430769	4,401,792
AB	BIGSTONE	D-3 A	-117.20812993	54.23545565	14,215,568

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO$_2$ STORAGE CAPACITY (tonnes)
AB	BILBO	FALHER A	-118.86874395	54.59615167	1,194,210
AB	BISTCHO	SULPHUR POINT F	-118.27659587	59.65559637	1,015,035
AB	BITTERN LAKE	GLAUCONITIC A	-113.05992938	52.99369838	1,876,122
AB	BITTERN LAKE	GLAUCONITIC SS	-113.20840475	53.05421240	1,098,114
AB	BLACK BUTTE	SUNBURST-SWIFT A	-111.04106066	49.02831343	1,000,345
AB	BLACK BUTTE	SAWTOOTH A	-111.05218467	49.02039513	2,437,681
AB	BLACK BUTTE	RUNDLE A	-111.05218500	49.02831705	3,615,237
AB	BLACKFOOT	VIKING K	-113.18451653	50.88166896	1,462,487
AB	BLACKFOOT	GLAUCONITIC K	-113.15560903	50.88522392	1,589,241
AB	BLOOD	BOW ISLAND A	-112.84114100	49.47808533	2,737,474
AB	BLOOD	BOW ISLAND Q	-112.74742061	49.50134308	2,419,528
AB	BLUEBERRY	KISKATINAW A	-119.04463204	56.10890912	3,566,407
AB	BLUERIDGE	JURASSIC B	-115.47360984	54.06304381	7,571,228
AB	BLUERIDGE	JURASSIC D	-115.41410798	54.10857132	1,061,973
AB	BLUERIDGE	JURASSIC F	-115.44744106	54.10614571	1,466,267
AB	BONANZA	GETHING B	-119.50125944	56.03369360	3,232,753
AB	BONANZA	BALDONNEL B	-119.63170585	56.07256190	1,112,064
AB	BONANZA	HALFWAY A	-119.65344185	56.05068803	1,744,158
AB	BONANZA	KISKATINAW A	-119.60562115	56.06522439	1,823,681
AB	BONANZA	KISKATINAW C	-119.55346734	56.05788963	4,299,548
AB	BONANZA	KISKATINAW D	-119.57954396	56.06521120	1,714,008
AB	BOUNDARY LAKE SOUTH	TRIASSIC O	-119.93095407	56.47184303	2,609,012
AB	BOUNDARY LAKE SOUTH	CHARLIE LAKE B	-119.96516418	56.61838157	1,819,842
AB	BOUNDARY LAKE SOUTH	KISKATINAW A	-119.83846297	56.30316320	1,480,425
AB	BOUNDARY LAKE SOUTH	KISKATINAW E	-119.93834716	56.36130495	3,409,748
AB	BOUNDARY LAKE SOUTH	KISKATINAW H	-119.91203351	56.39910322	3,466,474
AB	BOUNDARY LAKE SOUTH	KISKATINAW J	-119.94066620	56.31493825	4,907,078
AB	BOUNDARY LAKE SOUTH	KISKATINAW N	-119.72771502	56.26089283	1,867,817
AB	BRAZEAU RIVER	LOWER MANNVILLE O	-115.98184181	53.07407901	3,493,420
AB	BRAZEAU RIVER	ROCK CREEK D	-116.12408424	53.08523571	3,031,931
AB	BRAZEAU RIVER	ROCK CREEK G	-116.10406503	53.03968270	1,081,374
AB	BRAZEAU RIVER	ROCK CREEK P	-116.03703307	53.03951254	1,012,270
AB	BRAZEAU RIVER	ELKTON-SHUNDA A	-115.64036602	52.82121822	12,159,742

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	BRAZEAU RIVER	ELKTON-SHUNDA A	-115.64036602	52.82121822	11,481,976
AB	BRAZEAU RIVER	ELKTON-SHUNDA B	-115.83594478	52.97901951	30,431,114
AB	BRAZEAU RIVER	ELKTON-SHUNDA B	-115.83594478	52.97901951	34,539,580
AB	BRAZEAU RIVER	ELKTON-SHUNDA B	-115.83594478	52.97901951	1,792,980
AB	BRAZEAU RIVER	ELKTON-SHUNDA B	-115.83594478	52.97901951	10,163,706
AB	BRAZEAU RIVER	ELKTON-SHUNDA B	-115.83594478	52.97901951	1,024,838
AB	BRAZEAU RIVER	ELKTON-SHUNDA F	-115.68360912	53.14862282	1,890,378
AB	BRAZEAU RIVER	NISKU F	-115.87860882	53.12681256	1,352,402
AB	BRAZEAU RIVER	NISKU M	-115.86641721	53.15591814	3,203,878
AB	BRAZEAU RIVER	NISKU P	-115.69308517	53.12683646	13,070,435
AB	BRONSON	GETHING J	-116.44179492	53.97017683	1,042,231
AB	BRONSON	WABAMUN B	-116.48141491	53.93528949	1,022,188
AB	CAMPBELL-NAMAO	BLAIRMORE A	-113.61987304	53.69261284	1,156,779
AB	CARBON	GLAUCONITIC	-113.06333218	51.47754353	3,414,232
AB	CARBON	GLAUCONITIC	-113.06333218	51.47754353	10,124,396
AB	CARBON	GLAUCONITIC J	-112.97505164	51.47265566	1,212,772
AB	CARBON	ELLERSLIE A	-113.01722726	51.52505271	1,486,086
AB	CARDIFF	ELLERSLIE A	-114.19236771	53.66672330	2,640,090
AB	CAROLINE	BASAL MANNVILLE B	-114.75151790	51.97704568	1,365,997
AB	CAROLINE	BASAL MANNVILLE G	-114.79908787	51.97705099	1,188,869
AB	CAROLINE	RUNDLE A	-114.58197818	51.86191001	1,948,061
AB	CAROLINE	ELKTON A	-114.67496482	51.95511024	2,781,897
AB	CAROLINE	ELKTON S	-114.70394118	51.99159241	1,402,788
AB	CARSON CREEK	BEAVERHILL LAKE B	-115.73281902	54.27830851	16,791,684
AB	CARSTAIRS	ELKTON A	-114.22708862	51.56254390	73,118,319
AB	CAVALIER	GLAUCONITIC Q	-113.08647195	51.03049965	1,553,791
AB	CECIL	CHARLIE LAKE W	-119.10397307	56.33702981	1,426,122
AB	CECIL	KISKATINAW D	-119.51181018	56.25681402	2,694,346
AB	CESSFORD	BASAL COLORADO A	-111.49350031	50.94296067	1,183,010
AB	CESSFORD	BASAL COLORADO O	-111.71548452	51.12508958	5,341,870
AB	CESSFORD	MANNVILLE C	-111.61445648	51.16313827	2,628,952
AB	CESSFORD	MANNVILLE C	-111.61445648	51.16313827	1,856,166
AB	CESSFORD	MANNVILLE G	-111.77751211	51.16564726	5,608,422

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	CESSFORD	MANNVILLE H	-111.34957091	51.04856413	7,867,796
AB	CESSFORD	MANNVILLE I	-111.74546051	51.10805201	1,128,658
AB	CESSFORD	MANNVILLE J	-111.56329275	51.23422373	2,468,986
AB	CESSFORD	MANNVILLE V	-111.96456055	51.26335281	8,300,534
AB	CESSFORD	MANNVILLE P4P	-111.82753057	51.25501442	2,409,739
AB	CESSFORD	MANNVILLE O5O	-111.58259592	51.00618020	1,617,518
AB	CESSFORD	DETRITAL A	-111.38880886	50.97209381	1,854,381
AB	CHERHILL	BANFF W	-114.69362622	53.91447875	2,998,524
AB	CHICKEN	CHINOOK H	-118.97920190	54.38300579	1,860,976
AB	CHIGWELL	MANNVILLE A	-113.44761739	52.52130703	2,426,280
AB	CHIGWELL	MANNVILLE J	-113.58346560	52.63527461	1,067,541
AB	CHINCHAGA	SLAVE POINT A	-118.94297008	57.41711218	3,098,460
AB	CHINCHAGA	SLAVE POINT N	-118.98944905	57.37348879	1,283,132
AB	CHINCHAGA NORTH	SLAVE POINT A	-119.18208319	57.48475455	1,529,099
AB	CHIP LAKE	ROCK CREEK C	-115.43882016	53.60654742	1,561,030
AB	CLAIR	HALFWAY E	-118.76942393	55.31603575	1,063,965
AB	CLARESHOLM	GLAUCONITIC A	-113.52718383	50.12839550	1,729,691
AB	CLARESHOLM	GLAUCONITIC E	-113.47939295	50.11672535	1,253,546
AB	CLEAR PRAIRIE	BLUESKY A	-119.81133998	56.87304861	1,035,472
AB	CLIVE	D-2 A	-113.36820242	52.41144217	2,093,948
AB	CONNORSVILLE	VIKING A	-111.99778024	51.16553347	1,099,426
AB	CORBETT	VIKING A	-115.01113095	54.30294028	1,260,936
AB	COUNTESS	BOW ISLAND H	-112.31300425	50.74668516	1,376,857
AB	COUNTESS	BOW ISLAND N	-112.71052572	50.92438888	1,500,091
AB	COUNTESS	BASAL COLORADO A	-112.28494948	50.84529223	22,721,108
AB	COUNTESS	BASAL COLORADO A	-112.28494948	50.84529223	5,185,736
AB	COUNTESS	BASAL COLORADO A	-112.28494948	50.84529223	1,231,973
AB	COUNTESS	BASAL COLORADO A	-112.28494948	50.84529223	3,079,933
AB	COUNTESS	BASAL COLORADO E	-112.20163736	50.91084280	1,008,726
AB	COUNTESS	UPPER MANNVILLE S	-112.58580820	50.88004895	1,483,707
AB	COUNTESS	UPPER MANNVILLE AA	-112.62139118	50.95772463	1,242,986
AB	COUNTESS	UPPER MANNVILLE QQQ	-112.64460824	50.97962345	1,487,691
AB	COUNTESS	LOWER MANNVILLE M	-112.73766315	50.92880954	1,475,116

