CARBON CAPTURE, UTILIZATION, AND STORAGE FEASIBILITY STUDY FOR THE STRATHCONA INDUSTRIAL AREA

1 ABSTRACT

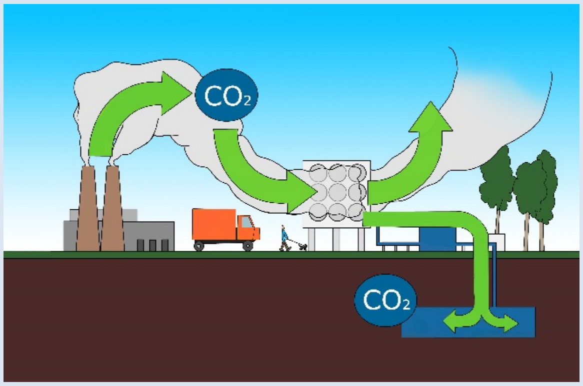
Carbon capture, utilization, and storage (CCUS) is the process of capturing carbon dioxide (CO_2) emissions to use in enhanced oil recovery (EOR) operations or to store in geological media. Alberta is unique in that the majority of the Alberta basin has been identified as suitable for CO_2 storage in geological media.

CCUS systems can be mega-scale (i.e., a storage hub utilized by multiple operators) or can be utilized on an individual project-scale. CCUS systems can be included in plans for upcoming projects or retrofitted into existing projects.

A critical first step in developing a CCUS system is conducting a desktop feasibility study to establish the regional geologic and hydrogeologic setting. This feasibility study is essential to determine geological formation temperature and pressure trends and ultimately, potential CCUS geologic targets.

There are various methods to store CO_2 within geological media; however, three were deemed the most appropriate for this study. They include CO_2 storage in saline aquifers, CO_2 storage in depleted gas reservoirs, and CO_2 for use in EOR operations.

Generally, aquifers used for CO_2 storage must be overlain by extensive, competent low permeability aquitards and have temperature and pressure conditions favourable for CO_2 to be stored in supercritical state.



These conditions are less important for hydrocarbon reservoirs since structural and stratigraphic traps have demonstrated good storage and sealing characteristics over geologic time. In the case of oil reservoirs, EOR with CO_2 may extend the production life of a mature reservoir by recovering stranded oil reserves.

A CCUS desktop feasibility assessment was conducted for the Strathcona Industrial Area located approximately 17 km southwest of Alberta's Industrial Heartland. Based on the feasibility assessment analysis methods and required criteria, six saline aquifers, one gas reservoir, and two oil reservoirs were identified as potential CCUS targets within the study area.

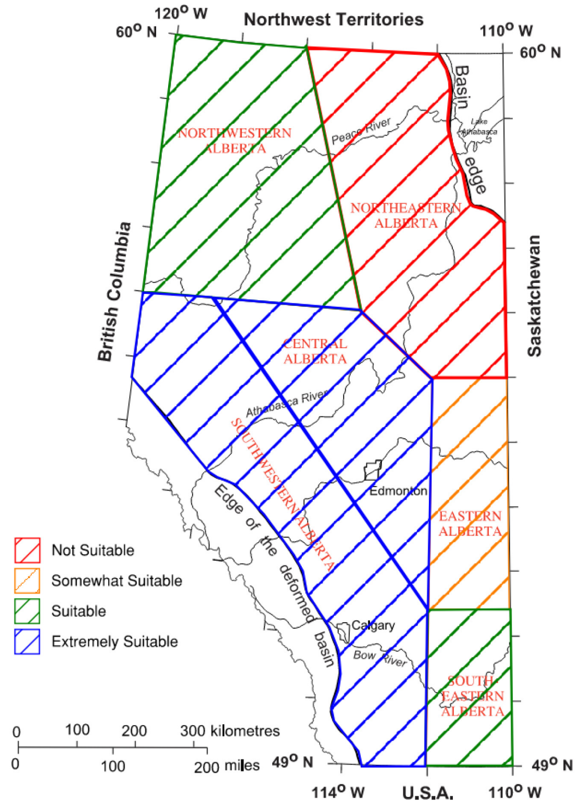
Following a feasibility assessment, a more detailed study including a focus on characterizing hydrostratigraphic units, groundwater flow patterns, caprock analysis, well penetration risks, permeability/porosity, injectivity, and regulatory and permitting requirements should be undertaken to reduce risks prior to field exploration and commercial development.

2 INTRODUCTION

Carbon capture, utilization, and storage (CCUS) is the process of capturing carbon dioxide (CO_2) emissions to use in enhanced oil recovery (EOR) operations or to store in geological media. CCUS can contribute to a reduction in greenhouse gas intensity and is an important component of Canada's transition to a low-carbon energy future.

