The Capacity for Carbon Dioxide Storage in Oil and Gas Pools in Northeastern Alberta

Submitted to:
Alberta Energy Research Institute

By:
Stefan Bachu, Ph.D., P. Eng.
Alberta Geological Survey
Alberta Energy and Utilities Board

July 2006

Disclaimer

The opinions expressed and recommendations made in this report are solely those of the author. They are not necessarily the views of the Alberta Energy and Utilities Board, the author's employer, nor are they intended to represent the views of the Alberta Energy Research Institute, which commissioned this report, or of any employee or agency of the Government of Alberta.

Executive Summary

Carbon dioxide capture from large stationary sources and storage in geological media is a technologically-feasible mitigation measure for the reduction of emissions of anthropogenic CO_2 into the atmosphere in response to climate change as a result of human activity. Carbon dioxide can be sequestered underground in oil and gas reservoirs, deep saline aquifers, uneconomic coal beds and salt caverns. The Alberta Basin, which underlies Alberta, provides a very large capacity for CO_2 storage in oil and gas reservoirs. However, the Athabasca-Cold Lake region in northeastern Alberta has less potential for CO_2 storage because it is shallow, being close to the zero edge of the basin. Because the oil sands plants in the Athabasca area are very large CO_2 emitters, of the order of several megatonnes/year each, plans are being developed to construct a pipeline that would bring CO_2 from the Fort McMurray area to the southwest in central Alberta, where it will connect to a major Alberta CO_2 trunk pipeline.

There are only 15 oil pools in northeastern Alberta, with insignificant CO_2 storage capacity compared with the ~609 Mt CO_2 potential capacity in ~5,300 gas pools. Most of the gas pools are small, with only less than 900 gas pools having CO_2 storage capacity greater than 100 kt CO_2, for a total of ~504 Mt CO_2. Of these, 76 gas pools have capacity greater than 1 Mt CO_2 each, for a total of 292 Mt CO_2. These gas pools are distributed almost evenly across northeastern Alberta, and are found at depths that vary between ~200 and 950 m. Upon depletion, these gas pools can be used for storing the CO_2 emitted by oil sands plants in the Athabasca area, allowing for a few decades of oil production with reduced atmospheric CO_2 emissions.

As a result of Gas-Over-Bitumen disputes between gas and bitumen producers in the Athabasca area, a significant number of gas pools in the McMurray-Wabiskaw sedimentary succession have been shut-in by EUB, or could be affected in the future. These gas pools have significant CO_2 storage capacity, estimated at greater than 185 Mt CO_2. Repressuring these gas pools with CO_2 from oil sands plants would achieve a dual objective of maintaining pressure in these gas reservoirs, thus preserving the ability to produce the underlying bitumen while producing the gas, and storing CO_2 from oil sands plants in the Fort McMurray area, thus reducing greenhouse gas emissions and allowing the development of oil sands resources in a responsible manner.

Table of Contents

Figures

Tables

1 Introduction

Interpretation of the temperature record on a scale of centuries to millennia indicates a slight increase in global average annual temperatures in the last 100-150 years, in the order of 0.4-0.6ºC (IPCC, 2001), with 2005 being the warmest year on record. The melting and retreat of polar ice caps and mountain glaciers corroborate this increase. Some severe weather effects around the globe, such as hurricanes and droughts, are attributed by some to global warming, and predictions are that humankind is facing significant climate change by the end of this century as a result of continuing warming forecasted to be in the order of 2-5ºC (IPCC, 2001). It is generally, but not unanimously accepted that the main cause of the observed global warming is the increase in atmospheric concentrations of greenhouse gases, such as carbon dioxide (CO_2) and methane (CH_4). This increase, observed since the beginning of the industrial revolution at the middle of the 19^{th} century, is due to human activity in land use (agriculture and deforestation) and ever-increasing consumption of fossil energy resources. Of all the greenhouse gases, CO_2, whose atmospheric concentrations have risen from pre-industrial levels of 280 ppm to 360 ppm, is responsible for about two thirds of the enhanced 'greenhouse effect' (Bryant, 1997). The relationship between CO_2 emissions (expressed by the amount of carbon C), economic growth (expressed by the gross domestic product - GDP) and energy production (E) is best illustrated by Kaya's identity (Kaya, 1995):

$$C = GDP \times \left(\frac{E}{GDP} \right) \times \left(\frac{C}{E} \right) \qquad (1)$$

In the above expression, (E/GDP) is the energy intensity of the economy and (C/E) is the carbon intensity of the energy system. Historical evidence shows that, although the carbon emission intensity of the economy (C/GDP) has decreased continuously since the beginning of the industrial revolution, carbon emissions have increased because the economy (GDP) is growing at a faster rate than the decrease in emission intensity (Kaya, 1995). Thus, in the context of worldwide population and economic growth, it is predicted that the continuing use of fossil fuels in a business-as-usual scenario, hence the increase in anthropogenic CO_2 emissions, will lead to an increase in the average global temperature of between 2ºC and 5ºC, depending on the climatic model being used, with significant effects on climate and world economy (IPCC, 2001).

While a direct causal link between the raise in greenhouse gas concentrations in the atmosphere and global warming has not been demonstrated and is still subject of scientific debate, circumstantial evidence points toward this link, which has been generally accepted by a broad segment of the scientific community (e.g., AGU, 2003) and by policy makers. Within the United Nations Framework Convention for Climate Change (UNFCCC), the Kyoto Protocol ratified in February 2005 provides that, by 2012, Annex I countries (developed and in transition) reduce their atmospheric CO_2 emissions by an average of 5% below their 1990 emissions. Canada, which ratified the Kyoto Protocol, has committed to reduce by 2012 its anthropogenic CO_2 emissions by 6% below the 1990 level of 607 Mt CO_2 (i.e., at 571 Mt CO_2/year). Although Canada's greenhouse gas emissions currently represent only 1.8% of the world total, it has one of the toughest emissions-reduction targets because, unlike major European countries and Russia, Canada's atmospheric CO_2 emissions increased continuously from 607 Mt CO_2 in 1990 to 754 Mt CO_2 in 2003 (a 24.2% increase), with projected emissions by 2010 of ~810 Mt CO_2 under a business-as-usual scenario. Thus, Canada must take drastic actions in the next few years if it is to meet its obligations under the Kyoto Protocol. Within Canada, Alberta's CO_2 emissions have increased as a result of population increase and robust economic development (see relation (1)), such that by 2000 Alberta became the province with the highest CO_2 emissions in Canada (Figure 1).

Figure 1. Canada's 2000 CO_2 emissions profile (source: Environment Canada, 2002).

In 1990, Alberta's CO_2 emissions at >170 Mt CO_2 were the second largest in Canada, below those of Ontario. By 2000, Alberta's emissions stood at 223 Mt CO_2 (Environment Canada, 2002) and it is expected that by 2010 the level of emissions in Alberta will increase considerably both in absolute terms and in relation to other provinces. This increase is mostly due to energy development (mainly oil sands), but also to petrochemical, power generation and manufacturing industries. In regard to reducing atmospheric CO_2 emissions, Alberta's position is that, while committed to taking effective action on climate change, the steps taken should balance economic risks and the realities of Alberta, hence the province's approach to climate change is based on reducing emission intensity rather than focusing on an absolute emission-reduction target[1]. Alberta's commitment is that, by 2020, the emission intensity relative to GDP will be reduced by 50% from 1990 levels, which is equivalent to a reduction of 60 MtCO_2, with a milestone target of 20 MtCO_2 by 2010 (compare these targets with annual emissions of 223 Mt CO_2 in 2000).

The following modified version of the Kaya identity (Bachu, 2003) expresses best the general categories of means for achieving a reduction in atmospheric CO_2 emissions:

[1] Albertans & Climate Change: Taking Action; Alberta Environment, 46 p., 2002.

$$NetC = P \times \left(\frac{GDP}{P} \right) \times \left(\frac{E}{GDP} \right) \times \left(\frac{C}{E} \right) - S \qquad (2)$$

where *P* and *S* are population and CO_2 sinks respectively, and (*GDP/P*) represents per capita GDP. Notwithstanding economic and/or population decline, which are both unacceptable and of very short duration if they happen, and then only locally but not globally, a sustained reduction in CO_2 emissions can be achieved by reducing the energy intensity of the economy (*E/GDP*) through energy efficiency and conservation, by reducing the carbon intensity of the energy system (*C/E*) by switching energy production to fuels that contain less carbon (e.g., gas) or no carbon at all (hydro, nuclear, wind, solar, etc.), and/or by increasing the capacity and capture rate of CO_2 sinks (*S*). The CO_2 sinks are of two kinds: terrestrial sinks, such as forests and soils, which capture diffuse CO_2 directly from the atmosphere after its release, and deep, sub-aerial sinks, such as geological media and the deep ocean, where CO_2 is stored after a process of capture from large stationary sources, transportation and emplacement. This process is known generically as CO_2 Capture and Storage, or CCS. Thus, short of a timely and major technological breakthrough, it is evident that no single set of measures will lead to a significant reduction in atmospheric emissions of anthropogenic CO_2 and that a whole portfolio of measures will have to be applied, including CCS (Turkenburg, 1997).