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	COUNTESS	LOWER MANNVILLE MM	-111.97821832	50.78304238	2,244,193
AB	COUNTESS	BASAL QUARTZ C	-112.16291791	50.68118501	1,345,562
AB	CRAIGMYLE	ELLERSLIE H	-112.42647612	51.71436605	1,799,111
AB	CRANBERRY	SLAVE POINT A	-118.54933187	57.36022484	29,263,859
AB	CRANBERRY	SLAVE POINT B	-118.63481117	57.24158239	5,255,859
AB	CROSSFIELD	BASAL QUARTZ A	-113.95047774	51.17031725	4,050,845
AB	CROSSFIELD	BASAL QUARTZ C	-113.80738078	51.10123516	4,102,566
AB	CROSSFIELD	BASAL QUARTZ G	-114.38835078	51.59839704	1,080,613
AB	CROSSFIELD	BASAL QUARTZ K	-114.33364117	51.48676767	1,004,706
AB	CROSSFIELD	BASAL QUARTZ M	-113.81077636	51.29026666	5,358,053
AB	CROSSFIELD	BASAL QUARTZ N	-113.80732014	51.18328973	3,026,353
AB	CROSSFIELD	BASAL QUARTZ O	-113.78874958	51.23715713	3,655,623
AB	CROSSFIELD	RUNDLE B	-113.97431907	51.16881495	80,893,168
AB	CROSSFIELD	RUNDLE F	-114.12129204	51.30729411	4,767,631
AB	CROSSFIELD	RUNDLE H	-114.27120178	51.51103044	1,181,314
AB	CROSSFIELD	RUNDLE I	-114.04447884	51.26839689	1,659,301
AB	CROSSFIELD	WABAMUN A	-113.89987242	51.16427463	69,341,741
AB	CROSSFIELD	WABAMUN B	-113.82475988	51.11420844	1,013,429
AB	CROSSFIELD EAST	ELKTON H	-114.08378559	51.56202531	2,133,705
AB	CROSSFIELD EAST	WABAMUN A	-114.02236885	51.49594296	59,866,298
AB	CRYSTAL	VIKING J	-114.34114073	53.01360096	1,935,873
AB	CUTBANK	FALHER A	-119.27181218	54.65432809	1,389,875
AB	CUTBANK	FALHER B	-119.32218903	54.65431969	1,930,046
AB	CUTBANK	FALHER C	-119.22987400	54.67859589	2,360,428
AB	CYN-PEM	ROCK CREEK AA	-115.47166409	53.39318218	1,588,227
AB	DIMSDALE	PADDY A	-118.95607802	55.17466388	9,228,775
AB	DOE	DOIG B	-119.82756780	56.06522551	3,628,293
AB	DOE	KISKATINAW B	-119.91881594	56.00703254	3,392,214
AB	DONALDA	LOWER MANNVILLE F	-112.56008093	52.57965664	1,605,034
AB	DORIS	LOWER MANNVILLE D	-114.69829580	54.48972833	2,762,937
AB	DRUMHELLER	MANNVILLE H	-112.73570278	51.61239701	1,025,252
AB	DRUMHELLER	MANNVILLE Q	-112.69850909	51.63432736	1,605,776
AB	DRUMHELLER	MANNVILLE W	-112.48960077	51.36509748	1,682,910

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	DRUMHELLER	MANNVILLE CC	-112.60161619	51.60804606	2,024,358
AB	DRUMHELLER	UPPER MANNVILLE H	-112.75914802	51.58908667	1,111,725
AB	DRUMHELLER	UPPER MANNVILLE UU	-112.57176148	51.48867955	1,038,968
AB	DRUMHELLER	LOWER MANNVILLE E	-112.70366664	51.61733899	1,350,139
AB	DUNVEGAN	GETHING B	-118.50299093	55.99617465	2,341,276
AB	DUNVEGAN	KISKATINAW C	-118.41813708	56.02164753	1,573,515
AB	EDSON	VIKING A	-116.35392770	53.21409389	2,042,201
AB	EDSON	VIKING B	-116.73888386	53.57319566	8,272,925
AB	EDSON	VIKING D	-116.77590227	53.66891670	5,585,405
AB	EDSON	BLUESKY G	-116.36518912	53.64575183	2,147,843
AB	EDSON	BLUESKY N	-116.72864478	53.57744506	1,463,191
AB	EDSON	GETHING A	-116.55796108	53.60869388	14,882,622
AB	EDSON	GETHING F	-116.32471506	53.24027365	1,463,884
AB	EDSON	GETHING G	-116.38434605	53.18501026	2,077,785
AB	EDSON	BLUERIDGE B	-116.17440797	53.50177875	6,113,387
AB	ELMWORTH	DUNVEGAN D	-119.45293391	55.03961486	1,713,010
AB	ELMWORTH	FALHER A-27	-119.30792227	55.13422214	2,276,543
AB	ELMWORTH	FALHER A-33	-119.38627582	54.90148756	1,181,047
AB	ELMWORTH	FALHER A-37	-118.99216488	54.91603702	1,123,499
AB	ELMWORTH	FALHER B-12	-119.59387220	55.09544027	2,716,294
AB	ELMWORTH	FALHER C-1	-119.49638421	54.93545589	2,106,424
AB	ELMWORTH	CHARLIE LAKE G	-118.87770815	55.01778512	1,159,311
AB	ELMWORTH	HALFWAY A	-119.40659297	55.02653690	1,552,739
AB	ELMWORTH	HALFWAY B	-118.85220284	54.96684565	1,012,869
AB	ENCHANT	UPPER MANNVILLE A	-112.23165109	50.15126503	3,354,040
AB	ENCHANT	UPPER MANNVILLE L	-112.16670983	50.24818637	2,136,879
AB	ENCHANT	UPPER MANNVILLE R	-112.17704798	50.19355151	1,760,686
AB	ENCHANT	LOWER MANNVILLE N	-112.27269660	50.25910198	1,532,653
AB	ENDIANG	UPPER MANNVILLE C	-112.18980430	52.00086805	1,377,789
AB	ERSKINE	BLAIRMORE	-112.88164541	52.34389826	1,929,290
AB	EYREMORE	BOW ISLAND A	-112.38280476	50.54534438	1,696,128
AB	EYREMORE	UPPER MANNVILLE G	-112.31468186	50.42893651	1,991,806
AB	FAIRYDELL-BON ACCORD	BASAL MANNVILLE B	-113.50874290	54.00726501	1,229,612

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO$_2$ STORAGE CAPACITY (tonnes)
AB	FARMINGTON	KISKATINAW A	-119.64483589	55.96341939	2,483,896
AB	FARMINGTON	KISKATINAW B	-119.71004528	55.95617843	1,386,498
AB	FARROW	MEDICINE HAT SD Undefined	-113.18078860	50.70872230	2,876,661
AB	FARROW	MEDICINE HAT SD Undefined	-113.14615150	50.71598620	1,556,210
AB	FENN-BIG VALLEY	VIKING B	-112.73935120	52.05362190	1,914,212
AB	FERINTOSH	ELLERSLIE H	-112.99139444	52.78513328	1,236,406
AB	FERRIER	GLAUCONITIC B	-114.98949400	52.28257137	1,665,760
AB	FERRIER	ELLERSLIE C	-115.00980420	52.37721583	1,004,939
AB	FERRIER	ELLERSLIE F	-114.94671594	52.26512917	1,201,211
AB	FERRIER	ELKTON A	-115.14495778	52.40186526	2,169,730
AB	FERRIER	ELKTON-SHUNDA A	-115.33551819	52.60956363	1,718,307
AB	FERRIER	ELKTON-SHUNDA B	-115.31846617	52.52746653	2,314,970
AB	FERRIER	SHUNDA D	-115.43114478	52.70153774	1,722,000
AB	FERRIER	PEKISKO B	-115.39188403	52.73425750	2,148,967
AB	FERRIER	PEKISKO D	-115.37979905	52.77791057	1,221,532
AB	FERRIER	BANFF A	-115.35968001	52.77301789	2,302,778
AB	FERRYBANK	VIKING A	-113.85337062	52.75705407	1,623,967
AB	FERRYBANK	LOWER MANNVILLE F	-113.84557288	52.76816232	1,222,840
AB	FERRYBANK	LOWER MANNVILLE S	-113.93074036	52.84749389	2,404,373
AB	FERRYBANK	BANFF A	-113.95218736	52.76335541	1,257,586
AB	FERRYBANK	BANFF B	-113.88586426	52.77788316	2,082,258
AB	FIR	D-1 A	-116.99920689	54.02832484	4,824,234
AB	FIR	D-3 A	-117.02005812	54.13406821	3,623,966
AB	FORESTBURG	UPPER MANNVILLE K	-112.22428119	52.55047643	1,034,151
AB	FORTY MILE	LOWER MANNVILLE E	-111.20678678	49.56441690	7,850,420
AB	FOX CREEK	VIKING A	-116.73393170	54.34946645	10,053,133
AB	FOX CREEK	MONTNEY B	-116.58888978	54.31329639	1,257,681
AB	GADSBY	MANNVILLE A	-112.57392902	52.15891317	1,066,395
AB	GADSBY	MANNVILLE I	-112.64802625	52.20830565	1,052,586
AB	GARDEN PLAINS	UPPER MANNVILLE U	-111.57621014	51.89618208	1,036,789
AB	GARRINGTON	ELKTON E	-114.63592456	52.07472734	8,494,765
AB	GARRINGTON	LEDUC D	-114.41831175	52.04973987	1,211,237
AB	GARRINGTON	LEDUC F	-114.48970826	51.98428401	2,287,141