Alberta is unique in its suitability for CCUS. Bachu et al. (2000) have identified that the majority of the Alberta basin is suitable for CO_2 storage in geological media. Another advantage is Alberta's large number of depleted hydrocarbon reservoirs which can be used for CO_2 application and/or storage.

CCUS systems can be scaled for various uses. Mega-scale CCUS systems allow for multiple industrial facilities to ship their CO_2 emissions to a central hub where it is then transported to a storage site and injected underground. Two such projects have been approved by the Alberta Government (2021): Shell Canada Energy's Quest Project and The Alberta Carbon Trunk Line (ACTL) Project. CCUS systems can also be utilized on an individual project-scale where CO_2 is captured and injected locally. Project-scale CCUS systems can be included in plans for upcoming projects or retrofitted into existing projects. Project-scale CCUS systems can be especially beneficial for projects that are located far away from CCUS hubs and/or otherwise constrained in terms of ability access hub infrastructure.



Alberta's suitability for CO_2 sequestration in geological media
*adapted from Bachu et al. 2000

A critical first step in developing a CCUS system is conducting a **desktop feasibility study** to establish the regional geologic and hydrogeologic setting. This feasibility study is essential to determining geological formation temperature and pressure trends and ultimately, potential CCUS geologic targets. The resulting regional findings can then be used to focus additional, more detailed, site-specific studies. This paper provides guidance on completing CCUS feasibility studies and includes a case study highlighting the process.

3 CCUS BACKGROUND

There are various methods to store CO_2 within geological media (Bachu et al. 2000). For purposes of this study, the following methods will be reviewed:

- CO_2 storage in saline aquifers
- CO_2 storage in depleted gas reservoirs
- CO_2 for use in EOR operations

Saline aquifers are defined as those containing groundwater with a total dissolved solids (TDS) concentration exceeding 4,000 mg/L (Province of Alberta 2021). There are two general criteria used for regional CO_2 storage screening studies in saline aquifers:

- Isolation from the surface by intervening thick, continuous, low permeability strata that provides for hydrodynamic trapping by virtue of long residence times.

- Temperatures greater than 31.1°C and pressures greater than 7.4 MPa. Under these pressure and temperature conditions, CO_2 still behaves as a gas but has a liquid density, approaching 900 kg/m^3 depending on the temperature and pressure (Bachu et al. 2000).

These criteria are less of a concern for depleted hydrocarbon reservoirs assuming injected CO_2 pressures will be maintained near or below the original static formation pressure. Hydrocarbon reservoirs in structural and stratigraphic traps have demonstrated good storage and sealing characteristics over geologic time and therefore can be used in CO_2 sequestration once a reservoir has been depressurized and is no longer exploited.

3.1 Storage Capacity

In general, saline aquifers have the largest storage capacity, oil and gas pools are well characterized, and EOR has unique economic drivers (CSLF 2007). These methods are discussed in the literature (e.g., CSLF 2007; Bachu et al. 2007, 2000) and are summarized below.

3.1.1 Carbon Dioxide Storage in Saline Aquifers

Suitable saline formations for CO_2 storage include deep aquifers composed of permeable sedimentary rock. The storage space comprised the intergranular and fracture pore volumes. The pore space is filled with high salinity water (brine) that possesses no significant value to commercial activities or animal and human consumption. Suitable sites must not only exhibit large pore volumes for CO_2 storage, but also high injectivity for CO_2 injection. Furthermore, the saline formations must be overlain by a low permeability layer (aquiclude or aquitard) to restrict CO_2 leakage to the surface or other sensitive subsurface layers (e.g., non-saline groundwater). Furthermore, the unique hydrodynamic conditions of the Western Canadian Sedimentary Basin can support confidence in long term storage ability of saline aquifers in areas where groundwater flow directions are against the structural dip, or basinward.

3.1.2 Carbon Dioxide Storage in Depleted Gas Reservoirs

Depleted gas reservoirs, or pools, provide the second largest class of storage options for CO_2 storage. Hydrocarbon (oil and gas) pools are comparable to aquifers in that they are composed of permeable sedimentary rock formations. CO_2 can be trapped in the reservoir pore space, and an overlapping impermeable layer (caprock) is necessary to restrict leakage. The presence of commercial oil and gas pools provides an assurance of the presence of a secure trap for CO_2. Throughout the hydrocarbon production process, the original gas is withdrawn from the pore space, thus creating a pressure and material deficit. If no injection (CO_2 or saline water) is undertaken to fill the voids; the surrounding formation water will invade the pore space. In the case of CCUS, this pore space is filled with injected CO_2 until the original formation pressure is attained.

The fundamental assumption that is commonly made for storage capacity calculation in the screening phase is that volume previously occupied by hydrocarbons becomes largely 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 by secondary and tertiary oil recovery. In reservoirs that are in hydrodynamic contact with an aquifer, formation water invades the reservoir as pressure is depleted. This leads to a decrease in pore space for CO_2 storage, but CO_2 injection can partially reverse the aquifer influx.

