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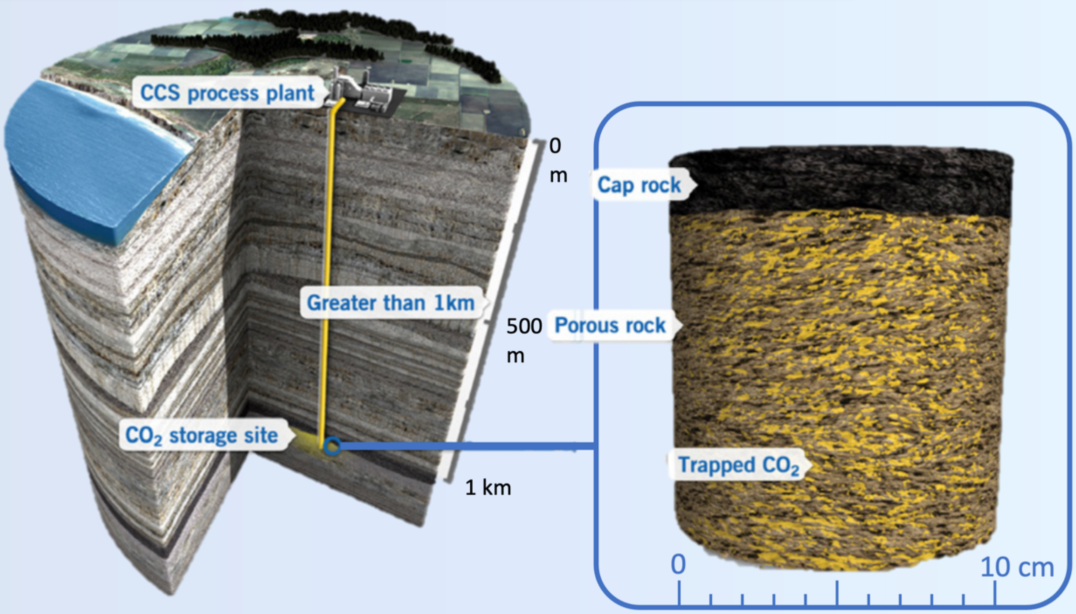
# REVIEW OF CARBON-DIOXIDE STORAGE POTENTIAL IN WESTERN CANADA:

## BLUE HYDROGEN ROADMAP TO 2050

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The Transition Accelerator
L'Accélérateur de transition

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## BLUE HYDROGEN ROADMAP TO 2050

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# ABOUT THE TRANSITION ACCELERATOR

The Transition Accelerator (The Accelerator) exists to support Canada's transition to a net zero future while solving societal challenges. Using our four-step methodology, The Accelerator works with innovative groups to create visions of what a socially and economically desirable net zero future will look like and build out transition pathways that will enable Canada to get there. The Accelerator's role is that of an enabler, facilitator, and force multiplier that forms coalitions to take steps down these pathways and get change moving on the ground.

Our four-step approach is to understand, codevelop, analyze and advance credible and compelling transition pathways capable of achieving societal and economic objectives, including driving the country towards net zero greenhouse gas emissions by 2050.

**1** UNDERSTAND the system that is being transformed, including its strengths and weaknesses, and the technology, business model, and social innovations that are poised to disrupt the existing system by addressing one or more of its shortcomings.

**2** CODEVELOP transformative visions and pathways in concert with key stakeholders and innovators drawn from industry, government, indigenous communities, academia, and other groups. This engagement process is informed by the insights gained in Stage 1.

**3** ANALYZE and model the candidate pathways from Stage 2 to assess costs, benefits, trade-offs, public acceptability, barriers and bottlenecks. With these insights, the process then re-engages key players to revise the vision and pathway(s), so they are more credible, compelling and capable of achieving societal objectives that include major GHG emission reductions.

**4** ADVANCE the most credible, compelling and capable transition pathways by informing innovation strategies, engaging partners and helping to launch consortia to take tangible steps along defined transition pathways.

# ABOUT THE AUTHORS

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**Richard Hares** is Principal, Carbon Management for Sproule, a global energy advisory firm, where he manages the Carbon Management practice area and helps clients chart the pathways to a net-zero future. He was previously a Geological $CO_2$ Storage Engineer at the University of Calgary, where he worked on mapping of geological $CO_2$ storage potential in Western Canada, provided insight into carbon dioxide storage resources required to support future low-carbon intensity products, and developed analytical tools for carbon capture and storage. Richard is a professional engineer with experience in resource evaluation and development as a petroleum and geological storage engineer, having worked in both Canada and the United Kingdom. Richard holds an M.Sc. in Sustainable Energy Development from the University of Calgary.

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## David B. Layzell PhD, FRSC

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# LIST OF ABBREVIATIONS

| ABBREVIATION | DEFINITION |
|---|---|
| ACTL | Alberta Carbon Trunk Line |
| AIH | Alberta Industrial Heartland |
| bbls/d | Barrels per day |
| boe/d | Barrels of oil equivalent per day |
| Blue Hydrogen | Hydrogen produced from natural gas and carbon capture and storage |
| CCS | Carbon Capture and Storage |
| CCUS | Carbon Capture Utilization or Storage |
| $CO_2$ | Carbon Dioxide |
| $CO_2e$ | Carbon Dioxide equivalent |
| $CO_2$-EOR | $CO_2$ Enhanced Oil Recovery |
| EERC | Energy and Environment Research Center |
| GHG | Greenhouse Gas |
| Gt | Gigatonne (thousand million metric tonnes) |
| H2 | Hydrogen gas |
| IEA | International Energy Agency |
| PCOR | Plains $CO_2$ Reduction Partnership |
| PTRC | Petroleum Technology Research Centre |
| MMbbls | Million barrels |

| | |
|---|---|
| Mt | Million metric tonnes |
| NATCARB | National Carbon Sequestration Database |
| NETL | National Energy Technology Laboratory |
| SMR | Steam Methane Reforming |
| SPE | Society of Petroleum Engineers |
| SRMS | Storage Resource Management System |
| WAG | Water-alternating-gas |

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# PREFACE

As of June 2021, 137 countries of the world, including Canada, have committed to net zero greenhouse gas (GHG) emissions, 90% of which have identified a target date of 2050. Renewable and nuclear energy will play a significant role, but given the scale of the challenge, the rate at which we must reduce emissions, and the economics of alternatives, there is a global consensus that carbon capture utilization and geological storage (CCUS) must play a significant role in the transition to net zero.