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	GEORGE	KISKATINAW D	-118.78543105	56.09017632	2,904,289
AB	GEORGE	KISKATINAW H	-118.50297510	56.07246459	11,179,574
AB	GEORGE	KISKATINAW J	-118.44866215	56.07013239	4,057,220
AB	GEORGE	KISKATINAW M	-118.56172905	56.10887961	2,501,853
AB	GEORGE	DEBOLT C	-118.74445309	56.14521240	1,205,978
AB	GHOST PINE	UPPER MANNVILLE KK	-113.07591185	51.73634984	1,166,147
AB	GHOST PINE	UPPER MANNVILLE VV	-112.90582260	51.50683230	1,005,278
AB	GHOST PINE	UPPER MANNVILLE O2O	-113.07725512	51.80665830	5,306,790
AB	GHOST PINE	LOWER MANNVILLE F	-113.04046579	51.66357369	1,935,927
AB	GHOST PINE	PEKISKO G	-112.84683969	51.70557875	2,813,351
AB	GILBY	UPPER MANNVILLE G	-114.50764200	52.52858980	1,232,516
AB	GILBY	BASAL MANNVILLE D	-114.24567359	52.45924599	5,079,245
AB	GILBY	BASAL MANNVILLE BBB	-114.10976353	52.44488641	1,736,436
AB	GILBY	RUNDLE H	-114.57139605	52.58129746	3,092,839
AB	GIROUXVILLE EAST	BLUESKY A	-117.36423517	55.55590482	1,229,783
AB	GLADYS	WABAMUN A	-113.68362377	50.71532410	3,488,257
AB	GOLD CREEK	BLUESKY A	-118.68693533	55.07601370	1,558,694
AB	GOLD CREEK	WABAMUN A	-118.57247880	54.84329217	1,638,066
AB	GOLD CREEK	WABAMUN G	-118.54704997	54.84330088	1,849,654
AB	GOLD CREEK	WABAMUN K	-118.58518999	54.81419668	4,561,311
AB	GOLDEN SPIKE	D-1 A	-113.87834941	53.42342737	1,768,557
AB	GOODWIN	BASAL QUARTZ B	-115.77519205	54.12559318	2,427,369
AB	GOODWIN	BASAL QUARTZ D	-115.83774596	54.06980789	1,049,857
AB	GORDONDALE	GETHING B	-119.68398307	55.87612544	1,782,620
AB	GORDONDALE	GETHING I	-119.48804526	55.94885725	1,472,342
AB	GORDONDALE	BALDONNEL B	-119.40975190	55.97788854	1,129,344
AB	GORDONDALE	KISKATINAW B	-119.72300713	55.86891613	4,410,665
AB	GRAND FORKS	ARCS D	-111.80159048	50.01150347	1,082,224
AB	GRANDE PRAIRIE	MONTNEY E	-118.51743309	55.21184407	3,949,015
AB	GREENCOURT	PEKISKO F	-115.15592200	54.11091805	1,274,729
AB	GREENCOURT EAST	JURASSIC A	-114.85734624	54.12399893	2,218,769
AB	GROAT	LEDUC B	-116.36754591	53.86469154	1,007,607
AB	HAMBURG	SLAVE POINT A	-119.77991494	57.37605501	28,012,055

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	HAMBURG	SLAVE POINT C	-119.66672493	57.40990765	3,172,722
AB	HAMBURG	SLAVE POINT G	-119.77513122	57.31534960	1,216,901
AB	HAMBURG	SLAVE POINT H	-119.65316802	57.32266985	1,536,540
AB	HAMBURG	SLAVE POINT U	-119.69384026	57.30805293	1,098,894
AB	HAMBURG	SLAVE POINT W	-119.58540298	57.46074522	1,050,940
AB	HAMBURG	SLAVE POINT X	-119.59896100	57.37350763	1,340,217
AB	HAMBURG	SLAVE POINT Y	-119.55829628	57.43167966	1,276,318
AB	HANLAN	CARDIUM A	-116.37828797	53.06861837	1,111,896
AB	HANNA	LOWER MANNVILLE M	-111.91552671	51.53974161	1,088,603
AB	HANNA	BANFF A	-111.93828602	51.63669908	1,656,626
AB	HARMATTAN-ELKTON	RUNDLE A	-114.48363532	51.63158848	2,038,477
AB	HARMATTAN-ELKTON	D-3 A	-114.51869208	51.72950539	4,835,680
AB	HEATHDALE	LOWER MANNVILLE A	-111.22015280	51.32681240	1,693,521
AB	HELDAR	NORDEGG B	-114.87671688	54.06249231	2,059,843
AB	HELDAR	NORDEGG F	-114.80812080	54.01334946	1,135,560
AB	HERRONTON	ELLERSLIE D	-113.45589422	50.79054864	1,002,704
AB	HERRONTON	TURNER VALLEY E	-113.40963017	50.62319014	1,003,446
AB	HIGH RIVER	CUTBANK A	-113.94165816	50.42694681	1,631,933
AB	HIGHVALE	BANFF O	-114.45432960	53.36684241	1,972,107
AB	HINES	BLUESKY A	-118.36538692	56.40482020	1,064,462
AB	HOLBURN	GLAUCONITIC C	-113.99398814	53.31584160	1,177,769
AB	HOLMBERG	GLAUCONITIC G	-112.58505955	52.87970782	1,045,214
AB	HOOKER	LIVINGSTONE FM Undefined	-113.95597670	50.23538340	1,040,352
AB	HUSSAR	VIKING B	-112.82557690	51.26170761	1,393,576
AB	HUSSAR	VIKING E	-112.60872725	51.03840046	1,134,014
AB	HUSSAR	BASAL COLORADO A	-112.83425872	51.11339710	1,469,099
AB	HUSSAR	BASAL COLORADO C	-112.70568849	51.03781686	2,241,712
AB	HUSSAR	GLAUCONITIC N	-112.70040903	51.02935431	15,165,454
AB	HUSSAR	GLAUCONITIC P	-112.80741070	51.07418548	2,598,520
AB	HUSSAR	GLAUCONITIC Q	-112.75311261	51.09849971	3,209,003
AB	HUSSAR	GLAUCONITIC R	-112.78414891	51.11785177	3,761,487
AB	HUSSAR	GLAUCONITIC W2W	-113.01213772	51.07345241	1,023,880
AB	HUSSAR	OSTRACOD R	-112.73049923	51.16595257	1,747,210

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	INNISFAIL	PEKISKO E	-114.21572878	51.99531698	2,414,324
AB	IRRICANA	PEKISKO A	-113.79460082	51.45232545	3,161,071
AB	IRRICANA	WABAMUN A	-113.72040575	51.31727831	2,718,010
AB	IRRICANA	WABAMUN B	-113.76338157	51.41357434	1,968,279
AB	IRRICANA	WABAMUN C	-113.68333360	51.46084870	3,547,368
AB	IRRICANA	WABAMUN F	-113.75875069	51.27997938	1,785,643
AB	JARVIE	ELLERSLIE B	-114.08982828	54.40929583	2,037,578
AB	JENNER	ARCS A	-111.20475852	50.68137141	5,458,053
AB	JOSEPHINE	KISKATINAW A	-119.37732731	56.19436767	2,854,706
AB	KARR	WABAMUN B	-118.13885487	54.55240989	1,705,331
AB	KAYBOB	NOTIKEWIN B	-116.74941284	54.52182158	14,232,550
AB	KAYBOB	NOTIKEWIN E	-116.91786178	54.65329702	7,059,585
AB	KAYBOB	GETHING J	-116.83739491	54.52328620	1,299,929
AB	KAYBOB	BEAVERHILL LAKE C	-116.59937301	54.49905914	2,395,752
AB	KAYBOB SOUTH	VIKING A	-116.92560577	54.36267447	3,283,468
AB	KAYBOB SOUTH	BLUESKY G	-116.54393806	54.03924706	1,580,101
AB	KAYBOB SOUTH	GETHING D	-116.45519972	54.14858483	5,214,689
AB	KAYBOB SOUTH	GETHING O	-116.75134287	54.13042336	1,051,622
AB	KAYBOB SOUTH	GETHING P	-116.93616520	54.39078274	5,315,221
AB	KAYBOB SOUTH	GETHING BB	-116.91380293	54.31952686	1,350,271
AB	KAYBOB SOUTH	GETHING H	-116.66603750	54.28857270	1,749,518
AB	KAYBOB SOUTH	BEAVERHILL LAKE A	-116.69856305	54.17299057	101,698,450
AB	KNOPCIK	PADDY C	-119.54406013	55.30869972	2,191,894
AB	KNOPCIK	NIKANASSIN E	-119.52580286	55.35955984	1,318,284
AB	KNOPCIK	JURASSIC D	-119.56683300	55.30146349	1,486,704
AB	KNOPCIK	HALFWAY C	-119.51554102	55.29999501	1,272,904
AB	KNOPCIK	HALFWAY N	-119.48894690	55.48139090	2,083,050
AB	KNOPCIK	MONTNEY A	-119.52964796	55.43059369	15,218,953
AB	LA GLACE	HALFWAY C	-118.86352521	55.38630735	1,151,573
AB	LA GLACE	MONTNEY A	-119.14126618	55.43963761	1,879,871
AB	LAMBERT	CARDIUM A	-117.10922194	53.53375268	1,149,353
AB	LAMBERT	CARDIUM B	-117.10922219	53.52643155	1,863,021
AB	LAMBERT	VIKING A	-117.12150631	53.51921228	1,468,145

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	LAPP	SLAVE POINT A	-119.50945321	57.57220534	1,264,818
AB	LAPP	SLAVE POINT C	-119.43653921	57.57700543	1,105,458
AB	LAPP	SLAVE POINT D	-119.43653920	57.59154128	1,336,481
AB	LAPP	SLAVE POINT E	-119.46388243	57.57699421	1,879,825
AB	LATHOM	UPPER MANNVILLE F	-112.42459913	50.70517141	1,250,384
AB	LATHOM	UPPER MANNVILLE G	-112.37840287	50.71506964	1,409,882
AB	LATHOM	UPPER MANNVILLE R	-112.34753428	50.67377887	2,573,658
AB	LELAND	GETHING A	-117.65529594	54.16757917	1,098,757
AB	LEO	LOWER MANNVILLE E	-112.48127009	52.07738230	1,890,131
AB	LITTLE BOW	UPPER MANNVILLE A	-112.67365975	50.25186532	2,404,467
AB	LONE PINE CREEK	WABAMUN A	-113.88024907	51.55890577	38,159,267
AB	LONE PINE CREEK	WABAMUN B	-113.72042837	51.52508491	1,288,115
AB	LONE PINE CREEK	WABAMUN E	-113.98522896	51.69265149	1,262,656
AB	LONG COULEE	GLAUCONITIC H	-112.91599312	50.40247983	1,695,565
AB	LONG COULEE	GLAUCONITIC Z	-112.78816997	50.31731160	1,007,115
AB	LONG COULEE	GLAUCONITIC LL	-112.95997564	50.36099104	1,785,921
AB	LONG COULEE	SAWTOOTH B	-112.81562792	50.39300732	1,068,395
AB	MAJEAU	UPPER MANNVILLE C	-114.37796005	53.96537482	1,533,413
AB	MAJORVILLE	UPPER MANNVILLE E	-112.66355912	50.60369770	1,214,610
AB	MAJORVILLE	UPPER MANNVILLE J	-112.55909044	50.55728723	1,065,535
AB	MAJORVILLE	UPPER MANNVILLE K	-112.60191267	50.62277136	2,431,152
AB	MAJORVILLE	UPPER MANNVILLE L	-112.62506868	50.62293098	1,411,533
AB	MALMO	ELLERSLIE C	-113.12358111	52.75560525	1,282,115
AB	MALMO	D-3 B	-113.13040911	52.74325096	2,763,796
AB	MARKERVILLE	ELLERSLIE E	-114.22003914	52.14195848	1,407,185
AB	MARKERVILLE	PEKISKO A	-114.27448287	52.05903415	5,663,991
AB	MCGREGOR	GLAUCONITIC C	-112.71937617	50.47008804	1,187,602
AB	MCLEOD	CARDIUM D	-116.05658676	53.77781983	2,265,777
AB	MCLEOD	GETHING D	-116.07656901	53.77289411	2,869,869
AB	MCLEOD	GETHING O	-116.02784007	53.93275306	1,378,244
AB	MCLEOD	GETHING GG	-116.10863503	53.88656106	4,069,707
AB	MEDICINE HAT	LOWER MANNVILLE O	-111.12983696	49.68158145	1,303,988
AB	MEDICINE LODGE	CARDIUM F	-117.08466282	53.57739038	1,071,850