Another important assumption is that CO_2 will be injected into depleted reservoirs until the reservoir pressure is brought back to the original static formation pressure. In some cases, reservoir depletion may damage the integrity of the reservoir and/or caprock, in which case the reservoir pressure cannot be increased to the original static formation pressure, while in other cases the pressure can be increased beyond the original static formation pressure as long as it remains below the lesser of the capillary entry pressure and the formation fracturing pressure of the caprock (CSLF 2007). Hence, raising the storage pressure to or beyond the original static formation pressure requires further site-specific assessment. Finally, in many cases, the structure that hosts a hydrocarbon reservoir is not filled to the spill point (structurally lowest point that can retain hydrocarbons). In such cases, additional pore space down to spill point can be used for CO_2 storage but requires increasing the reservoir pressure beyond the original static formation pressure.

3.1.3 Carbon Dioxide for use in Enhanced Oil Recovery Operations

In some cases, EOR, a CCUS variation, and decades old tertiary oil production process, may extend the production life of a mature well by recovering stranded oil reserves. Typically, primary oil production recovers up to only 30% of the original oil in place (OOIP). Secondary production practices (e.g., water flooding) raise the production from 20% to 50% of OOIP. Tertiary practices (EOR with CO_2) recover much of the remaining stranded oil reserves. In excess of 100 EOR operations have been deployed over the last three decades; one of the most noted being the Weyburn-Midale EOR project (PTRC 2021). In general, this experience provides proof-of-concept in that CO_2 can be successfully injected underground in large volumes. However, what was also learned is that both injectivity (the ease with which CO_2 is injected into a formation) and oil recovery rates vary considerably from location to location.

The purpose of CO_2 EOR is to generate multiple contact miscibility of the resident oil with CO_2 and displace the oil using this miscible bank. CO_2

has significant solubility in most reservoir crudes. At first contact, CO_2 and oil form two phases, a CO_2-rich carbonic phase and an oil-rich phase that contains about 80 mole percent CO_2. The less viscous carbonic phase moves forward and extracts more hydrocarbons until it becomes fully miscible with the oil. Theoretically, the miscible front displaces oil without leaving a residual oil phase; however, the geologic complexities and other heterogeneities in the system make this impossible to accomplish in practice. Nevertheless, CO_2 occupies most of the vacant pore and intergranular space created by the displaced oil reserves. The CO_2 flood for EOR is continued even after CO_2 breakthrough as a small associated fraction of oil is produced. This requires a large amount of CO_2 to be recycled into the reservoir.

Currently in most EOR projects, naturally occurring CO_2 is typically used and the process is not necessarily conducted to optimize CO_2 storage upon project closure. For EOR to be a valid greenhouse gas mitigation process, EOR best practices will need to be adjusted to inject anthropogenic CO_2, recycle any breakthrough CO_2 at the production wells, and optimize operations to maximize the volume of stored CO_2 as the reservoir depletes of oil.

4 CCUS FEASIBILITY ASSESSMENT PROCESS

To conduct a CCUS feasibility assessment and determine potential geological targets, a regional geologic framework needs to be established. This framework will be used to define equivalent hydrostratigraphy based on regional flow characteristics and defined as (from Bachu et al. 2007):

- aquifers – layers, formations, or group of formations of permeable rocks, saturated with water and with a degree of permeability that allows water withdrawal through wells

- aquitards – porous layers or beds from which water cannot be produced through wells but where the vertical flow is significant enough over large areas to feed adjacent aquifers

- aquicludes – layers or beds that have generally very low permeability

On a regional scale, the above classification is based on lithology, given the general hydraulic properties of rock types. Carbonates and sandstones are generally considered aquifers, siltstones, and shales are considered aquitards and salt beds are considered aquicludes. Groundwater flow is predominantly lateral in aquifers and vertical in the aquitards and aquicludes. In comparison to petroleum reservoir engineering terminology, the typical range in flow and storage properties is similar between aquifers and petroleum reservoirs. The main distinguishing factor is the typically larger areal extent of aquifers. In addition, caprock or seal in reservoir engineering terminology is comparable to aquitards and aquicludes in hydrogeology.

Hydrostratigraphic units are appropriate for the screening phase as the purpose is to develop a regional framework that focuses more detailed studies in the next phases. There can be a degree of heterogeneity within each hydrostratigraphic unit that would need to be characterized once the targets have been identified to optimize things like well placement and injectivity rates.