All economic forecasts predict that fossil fuels, which today provide close to 80% of the world's energy, are likely to remain a major component of world's energy supply and that their share will actually increase to close to 85% by 2050 (IEA, 2004). This is because of their inherent advantages, such as availability, competitive cost, ease of transport and storage, and large resources, and because other forms of energy are insufficient, too costly and/or unacceptable to the public. In addition, the need for stability and security of energy supplies, pursued by both developed and developing countries alike, will lead to an increase in the use of coal, abundantly found in North America, Australia, China and India, as a primary form of energy. Alberta, rich in oil, gas, oil sands and coal, will continue to produce energy to satisfy demand, and generate its power using mostly fossil fuels (mainly coal). However, Alberta has also to find ways to reduce its atmospheric CO_2 emissions without impeding economic development.

A recent study by the International Energy Agency (IEA, 2004) and a review by the International Panel on Climate Change (IPCC, 2005) have identified geological storage of CO_2 as being a technology that is immediately applicable as a result of the experience gained in other industries, particularly in oil and gas exploration and production, has large capacity, although unevenly distributed around the globe, and has retention times of centuries to millions of years. On the other hand, because adding CO_2 to the ocean will alter the local chemical environment, with ecosystem consequences on the marine environment, and because the long term effects of CO_2 storage in the ocean over large areas are not known (IPCC, 2005), ocean storage will likely not be implemented, at least not in the short-to-medium timeframe. Carbon dioxide capture and geological storage (CCGS) has the potential to break the link between economic development and CO_2 emissions as expressed by Kaya's identity (1), and has been identified as an important component of future energy systems that will contribute significantly to the reduction of anthropogenic CO_2 emissions into the atmosphere (e.g., IEA, 2004; Socolow, 2005).

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

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

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

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

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

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

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

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

Geological storage of CO_2 is in various phases of applicability and implementation, from demonstration to being a mature technology, depending on the storage medium (IPCC, 2005). At one end of the spectrum, CO_2 storage in enhanced oil recovery is a mature, economic technology, while, at the other end, CO_2 storage in uneconomic coal seams in conjunction with enhanced coalbed methane recovery is only in the demonstration phase. Storage of CO_2 in depleted oil and gas reservoirs and deep saline aquifers is a mature technology that is currently economic only under very specific conditions (IPCC, 2005). However, this technology is not without problems. On the capture side, the major impediment is the high cost of capture that needs to be reduced in a significant way. On the storage side, major gaps exist in defining and identifying appropriate sinks with the necessary capacity within economic distance from major CO_2 sources, and identifying, mitigating and remediating risks associated with possible leakage of CO_2. On a global scale, CO_2 leakage may partially offset the benefits of storage. Locally, leakage of CO_2 may lead to contamination of energy, mineral and groundwater resources, and harm vegetation, animal and even human life, depending on leakage rates, duration and circumstances. Thus, for large-scale implementation of CO_2 capture and geological storage, it is essential that sites are appropriately selected, designed, operated and monitored (IPCC, 2005).

Regarding CO_2 capture and geological storage (CCGS) in Canada, practically only the Alberta and Williston basins have, on a national scale, significant potential for CO_2 geological storage (Bachu, 2003). Except for the extreme northeastern part of the province, Alberta is underlain by the wedge-shaped Alberta Basin that reaches depths of more than 6000 m in the southwest at the Rocky Mountain Thrust and Fold Belt. Except for the shallow northeastern part, the basin meets all the general suitability criteria for CO_2 geological storage (Bachu and Stewart, 2002; Bachu, 2003):

- it is located in a tectonically stable region;
- has regional-scale flow systems confined by thick aquitards;
- has significant oil and gas reservoirs;
- has coal beds;
- has significant infrastructure in place;
- there are major stationary CO_2 sources in the area, including high-purity sources; and
- there is experience with acid-gas injection operations and CO_2 enhanced oil recovery.

By number of emitters and size of emissions, large stationary CO_2 sources in Alberta are located in four clusters and three distinct regions (Figure 2). In the northwest, major but

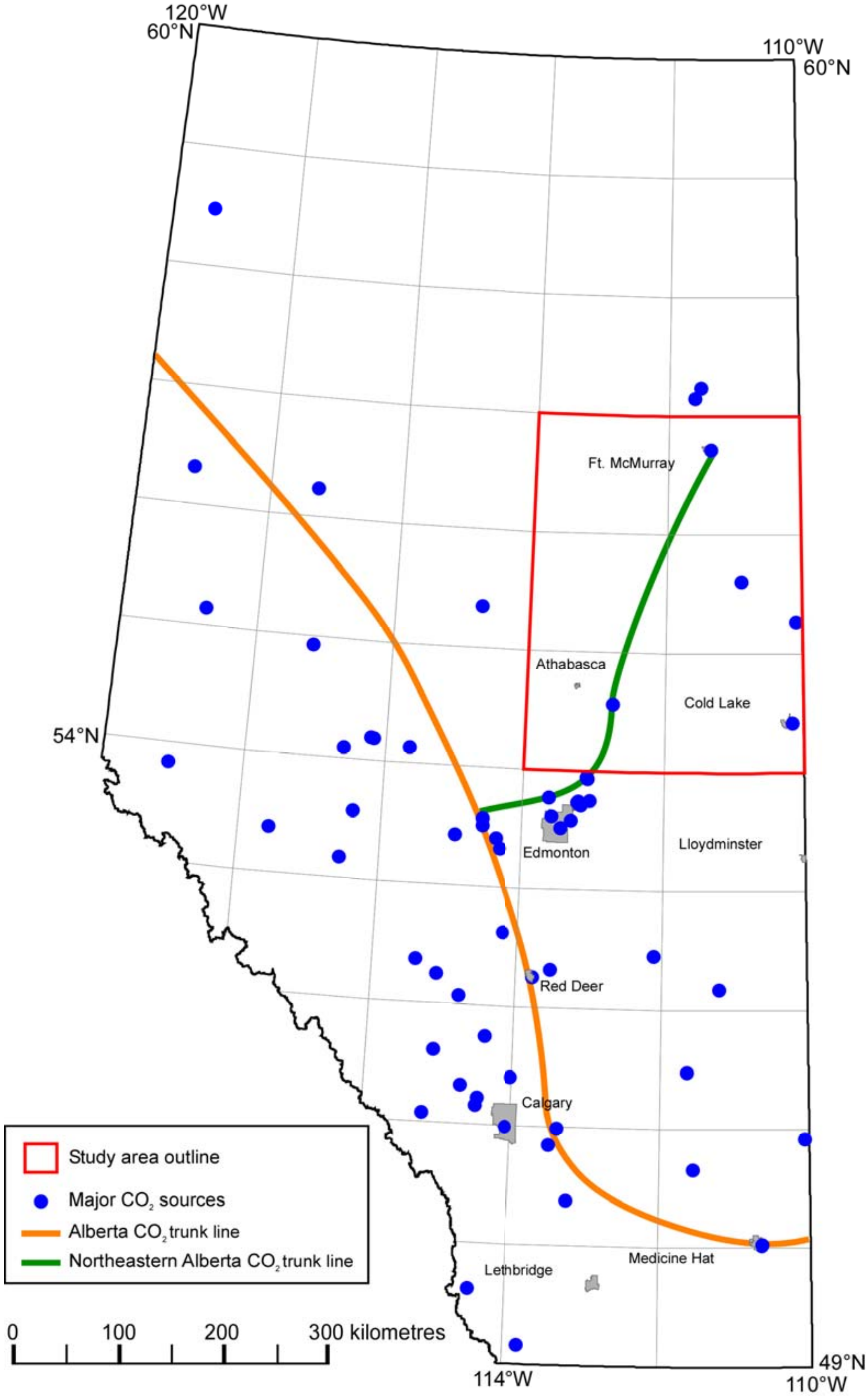

Figure 2. Location of major stationary CO_2-sources in Alberta and of the Northeastern Alberta study area. The planned *Alberta* and *Northeastern Alberta* CO_2 trunk pipelines are shown diagrammatically.

comparatively small CO_2 sources are mainly pulp mills, newspaper plants and gas plants (< 1 Mt CO_2 each). In the southwest along the Rocky Mountains, major and yet relatively small CO_2 sources are mainly energy producers (gas plants), and two cement or lime plants in the Bow Valley corridor. Major CO_2 sources in southeastern Alberta are mainly fertilizer plants and compressor stations along oil and gas pipelines. The clusters of very large CO_2-emitting plants (> 1 Mt CO_2) are around Red Deer (mainly petrochemicals), Wabamun Lake southwest of Edmonton (major coal-fired power plants), Edmonton-Fort Saskatchewan-Redwater (mainly refineries, upgraders, chemicals and petrochemicals), and Fort McMurray (oil sands). Sheerness and Battle River coal-fired power plants are located east of red Deer.