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	MEDICINE LODGE	VIKING A	-117.03197499	53.52544483	3,969,629
AB	MEDICINE RIVER	BASAL QUARTZ C	-114.41192574	52.41104158	1,410,137
AB	MEDICINE RIVER	BASAL QUARTZ Z	-114.27764059	52.34119975	1,491,821
AB	MEDICINE RIVER	BASAL QUARTZ LL	-114.37357289	52.39065738	2,738,567
AB	MEDICINE RIVER	JURASSIC M	-114.32560004	52.39940553	2,526,243
AB	MEDICINE RIVER	PEKISKO P	-114.21765129	52.33386971	1,876,255
AB	MEDICINE RIVER	PEKISKO Z	-114.21216569	52.30210142	1,383,807
AB	MINEHEAD	CARDIUM I	-116.45625287	53.15298562	2,715,894
AB	MINEHEAD	CARDIUM J	-116.45625287	53.15298562	1,539,268
AB	MINEHEAD	CARDIUM K	-116.45141614	53.14136646	1,412,607
AB	MINNEHIK-BUCK LAKE	PEKISKO A	-114.72087909	52.90817473	65,935,148
AB	MORINVILLE	LOWER MANNVILLE E	-113.59236079	53.83991205	1,426,809
AB	MORNINGSIDE	GLAUCONITIC D	-113.95728284	52.54005351	4,658,538
AB	MORNINGSIDE	ELLERSLIE F	-113.93937719	52.60178722	1,672,191
AB	NEWTON	UPPER MANNVILLE A	-114.43637104	54.00970420	1,100,865
AB	NITON	BASAL QUARTZ P	-115.58631921	53.63564849	1,091,150
AB	NORTHVILLE	JURASSIC D	-115.45719078	53.50588214	1,154,062
AB	OAK	KISKATINAW A	-118.81802415	56.23999664	1,116,420
AB	OBED	VIKING A	-117.19934121	53.58706008	1,114,157
AB	OBERLIN	MANNVILLE E	-112.87406871	52.26667842	1,800,434
AB	OKOTOKS	WABAMUN B	-113.85764295	50.73152722	22,900,669
AB	OLDMAN	CARDIUM A	-117.08589181	53.75194747	1,123,707
AB	OLDMAN	TRIASSIC A	-117.01545689	53.84709448	3,048,051
AB	PADDLE RIVER	JURASSIC DETR-RUND	-115.18780350	53.86593650	22,571,673
AB	PADDLE RIVER	JURASSIC DETRITAL&RUN	-115.13953380	53.89037162	4,744,209
AB	PARKLAND NORTHEAST	GLAUCONITIC A	-113.66264270	50.23870126	1,582,890
AB	PARKLAND NORTHEAST	GLAUCONITIC B	-113.51189442	50.23009297	3,708,658
AB	PECO	GETHING A	-116.23474121	53.14047394	10,315,372
AB	PEDIGREE	BLUESKY-MONTNEY A	-119.87496233	57.69721399	8,556,014
AB	PEMBINA	BELLY RIVER A	-114.49473558	53.16515161	1,741,726
AB	PEMBINA	ELLERSLIE PPP	-115.07325012	53.04953171	1,616,527
AB	PEMBINA	JURASSIC W	-115.33009321	53.22144911	1,201,166
AB	PEMBINA	JURASSIC YY	-115.35454614	53.11229143	1,039,110

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	PEMBINA	JURASSIC GGG	-114.72069520	53.22144855	1,981,724
AB	PEMBINA	JURASSIC MMM	-114.82521801	53.19958851	2,182,949
AB	PEMBINA	JURASSIC NNN	-114.76961514	53.18796078	2,289,992
AB	PEMBINA	JURASSIC WWW	-115.41145315	53.08800728	1,040,101
AB	PEMBINA	BANFF E	-114.45761079	53.06276529	1,549,962
AB	PEMBINA	NISKU DD	-115.33017015	53.15592747	1,041,426
AB	PENHOLD	LOWER MANNVILLE B	-113.82595781	52.13565355	2,166,509
AB	PEORIA	MONTNEY A	-118.24618473	55.58504423	1,010,776
AB	PINE CREEK	BELLY RIVER C	-116.80503828	53.74711379	1,376,819
AB	PINE CREEK	BLUESKY D	-116.44102484	53.71385606	2,446,924
AB	PINE CREEK	ELKTON A	-116.57803330	53.75198182	1,591,121
AB	PINE CREEK	WABAMUN	-116.71918487	53.95264258	5,411,755
AB	PINE CREEK	WABAMUN B	-116.74732185	53.90999239	15,906,070
AB	PINE CREEK	WABAMUN C	-116.84636672	53.82955017	8,610,747
AB	PINE CREEK	D-3	-116.75026694	53.97742312	18,844,625
AB	PINE CREEK	D-3 D	-116.88771103	54.03665642	5,504,536
AB	PLANTE	CARDIUM A	-117.13116380	53.75012550	1,669,092
AB	POUCE COUPE	BALDONNEL D	-119.94045346	55.96341478	2,921,480
AB	POUCE COUPE	BALDONNEL F	-119.82746120	55.94156675	1,788,208
AB	POUCE COUPE	TAYLOR FLAT A	-119.82744610	55.91979945	1,662,255
AB	POUCE COUPE	KISKATINAW F	-119.83398413	55.90162674	1,921,909
AB	POUCE COUPE	KISKATINAW H	-119.78829193	55.91249276	2,033,702
AB	POUCE COUPE SOUTH	PEACE RIVER A	-119.64405822	55.71170840	1,467,001
AB	POUCE COUPE SOUTH	PEACE RIVER B	-119.89570643	55.74422224	1,509,056
AB	POUCE COUPE SOUTH	GETHING A	-119.67835205	55.71002615	1,528,168
AB	POUCE COUPE SOUTH	GETHING E	-119.52593990	55.67225533	1,088,852
AB	POUCE COUPE SOUTH	GETHING G	-119.84922025	55.73764511	1,083,211
AB	POUCE COUPE SOUTH	CADOMIN E	-119.59059112	55.71589595	2,203,736
AB	POUCE COUPE SOUTH	BALDONNEL B	-119.51666997	55.69721930	2,516,582
AB	POUCE COUPE SOUTH	HALFWAY A	-119.76640346	55.72466088	1,940,490
AB	POUCE COUPE SOUTH	HALFWAY D	-119.51823395	55.65185052	1,554,458
AB	POUCE COUPE SOUTH	DOIG B	-119.60427893	55.74413628	7,509,098
AB	POUCE COUPE SOUTH	MONTNEY A	-119.63419285	55.64362511	7,443,827

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	PREVO	PEKISKO B	-114.12973789	52.35817353	3,019,253
AB	PRINCESS	BASAL MANNVILLE E	-111.54713358	50.69337966	1,168,117
AB	PRINCESS	JEFFERSON B	-111.55896776	50.68790714	5,538,468
AB	PROGRESS	GETHING B	-119.43535623	55.78141225	1,331,801
AB	PROGRESS	GETHING F	-119.51938623	55.76315082	1,013,819
AB	PROGRESS	BALDONNEL C	-119.42507204	55.69259220	1,728,071
AB	PROGRESS	HALFWAY A	-119.27789291	55.70270338	14,045,592
AB	PROGRESS	HALFWAY F	-119.39920003	55.72167595	1,019,517
AB	PROGRESS	HALFWAY AA	-119.37040699	55.84707843	1,083,139
AB	PROGRESS	HALFWAY BB	-119.33203905	55.67948918	1,121,217
AB	PROGRESS	HALFWAY CC	-119.22866815	55.70854574	1,002,451
AB	PROGRESS	DOIG D	-119.32694195	55.66065568	1,111,926
AB	PROVOST	UPPER MANNVILLE AA	-111.50925440	51.76892304	4,054,861
AB	PROVOST	LOWER MANNVILLE I	-111.87400129	52.19385808	1,168,767
AB	PROVOST	LOWER MANNVILLE EE	-112.14393620	52.08718087	1,578,633
AB	RAINBOW	KEG RIVER FFF	-119.04656195	58.39071489	1,421,322
AB	RAINBOW SOUTH	SULPHUR POINT A	-119.36733174	58.32523168	1,059,104
AB	RED ROCK	FALHER E	-119.37258884	54.63976469	2,115,898
AB	RED ROCK	FALHER G	-119.54908842	54.62525015	1,243,213
AB	REDLAND	UPPER MANNVILLE A	-113.06032030	51.29050440	3,135,115
AB	RETLAW	BASAL COLORADO B	-112.39702555	50.08358026	2,861,640
AB	RETLAW	MANNVILLE J	-112.38184400	50.05518816	1,036,699
AB	RETLAW	MANNVILLE X	-112.41827447	50.02020144	1,514,018
AB	RETLAW	MANNVILLE Y	-112.47858377	50.00784062	4,501,341
AB	RETLAW	MANNVILLE Z	-112.54562387	49.98539526	1,037,674
AB	RETLAW	MANNVILLE G2G	-112.32500477	49.98238711	1,818,411
AB	RETLAW	MANNVILLE A3A	-112.49562092	50.06240686	4,632,933
AB	RETLAW	MANNVILLE B3B	-112.57154056	49.93406110	1,068,622
AB	RICH	GLAUCONITIC F	-112.95118739	52.04094485	4,410,190
AB	RICH	GLAUCONITIC G	-112.92866534	51.99242710	1,335,446
AB	RICHDALE	UPPER MANNVILLE B	-111.77311705	51.71920061	1,572,286
AB	RICHDALE	UPPER MANNVILLE X	-111.67069974	51.65531678	1,004,185
AB	RICHDALE	LOWER MANNVILLE T	-111.82552298	51.65775883	1,416,854