In the early stages of this transition, CCUS could help to reduce the emissions footprint of fossil carbon-based energy carriers (like gasoline, diesel, or natural gas) that dominate current energy systems. However, since the combustion of these fuels generates large GHG emissions, they must ultimately be replaced with zero-carbon (or carbon neutral) energy carriers like electricity and hydrogen that are themselves produced with very low, if not zero emissions.

The use of fossil fuels (or biomass) to produce low-emission hydrogen and electricity centralizes the generation of $CO_2$, creating the potential for CCUS to be a pillar in the transition to net-zero. However, this can only work if there is sufficient, economically viable geological storage capacity.

This study summarizes what is known about the CCUS potential in the Western Canadian Sedimentary Basin (WCSB), home to most of Canada's oil and gas operations.

# EXECUTIVE SUMMARY

The Canadian federal and provincial governments have identified carbon capture, utilization, and storage (CCUS) as a major component of their strategies to reduce greenhouse gas (GHG) emissions. Recent announcements have included a federal commitment to achieve net-zero GHG emissions by 2050, and a 40-45% emission reduction target by 2030. To achieve these targets, the federal government has set out a carbon pricing strategy to 2030, a Hydrogen Strategy for Canada, and a commitment to explore an investment tax credit system for carbon capture and storage.

The global interest in hydrogen as a zero-emission energy carrier/fuel has renewed interest in CCUS since relatively low-cost "blue" hydrogen can be made by reforming natural gas and preventing the resulting carbon dioxide ($CO_2$) from being released to the atmosphere. For every kilogram of blue hydrogen being produced, 8 to 9 kg of $CO_2$ must be captured and sequestered.

This report offers a review of $CO_2$ storage projects in the Western Canadian Sedimentary Basin (WCSB), discusses the $CO_2$ storage resources in the WCSB, identifies knowledge gaps and suggests strategies for future CCUS deployment. This $CO_2$ storage potential is not only critical for Canada's Hydrogen Strategy, but also for decarbonization of the existing fossil economy in Western Canada.

Western Canada has both world-class storage geology and large in-place oil in mature reservoirs suitable to store $CO_2$. In 2019, $CO_2$ emissions from large stationary, industrial sources were 129 Mt $CO_2$/yr in Alberta. When combined with future $CO_2$ storage required to support blue hydrogen, CCUS demand could amount to hundreds of millions of tons per year by 2050. For example, meeting the 2050 targets in the federal Hydrogen Strategy for Canada using blue hydrogen would create a CCUS demand of nearly 200 Mt$CO_2$/y. Currently, 4.8 Mt of $CO_2$ per year is stored in Western Canada, 3.6 Mt through $CO_2$-enhanced oil recovery ($CO_2$-EOR), with the majority going into the Weyburn field $CO_2$-EOR project in Saskatchewan. The remainder, 1.2 Mt of $CO_2$ per year, is stored through saline aquifer storage projects – Quest and Aquistore.

$CO_2$ storage opportunities have been studied extensively in Western Canada through basin- and regional-scale studies as well as project- and site-specific studies tied to existing $CO_2$ sources. Conclusions from these past studies are encouraging – the $CO_2$ storage potential is massive. Western Canada has been estimated to have a $CO_2$ storage resource of 360 gigatonnes (Gt) in saline aquifers alone, with 78 Gt in Alberta.

> "…storage potential in Alberta alone is sufficient for 390 years of $CO_2$ injection at 200 Mt$CO_2$/y."

To provide a sense of scale for this number, if the Alberta resource was converted to proven capacity, it would be sufficient for 390 years of $CO_2$ injection at 200 Mt $CO_2$/yr. There are also 870 Mt of $CO_2$ storage potential through $CO_2$-EOR and many gigatonnes of $CO_2$ storage potential through depleted gas pools in

Alberta. The challenge is to increase the resolution in storage resource estimates and, in the process, identify economically viable storage capacity that can be used to support transformation of the energy system.

Storage projects have demonstrated conclusively that $CO_2$ storage resources can be converted to economically viable storage capacity. That said, despite having sources of $CO_2$, large storage resources, and key infrastructure, there are few operating storage projects today in Western Canada. While many saline aquifer, site-specific storage projects have been proposed and studied, only four projects – Shell Quest, Aquistore, Project Pioneer, and Fort Nelson CCS Project – have proceeded past the reservoir characterization phase to drilling pilot evaluation wells. Of these, only Quest in Alberta and the Aquistore project in Saskatchewan are operating today. Both projects are providing dedicated storage for their associated $CO_2$ sources. These two projects account for the only $CO_2$ storage capacity, 55.8 Mt, that is considered a storage resource with a high level of certainty.

For Canada to transform the energy system and meet our net-zero targets, particularly using hydrogen and CCUS, $CO_2$ storage projects must be accelerated, with a focus on areas that have already been partially de-risked through past studies or are lower-risk due to the presence of existing infrastructure. At a demand for $CO_2$ storage capacity of 200 Mt per year by 2050, Western Canada would require more than 150 Quest-sized $CO_2$ storage projects to support future blue hydrogen production alone.

> "…$CO_2$ storage opportunities need to be de-risked and matured at a faster pace to support both future emission reduction targets and blue hydrogen production."

Future $CO_2$ storage development will be driven, in part, by the proximity to $CO_2$ emissions sources. The Alberta Industrial Heartland and Central Alberta are strategically positioned for future CCUS projects given the clustering of current $CO_2$ emissions sources, future demand for blue hydrogen, and proximity to deep saline aquifer storage and $CO_2$-EOR potential. Development of large, easily accessible geologic storage capacity in these areas could enable production of low-emission hydrogen and accelerate the transition to net-zero.

# 1 INTRODUCTION

Carbon dioxide capture, utilization, and storage (CCUS) in geological media is a proven technology that can reduce anthropogenic carbon dioxide ($CO_2$) emissions known to be the largest contributor to global climate change. In CCUS, $CO_2$ is captured from an emissions source, compressed to make it suitable for transport, and moved to a location where the geology is suitable for its injection and storage.[1] In some cases, this $CO_2$ may be utilized in enhanced oil recovery (EOR) where, in the process of storage, it allows additional oil to be extracted from aging oilfields. Canada has demonstrated knowledge and technology to capture and store $CO_2$ through the current operating large-scale saline aquifer storage and $CO_2$-EOR projects: Weyburn, Midale, Aquistore, Quest and Clive, among others.