All the major stationary CO_2 sources in Alberta except those in the northeast (Cold Lake to Athabasca) are underlain by a sufficiently thick sedimentary succession that allows "on-site" or "near-site" CO_2 storage in any combination of oil and gas reservoirs, deep saline aquifers and possibly coal beds (Bachu and Stewart, 2002). Only the oil sands plants in the Athabasca area are "stranded" in the sense that the sedimentary succession is too shallow, being close to the basin zero edge, and not suitable for CO_2 storage. Thus, CO_2 captured from these sources has to be taken to potential storage sites in the west or southwest. The CO_2 sources in the Cold Lake area are in a similar situation.

Mindful of the particular circumstances of their plant location, major oil sands and heavy oil producers including Shell, Suncor, Husky, Nexen, CNRL, Imperial Oil and ConocoPhillips have formed a consortium (ICON – **I**ntegrated **CO_2** **N**etwork) and have developed plans for bringing CO_2 captured at plants in the Athabasca area to major oil fields in central Alberta, such as Swan Hills and Pembina (Figure 2). The concept is at the base of even broader plans for developing a major CO_2 trunk line in Alberta that would run essentially from the northwest to the southwest and collect CO_2 from major emitters, and that would distribute CO_2 to storage sites, including oil fields with potential for enhanced oil recovery (e.g., Edwards 2000). In time, this pipeline would extend to southeastern Alberta (Medicine Hat area) and turn east into Saskatchewan to collect CO_2 from major sources, such as the COOP refinery in Regina, and distribute it to storage sites in the Williston Basin including oil fields in southeastern Saskatchewan. Later on the pipeline could extend in the opposite direction, in northeastern British Columbia, where several large CO_2 producers are found (mainly energy producers and pulp mills).

Although in the broadest sense the shallow sedimentary succession in northeastern Alberta is not suitable for CO_2 storage, some storage potential exists as demonstrated by the presence of oil and gas reservoirs in the region. Thus, while oil and gas reservoirs in northeastern Alberta may not be the focused target for CO_2 storage, they might be used given the opportunity that will be created by the construction of a major pipeline that would bring CO_2 from the Fort McMurray area to the Fort Saskatchewan area. The purpose of the work reported here was to inventory the capacity for CO_2 storage in oil and gas reservoirs in northeastern Alberta and to identify potential targets for CO_2 storage along a CO_2 pipeline that would bring CO_2 from the Fort McMurray cluster of major CO_2 emitters to the Edmonton-Fort Saskatchewan-Redwater cluster where it would connect to a (inter)provincial CO_2 trunk line. The study area is defined by 110°-114°W longitude and 54°-57°N latitude (Figure 2). Major oil and gas pipelines are already laid out through the study area, with the main ones running along Highway 63 to Fort McMurray (Figure

3), and most likely a future CO_2 trunk pipeline will run along the same right-of-way corridor.

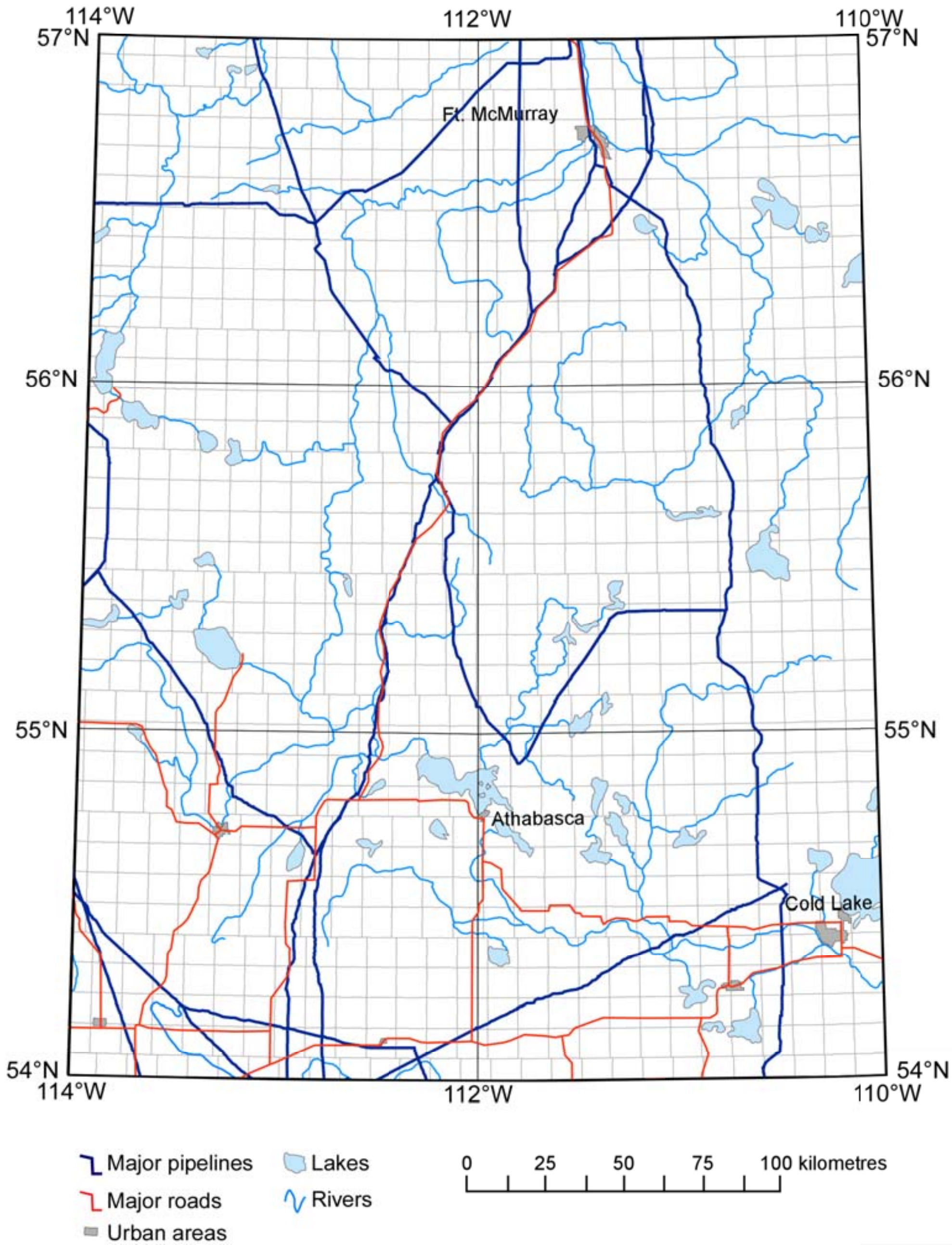

Figure 3. Hydrography, roads and main pipelines in the Northeastern Alberta study area.

Previous work performed by the author on behalf of Alberta Environment has estimated and inventoried the capacity for CO_2 storage in oil and gas reservoirs in Alberta (Bachu and Shaw, 2005; Bachu 2006). However, two major restrictions were applied in the previous work regarding CO_2 storage capacity estimates. The first restriction was rather methodological, in that only uncommingled reservoirs were considered [commingled reservoirs are reservoirs that are physically separated but that are produced through the same well(s)]. The second restriction was based on the broadly accepted concept that CO_2 storage in geological media has to take place at depths greater than 800-900 m to ensure high CO_2 density, hence storage efficiency for a given volume of pore space. Neither one of these restrictions is iron clad and can be relaxed depending on circumstances. Carbon dioxide can be stored in shallow oil and gas reservoirs with no physical restriction, the only downside being that the storage efficiency would be lower than for a deeper reservoir with the same available pore space. Nevertheless, CO_2 would be stored in these reservoirs as proven by the containment characteristics of the reservoirs.