4.1 Analysis Methods

Once the regional hydrostratigraphy has been established, the following criteria can be considered to identify potential target aquifers and reservoirs:

Aquifers:

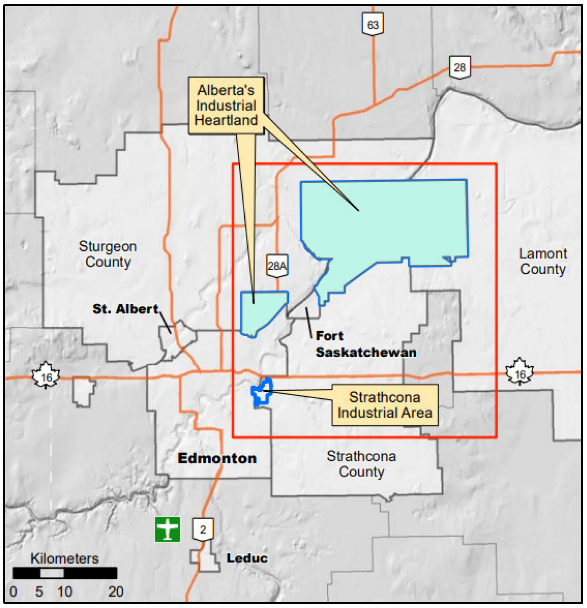
- Regional groundwater flow systems: Generally speaking, where present the Colorado Group separates overlying local and intermediate groundwater flow systems from underlying, more isolated regional groundwater flow systems with relatively long residence time.
- Aquitards: an overlying competent, regionally extensive aquitard prevents CO_2 leakage.
- Continuity and thickness: relatively thick and laterally continuous aquifers are ideal candidates.
- Temperature and pressure: aquifers require temperature and pressure conditions that allow for injected CO_2 to be in supercritical state.
- Base of Groundwater Protection: The depth at which saline groundwater (TDS concentration greater than 4,000 mg/L) begins. Generally, aquifer salinity increases with depth.

Reservoirs:

- Presence: pool maps can be used to determine if a reservoir is present within the area of interest.
- Production: historical hydrocarbon production can be used to approximate injection capacity and should be in excess of the projected CO_2 volume to be injected over the life of the project.
- Age and history: depleted reservoirs at the end of economic life are more amenable to transition to CCUS projects. Conversely, old fields with many well penetrations would need to be investigated to qualify the relative risk due to potential casing failures or leakage through the annular seal.

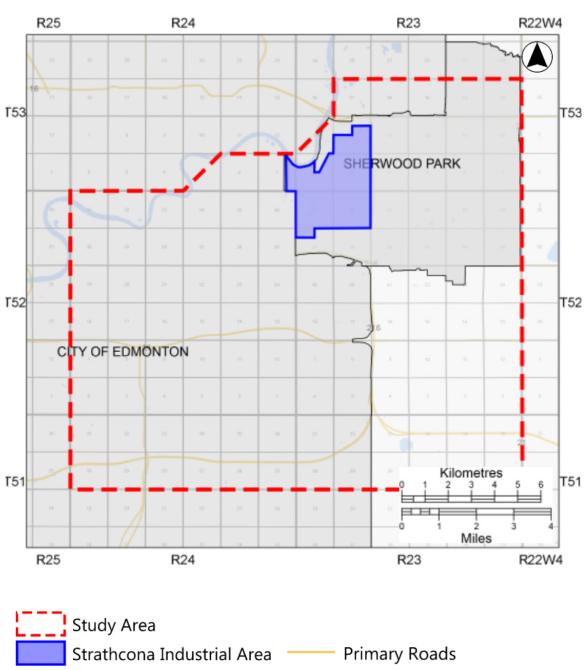
5 CASE STUDY

Matrix Solutions Inc. completed a CCUS feasibility study for the Strathcona Industrial Area (SIA) located in Sherwood Park, AB approximately 17 km southwest of Alberta’s Industrial Heartland. The SIA falls within Central Alberta where the Alberta basin is rated as “extremely suitable” for CO_2 storage (Bachu et al. 2000.)