Geological storage of $CO_2$ has been identified by the province of Alberta and the federal government as a major component of their strategies for reducing greenhouse gas emissions. To date, the province has committed over $1.2 billion to two CCS projects in Alberta: Quest and Alberta Carbon Trunk Line (ACTL) [1]. In addition, the province has created a world-leading regulatory framework for CCUS that addresses many of the challenges associated with geologic storage of $CO_2$ [2]. At the federal level, the 2021 budget stated that CCUS is an important tool for Canada to achieve net-zero by 2050. The importance of CCUS is reflected in the allocation of $319 million over seven years to support research and demonstration to improve the commercial viability of CCUS technologies, and the promise to introduce an investment tax credit for capital invested in CCUS projects to reduce emissions by at least 15 million tonnes (Mt) of $CO_2$ annually [3]. The Canadian federal government also announced plans in December 2020 to increase the federal carbon tax from $50/tonne in 2022 to $170/tonne by 2030 [4]. The $170/tonne carbon tax should also incentivize industry to invest further in CCUS projects.

*"...CCUS is an important tool for Canada to achieve net-zero by 2050."*

The Hydrogen Strategy for Canada was also announced by the federal government in December 2020. This outlined the future hydrogen demand goal of up to 4 Mt per year by 2030 and 20 Mt per year by 2040, with the equivalent greenhouse gas emissions abatement of 45 Mt $CO_2e$ and 190 Mt $CO_2e$ per year, respectively [5].[2] The Hydrogen Strategy envisions production of hydrogen both from water electrolysis and reforming of natural gas with capture of the resulting $CO_2$ emissions, commonly referred to as "green" and "blue" hydrogen, respectively. Western Canada is well-positioned to be a leader in blue hydrogen production [6]. In line with the Hydrogen Strategy, the $CO_2$ storage requirement from blue hydrogen production alone could

[1] The term "geologic $CO_2$ sequestration" is sometimes used instead of "geologic $CO_2$ storage" with the same meaning. We use the latter term in this report.
[2]Assumes all GHG emissions abated are from blue hydrogen, used to support transportation, and that the emissions are reduced by 80% to 95% relative to the incumbent gasoline or diesel fuels [6].

grow to almost 200 Mt per year.[3] The demand for $CO_2$ storage capacity could increase further if the potential for a future hydrogen export market materializes. This means that, if blue hydrogen is to play a significant role in the future energy system in Western Canada, geological $CO_2$ storage capacity will need to grow substantially.

***Do the storage resources exist to meet this demand and what will it take to convert them to usable storage capacity?*** This report addresses this question by reviewing past work on the geological $CO_2$ storage resource potential of the Western Canadian Sedimentary Basin. It also recommends policy, research, and investment activities to further assess and convert this resource into usable storage capacity in order to support Canada in achieving its 2050 net-zero targets.

[3] Reforming natural gas into “blue" hydrogen results in around 9 kg $CO_2$ captured for every kg $H_2$ produced [6].

# 2 IDENTIFYING $CO_2$ STORAGE OPPORTUNITIES

Geological $CO_2$ storage is a major component of the path to industrial sector decarbonization and blue hydrogen production. In geologic storage, $CO_2$ is injected into a well characterized and carefully selected geological formation where it is expected to be permanently retained and kept away from the atmosphere. $CO_2$ storage and the technologies associated with it are well understood. They have been implemented for decades by the petrochemical and oil and gas industries through $CO_2$-enhanced oil recovery ($CO_2$-EOR), acid gas ($CO_2$ and $H_2S$) disposal, and wastewater disposal [7]. Furthermore, the best practices in geological storage have been described in Canadian and International standards [8], [9]. There are many ways to store $CO_2$ in geological media, most notably:

- Injection into deep saline aquifers,
- Use in $CO_2$-EOR,
- Injection into depleted gas reservoirs.

There are several important criteria to consider when analyzing the suitability of a geological media for $CO_2$ storage. Geology suitable for $CO_2$ storage must have:

1) **Capacity**: the formation has enough space in pores of the rock (known as "pore space") to hold a significant volume of $CO_2$;
2) **Injectivity**: the formation has sufficient injectivity for the formation to accept the $CO_2$ at the rate that is delivered from the source; and
3) **Containment**: the formation must be able to indefinitely confine the injected $CO_2$ safely underground to ensure storage and integrity [10], [11].

Formation depth, temperature, pressure and salinity, faulting and fracturing, and proximity to existing activities and major sources of $CO_2$ must all be considered [12] in evaluating these three key criteria. The temperature and pressure determine the phase in which the fluid exists and, thus, density of the stored $CO_2$. The pressure and temperature of the formation are generally correlated with depth – the greater the depth, the higher the temperature and pressure. Storage at depths and, thus, pressures sufficient for $CO_2$ to exist as a liquid or supercritical fluid (rather than a gas) is strongly preferred. These conditions improve storage efficiency and, as more $CO_2$ can be held in the pore space, and result in a lower buoyant force, reducing the possibility of leakage [13], [10]. $CO_2$ reaches a supercritical state at temperatures greater than 31.1 °C and pressures greater than 7.28 MPa [14]. Also, for example, formation temperature and salinity of the water naturally present in the media determine the solubility of the $CO_2$, effecting the amount of $CO_2$ that may eventually dissolve in this water.

The processes that act to contain or "trap" injected $CO_2$ within a target formation are complex, with different mechanisms operating over different length scales and time horizons [10]. Carbon dioxide is stored through a combination of trapping processes [15], [16]. In **physical trapping**, $CO_2$ is retained in the structural and stratigraphic features of the formation, and as a "residual phase" left in pores of the rock as $CO_2$ moves in the formation. In **chemical trapping**, $CO_2$ dissolves in the brine present in the subsurface and, subsequently, can react with alkaline minerals to form carbonate minerals. Physical trapping mechanisms are the primary means of affecting $CO_2$ storage and, thus, operate on a much shorter time horizon than chemical. The way in which physical trapping plays out is specific to the features of the target formation and the way in which $CO_2$ is injected. Chemical trapping, such as dissolution and mineralization, usually occurs very slowly and evidence of chemical trapping will only become evident over a much longer time horizon [17].

Injection and storage of carbon dioxide is currently being practiced in Western Canada through $CO_2$-enhanced oil recovery and deep saline aquifer storage. This review focuses on these two routes plus the additional option of storage in depleted gas reservoirs.

## 2.1 $CO_2$ Storage in Deep Saline Aquifers

Deep saline aquifers are porous formations that extend over large areas and contain high-salinity formation water that is not fit for agricultural use or human consumption [14], [18]. The process of injecting $CO_2$ into deep saline aquifers is technically proven, similar to injection processes undertaken in oil and gas recovery. Deep saline aquifers also have a relatively lower risk of $CO_2$ leakage along existing wells because they tend to be penetrated by fewer wells than hydrocarbon reservoirs [15]. Fewer well penetrations does, however, mean saline aquifers are less well characterized than known oil and gas reservoirs [17]. This means there is often much more work needed to prove there will be sufficient capacity and injectivity for the desired volumes of $CO_2$, and that it will be contained through physical or chemical trapping.