Commingled reservoirs may have significant storage capacity and it was only a matter of developing the necessary methodology for capacity calculations and including them in CO_2 storage capacity estimates. Approximately 27,500 uncommingled gas reservoirs in Alberta, with original gas in place (OGIP) of 3.5 trillion m^3, have an estimated CO_2 storage capacity in the order of 7 Gt CO_2. By comparison, 2,474 commingled gas reservoirs in Alberta have 3 trillion m^3 OGIP (85% as much as the uncommingled gas reservoirs), thus there must be significant CO_2 storage capacity in these gas reservoirs and they should be accounted for in an area-specific study like this one. On the other hand, ~8,100 uncommingled oil reservoirs in Alberta with original oil in place (OOIP) of ~7.4 billion m^3 have a much smaller CO_2 storage capacity, in the order of 400 Mt CO_2, including EOR. The 476 commingled oil reservoirs in Alberta with ~2.2 billion m^3 OOIP (30% of the uncommingled ones) are usually water flooded or even in tertiary recovery (gas or solvent flooded), thus the expected CO_2 storage capacity in these commingled oil reservoirs is expected to be less than 100 Mt CO_2 (i.e., province-wide they represent ~1% of the storage capacity in gas reservoirs). Thus, commingled oil reservoirs are not included in this study because of methodology difficulties and because there are very few commingled oil reservoirs in the study area, if any. Therefore, this report is not just a summary of work previously performed for Alberta Environment restricted geographically to northeastern Alberta, but it includes shallow reservoirs with no depth limit, and commingled gas reservoirs as well.

2 Methodology for Estimating the Capacity for CO_2 Storage in Oil and Gas Reservoirs

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

Another important assumption is that CO_2 will be injected into depleted oil and gas reservoirs until the reservoir pressure is brought back to the original, or virgin, reservoir pressure. The results thus obtained represent a conservative estimate because the pressure can generally be raised beyond the original reservoir pressure as long as it remains safely below the threshold rock-fracturing pressure. In this case, the CO_2 storage capacity would be higher due to CO_2 compression. However, the risk of raising the storage pressure beyond the original reservoir pressure requires a case-by-case reservoir analysis that is not practical for basin-scale evaluations.

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

2.1 Theoretical CO_2-Storage Capacity

Only non-associated and associated gas reservoirs are considered in CO_2-sequesteration capacity calculations because solution gas is taken into account in oil reservoirs through the oil shrinkage factor. Since reserves databases indicate the volume of original gas in place (OGIP) at surface conditions, the mass-capacity for CO_2 storage in a reservoir at in situ conditions, M_{CO2}, is given by:

$$M_{CO2} = \rho_{CO2r} \cdot R_f \cdot (1 - F_{IG}) \cdot OGIP \cdot [(P_s \cdot Z_r \cdot T_r) / (P_r \cdot Z_s \cdot T_s)] \qquad (3)$$

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).

The CO_2 storage capacity of single-drive oil reservoirs is calculated similarly to gas reservoirs on the basis of reservoir rock volume (area [A] times thickness [h]), porosity (ϕ) and oil saturation ($1 - S_w$), where S_w is the water saturation. For reservoirs flooded with or invaded by water, the volume available for CO_2 storage is reduced by the volume of injected and/or invading water (V_{iw}). If water is produced with oil, then the volume available for CO_2 storage 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:

$$M_{CO2} = \rho_{CO2res} \cdot [R_f \cdot A \cdot h \cdot \phi \cdot (1 - S_w) - V_{iw} + V_{pw}] \qquad (4)$$

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.

Carbon dioxide can be used in tertiary enhanced oil recovery in miscible floods. Based on the experience gained in the United States, where CO_2-EOR is being practiced for more than 30 years at close to 70 oil fields in the Permian Basin of west Texas, a series of technical criteria were developed for assessing the suitability of oil reservoirs for CO_2-EOR and are reviewed and summarized in several publications (Taber *et al.*, 1997; Kovscek, 2002; Shaw and Bachu, 2002). However, an assessment of the few oil reservoirs in the study area has shown that none of them is suitable for CO_2-EOR mainly because, being too shallow, they do not meet the pressure conditions necessary to achieve miscibility. Thus, no estimates of CO_2 storage capacity in EOR operations have been carried out in this study.

2.2 Effective CO_2-Storage Capacity

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

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

Table 1. Criteria for establishing the strength and effect of underlying aquifers on the CO_2 storage capacity in depleted oil and gas reservoirs in the Western Canada Sedimentary Basin and the corresponding coefficient of reduction in CO_2 storage capacity.

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

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

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

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

Depending on reservoir temperature and pressure, the density of supercritical or liquid CO_2 may range between approximately 200 and 800 kg/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 and Preuss, 2004). This negatively affects the CO_2 storage, and the oil recovery in the case of EOR.

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

The presence of water in the reservoir also has the effect of reducing the CO_2 storage capacity, as discussed previously. Water may be present because of initial water saturation, because of water invasion as the reservoir is depleted, or because it was introduced during secondary and/or tertiary recovery. As a result of capillary forces, irreducible water (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 storage can be expressed by capacity coefficients ($C < 1$) in the form (Doughty and Preuss, 2004):

$$M_{CO2eff} = C_m \cdot C_b \cdot C_h \cdot C_w \cdot C_a \cdot M_{CO2res} \qquad (5)$$

where M_{CO2eff} is the effective reservoir capacity for CO_2 storage, and the subscripts m, b, h, w and a stand for mobility, buoyancy, heterogeneity, water saturation, and aquifer strength, respectively, and refer to the phenomena discussed previously. These capacity coefficients likely vary over a wide range, depending on reservoir characteristics, and this explains the wide range of incremental oil recovery (7 to 23% of OOIP) and CO_2 utilization (0.7 to 4.7 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 storage in depleted hydrocarbon reservoirs. The first four capacity coefficients can be captured in a single 'effective' coefficient:

$$C_{eff} = C_m \cdot C_b \cdot C_h \cdot C_w \qquad (6)$$

which can be estimated on the basis of experience with CO_2-flood EOR. A review of capacity coefficients for CO_2 storage in aquifers suggests that $C_{eff} < 0.3$. 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-storage capacity, such that $C_w \approx 1$ too. Although reservoir heterogeneity may reduce the CO_2 storage 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 storage 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.

2.3 Practical CO_2-Storage Capacity

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

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

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

In terms of CO_2 storage capacity, most reservoirs are relatively small in volume, and have a low capacity for CO_2 storage, rendering them uneconomic. On the other hand, associated oil and gas reservoirs (oil reservoirs with a gas cap) have a CO_2 storage capacity that is equal to the sum of the individual capacities of each reservoir. Considering the size of major stationary CO_2-sources, it is most likely that only reservoirs with large CO_2-storage capacity will be considered in the short and medium term. Building the infrastructure for CO_2 capture, transportation and injection is less costly if the size of the sink is large enough, and if its lifespan is long enough, to justify the needed investment and reduce the cost per ton of sequestered CO_2. In the previous study performed for Alberta Environment, only 886 oil and gas reservoirs with individual CO_2-storage capacity greater than 1 Mt CO_2/year were selected at the end of the capacity assessment process and identified as potential CO_2 sinks.

Notwithstanding the above general criteria for determining the practical CO_2-storage capacity in a given region, in this study of CO_2 storage capacity in northeastern Alberta some of the criteria for screening out shallow and/or small reservoirs were relaxed, in order to obtain a complete picture of the potential for CO_2 storage between Fort McMurray and Fort Saskatchewan.

3 Capacity for CO_2 Storage in Oil and Gas Pools in Northeastern Alberta

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

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

The Alberta 2004 oil and gas reserves databases contain 10,438 and 45,726 entries, respectively, differentiated on the basis of field and pool, and the on mode of production (single drive, primary, flooded, etc.) in the case of oil reservoirs, or sequence in the case of gas reservoirs. In the case of gas pools divided into sequence entities, and in the case of oil pools divided by production mode, the EUB reserves databases contain also an entry that provide the "Total" reserves for that pool, although some individual characteristics are provided at the individual level. These "Total" entries were eliminated from CO_2-storage capacity calculations, otherwise it will double-count the respective capacity.