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	RICHDALE	LOWER MANNVILLE JJ	-111.55257376	51.69255256	2,021,791
AB	ROBIN	GLAUCONITIC A	-112.69093760	50.14790730	2,018,899
AB	ROBIN	GLAUCONITIC B	-112.71550816	50.11815259	1,046,291
AB	ROSEVEAR	BELLOY A	-116.23580897	53.73262309	1,128,148
AB	ROSEVEAR	BEAVERHILL LAKE A	-116.11463921	53.70832236	14,858,976
AB	ROSEVEAR	BEAVERHILL LAKE B	-116.10235596	53.64696331	10,732,146
AB	ROWLEY	PEKISKO A	-112.76962275	51.72627825	1,959,668
AB	ROYCE	WABAMUN A	-118.98951004	56.25456903	1,563,068
AB	RYCROFT	GETHING D	-118.73741084	55.65770949	2,126,835
AB	SADDLE HILLS	PADDY B	-118.94219183	55.46875579	2,978,406
AB	SADDLE HILLS	CADOTTE E	-118.96529428	55.48624999	1,017,150
AB	SAKWATAMAU	UPPER MANNVILLE B	-115.96407318	54.34860405	1,080,265
AB	SEIU LAKE	UPPER MANNVILLE A	-112.46109835	51.15923856	3,195,391
AB	SHANE	KISKATINAW B	-118.23893031	55.70132551	3,490,041
AB	SHANE	KISKATINAW C	-118.27222400	55.74490990	1,066,133
AB	SIMONETTE	DUNVEGAN F	-117.76213783	54.39871902	5,285,429
AB	SIMONETTE	GETHING A	-117.85948883	54.38262235	2,171,562
AB	SIMONETTE	GETHING J	-117.89691201	54.40207990	1,082,963
AB	SIMONETTE	WABAMUN A	-117.80525190	54.39709038	2,231,073
AB	SINCLAIR	PADDY D	-119.71370720	55.35716383	1,519,582
AB	SINCLAIR	HALFWAY H	-119.75652285	55.30872146	2,734,757
AB	SINCLAIR	DOIG A	-119.71862012	55.34013426	20,900,912
AB	SINCLAIR	MONTNEY A	-119.75015318	55.41411322	4,297,543
AB	SINCLAIR	MONTNEY D	-119.81635333	55.38623118	1,033,191
AB	SMOKY	CARDIUM B	-118.30999012	54.04305528	1,577,635
AB	SMOKY	CARDIUM C	-118.40013078	54.08678349	1,152,257
AB	SNOWFALL	SLAVE POINT B	-119.27246094	57.57699372	1,373,089
AB	SOUNDING	UPPER MANNVILLE B	-111.21239550	51.61260012	1,206,918
AB	ST ALBERT-BIG LAKE	OSTRACOD A	-113.73423031	53.61369265	11,677,034
AB	ST ALBERT-BIG LAKE	BASAL QUARTZ B	-113.70956416	53.63127085	2,189,864
AB	ST ANNE	UPPER MANNVILLE B	-114.59397121	53.65326493	1,074,732
AB	STANMORE	UPPER MANNVILLE T	-111.51700572	51.38698407	1,785,599
AB	STANMORE	UPPER MANNVILLE CCC	-111.47014585	51.48155706	1,591,032

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	STANMORE	UPPER MANNVILLE KKK	-111.50141053	51.36991990	1,159,311
AB	STETTLER	UPPER MANNVILLE G	-112.85028110	52.26667934	1,084,115
AB	STETTLER NORTH	LOWER MANNVILLE B	-112.73983001	52.36124917	1,108,043
AB	STRACHAN	GLAUCONITIC B	-115.13456691	52.22436132	2,425,535
AB	STRACHAN	GLAUCONITIC D	-115.18009913	52.25345533	1,194,115
AB	STRATHMORE	VIKING B	-113.40972870	50.87602563	1,173,337
AB	STROME	ELLERSLIE K	-112.28740666	52.71274396	2,099,970
AB	SUFFIELD	UPPER MANNVILLE I	-111.11121361	50.47053221	7,991,347
AB	SULLIVAN LAKE	UPPER MANNVILLE B	-111.83833306	52.01182693	1,876,526
AB	SUNCHILD	ELKTON-SHUNDA A	-115.52790786	52.76517137	1,164,137
AB	SUNDANCE	VIKING A	-116.95423100	53.69381172	6,984,466
AB	SUNDANCE	TRIASSIC A	-117.03553805	53.64282544	1,309,987
AB	SUNNYNOOK	UPPER MANNVILLE B	-111.34230757	51.23420028	2,724,476
AB	SUNNYNOOK	UPPER MANNVILLE U	-111.37709829	51.24881016	1,103,455
AB	SUNNYNOOK	BASAL MANNVILLE J	-111.32683450	51.23240170	1,524,034
AB	SUNNYNOOK	BASAL MANNVILLE V	-111.38501730	51.16689980	1,256,637
AB	SUPERBA	GLAUCONITIC B	-110.33358749	51.27912075	1,929,812
AB	SUPERBA	GLAUCONITIC C	-110.43068653	51.22527859	1,045,796
AB	SWALWELL	VIKING A	-113.32467674	51.50271490	2,010,051
AB	SYLVAN LAKE	LOWER MANNVILLE A	-114.37471773	52.25105996	4,310,822
AB	SYLVAN LAKE	JURASSIC HH	-114.37553439	52.21852729	3,534,332
AB	SYLVAN LAKE	ELKTON-SHUNDA A	-114.34382605	52.21619662	4,705,354
AB	SYLVAN LAKE	ELKTON-SHUNDA M	-114.32313507	52.20259267	1,128,329
AB	SYLVAN LAKE	SHUNDA B	-114.35882595	52.26081899	1,479,036
AB	TANGENT	DEBOLT B	-117.48567199	55.91971004	1,531,390
AB	TEEPEE	MONTNEY A	-118.51557909	55.32038861	1,693,281
AB	THORSBY	GLAUCONITIC D	-114.02392583	53.23155176	1,297,440
AB	THORSBY	GLAUCONITIC H	-113.98086521	53.27720876	2,508,393
AB	THORSBY	GLAUCONITIC I	-114.07509581	53.23588976	1,081,582
AB	THREE HILLS CREEK	ELLERSLIE C	-113.64241015	52.11070556	1,210,533
AB	THREE HILLS CREEK	PEKISKO	-113.55015577	51.98929655	10,772,050
AB	TWO CREEK	VIKING A	-116.42040990	54.50741314	1,135,221
AB	TWO CREEK	NOTIKEWIN A	-116.27861817	54.41176112	1,707,300

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	TWO CREEK	NOTIKEWIN B	-116.32678998	54.42326786	2,473,484
AB	VALHALLA	PADDY C	-119.26180994	55.63490496	1,623,974
AB	VALHALLA	BLUESKY J	-119.11225110	55.62500047	1,979,094
AB	VALHALLA	BLUESKY K	-119.23504596	55.51409867	1,457,187
AB	VALHALLA	BLUESKY L	-119.25443327	55.46873165	1,097,763
AB	VALHALLA	BLUESKY Q	-118.99082189	55.63742025	1,037,892
AB	VALHALLA	HALFWAY B	-119.19436260	55.35048340	13,166,019
AB	VALHALLA	MONTNEY H	-119.28407280	55.55663536	1,040,381
AB	VALHALLA	MONTNEY L	-119.18545504	55.47799244	4,033,715
AB	VALHALLA	MONTNEY Y	-119.15098616	55.49055457	2,252,515
AB	VALHALLA	MONTNEY Z	-119.25441694	55.54136104	1,048,598
AB	VAUXHALL	UPPER MANNVILLE B	-112.29087810	49.97506561	2,062,253
AB	VERGER	BASAL COLORADO A	-112.05837986	50.85926102	2,702,562
AB	VERGER	MANNVILLE D	-111.99831393	50.93416148	1,287,106
AB	VERGER	UPPER MANNVILLE U	-111.74762690	50.90678440	1,177,080
AB	WAPITI	CADOTTE L	-119.34814495	54.85787015	1,518,946
AB	WAPITI	CADOTTE T	-119.63472004	54.72999065	1,251,180
AB	WAPITI	NOTIKEWIN A	-119.56419425	54.81422883	1,049,646
AB	WAPITI	NOTIKEWIN D	-119.47103097	54.80448733	2,293,140
AB	WAPITI	NOTIKEWIN H	-119.38626879	54.81421860	2,185,635
AB	WAPITI	NOTIKEWIN I	-119.32272317	54.81424376	1,786,413
AB	WAPITI	NOTIKEWIN L	-119.64044203	54.78513649	1,425,074
AB	WAPITI	NOTIKEWIN M	-119.76301750	54.79060120	1,389,621
AB	WAPITI	NOTIKEWIN N	-119.13203403	54.84330623	1,353,329
AB	WAPITI	FALHER A-1	-119.23376480	54.85785126	1,162,260
AB	WAPITI	FALHER A-5	-119.27609335	54.86269172	1,340,047
AB	WAPITI	FALHER A-6	-118.92857420	54.86506394	1,341,306
AB	WAPITI	FALHER A-10	-119.84378837	54.78515069	1,205,908
AB	WAPITI	FALHER C-1	-119.32273132	54.78514994	4,632,941
AB	WAPITI	FALHER C-2	-119.14475309	54.79967159	1,972,620
AB	WAPITI	FALHER C-3	-119.20834405	54.78511094	2,236,603
AB	WAPITI	FALHER C-4	-119.47522721	54.78033506	1,433,881
AB	WAPITI	FALHER E-1	-118.99467497	54.73802154	5,543,617