Deep saline aquifer $CO_2$ storage resources are the largest contributor to the overall Western Canadian Sedimentary Basin (WCSB) storage resource. The WCSB comprises the Alberta Basin and the Williston Basin. The two provinces with the most $CO_2$ storage potential through deep saline aquifers are Alberta and Saskatchewan, which cover most of the Alberta and Williston basins.

> "Deep saline aquifer $CO_2$ storage resources are the largest contributor to the overall Western Canadian Sedimentary Basin (WCSB) storage resource."

Both the Alberta Basin and the Williston Basin have stable tectonics and are geologically suitable for $CO_2$ storage [19]. The geology and stratigraphy of Alberta's subsurface are favourable for deep injection and storage of carbon dioxide. The sedimentary formations of the Alberta Basin are thickest where the basin is deepest, in western Alberta and British Columbia immediately adjacent to the Rocky Mountains. Williston Basin formations are thickest in the basin center located in North Dakota, and thin outward to the edge generally found in northern Saskatchewan and southwestern Manitoba [10]. All else being equal, the thicker the formation, the greater the potential storage capacity. Most aquifers are overlain by competent, thick, and regional extensive seals or aquitards that would prevent upward migration of injected $CO_2$, providing containment [14]. This said, the shallow eastern edge of the Alberta Basin is unsuitable for storage because of its shallow depth, low temperatures, and pressures and proximity to the basin edge [20].

## 2.2 Storing $CO_2$ via the $CO_2$-Enhanced Oil Recovery Process

$CO_2$ storage in oil reservoirs occurs when $CO_2$ is applied in enhanced oil recovery ($CO_2$-EOR). The $CO_2$ enhanced oil recovery (EOR) process can be implemented in oil field operations to assist in the recovery of oil remaining in the reservoir after the initial phases of production. $CO_2$ is injected in the reservoir and contacts the remaining oil, reducing oil viscosity, improving oil mobility, and displacing oil towards production wells. Oil, water and some of the injected $CO_2$ are then produced, with the $CO_2$ being separated, recompressed, and generally re-injected [21]. $CO_2$ injection is often combined with water injection in a process called water-alternating-gas (WAG) injection. WAG schemes are usually implemented to improve efficiency of oil recovery in heterogeneous reservoirs. $CO_2$-EOR projects have shown they can increase recovery of the original oil in place (OOIP) by between 7% and 23% [22]–[24]. While some fraction of the $CO_2$ injected is produced, virtually all of the $CO_2$ introduced to an EOR project is recycled and eventually stored in the reservoir pore space through capillarity, dissolution in formation water and oil, and structural or stratigraphic trapping mechanisms [22], [25]–[28]. The only exception would be if an operator were to intentionally seek to produce $CO_2$, e.g., for use in another project.

The Alberta and Williston basins have reached a mature stage of exploration and production of hydrocarbons, meaning that many oil fields may be suitable for $CO_2$ storage through EOR [14]. However, not all oil reservoirs are ideal for $CO_2$-EOR, and factors such as oil density, miscibility with $CO_2$, depth, permeability, porosity, oil saturation all impact the suitability of $CO_2$-EOR candidates. Screening and selecting reservoirs for $CO_2$-EOR suitability and quantifying incremental oil and $CO_2$ storage potential have been the subject of many studies in Western Canada [19], [22]. The majority of Alberta oil fields suitable for $CO_2$-EOR are found along the west-southwestern edge of the WCSB. The province of Saskatchewan also has potential for the implementation of $CO_2$-EOR, as there are many suitable candidates for miscible $CO_2$-EOR in the southeastern portion of the province [29]. The $CO_2$ storage potential through $CO_2$-EOR in British Columbia is estimated to be very small, approximately 5 Mt [30].

$CO_2$-enhanced oil recovery has the smallest potential storage capacity of all the options for geological $CO_2$ storage in the WCSB. That said, more $CO_2$ has effectively been stored through $CO_2$-EOR than in saline aquifers around the world because the value of incremental oil recovered has historically been more than sufficient to offset the cost of $CO_2$ capture from some sources (e.g., ethanol mills, fertilizer production). Thus, $CO_2$-EOR is a proven technology that, under the right conditions, could not only store $CO_2$ but anchor development of infrastructure for storage in deep saline aquifers [11], [31].

## 2.3 Depleted Gas Reservoirs as a Candidate for Storing $CO_2$

Previously produced depleted gas reservoirs are appealing candidates for storing $CO_2$ because containment has been proven, reservoir characteristics are known, and primary recovery has removed as much as 95% of the original gas in place [32], [33]. These reservoirs have demonstrated through their life that they can sufficiently store hydrocarbons with the trapping mechanisms (structural, stratigraphic, lithologic) similar to those employed in $CO_2$-EOR to store $CO_2$ [14]. Depleted gas reservoirs are typically low pressure from being produced, with most gas reservoirs in Western Canada having weak or no aquifer support [34]. Major operational challenges can result from $CO_2$ injection into low-pressure reservoirs, causing supercritical $CO_2$

to vaporize and expand in the near-wellbore or injection tubing. This expansion can cause pressure control issues and strong cooling due to Joule–Thomson effects, negatively impacting well injectivity and potentially integrity of the injection well itself. Potential solutions are heating the $CO_2$ near the wellhead or downhole and pipeline transport in the gas phase, but these interventions can be prohibitively expensive [33].

Gas reservoirs are distributed similarly to oil reservoirs in Alberta, with large accumulations found along the west-southwestern edge of the WCSB, the foothills of the Rocky Mountains [32]. Gas reservoirs can also be found in the shallower eastern area of the Alberta Basin [17]. Depleted gas reservoirs have a larger cumulative $CO_2$ storage potential than $CO_2$-EOR due to the higher recovery factor and because they have a larger accessible pore volume. Also, the number of oil pools (i.e., aggregations of proximate oil reservoirs) is less than one-third of the number of gas pools (i.e., aggregations of proximate gas reservoirs) in Alberta [35], [36]. Another advantage of depleted gas pools is that fewer gas pools are co-mingled (i.e., gas is produced from multiple different pools using a single well), simplifying measurement, monitoring, and the containment of stored $CO_2$ [32].