In the area defined in this study (110°-114°W, 54°-57°N) there are only 9 oil reservoirs and one oil reservoir with an associated gas cap. None of these oil reservoirs is suitable for CO_2 EOR, thus CO_2 storage capacity calculations were performed based on reservoir depletion only. There are 4,908 uncommingled gas pools in the study area, and 389 commingled gas pools.

Table 2 shows the range of variability in the data needed for calculating the CO_2 storage capacity for the 10 oil reservoirs and 5,298 gas reservoirs in northeastern Alberta that were considered in this study. It is worth noting that reservoir depth varies from 161 m to 1,163 m for gas reservoirs, and from 571 to 1,198 m for oil reservoirs. If only reservoirs deeper than 800 m would have been considered, as generally recommended (e.g., IPCC 2005), then only 5 oil reservoirs and 282 gas reservoirs would have passed this screening criterion, greatly reducing the capacity estimates of and potential for CO_2 storage in the area. More than 3,400 gas reservoirs contain CO_2 to various proportions (see Table 2), and this CO_2 will be produced together with the remaining gas reserves.

Table 2. Range of characteristics of oil and gas pools in northeastern Alberta.

Reservoir Type	Parameter	Minimum	Maximum
Oil	OOIP (10^3 m^3)	7.6	840
	Recovery Factor	0.01	0.13
	Depth (m)	571.2	1198.7
	Area (ha)	1	740
	Net Pay (m)	1.7	19
	Water Saturation	0.1	0.68
	Porosity	0.11	0.32
	Shrinkage Factor	0.89	0.99
	Initial Pressure (kPa)	3,295	9,299
	Temperature (ºC)	21	38
	Oil Density (kg/m^3)	817	990
	Oil Gravity (ºAPI)		
Gas	OGIP (10^6 m^3)	1	38,824
	Recovery Factor	0.3	0.95
	Depth (m)	161.0	1163.2
	Initial Pressure (kPa)	1,000	12,360
	Temperature (ºC)	2	59
	Compressibility (Z factor)	0.798	0.994
	CO_2 Content (%)	0.0	0.1138

The theoretical CO_2-storage capacity at depletion was calculated for the oil and gas reservoirs in northeastern Alberta according to relations (3) and (4). The effective storage capacity was then calculated for all of them according to relations (5) and (6) on the basis of aquifer support as determined according to the criteria presented in Table 1. After calculations at the individual reservoir level (sequence in the case of gas reservoirs), the CO_2-storage capacity estimates were summed at the pool level on the basis of field and pool code. The storage capacity of commingled gas reservoirs was obtained by summing the capacities of the individual reservoirs. The storage capacity of 7.5 t CO_2 in the oil leg of the oil reservoir with a gas cap is negligible compared with the 41,116 t CO_2 storage capacity in the gas cap; hence this reservoir was considered subsequently only as a gas reservoir. Table 3 presents by pool type the characteristics of their effective CO_2-storage capacity. A list of all the reservoirs and their storage capacity is provided on the accompanying CD.

Table 3. Characteristics of CO_2 storage capacity in oil and gas pools in northeastern Alberta.

Pool Type	Production	No. Pools	CO_2 Storage Capacity (t)			
			Minimum	Maximum	Average	Cumulative
Oil	Single drive	15	11	1342	348	5,220
Gas	Uncommingled	4,909	632	7,193,500	76,934	377,668,327
	Commingled	389	1,822	35,856,082	594,923	231,425,159
	All	5,298	632	35,856,082	114,967	609,093,486

Examination of Table 3 shows that the CO_2 storage capacity in oil reservoirs in northeastern Alberta is insignificant compared with that of gas reservoirs. Furthermore, commingled gas reservoirs, although less than 10% in number when compared with uncommingled gas reservoirs, are bigger and have cumulative storage capacity comparable to that of the uncommingled reservoirs (61%).

The total CO_2 storage capacity in gas reservoirs in northeastern Alberta is significant at ~609 Mt CO_2. This represents approximately 100 times the current annual emissions of an oil sands plant. Figure 4 presents histograms of their individual and cumulative CO_2 storage capacity. However, the CO_2 storage capacity of the great majority of these 5,298 gas reservoirs is small, as indicated by their average of ~0.115 Mt CO_2. Only 76 gas reservoirs have individual storage capacity greater than 1 Mt CO_2 each (average 3.8 Mt CO_2). These pools, which represent 1.4% of the gas pools in the area, have a cumulative CO_2-storage capacity of ~292 Mt CO_2 (48% of the total), and they represent the practical CO_2 storage capacity in northeastern Alberta. Figure 5 presents histograms of the individual and cumulative CO_2 storage capacity for these 76 gas reservoirs, and Figure 6 shows their location. Table 4 presents their respective name, location and depth, and CO_2 storage capacity. It is worth noting that twenty-four of the 76 gas pools with large CO_2 storage capacity are commingled gas pools, with cumulative capacity of ~185.6 Mt CO_2 (63.6%).

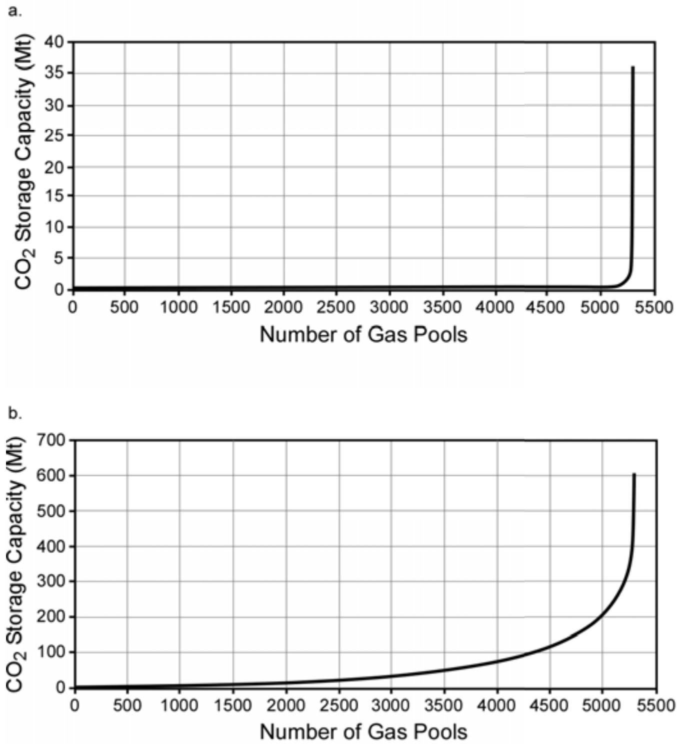

Figure 4. Histogram of the CO_2 storage capacity in all the gas reservoirs in northeastern Alberta: a) individual capacity, and b) cumulative capacity.

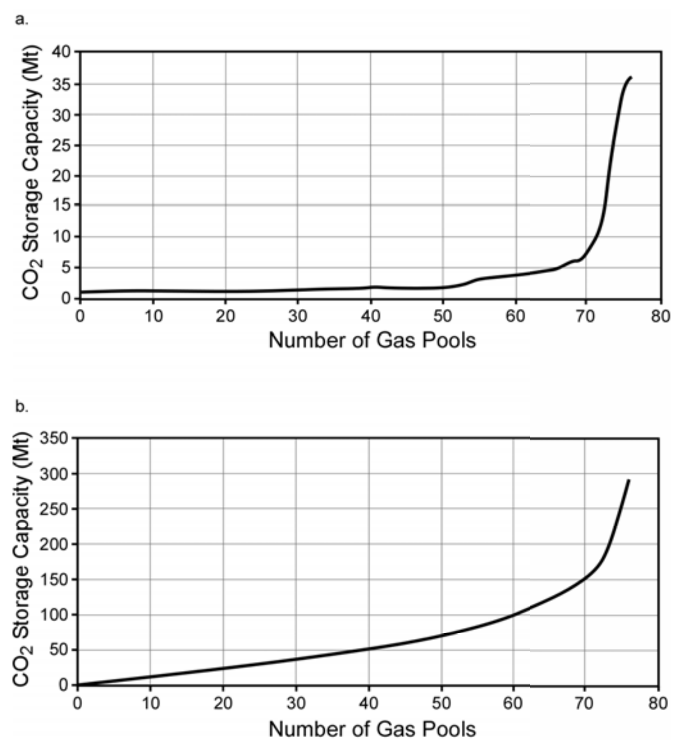

Figure 5. Histogram of the CO_2 storage capacity in the 76 gas reservoirs in northeastern Alberta with capacity greater than 1 Mt CO_2 each: a) individual capacity, and b) cumulative capacity.