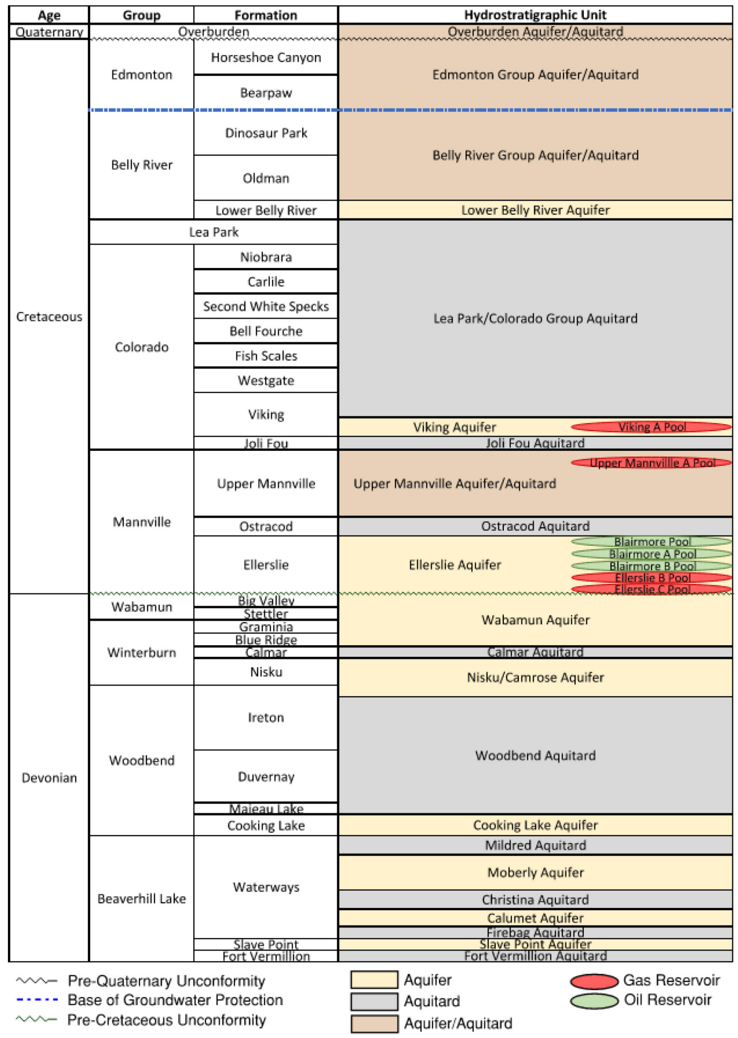
Case Study: Location of SIA
*Alberta's Industrial Heartland 2019

A study area (SA) was developed and encompassed approximately 117 sections around the SIA in townships 051 to 053 and ranges 23 to 24 W4M.

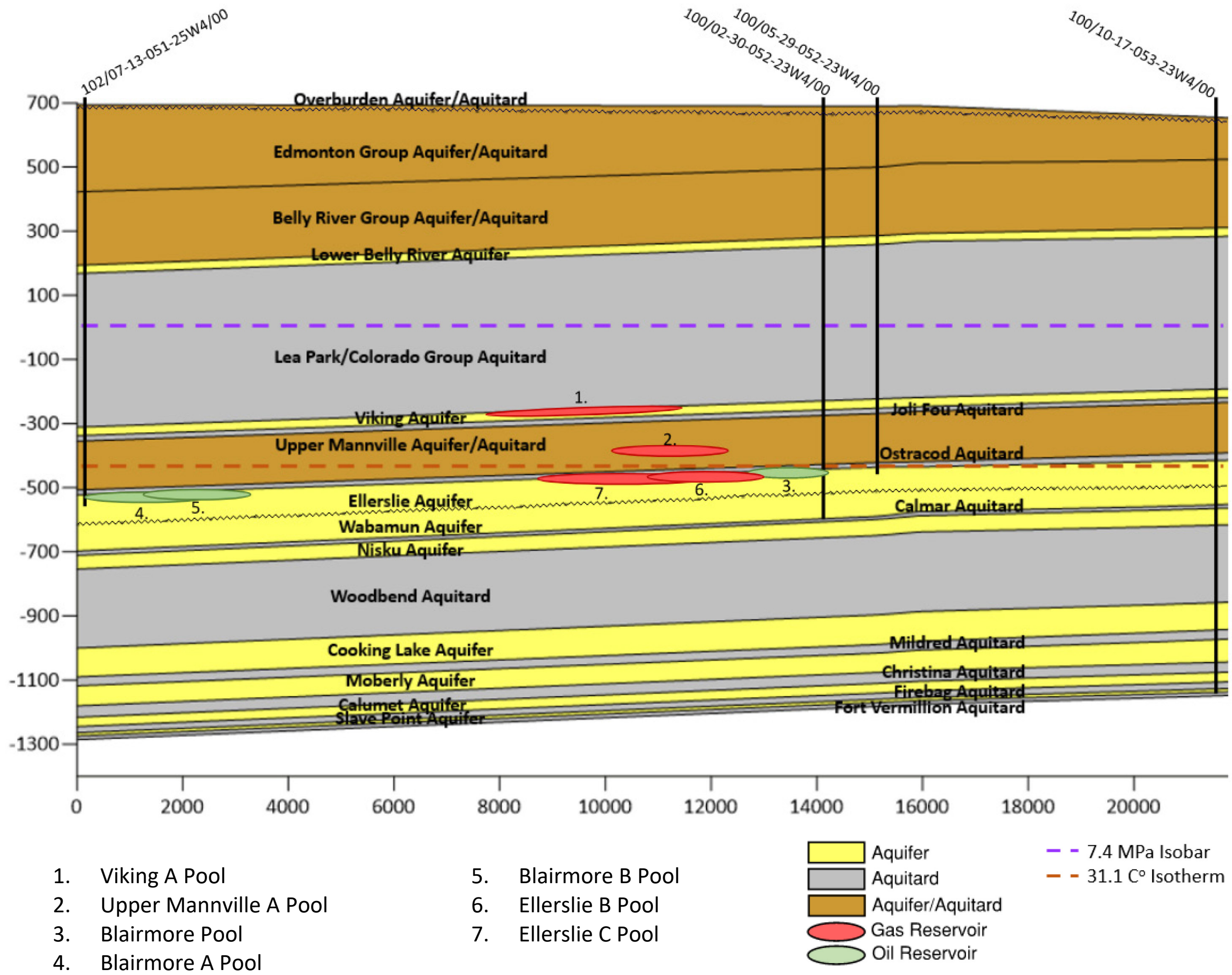


Case Study: Study Area

A hydrostratigraphic column was developed to define the geologic and hydrogeologic framework of the SA. Formations of the Cretaceous and Upper Devonian ages were considered.