## 2.4 Risk Management and Regulation

Containment is critical for $CO_2$ storage as the primary hazard associated with storage is $CO_2$ leakage. $CO_2$, due to its buoyant and mobile nature, can find leakage pathways. A continuous caprock or seal that acts as an effective barrier to the upward migration of $CO_2$ is required to prevent leakage [37]. Those saline aquifer formations that are overlain with tight rocks such as shales and evaporites are generally suitable storage candidates. Extensive faulting, fracturing, or seismicity may also lead to fluid leakage [11]. That said, research suggests that upwards migration of $CO_2$ along wellbores or through abandoned wells is a relatively more probable hazard than leakage through caprock [38]. The tendency of deep saline aquifers to have fewer well penetrations through the overlying caprock is favourable, as $CO_2$ can leak through existing wellbores to overlying formations, shallow groundwater aquifers, or the surface. Common leakage pathways in existing wellbore result from poor cementing, casing leakages due to corrosion or poor design or completion of well abandonment [39].

Saline aquifer injectivity is an important consideration impacting the ability to store $CO_2$, the duration of injection, $CO_2$ plume evolution, the number of required injection wells and their configuration and the project economics [11]. If injection wells can be drilled in areas of higher injectivity, fewer wells will be required, and injection pressures can be reduced. Because injection pressures can be reduced, the distance over which pressures will be elevated in the subsurface and, as a result, could drive $CO_2$ (or brine upwards). This means that a smaller area will need to be monitored for leakage or other fluid migration, as well. $CO_2$ storage operations may also consider active formation pressure management to reduce the pressure footprint of the project and to optimize the storage capacity of the formation [40].

While risks associated with property designed and implemented $CO_2$ storage projects are expected be very low, responsible operators will monitor projects to ensure they perform as expected, risks are managed, and regulatory requirements are met. Risks to surrounding environmentally sensitive or protected areas, public safety, and relating to public perception must, in particular, be considered. Storage projects must, thus, understand monitoring, measurement, and verification (MMV) options and build MMV plans to focus on risk mitigation. Regulatory hurdles can introduce risk as well. A mature regulatory environment is necessary to reducing the risks surrounding acquiring the right to the storage space, permission to inject $CO_2$, and long-term liability after cessation of injection [19].

"A mature regulatory environment is necessary to reducing the risks surrounding acquiring the right to the storage space, permission to inject $CO_2$, and long-term liability after cessation of injection."

## 2.5 Characterizing Storage Resource Estimates

Resource classification systems exist for a wide range of natural resources (e.g., oil and gas, minerals), and provide a comparable basis for assessing their potential. Commonly used systems generally evaluate maturity of resources along two dimensions: the state of knowledge about a specific resource and the cost of accessing these resources (with current technology). The Society of Petroleum Engineering (SPE) developed the Storage Resource Management System (SRMS) to classify $CO_2$ storage resources [41]. The methodology is based on the well-established SPE gas and oil reserves classification system, the Petroleum Resource Management Scheme [42]. It shares many similarities with $CO_2$ storage classification systems proposed by, for example, the Carbon Sequestration Leadership Forum (CSLF) [43] and Gorecki et al. [44], and is becoming increasingly used by $CO_2$ storage project developers.

In the SPE-SRMS, the highest classification of $CO_2$ storage resource is "capacity". For a $CO_2$ storage resource to be considered capacity, it must satisfy several criteria, including being discovered, characterized, injectable, and sufficiently well-defined to establish its commercial viability. The critical questions to determine commerciality or capacity resource maturity are [41]:

- Does the project have all the necessary approvals for development?
- Is the project sufficiently defined to establish commercial viability?
- Is the project actively injecting?

The next level are "contingent resources", which are potentially accessible in known geological formations, but projects are not considered mature enough for commercial development. These resources must be discovered, and the geological formation well characterized. The contingencies that characterize these resources include, for example, access to captured $CO_2$ (e.g., proximity to a $CO_2$ source and infrastructure), economic conditions that do not support development (e.g., a value associated with $CO_2$ storage and access to financing), or the absence of required stakeholder approval (e.g., permits, community consultation) [41]. Most site-specific or project-level studies in Western Canada classify as contingent resources.

The least resolved resources are termed “prospective.” These are resources that remain undiscovered, but where the geological formation has been evaluated for potential storage. Thus, a prospective resource estimate represents the quantity of storage resource estimated to be potentially accessible within undiscovered geologic formations by the application of future exploration or development projects [41].

# 3 DEEP SALINE AQUIFER $CO_2$ STORAGE RESOURCES IN WESTERN CANADA

Many studies have been conducted to assess the $CO_2$ storage resource in Western Canada. These range from basin or regional studies to local studies and site-specific projects. Confidence and maturity of calculated storage resource potential tends to increase as the geographic extent of an assessment decreases. **Figure 1** illustrates that basin or regional-scale assessments tend to have the lowest level of detail, and thus result in the most uncertain estimates of $CO_2$ resources. This relationship results from the relatively low resolution of data, large uncertainty, and coarse methods that are applied for assessments over large geographic scales in contrast to the much higher resolution, smaller uncertainty, and computationally intensive methods. The $CO_2$ storage resource is on the order of gigatonnes (Gt) of $CO_2$ storage at the basin-scale to tens of millions of tonnes (Mt) at the project or site scale.

The saline aquifer storage resource, like that of hydrocarbons, is discovered in geological formations through well drilling and testing, sampling, and logging. Because hydrocarbon exploration has been ongoing for many decades in most sedimentary basins, much of the data needed to identify saline aquifer storage resources has been collected. With data in hand, $CO_2$ storage resources can be assessed using a number of methods, such as: volumetric estimates, material balances, injection performance analysis, and dynamic reservoir modeling.

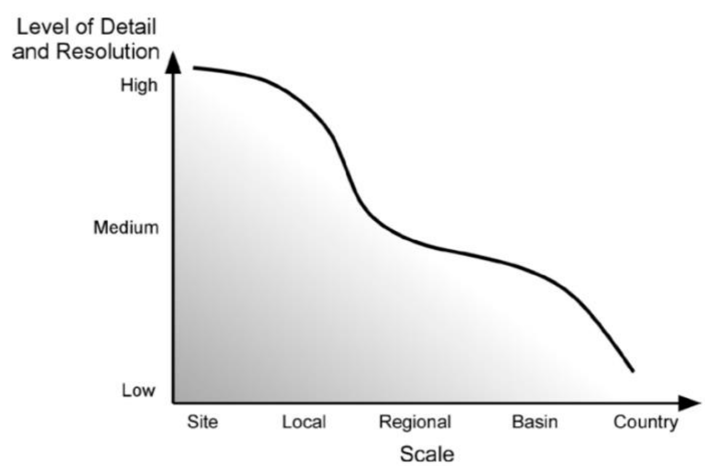



**Figure 1. Relationship between level of detail of a $CO_2$ storage potential assessment and its scale.**
Source: Bachu et al. [31].