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	WAPITI	FALHER F-1	-119.10607091	54.70424098	11,946,439
AB	WAPITI	CADOMIN B	-119.00487533	54.84331316	1,618,637
AB	WASKAHIGAN	DUNVEGAN B	-117.52432973	54.46643337	4,591,940
AB	WASKAHIGAN	PEACE RIVER B	-117.43511185	54.46917318	2,252,619
AB	WASKAHIGAN	PEACE RIVER E	-117.56199588	54.43604640	1,095,734
AB	WAYNE-ROSEDALE	VIKING B	-112.68252571	51.27876941	2,058,910
AB	WAYNE-ROSEDALE	BASAL COLORADO A	-112.48959412	51.35057097	1,009,271
AB	WAYNE-ROSEDALE	GLAUCONITIC A	-112.74041715	51.42622115	3,245,330
AB	WAYNE-ROSEDALE	GLAUCONITIC G	-112.75914831	51.36506834	2,742,255
AB	WAYNE-ROSEDALE	GLAUCONITIC I	-112.78257773	51.39414274	1,037,244
AB	WAYNE-ROSEDALE	GLAUCONITIC T	-112.41310919	51.24807402	1,659,762
AB	WAYNE-ROSEDALE	GLAUCONITIC T	-112.41310919	51.24807402	4,742,437
AB	WAYNE-ROSEDALE	OSTRACOD A	-112.73569521	51.33598846	2,208,063
AB	WAYNE-ROSEDALE	OSTRACOD E	-112.54697396	51.22257035	1,221,221
AB	WAYNE-ROSEDALE	BASAL QUARTZ EEE	-112.40758524	51.32516063	1,088,470
AB	WEMBLEY	HALFWAY X	-119.11559315	55.35964751	2,015,845
AB	WEMBLEY	MONTNEY B	-119.12207808	55.37053634	1,168,864
AB	WESTEROSE SOUTH	BANFF E	-114.24503296	52.94010770	1,029,884
AB	WESTEROSE SOUTH	D-1 B	-114.11053509	52.75614035	1,446,165
AB	WESTEROSE SOUTH	D-3 A	-114.05519868	52.82276037	119,725,631
AB	WESTLOCK	LOWER MANNVILLE B	-113.81072211	54.19278246	1,892,844
AB	WESTPEM	OSTRACOD L	-115.99541489	53.34705946	2,076,078
AB	WESTPEM	NISKU E	-115.79332700	53.22868600	2,436,935
AB	WHITECOURT	JURASSIC C	-115.55994401	54.23468339	7,137,953
AB	WHITECOURT	JURASSIC D	-115.60960380	54.18460335	4,412,849
AB	WHITECOURT	PEKISKO E	-115.57800286	54.18966842	6,726,254
AB	WHITEHORSE	NISKU B	-116.15902708	53.33049219	1,992,740
AB	WILDHAY	CARDIUM A	-117.58149007	53.75914465	1,231,050
AB	WILDUNN CREEK	VIKING B	-111.87020930	51.47477368	1,896,044
AB	WILLESDEN GREEN	GLAUCONITIC SS Undefined	-114.62165820	52.60865520	1,212,228
AB	WILLESDEN GREEN	BANFF A	-115.22264915	52.71970833	1,546,009
AB	WILLESDEN GREEN	BANFF C	-115.22264918	52.73425526	1,189,455
AB	WILLESDEN GREEN	BANFF E	-115.22265578	52.76335349	1,141,794

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
AB	WILSON CREEK	PEKISKO A	-114.55277258	52.70993210	4,720,390
AB	WILSON CREEK	BANFF C	-114.48020932	52.72145824	2,221,900
AB	WINDFALL	WINTERBURN A	-116.28895612	54.13041826	2,708,764
AB	WINDFALL	WINTERBURN D	-116.31395017	54.14497590	1,378,886
AB	WINTERING HILLS	VIKING E	-112.35175324	51.05091554	1,248,441
AB	WIZARD LAKE	BASAL QUARTZ A	-113.85822261	53.16567904	1,088,417
AB	WOLF SOUTH	ROCK CREEK B	-116.18834696	53.41884343	2,470,889
AB	WOOD RIVER	LOWER MANNVILLE B	-113.29370882	52.70512549	1,402,237
AB	WORSLEY	D-3 A	-119.03870419	56.55186609	1,509,614
AB	WORSLEY	D-3 D	-118.73260504	56.55183975	2,629,422
AB	WORSLEY	D-3 E	-118.63915980	56.55914273	1,306,194
AB	WORSLEY	D-3 G	-119.11589816	56.55624430	1,521,483
AB	WORSLEY	D-3 W	-118.67915307	56.55915153	1,100,306
AB	WORSLEY	GRANITE WASH A	-119.05200999	56.58825536	1,507,538
AB	ZAMA	SULPHUR POINT H	-118.68834719	59.15156106	1,032,315
BC	ADSETT	SLAVE POINT A	-122.69062000	58.11041700	4,147,573
BC	ADSETT	SLAVE POINT B	-122.67188000	58.15208300	1,910,755
BC	AITKEN CREEK NORTH	BLUESKY A	-122.00938000	57.03541700	3,148,876
BC	ALCES	KISKATINAW A	-120.19553320	56.22383740	2,242,217
BC	ATTACHIE	BASAL KISKATINAW A	-121.43365530	56.29646360	2,460,656
BC	BEAR FLAT	HALFWAY B	-121.09119600	56.32916340	1,849,378
BC	BEAVERDAM	UPPER HALFWAY A	-120.45312000	56.94791700	1,195,482
BC	BEAVERTAIL	HALFWAY E	-120.72187000	56.82708300	1,111,690
BC	BEG	BALDONNEL A	-122.05938000	56.93541700	1,973,901
BC	BEG	BALDONNEL C	-122.41563000	57.25208300	2,651,573
BC	BIRCH	BALDONNEL A	-121.54688000	56.93125000	1,589,810
BC	BLUEBERRY	DUNLEVY A	-121.83100430	56.64888330	9,524,608
BC	BLUEBERRY	DUNLEVY B	-121.89687000	56.78125000	6,804,388
BC	BLUEBERRY	BALDONNEL B	-121.95312000	56.82291700	2,320,887
BC	BLUEBERRY	HALFWAY B	-121.95312000	56.83125000	4,781,533
BC	BLUEBERRY EAST	BALDONNEL A	-121.84687000	56.77708300	1,495,732
BC	BOUNDARY LAKE	GETHING A	-120.12951310	56.35825000	1,151,461
BC	BOUNDARY LAKE	COPLIN A	-120.02971990	56.51809140	1,177,704

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
BC	BOUNDARY LAKE	HALFWAY B	-120.00969830	56.51447830	1,564,167
BC	BOUNDARY LAKE	BELLOY I	-120.16919020	56.28201060	4,173,342
BC	BOUNDARY LAKE	BELLOY K	-120.11650420	56.31109720	3,637,718
BC	BOUNDARY LAKE	BELLOY O	-120.22187630	56.31109720	1,019,383
BC	BOUNDARY LAKE	BASAL KISKATINAW	-120.22838070	56.30007680	2,286,497
BC	BOUNDARY LAKE NORTH	HALFWAY B	-120.19580040	56.52893050	1,733,473
BC	BUBBLES	BALDONNEL A	-122.03437000	57.19375000	11,302,725
BC	BUBBLES NORTH	BALDONNEL/UPPER CHARLIE LAKE A	-122.22813000	57.33125000	7,575,240
BC	BUBBLES NORTH	HALFWAY A	-122.17812000	57.33125000	1,926,871
BC	BUBBLES NORTH	HALFWAY C	-122.10938000	57.31458300	1,364,301
BC	BUICK CREEK	DUNLEVY H	-120.90313000	56.79791700	1,186,525
BC	BUICK CREEK	NORTH PINE A	-121.04688000	56.70208300	1,816,984
BC	BUICK CREEK WEST	BLUESKY A	-121.47813000	56.90208300	2,003,962
BC	CABIN	SLAVE POINT B	-121.72813000	59.34375000	2,098,510
BC	CABIN	SLAVE POINT C	-121.62188000	59.27708300	1,222,729
BC	CABIN	SLAVE POINT E	-121.52813000	59.23125000	1,636,502
BC	CACHE CREEK	COPLIN A	-121.44534300	56.65990300	2,718,987
BC	CACHE CREEK	COPLIN B	-121.60313000	56.73125000	1,342,546
BC	CACHE CREEK	HALFWAY A	-121.44534300	56.65990300	5,386,102
BC	CECIL LAKE	GETHING A	-120.64336460	56.28923710	1,154,852
BC	CHINCHAGA RIVER	BLUESKY-GETHING-DETRITAL A	-120.02187000	57.33541700	2,093,938
BC	CHINCHAGA RIVER	LOWER CHARLIE LAKE/MONTNEY A	-120.09063000	57.31041700	1,326,953
BC	CHINCHAGA RIVER	SLAVE POINT A	-120.06562000	57.31458300	1,438,866
BC	CLARKE LAKE	SLAVE POINT B	-122.85938000	58.65625000	1,671,571
BC	CLARKE LAKE	PINE POINT C	-122.75312000	58.69791700	2,276,916
BC	CLARKE LAKE	PINE POINT D	-122.74062000	58.71458300	1,119,350
BC	CLARKE LAKE	PINE POINT E	-122.85313000	58.73541700	1,119,309
BC	CUTBANK	PADDY C	-120.20937000	55.32708300	1,404,861
BC	DOE	GETHING A	-120.00598230	55.93981970	1,356,534
BC	DOE	BALDONNEL A	-120.01919600	55.96168100	2,273,540
BC	DOE	WABAMUN A	-120.20837660	55.99438280	3,301,128
BC	EKWAN	JEAN MARIE A	-120.78437000	58.54375000	5,281,930
BC	FIREWEED	BLUESKY B	-121.47187000	56.80208300	1,163,352

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
BC	FIREWEED	DUNLEVY B	-121.55312000	56.88125000	1,312,998
BC	FIREWEED	DUNLEVY H	-121.67188000	56.83541700	2,447,180
BC	FIREWEED	BALDONNEL E	-121.59687000	56.78541700	1,766,411
BC	FLATROCK	HALFWAY G	-120.49181090	56.28562390	1,799,038
BC	FLATROCK WEST	HALFWAY C	-120.54449700	56.35463680	2,184,247
BC	FORT ST JOHN	BALDONNEL A	-120.75524120	56.20197730	12,533,550
BC	FORT ST JOHN	HALFWAY A	-120.79491830	56.20559050	7,117,805
BC	FORT ST JOHN	HALFWAY C	-120.86061320	56.27099020	1,035,527
BC	FORT ST JOHN	LOWER BELLOY A	-120.81443170	56.22022420	1,483,429
BC	FORT ST JOHN SOUTHEAST	BALDONNEL A	-120.60368750	56.17650390	3,165,274
BC	FORT ST JOHN SOUTHEAST	HALFWAY A	-120.59350580	56.15427790	4,130,526
BC	FORT ST JOHN SOUTHEAST	BELLOY A	-120.60368750	56.17650390	7,295,931
BC	GUNDY CREEK WEST	DUNLEVY A	-122.15937000	56.76041700	1,829,034
BC	GUNDY CREEK WEST	BALDONNEL A	-122.15937000	56.76041700	1,165,148
BC	GUNNELL CREEK	JEAN MARIE A	-121.78437000	58.81875000	17,655,239
BC	HALFWAY	BALDONNEL A	-121.85069760	56.51447830	1,356,971
BC	HELMET	JEAN MARIE A	-120.81562000	59.41875000	1,390,154
BC	HELMET	JEAN MARIE F	-120.97187000	59.51458300	3,700,656
BC	HELMET	SLAVE POINT A	-120.73438000	59.36875000	9,076,760
BC	HELMET	SLAVE POINT B	-120.60313000	59.31458300	1,362,057
BC	HELMET NORTH	JEAN MARIE A	-120.50312000	59.84791700	18,884,202
BC	HIDING CREEK	FALHER C B	-120.03437000	54.79375000	1,691,375
BC	HOFFARD	SLAVE POINT B	-122.04063000	58.68958300	1,654,269
BC	HOFFARD	SLAVE POINT D	-122.17812000	58.71875000	1,767,850
BC	HOSSITL	SLAVE POINT A	-121.14687000	59.90208300	2,608,129
BC	HOSSITL	SLAVE POINT G	-121.21563000	59.99375000	1,247,501
BC	HOSSITL	SLAVE POINT H	-121.15313000	59.91875000	1,170,116
BC	HOSSITL	SLAVE POINT I	-121.14062000	59.89375000	1,132,648
BC	INGA	DUNLEVY A	-121.67812000	56.79791700	1,148,034
BC	INGA	DUNLEVY D	-121.72187000	56.81458300	1,060,478
BC	INGA	BALDONNEL B	-121.59821790	56.48561680	1,828,606
BC	INGA	HALFWAY E	-121.70312000	56.78541700	3,254,784
BC	JEDNEY	HALFWAY D	-122.39687000	57.38541700	1,001,547