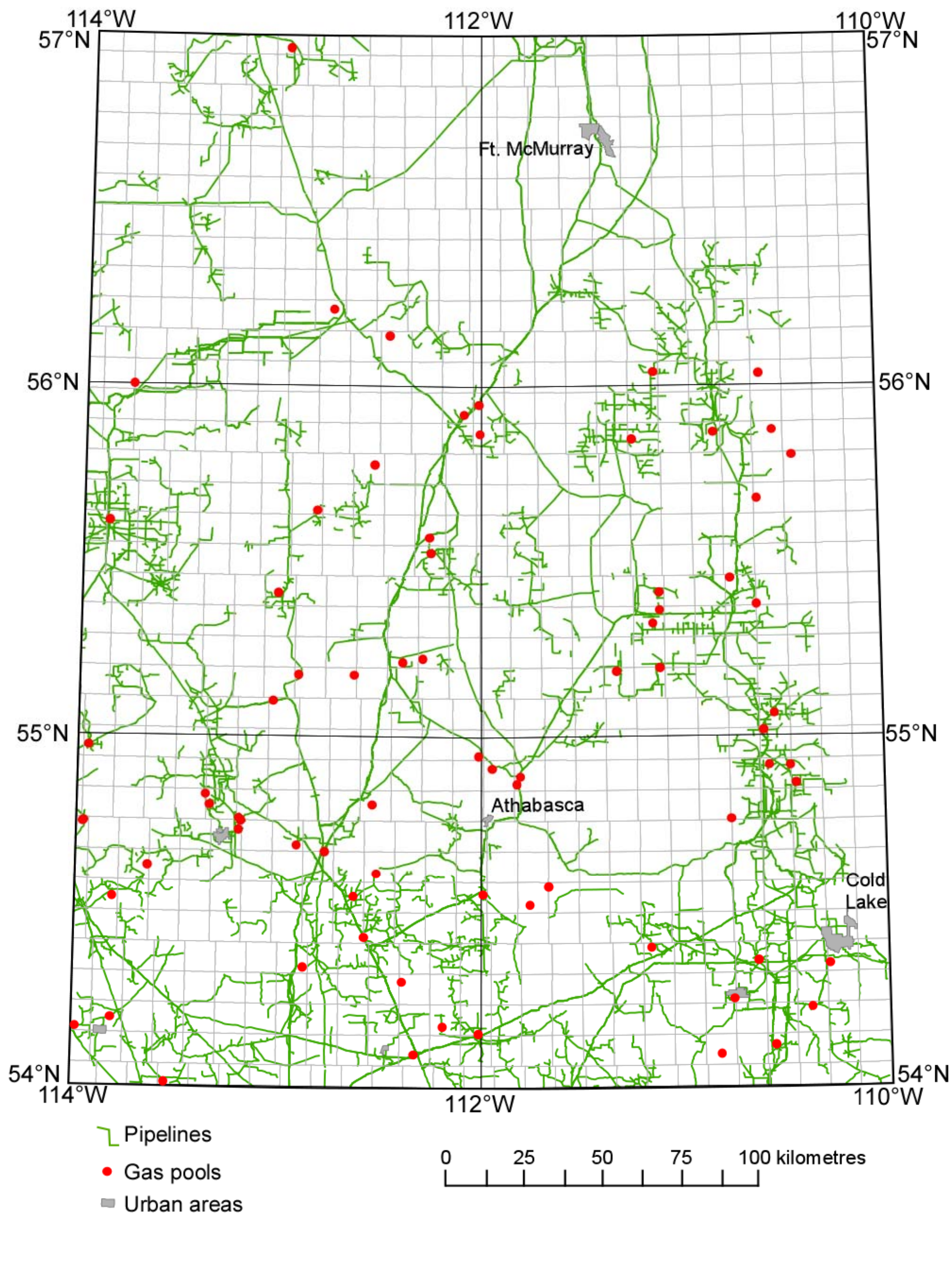

Figure 6. Location of the 76 gas reservoirs in northeastern Alberta with CO_2 storage capacity greater than 1 Mt CO_2 each.

Table 4. List of the 76 gas reservoirs in northeastern Alberta with CO_2 storage capacity greater than 1 Mt CO_2 each.

Field Code	Pool Code	Field Name	Pool Name	Pool Type	Longitude	Latitude	Depth (m)	CO_2 Storage Capacity (tonnes)
439	328064	HARDY	MCMURRAY L & O	Commingled	-110.430000	55.800000	303.2	1,012,754.6
76	250001	ATHABASCA EAST	UPPER MANNVILLE A		-113.186836	54.760129	516.9	1,034,173.3
912	218002	TWEEDIE	VIKING B		-112.012711	54.944794	233.5	1,066,723.3
945	328013	THORNBURY	MCMURRAY M		-112.011200	55.945524	461.0	1,067,001.7
945	328007	THORNBURY	MCMURRAY G		-112.005775	55.862492	466.6	1,067,979.6
382	306102	FLAT	WABISKAW-WABAMUN B		-112.773712	54.672650	581.7	1,069,489.0
93	658005	BAPTISTE	WABAMUN E		-113.343666	54.804260	585.9	1,090,952.5
527	250010	KIRBY	UPPER MANNVILLE J		-111.139458	55.324150	467.2	1,153,199.2
154	262003	BONNYVILLE	GRAND RAPIDS C		-110.761932	54.250582	317.1	1,158,280.5
87	696360	ATMORE	NISKU A & MCMURRAY B	Commingled	-112.540000	54.806667	514.7	1,158,794.7
110	250012	BELLIS	UPPER MANNVILLE L		-112.188599	54.173330	573.3	1,160,574.6
199	263260	CASLAN	GRD RP A_B & NISKU A	Commingled	-112.515000	54.610000	503.2	1,172,129.0
387	256009	FORT KENT	COLONY I		-110.640663	54.359903	305.3	1,173,153.5
125	262017	BIG BEND	GRAND RAPIDS Q		-113.967331	54.750095	597.9	1,178,089.4
125	658001	BIG BEND	WABAMUN A		-113.961823	54.752187	810.2	1,200,102.3
639	250003	NEWBROOK	UPPER MANNVILLE C		-112.874146	54.341624	576.9	1,215,939.6
518	262001	KEHIWIN	GRAND RAPIDS A		-110.827705	54.094956	397.2	1,242,773.2
186	250360	CALLING LAKE WEST	U MANN A_C & L MANN A	Commingled	-112.910000	55.177500	405.7	1,246,875.4
222	256021	CLAY	COLONY U		-112.015442	54.152501	519.7	1,252,342.5
862	251861	STEELE	U MANN B & GRD RP R	Commingled	-113.643333	54.630000	691.3	1,253,574.8
945	328009	THORNBURY	MCMURRAY I		-112.085609	55.917721	478.4	1,254,799.0
417	328060	GRAHAM	MCMURRAY B_E & L	Commingled	-110.527500	55.872500	243.0	1,264,224.3
564	250015	LEMING	UPPER MANNVILLE O		-110.764481	54.764790	436.1	1,264,603.0
724	696001	PORTAGE	NISKU A		-112.824875	55.645744	386.7	1,273,689.1
630	248001	MURIEL LAKE	MANNVILLE A		-110.563286	54.119085	406.2	1,277,639.7
36	262061	FISHER	GRD RP B_SS & F2F	Commingled	-110.570000	54.917500	376.0	1,294,688.9
76	300701	ATHABASCA EAST	GLAUC-L MANN-WAB A		-113.196106	54.766256	609.4	1,317,267.3
76	300601	ATHABASCA EAST	GLAUCONITIC-WABAMUN A		-113.198174	54.733934	600.7	1,348,699.1
651	310005	NIXON	LOWER MANNVILLE E		-112.390770	55.213069	452.7	1,394,894.2
261	262960	CRAIGEND	GRD RP S6S&MCMY C	Commingled	-111.760000	54.520000	451.4	1,404,177.0
527	250747	KIRBY	UPPER MANNVILLE U2U		-111.105043	55.361467	441.6	1,415,742.8