Basin and regional scale studies often estimate $CO_2$ storage resources using volumetric-based assessment methodologies and static geological models combined with generic lithology-based storage efficiency [17]. These methods generally start with an estimate of the pore volume that is suitable and accessible for storage. Screening cut-offs can be applied to define storage suitability. For example, Western Canadian storage studies typically use depth and porosity cut-offs [17], [31], [45]. The accessible pore volume is then multiplied by a storage efficiency coefficient, which is defined as the ratio of volume accessible to or occupied by $CO_2$ to that of the total pore volume [46]. This coefficient is much less than one because $CO_2$ is not particularly effective at displacing brine that exists in the formation.

A common volumetric methodology and set of storage efficiency factors used to calculate $CO_2$ storage on a regional scale is the US Department of Energy National Energy Technology Lab (USDOE-NETL) storage method [47]. The USDOE-NETL storage efficiency coefficients are used to produce the Carbon Sequestration Atlas of United States and Canada [31]. Other volumetric methodologies used to assess $CO_2$ storage resources include CSLF (2007), and USGS (2013) and have previously shown to be statistically equivalent to the USDOE-NETL methodology and lead to efficiency factors between 1.5–3.6% [46]. However, for any specific site, the storge efficiency may vary widely from the efficiency factor applied regionally, across an entire aquifer [46].

Most past assessments of Western Canada are regional studies that use the volumetric-based approaches to quantify storage resources. Volumetric-type estimates are suitable for basin-scale assessments; however, this assessment methodology doesn't consider dynamic aspects of $CO_2$ injection, including injectivity constraints, $CO_2$ plume development, and pressure and brine management requirements. Further, $CO_2$ storage assessment requires evaluation beyond the physical storage limitations of the aquifers themselves and should include other risks such as well leakage, seal thickness, continuity, and surface risks. Few assessments of Western Canada have progressed to drilling of evaluation wells, full-scale dynamic reservoir simulation, and performing injectivity testing and/or cost modelling to test commercial viability. Thus, while it is clear there are significant storage resources in Western Canada, most of the resources are relatively immature from an evaluation point of view (i.e., being both uncertain and/or previously identified as sub-commercial).

"…$CO_2$ storage assessment requires evaluation beyond the physical storage limitations of the aquifers themselves and should include other risks such as well leakage, seal thickness, continuity, and surface risks."

Based on the SPE SRMS, the total amount of high certainty $CO_2$ resources, classified as "capacity", are very small compared to the current amount of $CO_2$ emissions from Western Canada or $CO_2$ storage requirement for future blue hydrogen production. The only high certainty $CO_2$ capacity can be attributed to Shell Quest and the Saskatchewan Aquistore projects, which together total 56 Mt. Most $CO_2$ storage resources in Western Canada are likely classified as either contingent or prospective resources. This is due to the current project status or the level of evaluation being insufficient to assess the commerciality. For example, the PCOR Basal Cambrian basin-scale saline formation assessment would be considered a prospective $CO_2$ resource [31]. The maturity of the $CO_2$ storage estimates in Western Canada are discussed in the following sections.

## Summary of Findings: Saline Aquifer Storage Potential

- Western Canada has significant $CO_2$ storage potential, including that in deep saline aquifers, $CO_2$-EOR, and depleted gas reservoirs. Storage resource potential from saline aquifers only is estimated as:
  - 360 Gt $CO_2$ (50% probability)
  - 187 Gt $CO_2$ (90% probability) and
  - 629 Gt (10% probability)
- However, most $CO_2$ storage potential in Western Canada is currently not de-risked sufficiently to be considered commercial and mature enough to meet both emissions reduction targets and support future blue hydrogen production ambitions.
- The current highly certainty estimate of saline aquifer storage capacity is 56 Mt $CO_2$
- Several gigatonnes of $CO_2$ storage opportunity have been identified in the Alberta Industrial Heartland (NE of Edmonton) and other regions of Central Alberta though six studies, with one site-specific study, Quest, achieving commercial operations.
- Detailed geological and geo-mechanical assessments are needed on regions across the Western Canadian Sedimentary Basin to develop more mature estimates of storage potential, containment risk and the optimal location for wells for injection, testing and monitoring.

## 3.1 Regional or Basin-Scale Saline Assessments of Storage Resource

Basin-scale and regional studies have assessed the suitability and $CO_2$ storage potential of deep saline aquifers in Western Canada; these studies include Huang et al. [48], Bachu et al. [17], Liu et al. [49], Rebscher et al. [50], Bachu et al. [45], Michael et al. [51], Bachu and Shaw [34], Bachu [32], Bachu and Adams [52], Bachu and Stewart [53], Bachu et al. [14], and many Energy & Environment Research Center (EERC) and Plains $CO_2$ Reduction (PCOR) Partnership studies. The $CO_2$ storage estimates from these studies are summarized in Figure **2**. These studies cover different formations and geographic extents and, while they are all based on volumetric estimates (reflecting potential for physical trapping), some include contributions from chemical trapping (e.g., Bachu and Adams [52]). Thus, the values from these studies are not directly comparable, but they do show that there are substantial prospective resources in Western Canada.

While not addressed in this report, there have also been multiple studies in Western Canada that address other aspects of $CO_2$ saline aquifer storage, pertaining to measurement and monitoring, risk identification and mitigation, infrastructure requirements, injectivity, $CO_2$ purity, and regulatory considerations.