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO$_2$ STORAGE CAPACITY (tonnes)
BC	JEDNEY WEST	HALFWAY A	-122.29688000	57.23541700	1,248,838
BC	KLUA	SLAVE POINT B	-122.30312000	58.64791700	3,889,299
BC	KLUA	SLAVE POINT D	-122.29063000	58.56458300	2,171,413
BC	KLUA	PINE POINT A	-122.23438000	58.59375000	1,386,348
BC	KLUA	PINE POINT D	-122.23438000	58.48541700	2,572,741
BC	KLUA	PINE POINT E	-122.19062000	58.47708300	1,031,383
BC	KLUA	PINE POINT H	-122.27187000	58.48541700	1,607,699
BC	KLUA	PINE POINT J	-122.27187000	58.45625000	1,239,528
BC	KLUA	PINE POINT L	-122.19688000	58.44375000	1,626,828
BC	KLUA	PINE POINT M	-122.22813000	58.45208300	1,659,532
BC	KOBES	CHARLIE LAKE B	-122.04063000	56.49791700	1,967,932
BC	KOBES	DEBOLT C	-122.10313000	56.57708300	3,123,478
BC	KOTCHO LAKE	SLAVE POINT A	-121.33437000	58.97291700	3,632,237
BC	KOTCHO LAKE EAST	SLAVE POINT B	-121.15937000	58.95208300	1,655,326
BC	KOTCHO LAKE EAST	SLAVE POINT C	-121.12812000	58.89791700	4,761,909
BC	LADYFERN	SLAVE POINT A	-120.07812000	57.16041700	33,115,670
BC	LADYFERN	SLAVE POINT B	-120.00312000	57.13541700	3,704,380
BC	LAPP	HALFWAY A	-120.89687000	57.53541700	1,274,278
BC	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE A	-122.05312000	57.36041700	61,432,405
BC	LAPRISE CREEK	BALDONNEL/UPPER CHARLIE LAKE B	-121.90313000	57.41458300	12,020,880
BC	LOUISE	SLAVE POINT A	-121.49688000	59.23125000	2,213,379
BC	MARTIN	BALDONNEL A	-121.47813000	57.36458300	1,969,618
BC	MAXHAMISH LAKE	CHINKEH A	-123.13438000	59.79791700	22,980,860
BC	MEL	SLAVE POINT A	-121.59063000	59.17291700	6,053,618
BC	MIDWINTER	JEAN MARIE A	-120.90313000	59.85208300	2,439,061
BC	MIDWINTER	JEAN MARIE C	-120.60313000	59.91875000	3,305,424
BC	MILO	PINE POINT A	-123.08437000	58.64375000	1,126,217
BC	MILO	PINE POINT B	-123.03437000	58.69375000	1,633,647
BC	MONIAS	HALFWAY	-121.20036630	56.11434930	54,003,674
BC	MONIAS	HALFWAY T	-121.29189490	56.05978620	4,922,962
BC	MONIAS	HALFWAY U	-121.39631490	56.02708450	1,925,260
BC	NIG CREEK	BALDONNEL A	-121.72813000	57.06041700	33,550,157
BC	NIG CREEK NORTH	BLUESKY A	-121.62812000	57.20625000	6,112,502

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
BC	NOEL	CADOTTE L	-120.57188000	55.29791700	1,058,406
BC	NOEL	BASAL BLUESKY A	-120.47187000	55.18541700	1,681,325
BC	OAK	BALDONNEL A	-120.72239370	56.44912310	1,186,688
BC	OAK	HALFWAY G	-120.66778420	56.52170440	1,534,727
BC	OSBORN	GETHING A	-120.15313000	56.69375000	1,024,901
BC	PEGGO-PESH	JEAN MARIE A	-120.08437000	59.32708300	10,907,889
BC	PEGGO-PESH	JEAN MARIE B	-120.37812000	59.08958300	1,863,772
BC	PEGGO-PESH	SLAVE POINT A	-120.08437000	59.30625000	1,654,441
BC	PETITOT RIVER	SLAVE POINT A	-121.91563000	59.77291700	2,374,683
BC	RED CREEK	BEAR FLAT A	-121.23592000	56.39835700	1,124,601
BC	RED CREEK	HALFWAY A	-121.23592000	56.39835700	1,237,639
BC	RED CREEK NORTH	HALFWAY A	-121.28210160	56.44550980	1,764,297
BC	RIGEL	DUNLEVY F	-120.62774100	56.65629000	39,652,024
BC	RIGEL	CECIL A	-120.73438000	56.75625000	1,358,896
BC	ROGER	PINE POINT A	-122.61562000	58.76875000	4,600,986
BC	SAHTANEH	JEAN MARIE A	-121.71563000	58.75208300	1,081,523
BC	SAHTANEH	SLAVE POINT B	-121.69062000	58.73958300	1,549,807
BC	SAHTANEH	PINE POINT B	-121.47813000	58.68958300	3,296,732
BC	SEPTIMUS	HALFWAY A	-120.80879140	56.06339970	1,791,022
BC	SEXTET	SLAVE POINT D	-121.62188000	58.66041700	2,958,138
BC	SIERRA	JEAN MARIE A	-121.31562000	58.69375000	4,929,700
BC	SIERRA	SLAVE POINT A	-121.31562000	58.68958300	1,843,946
BC	SIERRA	PINE POINT A	-121.34687000	58.81458300	58,041,890
BC	SIERRA	PINE POINT E	-121.28437000	58.82708300	3,628,407
BC	SIERRA	PINE POINT G	-121.22187000	58.83125000	2,036,297
BC	SIERRA	PINE POINT J	-121.45937000	58.74791700	3,565,200
BC	SILVER	BLUESKY A	-121.27187000	57.46458300	6,153,732
BC	SILVERBERRY	NORTH PINE A	-121.12631080	56.63081810	1,156,211
BC	SIPHON	DUNLEVY A	-120.43262040	56.50006980	3,465,284
BC	SIPHON	HALFWAY A	-120.43912490	56.48923000	1,898,658
BC	STODDART	BELLOY A	-121.02517580	56.46736990	29,368,959
BC	STODDART WEST	HALFWAY B	-121.19656810	56.48923000	1,200,351
BC	STODDART WEST	BELLOY A	-121.15038650	56.48923000	3,377,015

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)
BC	STODDART WEST	BELLOY H	-121.14633240	56.51447830	1,775,300
BC	STODDART WEST	BELLOY I	-121.14633240	56.53254350	1,142,441
BC	SUNDOWN	CADOTTE A	-120.52813000	55.43541700	6,409,377
BC	SWAN LAKE	MONTNEY A	-120.10313000	55.60208300	2,361,749
BC	TOWN	HALFWAY A	-122.23438000	56.97291700	1,211,933
BC	TSEA	SLAVE POINT B	-121.85938000	59.49375000	1,064,747
BC	TSEA	SLAVE POINT C	-121.85938000	59.55208300	1,986,130
BC	TSEA	SLAVE POINT E	-121.85313000	59.58958300	1,335,750
BC	TWO RIVERS	HALFWAY A	-120.46546790	56.18011720	2,923,342
BC	UMBACH	BLUESKY A	-121.35313000	57.14791700	1,140,219
BC	WILDER	HALFWAY A	-120.91980370	56.24551690	7,672,200
BC	WILLOW	HALFWAY A	-120.62188000	57.08541700	1,624,652
BC	WILLOW	HALFWAY B	-120.57812000	57.12291700	1,283,634
SK	BEVERLEY EAST	CANTUAR SAND (VOL UNIT NO. 1)	-108.14720322	50.26631760	1,357,211
SK	GULL LAKE	CANTUAR SAND	-108.52020813	50.12786127	3,152,436
SK	MERRYFLAT	SECOND WHITE SPECKS	-110.00105486	49.49660965	1,093,116

Appendix B- List of oil pools in the Western Canada Sedimentary Basin that are suitable for CO_2-flood EOR and have an estimated effective CO_2-sequestration capacity greater than 1 Mt CO_2 each.