Case Study: Hydrostratigraphic Column



Case Study: Hydrostratigraphic SW-NE Cross-section

The extent, thickness, and distribution of the hydrostratigraphic units within the SA were characterized by using geophysical well log data.

Based on analysis methods and required criteria, six saline aquifers, one gas reservoir, and two oil reservoirs were identified as potential CCUS targets within the SA. For hydrocarbon reservoirs, a historical cumulative barrels of oil equivalent (BOE) production of at least 333 thousand barrels (Mbbl; or approximately 2 billion cubic feet of gas) was used as a cut-off. This cut-off equates to a hypothetical injection capacity for an industrial project.

5.1 Saline Aquifers

The Ellerslie, Wabamun, Nisku, Cooking Lake, Moberly, and Calumet aquifers were determined to be potential storage targets. These aquifers are located below the Colorado Group and have isolated regional groundwater flow systems with relatively long residence times. All are relatively thick and continuous. Pressure and temperature data indicate that these aquifers will allow for injected CO_2 to be in supercritical state.

TABLE A Summary of Potential Aquifer Targets

Aquifer Name	Formation	Approximate Depth* (m)	Average Thickness* (m)	Original Aquifer Pressure* (MPa)	Average Temperature* (deg C°)	Number of Active Wells*		
						Hydrocarbon Production	Groundwater Production	Disposal
Ellerslie Aquifer	Ellerslie	1,142	51.0	8.1	40	0	0	0
Wabamun Aquifer	Big Valley, Stettler, and Graminia	1,210	82.0	8.1	40	0	0	0
Nisku/Camrose Aquifer	Nisku and Ireton	1,249	48.0	9.7	44	0	0	8
Cooking Lake Aquifer	Cooking Lake	1,570	90.0	12.8	47	0	0	0
Moberly Aquifer	Waterways	1,620	70.0	---	---	0	0	0
Calumet Aquifer	Waterways	1,730	25.0	---	---	0	0	0

* Evaluated over Study Area extent

--- No data available

5.1.1 Ellerslie Aquifer

The Ellerslie Aquifer consists of the lower, quartz sandstone-dominated portion of the Ellerslie Formation. It is overlain by the Ostracod Aquitard, which is on average 30 m thick within the SA. Hydrocarbon production data in the SA indicates that the aquifer contains local gas and oil accumulations that are economic reservoirs that were historically exploited in the SA.

5.1.2 Wabamun Aquifer

The Wabamun Aquifer consists of the limestones and dolomites of the Big Valley and Stettler formations, and sandstones of the Graminia Formation. It is overlain by the Ellerslie Aquifer, and there is likely hydraulic communication between these two units.

5.1.3 Nisku/Camrose Aquifer

The Nisku/Camrose Aquifer consists of the dolomites of the Nisku Formation and Camrose member of the Ireton Formation. It is overlain by thin evaporites at the top of the Nisku Formation and by the siltstones and shales of the Calmar Formation. Together, these comprise the Calmar Aquitard, which is on average 10 m thick within the SA. Injection data in the SA indicates that the aquifer is currently used for disposal purposes.

5.1.4 Cooking Lake Aquifer

The Cooking Lake Aquifer consists of the limestones of the Cooking Lake Formation. It is overlain by the Woodbend Aquitard, which is on average 250 m thick within the SA.

5.1.5 Moberly Aquifer

The Moberly Aquifer consists of the dolomites of the Moberly member of the Waterways Formation. It is overlain by the Mildred Aquitard, which is on average 28 m thick within the SA.

5.1.6 Calumet Aquifer

The Moberly Aquifer consists of the limestones of the Calumet member of the Waterways Formation. It is overlain by the Christina Aquitard, which is on average 33 m thick within the SA.