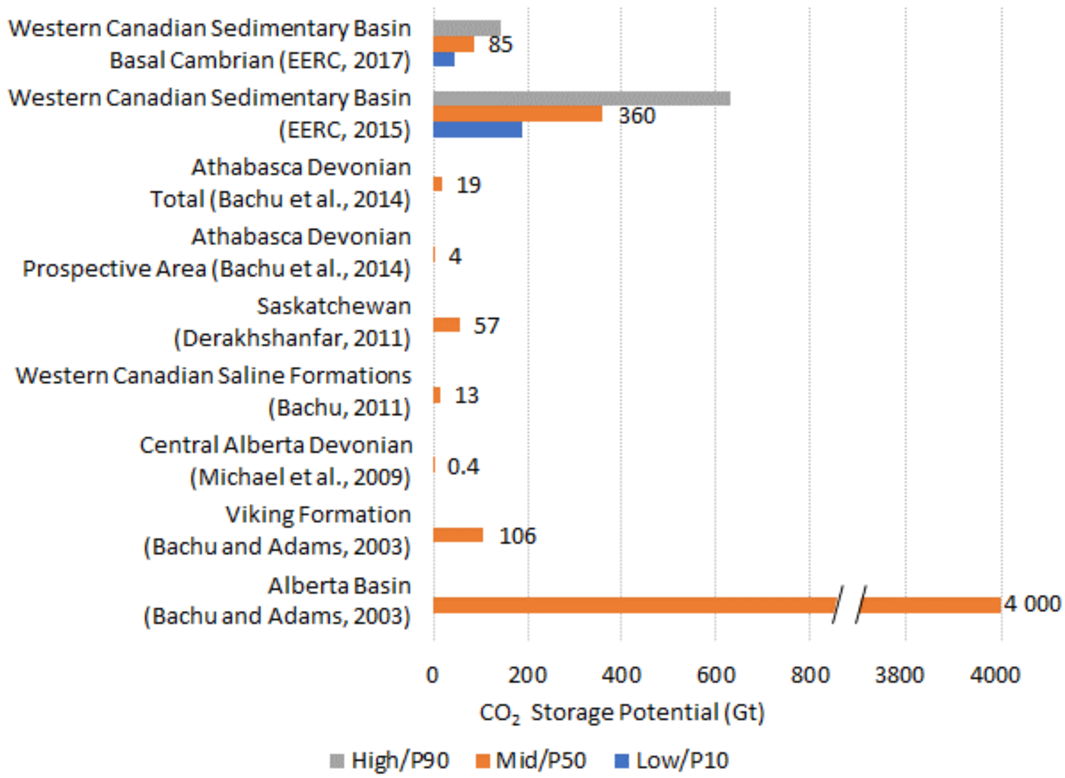
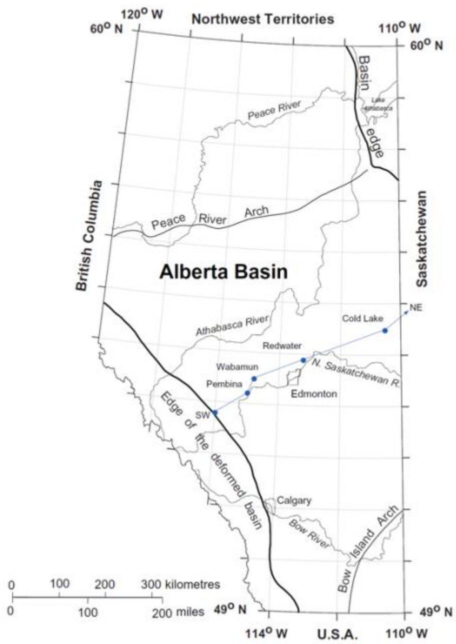



**Figure 2. Estimated $CO_2$ storage resources from regional saline aquifer studies.**

Data labels report the central, or where specified, 50th percentile (P50) estimate for each study. P90 represents a 90th percentile estimate and, P10 represents a 10th percentile estimate. Note the broken axis in order to show the large estimate for the Alberta Basin by Bachu and Adams [52]. Because these results cover different geological formations and spatial extents, they are not directly comparable and would generally be considered prospective resources.

The broadest study involved the Geological Survey of Canada (GSC), Alberta Innovates, and the Plains $CO_2$ Reduction Partnership (PCOR), contributing to the 2015 NETL North America Carbon Storage Atlas and 2017 PCOR Partnership Atlas. Seven regional aquifers in the Alberta and Williston basin were evaluated for carbon dioxide storage potential by the Geological Survey of Canada (GSC) and Alberta Innovates – Technology Futures (Alberta Innovates) between 2011 and 2015: Viking Formation, Winipegosis/Keg River (Elk Point Group), Slave Point (Beaverhill Lake Group), Cooking Lake / Leduc (Woodbend Group), Nisku (Winterburn Group), and Rundle Group (**Figures Figure** 3, **Figure** 4). These aquifers have a cumulative $10^{th}$ percentile (P10), median (P50) and $90^{th}$ percentile (P90) prospective $CO_2$ storage resource of 187 Mt, 360 Mt, and 629 Mt of $CO_2$, respectively. These deep saline aquifers were prioritized due to their favourable storage characteristics such as porosity, thickness, depth, large areal extent, seal integrity, and proximity to major $CO_2$ sources [54]. Shallower sedimentary units in the Lower and Upper Cretaceous, such as the Cardium and Mannville groups, were not evaluated by the Geological Survey of Canada and Alberta Innovates.




## Alberta's Regional Estimates for $CO_2$ Storage

| Geological Region | Estimated Storage Capacity (gigatons) |
|---|---|
| Viking Group | 33 |
| Rundle Group (Carboniferous) | 2.1 |
| Winterburn Group | 1.8 |
| Woodbend Group | 1.6 |
| Beaverhill Lake Group | 1.5 |
| Elk Point Group | 2.1 |
| Basal Cambrian Group | 36 |
| **TOTAL** | **78** |