Field Code	Pool Code	Field Name	Pool Name	Pool Type	Longitude	Latitude	Depth (m)	CO_2 Storage Capacity (tonnes)
527	250748	KIRBY	UPPER MANNVILLE V2V		-111.109329	55.412890	458.7	1,429,652.8
261	262016	CRAIGEND	GRAND RAPIDS P		-111.667953	54.572215	369.4	1,434,000.2
444	306262	HANGINGSTONE	WBSK-MCMY MU#2	Commingled	-111.126190	56.039524	417.9	1,532,745.9
36	328001	FISHER	MCMURRAY A		-110.467064	54.915489	523.7	1,536,437.8
396	716001	GRANOR	GROSMONT A		-112.750038	56.218772	319.3	1,537,405.7
356	262008	GRIST	GRAND RAPIDS H		-111.107755	55.196842	320.1	1,572,588.6
491	262001	IPIATIK	GRAND RAPIDS A		-111.324852	55.188099	315.4	1,592,295.5
325	696004	EDWAND	NISKU D		-112.388397	54.300245	671.8	1,616,583.1
881	256004	SUGDEN	COLONY D		-111.163589	54.397824	318.1	1,637,218.3
912	716001	TWEEDIE	GROSMONT A		-111.821312	54.866155	471.3	1,643,512.0
523	262002	KENT	GRAND RAPIDS B		-110.291565	54.348608	281.3	1,665,451.4
407	658002	GAMBLER	WABAMUN B		-113.035126	55.101805	519.7	1,737,646.3
150	310001	BOLLOQUE	LOWER MANNVILLE A		-113.813713	54.537477	869.5	1,746,443.2
125	658008	BIG BEND	WABAMUN H		-113.947639	54.968337	759.0	1,772,782.5
209	256007	CHARLOTTE LAKE	COLONY G		-110.380470	54.224929	329.7	1,781,384.9
731	262001	MOORE	GRAND RAPIDS A		-110.439583	54.865931	363.2	1,856,604.2
110	250002	BELLIS	UPPER MANNVILLE B		-112.329650	54.092966	503.1	1,873,619.1
380	696005	FIGURE LAKE	D-2 E		-112.627068	54.543616	645.7	1,885,780.5
946	310002	WESTLOCK	LOWER MANNVILLE B		-113.810722	54.192782	950.1	1,892,844.1
912	262004	TWEEDIE	GRAND RAPIDS D		-111.945000	54.908683	284.1	1,932,272.8
640	306261	NEWBY	WBSK ADD MCMY BD	Commingled	-110.590000	56.034000	197.8	2,121,911.0
298	716002	DUNCAN	GROSMONT B		-112.252388	55.523412	578.9	2,464,563.4
221	696001	CHERPETA	NISKU A		-113.016418	55.410734	609.3	2,478,637.8
471	306760	HOOLE	WBSK A_M_WAB A&BLUE A	Commingled	-113.762000	56.000000	442.9	3,159,803.2
225	306260	CHARD	WBSK & MCMURRAY MU#1	Commingled	-110.826842	55.867895	254.6	3,281,077.8
36	280002	FISHER	CLEARWATER B		-110.597069	55.017500	437.9	3,549,014.4
93	249560	BAPTISTE	MANN G & WAB C	Commingled	-113.363333	54.833333	539.7	3,601,587.3
651	311460	NIXON	L MANN M & GROSMONT A	Commingled	-112.290000	55.223333	441.7	3,646,170.9
367	218760	FAIRYDELL-BON ACCORD	U VIK AC & M VIK AB	Commingled	-113.542000	54.012000	784.4	3,941,076.3
184	696002	CALLING LAKE	D-2 B		-112.634392	55.175459	466.0	3,943,742.0
380	696160	FIGURE LAKE	UPPER MANN BY_CC&D-2B	Commingled	-112.576000	54.428000	571.1	4,101,157.9
439	306260	HARDY	WBSK&MCMY MU#1	Commingled	-110.611579	55.678421	340.8	4,131,439.2
912	262960	TWEEDIE	GR H_I_X &MCM A_H_L&T	Commingled	-111.803333	54.886667	400.6	4,289,177.8

Field Code	Pool Code	Field Name	Pool Name	Pool Type	Longitude	Latitude	Depth (m)	CO_2 Storage Capacity (tonnes)
724	328201	PORTAGE	MCMURRAY-GROSMONT A		-112.538071	55.776606	363.9	4,767,059.7
473	716001	HOUSE	GROSMONT A		-112.466461	56.143965	303.9	4,773,533.4
261	716001	CRAIGEND	GROSMONT A		-111.989662	54.549364	507.4	5,301,049.4
298	328006	DUNCAN	MCMURRAY F		-112.260597	55.568305	524.7	5,802,557.5
527	250004	KIRBY	UPPER MANNVILLE D		-110.620934	55.376352	380.3	6,047,620.1
382	306101	FLAT	WABISKAW-WABAMUN A		-112.911591	54.690389	562.9	7,193,499.2
36	262763	FISHER	GRD RAP & CLWT MU#2	Commingled	-110.541250	55.065000	359.2	8,670,082.4
946	218160	WESTLOCK	VIKING & L MANN MU#1	Commingled	-113.979286	54.165000	779.7	11,857,620.6
559	248060	LEISMER	MANNVILLE MU#1	Commingled	-111.238615	55.849385	369.5	21,919,099.5
538	306460	LIEGE	MANN&DEVONIAN MU#1	Commingled	-112.986538	56.961923	261.6	28,264,676.2
527	250361	KIRBY	U & L MANN MU#1	Commingled	-110.753514	55.451622	327.0	35,382,327.9
597	306860	MARTEN HILLS	WBSK A & WAB A	Commingled	-113.870000	55.610000	688.1	35,856,082.3

The 76 large gas pools are, by and large, evenly distributed across northeastern Alberta, except for the northeastern corner where only oil sands deposits are present (Figure 6). Many of them are within relatively short distance from existing major pipelines. Obviously, pipeline infrastructure is already in place and this infrastructure could be used to reverse flow direction to the reservoir for CO_2 storage as opposed to gathering gas from the reservoir as it is now. The depth of the 76 gas pools with very large CO_2-storage capacity varies between 198 m and 950 m, with only three pools being at a depth greater than 800 m. Their combined CO_2 storage capacity is only ~8.8 Mt CO_2. Neglecting the shallower gas reservoirs from consideration, as generally recommended, would lead to losing significant CO_2 storage capacity, practically rendering the entire northeastern Alberta region unsuitable for CO_2 storage.

Besides these 76 gas reservoirs with individual capacity greater than 1 Mt CO_2 each, there are another 807 gas reservoirs in northeastern Alberta with storage capacity between 100 kt and 1 Mt CO_2, with cumulative capacity of ~212 Mt CO_2 (average ~263 kt CO_2). These reservoirs can also be used for CO_2 storage if the infrastructure costs are low.

Many gas reservoirs in the McMurray-Wabiskaw sedimentary succession in the Athabasca area overlie bitumen reservoirs. Production of the gas in these reservoirs normally leads to a drop in pressure ("pressure depletion"), and bitumen producers in the area have expressed concerns that this may negatively affect in the future the in situ production of bitumen using steam-assisted gravity drainage (SAGD). As a result, the Alberta Energy and Utilities Board (EUB) decided in 2000 to stop gas production in a number of gas pools that overlie bitumen reserves. There were 1862 gas pool members that were or could be affected by the EUB decision, and these group into 1051 gas pools on the basis of field and pool codes. Of these, 819 gas pools were matched with and identified with pools in the EUB 2004 reserves database (the mismatch for the other 232 pools is due to changes in reserves databases). Of the 819 matched pools, 783 are in the study area (651 uncommingled and 132 commingled gas pools), and these gas pools have considerable CO_2 storage capacity of ~185 Mt CO_2. This shows that repressuring of these gas pools with CO_2 from oil sands plants would achieve a dual objective of maintaining pressure in these gas reservoirs, thus preserving the ability to produce the underlying bitumen while producing the gas, and storing CO_2 from oil sands plants in the Fort McMurray area, thus reducing greenhouse gas emissions and allowing the development of oil sands resources in a responsible manner. Most of these gas pools are small, but there are 21 gas pools with CO_2 storage capacity greater than 1 Mt CO_2 each, the largest having 35 Mt CO_2 capacity. Given the dual objective of repressuring these gas reservoirs with CO_2, building the necessary infrastructure to utilize even the small gas pools may be economically justifiable.