5.1.7 Saline Aquifers Not Considered

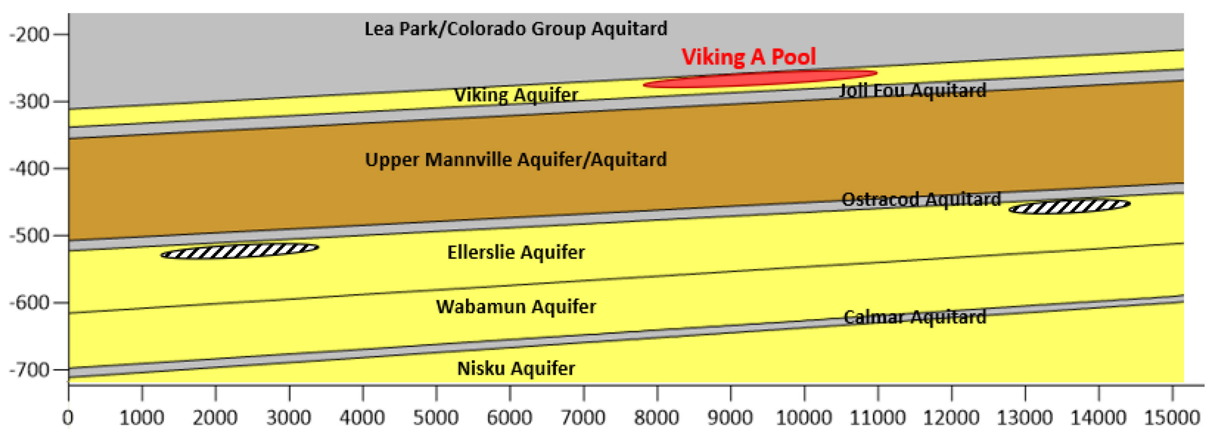
The Lower Belly River, Viking, and Slave Point aquifers were also identified; however, these aquifers were deemed poorly developed and/or too thin to be utilized for CO_2 storage. Furthermore, the Lower Belly River Aquifer did not have a temperature of greater than 31.1°C and did not meet conditions for CO_2 to be in a supercritical state.

5.2 Depleted Gas Reservoirs

The Viking A Pool was determined to be the only high productivity, depleted gas reservoir in the SA that is a potential storage target.

TABLE B Summary of Potential Gas Reservoir Targets

Pool Name	Formation	Approximate Depth (m)	Reservoir Pressure			Production			
			Original (MPa)	Most Recent (MPa)	Most Recent Date	First Date	Last Date	Number of Wells	BOE (Mbbl)
Viking A	Viking	1,158	5.5	4.9	1977-06-01	1972-11-01	1992-12-31	3	591



5.2.1 Viking A Pool

The Viking A Pool is a gas pool within the Viking Formation. The pool was estimated to have had an initial reservoir pressure of 5.5 MPa. The most recent reservoir pressure was 4.9 MPa measured in June 1997, approximately 15 years before the last recorded production date (December 1992), and is likely not representative of the current reservoir pressure. The pool has a low density of wells which have produced a total cumulative gas amount of approximately 3.5 Bcf (or barrel of equivalent energy amount of 591 Mbbl). The production wells were abandoned in 1986 and 1991. High cumulative production data indicates that the Viking A Pool may have large CO_2 storage potential.

5.2.2 Depleted Gas Reservoirs Not Considered

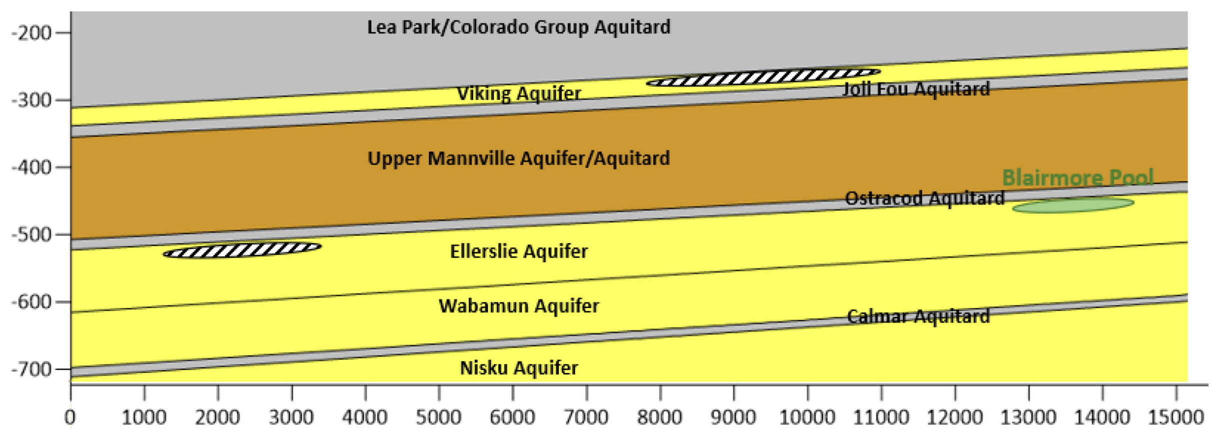
The Upper Mannville A, Ellerslie B, and Ellerslie C pools were also identified; however, these pools did not have a historical cumulative BOE production of at least 333 Mbbl to meet the hypothetical CO_2 injection capacity.