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)		
					AT DEPLETION	IN EOR @ 50% HCPV	TOTAL
AB	KAKWA	A CARDIUM A	-118.70179000	54.41645305	822,020	2,449,709	3,271,729
AB	CHERHILL	BANFF H	-114.77745094	53.86329375	150,328	1,653,093	1,803,421
AB	WAYNE-ROSEDALE	BASAL QUARTZ B	-112.73974566	51.30434283	336,483	1,817,866	2,154,350
AB	LANAWAY	CARDIUM	-114.41122422	52.09150241	120,636	881,730	1,002,366
AB	PEMBINA	CARDIUM	-115.04342700	53.16117932	13,067,517	76,599,256	89,666,773
AB	BONNIE GLEN	CARDIUM A	-113.91102590	52.97441234	126,212	931,377	1,057,589
AB	RICINUS	CARDIUM A	-115.16262803	52.09921052	876,735	1,574,817	2,451,552
AB	ELMWORTH	CHARLIE LAKE A	-118.89733905	54.90422451	237,934	974,217	1,212,151
AB	MANIR	CHARLIE LAKE A	-118.37454192	55.24416977	129,592	958,203	1,087,795
AB	SWALWELL	D-1 A	-113.62187955	51.50171267	141,255	1,610,182	1,751,436
AB	EXCELSIOR	D-2	-113.48330716	53.82089417	705,907	558,282	1,264,190
AB	DRUMHELLER	D-2 A	-112.68054198	51.50648322	678,521	561,235	1,239,756
AB	FENN-BIG VALLEY	D-2 A	-112.76060461	52.06607880	14,717,480	12,326,991	27,044,471
AB	WEST DRUMHELLER	D-2 A	-112.85057757	51.53512140	730,660	2,171,810	2,902,470
AB	WIMBORNE	D-2 A	-113.61969820	51.87569867	104,349	1,116,937	1,221,286
AB	DRUMHELLER	D-2 B	-112.70874772	51.48299798	524,127	1,227,120	1,751,248
AB	LEDUC-WOODBEND	D-2 B	-113.64797227	53.22390478	1,081,517	2,203,938	3,285,455
AB	HOMEGLEN-RIMBEY	D-3	-114.14762074	52.68396373	1,224,196	4,002,244	5,226,439
AB	INNISFAIL	D-3	-114.08343528	51.98472383	7,624,442	6,324,461	13,948,903
AB	STURGEON LAKE	D-3	-117.50406607	55.18215360	2,529,582	3,807,293	6,336,875
AB	STURGEON LAKE SOUTH	D-3	-117.25849202	54.94652773	14,154,213	13,852,411	28,006,624
AB	WESTEROSE	D-3	-113.99572825	52.92786138	9,269,528	12,251,709	21,521,237
AB	BONNIE GLEN	D-3 A	-113.93262493	53.03437422	23,575,113	46,915,441	70,490,554
AB	GLEN PARK	D-3 A	-113.84323937	53.19737513	1,062,966	1,522,090	2,585,056
AB	ST ALBERT-BIG LAKE	D-3 A	-113.71146409	53.60792363	533,223	901,085	1,434,309
AB	WESTEROSE SOUTH	D-3 A	-114.05519868	52.82276037	398,004	1,237,079	1,635,082
AB	WIMBORNE	D-3 A	-113.62093376	51.89718056	2,215,818	3,359,797	5,575,616
AB	WINDFALL	D-3 A	-116.16401717	54.16394513	1,952,112	4,551,199	6,503,310
AB	MORINVILLE	D-3 B	-113.69811978	53.66427615	514,594	501,010	1,015,604

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)		
					AT DEPLETION	IN EOR @ 50% HCPV	TOTAL
AB	WEMBLEY	DOIG E	-119.15100102	55.29714122	165,266	1,078,619	1,243,885
AB	MITSUE	GILWOOD A	-114.56233237	55.21347908	391,620	1,240,624	1,632,244
AB	NIPISI	GILWOOD A	-115.18846112	55.90624247	1,595,807	4,522,588	6,118,394
AB	NIPISI	GILWOOD C	-115.10640820	55.69903564	300,682	943,596	1,244,279
AB	HUSSAR	GLAUCONITIC A	-112.83042139	51.10556577	1,327,374	1,219,942	2,547,315
AB	PROGRESS	HALFWAY B	-119.37915831	55.68243516	242,887	1,389,852	1,632,740
AB	WEMBLEY	HALFWAY B	-119.12004896	55.28815396	1,034,305	4,083,310	5,117,615
AB	RAINBOW SOUTH	KEG RIVER N	-119.57302087	58.29986023	80,989	1,246,184	1,327,173
AB	UTIKUMA LAKE	KEG RIVER SAND A	-115.33728019	56.06029100	2,120,635	4,679,940	6,800,575
AB	UTIKUMA LAKE	KEG RIVER SAND N	-115.35201999	56.02234065	383,517	993,249	1,376,766
AB	RAINBOW	KEG RIVER U	-119.01474814	58.61607911	237,036	948,176	1,185,213
AB	LANAWAY	MANNVILLE	-114.33178675	52.10534878	211,411	813,980	1,025,391
AB	GARRINGTON	MANNVILLE D	-114.57605730	52.04096414	146,475	1,233,928	1,380,404
AB	VALHALLA	MONTNEY B	-119.28783398	55.49482919	80,693	1,031,603	1,112,296
AB	RAINBOW	MUSKEG O	-119.34184995	58.43380966	178,056	1,620,263	1,798,320
AB	WAYNE-ROSEDALE	NISKU A	-112.83476310	51.39119630	424,075	1,061,513	1,485,588
AB	MEDICINE RIVER	PEKISKO N	-114.30467175	52.35537936	237,108	852,036	1,089,145
AB	CAROLINE	RUNDLE A	-114.58197818	51.86191001	681,674	1,631,454	2,313,128
AB	HARMATTAN-ELKTON	RUNDLE C	-114.50613404	51.70883210	2,648,122	6,614,113	9,262,235
AB	MOOSE	RUNDLE C	-114.87947818	50.97189643	443,257	4,569,710	5,012,967
AB	WILLESDEN GREEN	SECOND WHITE SPECKS L	-114.73654185	52.53886644	77,858	1,420,379	1,498,238
AB	CHINCHAGA NORTH	SLAVE POINT A	-119.18208319	57.48475455	468,619	1,193,211	1,661,829
AB	GOLDEN	SLAVE POINT A	-116.21584309	56.52073405	748,298	1,326,436	2,074,734
AB	SLAVE	SLAVE POINT H	-116.07006773	56.25145573	400,024	1,111,462	1,511,486
AB	SLAVE	SLAVE POINT S	-116.11681383	56.28609456	408,504	840,009	1,248,513
AB	STURGEON LAKE SOUTH	TRIASSIC A	-117.18880499	54.95306778	153,955	991,716	1,145,671
AB	ANTE CREEK NORTH	TRIASSIC E	-117.65662389	54.78961543	425,423	4,742,090	5,167,513
AB	STURGEON LAKE SOUTH	TRIASSIC F	-117.70691708	54.98285898	315,072	3,480,462	3,795,534
AB	JUMPBUSH	UPPER MANNVILLE A	-112.65714336	50.69796347	456,618	759,066	1,215,684
AB	WILLESDEN GREEN	VIKING A	-114.72393789	52.46136047	382,864	2,208,295	2,591,159
AB	GARRINGTON	WABAMUN A	-114.13597925	51.75461516	782,888	2,204,982	2,987,870
BC	EAGLE WEST	BELLOY	-120.79491830	56.32555020	7,245,470	4,762,244	12,007,713
BC	EAGLE	BELLOY-KISKATINAW	-120.72889810	56.29646360	2,576,448	1,677,127	4,253,575

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO_2 STORAGE CAPACITY (tonnes)		
					AT DEPLETION	IN EOR @ 50% HCPV	TOTAL
BC	BLUEBERRY	DEBOLT	-121.91563000	56.77708300	848,574	564,471	1,413,045
BC	BLUEBERRY	DEBOLT	-121.86562000	56.70625000	1,299,989	1,719,928	3,019,917
BC	BOUNDARY LAKE	HALFWAY	-120.09666560	56.37288360	689,876	484,766	1,174,642
BC	BUICK CREEK	LOWER HALFWAY	-121.05312000	56.78125000	869,582	802,504	1,672,086
BC	BUICK CREEK	LOWER HALFWAY	-121.07812000	56.68958300	579,875	632,468	1,212,343
BC	BUICK CREEK	LOWER HALFWAY	-121.06562000	56.73958300	1,300,014	1,589,245	2,889,260
MB	PIERSON	MISSION CANYON 3A B	-101.22444200	49.22010000	964,313	51,752	1,016,066
SK	NOTTINGHAM	ALIDA (NORTH ALIDA BEDS UNIT)	-101.76562758	49.43627995	2,477,591	2,026	2,479,617
SK	CARNDUFF	FROBISHER	-101.95394756	49.17219816	2,727,744	1,880	2,729,625
SK	ALIDA WEST	FROBISHER-ALIDA	-101.91815033	49.45326977	2,116,723	3,063	2,119,786
SK	CANTAL SOUTH	FROBISHER-ALIDA	-101.94567989	49.37516070	1,083,369	835	1,084,204
SK	GAINSBOROUGH NORTH	FROBISHER-ALIDA	-101.47793658	49.18073596	1,014,593	1,113	1,015,706
SK	WORDSWORTH	FROBISHER-ALIDA	-102.54635642	49.51903409	1,529,297	1,641	1,530,938
SK	BEMERSYDE	RED RIVER	-103.02419057	50.03992608	3,188,945	406	3,189,351
SK	MIDALE SOUTH	RED RIVER	-103.36861984	49.46164681	1,009,610	859	1,010,468
SK	REDVERS	TILSTON	-101.68486351	49.59925048	9,571,340	75	9,571,415
SK	FRYS	TILSTON-SOURIS VALLEY	-101.54278817	49.59920127	1,176,553	1,077	1,177,629
SK	PARKMAN	TILSTON-SOURIS VALLEY	-101.91353704	49.73318900	5,337,769	6,459	5,344,228
SK	HITCHCOCK	WINNIPEGOSIS	-103.09386868	49.24617649	2,148,602	3,567	2,152,169

Appendix C - List of oil pools in the Western Canada Sedimentary Basin, not suitable for CO$_2$-flood EOR, that have an estimated effective CO$_2$-sequestration capacity greater than 1 Mt CO$_2$ each.

PROVINCE	FIELD NAME	FORMATION OR POOL NAME	LONGITUDE	LATITUDE	ESTIMATED PRACTICAL CO$_2$ STORAGE CAPACITY AT DEPLETION (tonnes)
AB	SUFFIELD	UPPER MANNVILLE J	-111.04309861	50.67563653	1,039,575
AB	BANTRY	MANNVILLE A	-111.63960332	50.47531240	4,067,524
AB	TABER NORTH	GLAUCONITIC A	-112.07482891	49.87965096	1,382,662
AB	BELLSHILL LAKE	BLAIRMORE	-111.68781338	52.55264954	1,787,628
AB	ERSKINE	D-3	-112.88508615	52.34552965	1,494,227
AB	REDWATER	D-3	-113.07520324	53.93209910	20,546,280
BC	STODDART WEST	DOIG	-121.32587000	56.58348730	2,101,616
SK	HANDSWORT	ALIDA	-102.85374404	49.83146490	1,077,232
SK	MIDALE	CENTRAL FROBISHER	-103.38398095	49.47090216	2,050,232
SK	HUNTOON	FROBISHER	-103.19228649	49.53716798	1,551,106
SK	INNES	FROBISHER	-103.33860198	49.60216722	2,111,093
SK	RAPDAN NORTH	LOWER SHAUNAVON	-108.57312637	49.37092617	1,246,488
SK	TATAGWA CENTRAL	MIDALE	-103.99075870	49.45737005	3,468,979
SK	UNION JACK	MIDALE	-103.95975268	49.63546605	3,034,064
SK	CLINTONVILLE	SHAUNAVON	-108.54502518	49.68386163	9,835,091
SK	EASTBROOK	SHAUNAVON	-108.64167124	49.37403918	2,666,584
SK	EASTEND	SHAUNAVON	-108.61796817	49.48012053	13,017,443