The generally accepted depth for storing CO_2 is greater than 800 m, but this is based on reasons of storage effectiveness, since at depths greater than this CO_2 will likely be in dense supercritical phase, hence more CO_2 will be stored for the same volume of pore space. However, as long as containment is ensured, there is no reason not to store CO_2 at shallower depths where CO_2 would be in less-dense gaseous phase.

4 Conclusions

Alberta is currently the province with the highest CO_2 emissions in Canada, and these emissions are increasing at an accelerating pace as new oil sands plants, upgraders and other petrochemical facilities are being built. Fortunately for Alberta, on one hand a large percentage of CO_2 emissions originate in large stationary sources, and on the other hand the Alberta Basin, which underlies the province, provides a very large capacity for CO_2 storage in oil and gas reservoirs, deep saline aquifers and, potentially, in deep, unmineable coal beds. However, the Athabasca-Cold Lake region in northeastern Alberta has less potential for CO_2 storage because it is shallow, being close to the zero edge of the basin. Because the oil sands plants in the Athabasca area are very large CO_2 emitters, of the order of several megatonnes/year each, plans are being developed to construct a pipeline that would bring CO_2 from the Fort McMurray area to the southwest in central Alberta, where it will connect to a major Alberta CO_2 trunk pipeline. Notwithstanding the general lack of suitability for CO_2 storage of the northeastern part of Alberta, there are more than 5,000 gas reservoirs in the region that may serve as CO_2 sinks.

There are only 15 oil pools in northeastern Alberta, with insignificant CO_2 storage capacity compared with the ~609 Mt CO_2 potential capacity in ~5,300 gas pools. Most of the gas pools are small, with only less than 900 gas pools having CO_2 storage capacity greater than 100 kt CO_2, for a total of ~504 Mt CO_2. Of these, 76 gas pools have capacity greater than 1 Mt CO_2 each, for a total of 292 Mt CO_2. These gas pools are distributed almost evenly across northeastern Alberta, and are found at depths that vary between ~200 and 950 m. Upon depletion, these gas pools can be used for storing the CO_2 emitted by oil sands plants in the Athabasca area, allowing for a few decades of oil production with reduced atmospheric CO_2 emissions.

As a result of Gas-Over-Bitumen disputes between gas and bitumen producers in the Athabasca area, a significant number of gas pools in the McMurray-Wabiskaw sedimentary succession have been shut-in by EUB, or could be affected in the future. These gas pools have significant CO_2 storage capacity, estimated at greater than 185 Mt CO_2. Repressuring these gas pools with CO_2 from oil sands plants would achieve a dual objective of maintaining pressure in these gas reservoirs, thus preserving the ability to produce the underlying bitumen while producing the gas, and storing CO_2 from oil sands plants in the Fort McMurray area, thus reducing greenhouse gas emissions and allowing the development of oil sands resources in a responsible manner.

References

AGU (American Geophysical Union) (2003): AGU position statement on human impacts on climate change; EOS, Transactions AGU, v. 84, no. 51, 574 p.

Bachu, S. (2003): Screening and ranking of sedimentary basins for sequestration of CO_2 in geological media; Environmental Geology, v. 44, no. 3, p. 277-289.

Bachu, S. (2006): The capacity for CO_2 storage in oil and gas reservoirs in Alberta – An update; Report to Alberta Environment. 31 p.

Bachu, S. and Shaw, J.C. (2003): Evaluation of the CO_2 sequestration capacity in Alberta's oil and gas reservoirs at depletion and the effect of underlying aquifers; Journal of Canadian Petroleum Technology, v. 42, no. 9, p. 51-61.

Bachu, S. and Shaw, J.C. (2005): CO_2 storage in oil and gas reservoirs in western Canada: Effect of aquifers, potential for CO_2-flood enhanced oil recovery and practical capacity; Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Volume 1: Peer-Reviewed Papers and Overviews, E.S. Rubin, D.W. Keith and C.F. Gilboy (eds.), Elsevier, p. 361-369.

Bachu, S. and Stewart, S. (2002): Geological sequestration of anthropogenic carbon dioxide in the Western Canada Sedimentary basin: Suitability analysis; Journal of Canadian Petroleum Technology, v. 41, no. 2, p. 32-40.

Bachu, S., Shaw, J.C. and Pearson, R.M. (2004): Estimation of oil recovery and CO_2 storage capacity in CO_2-EOR incorporating the effect of underlying aquifers; SPE Paper 89340, presented at the Fourteenth SPE/DOE Improved Oil Recovery Symposium, Tulsa, OK, April 17-21, 2004, 13 p.

Bondor, P.L. (1992): Applications of carbon dioxide in enhanced oil recovery; Energy Conversion and Management, v. 33, p. 579–586.

Bryant, E. (1997): Climate Process and Change; Cambridge University Press, Cambridge, U.K., 209 p.

Doughty, C. and Pruess, K. (2004): Modeling supercritical carbon dioxide injection in heterogeneous porous media; Vadose Zone Journal, v. 3, no. 3, p. 837-847.

Edwards, K (2000): CO_2 in Alberta – A vision of the future; Journal of Canadian Petroleum Technology, v. 39, no. 9, p. 48-53.

Environment Canada (2002): Canada's Greenhouse Gas Inventory 1990-2000; Greenhouse Gas Division, EPS 5/AP/8, Environment Canada, ISBN 0-660-18894-5, 149 p.

Hadlow, R.E. (1992): Update of industry experience with CO_2 injection; SPE Paper 24928, presented at the Sixty Seventh SPE Annual Technical Conference, October 4-7, 1992, Washington, D.C., 10 p.

Holt, T., Jensen, J.I. and Lindeberg, E. (1995): Underground storage of CO_2 in aquifers and oil reservoirs; Energy Conversion and Management, v. 36, p. 535–538.

IEA (International Energy Agency) (2004): Prospects for CO_2 Capture and Storage; IEA/OECD, Paris, France, 249 p.

IPCC (Intergovernmental Panel on Climate Change) (2001): Climate Change 2001: Synthesis Report; R.T. Watson and the Core Writing Team (eds.), Cambridge University Press, Cambridge, U.K., and New York, NY, U.S.A., 397 p.

IPCC (Intergovernmental Panel on Climate Change) (2005): IPCC Special Report on Carbon Dioxide Capture and Storage; B. Metz, O. Davidson, H.C. de Coninck, M. Loos and L.A. Mayer (eds.), Cambridge University Press, Cambridge, U.K., and New York, NY, U.S.A., 442 p.

Kaya, Y. (1995): The role of CO_2 removal and disposal; Energy Conversion and Management, v. 36, p. 375-380.

Kovscek, A.R. (2002): Screening criteria for CO_2 storage in oil reservoirs; Petroleum Science and Technology, v. 20, no. 7-8, p. 841-866.

Shaw, J. and Bachu, S. (2002): Screening, evaluation, and ranking of oil reservoirs suitable for CO_2-flood EOR and carbon dioxide sequestration; Journal of Canadian Petroleum Technology, v. 41, no. 9, p. 51–61.

Socolow, R.H. (2005): Can we bury global warming?; Scientific American, v. 293, no. 1, p. 49-55.

Span, P. and Wagner, W. (1996): A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 1100 K at pressures up to 800 MPa; Journal of Chemical Reference Data, v. 25, no. 6, p. 1509-1596.

Stephenson, D.J., Graham, A.G. and Luhning, R.W. (1993): Mobility control experience in the Joffre Viking miscible CO_2 flood; SPE Reservoir Engineering, v. 8, no. 3, p. 183–188.

Stevens, S.H., Kuuskra, V.A. and Gale, J. (2001): Sequestration of CO_2 in depleted oil & gas fields: global capacity, costs and barriers; Proceedings of the 5th International Conference on Greenhouse Gas Control Technologies (GHGT- 5), D.J. Williams, R.A. Durie, P. McMullan, C.A.J. Paulson and A.Y. Smith (eds.), CSIRO Publishing, Collingwood, VIC, Australia, p. 278-283.

Taber, J.J., Martin, F.D. and Seright, R.S. (1997): EOR screening criteria revisited – part 1: introduction to screening criteria and enhanced recovery field projects; SPE Reservoir Engineering, v. 12, no. 3, p. 189–198.

Turkenburg, W.C. (1997): Sustainable development, climate change, and carbon dioxide removal (CDR); Energy Conversion and Management, v. 38S, p. S3-S12.

Winter, E.M. and Bergman, P.D. (1993): Availability of depleted oil and gas reservoirs for disposal of carbon dioxide in the United States; Energy Conversion and Management, v. 34, no. 9-11, p. 1177–1187.