5.3 Enhanced Oil Recovery Operations

The Blairmore and Blairmore B pools were determined to be potential EOR operation targets.

TABLE C Summary of Potential Oil Reservoir Targets

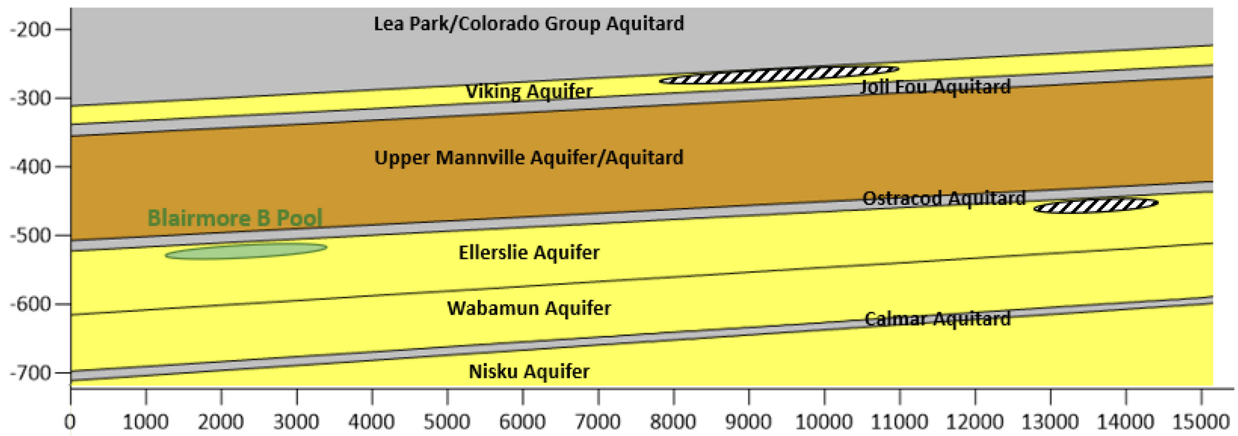
Pool Name	Formation	Approximate Depth (m)	Reservoir Pressure			Production			
			Original (MPa)	Most Recent (MPa)	Most Recent Date	First Date	Last Date	Number of Wells	BOE (Mbbl)
Blairmore	Ellerslie	1,195	7.4	6.9	1965-05-26	1952-01-22	2007-09-30	12	1,193
Blairmore B	Ellerslie	1,166	9.5	5.9	1965-06-16	1951-05-08	1969-06-30	5	497



5.3.1 Blairmore Pool

The Blairmore Pool is an oil pool within the Ellerslie Formation. The pool is estimated to have had an initial reservoir pressure of 7.4 MPa. The most recent reservoir pressure was 6.9 MPa measured in May 1965, approximately 42 years before the last recorded production date (September 2007), and is likely not representative of the current reservoir pressure.

The pool has a high density of wells which have produced a total cumulative BOE amount of approximately 1,193 Mbbl. As of November 2019, all wells were abandoned except for one which is suspended. Eight wells in this pool are either deviated or horizontal and have been stimulated via hydraulic fracturing indicating that the reservoir native permeability may be relatively lower than other reservoirs in the area.



5.3.2 Blairmore B Pool

The Blairmore B Pool is an oil pool within the Ellerslie Formation. The pool is estimated to have had an initial reservoir pressure of 9.5 MPa. The most recent reservoir pressure was 5.9 MPa measured in June 1965, approximately 4 years before the last recorded production date (June 1969). The pool has a low density of wells which have produced a total cumulative BOE amount of approximately 497 Mbbl. As of August 1970, all production wells were abandoned.

5.3.3 EOR Operations Not Considered

The Blairmore A Pool was also identified; however, the pool did not have a historical cumulative BOE production of at least 333 Mbbl to meet the hypothetical CO_2 injection capacity.

6 CONCLUDING DISCUSSION AND NEXT STEPS

Based on the feasibility assessment analysis methods and required criteria, six saline aquifers, one gas reservoir, and two oil reservoirs were identified as potential CCUS targets within the SA centred on the SIA.

After deciding on a preferred CCUS target, a more detailed study with the following next steps are recommended:

- a more detailed investigation of historical well penetrations through the target reservoir or aquifer including development of a relative risk based on completions and age of wells
- a geomechanical study for target reservoir including identification of regional stress field and caprock fracture pressure
- top structure and net isopach maps for target unit and caprock
- a compilation of reservoir porosity and permeability information from available core analysis and pressure transient tests (i.e., drill stem tests [DSTs])
- an estimate of injectivity of target unit using compiled permeability and pressure information and analytical methods
- a detailed review of pressures to establish the regional groundwater flow patterns
- identification of regulatory approvals, permits, and tenure requirements necessary for EOR and CO_2 sequestration projects in Alberta

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