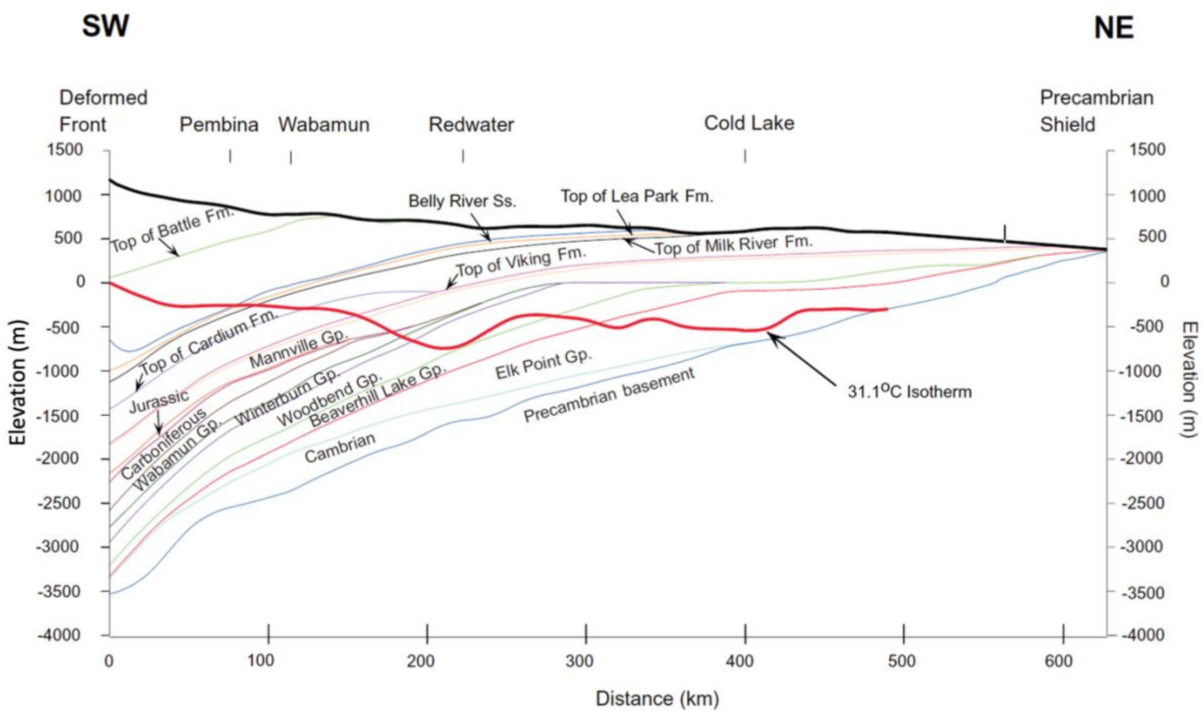



**Figure 3. Map of the Alberta Basin, including a line of cross-section (left) and associated cross-section through Alberta basin showing the position of 31.1°C isotherm in relation to various sedimentary units with Alberta (right)**

Reproduced from Bachu et al. [14]. P50 $CO_2$ storage estimates (Gt) for the seven highest priority saline aquifers shown in the cross section from the PCOR Atlas [31].

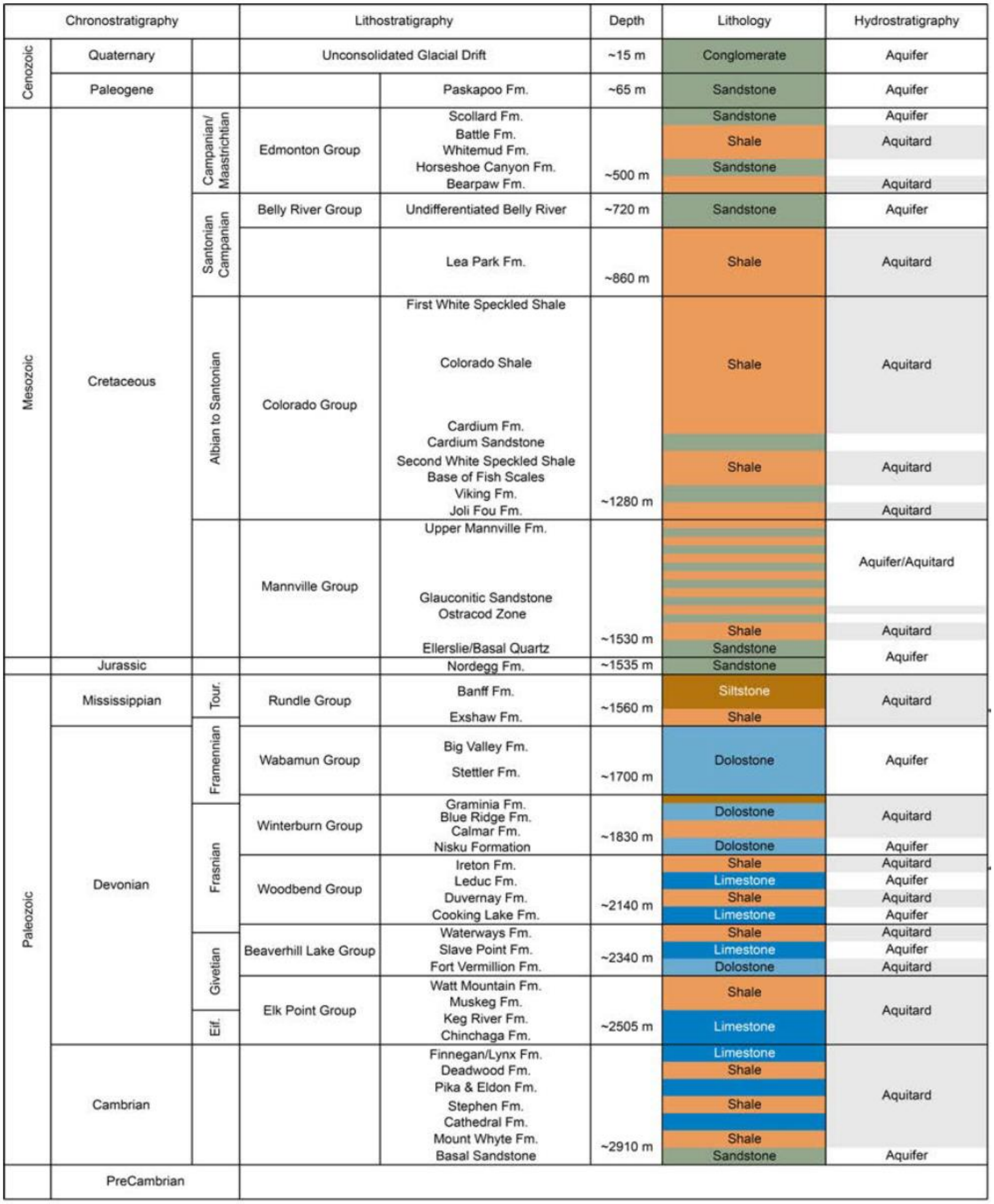



**Figure 4. Stratigraphic column that includes relevant Cambrian, Devonian, and Cretaceous aquifers and aquitards.**

Reproduced from Bachu et al. [13].

The deep saline storage aquifer resource in Western Canada is dominated by the Basal Cambrian unit, **containing over twenty times the $CO_2$ storage potential of the other six studied aquifers**, with the majority coming from the province of Saskatchewan (**Figure 5**). The Basal Cambrian is the deepest saline aquifer and is at the base of the central portion of the Western Canadian Sedimentary Basin directly on top of the Precambrian basement (**Figures 3, 4**). The aquifer is prolific in size, spanning three Canadian provinces and approximately 811,000 square kilometers. The Basal Cambrian is also the most extensively studied of all the major regional saline aquifers, having been the focus of a three-year bi-national study between the United States and Canada. The large storage potential is attributed to the larger area, higher porosity, and greater thickness. Through volumetric modelling and reservoir simulation, the study concluded that the Basal Cambrian is a large and viable target for long-term geological storage of $CO_2$ [31]. **Figure 6** shows the cumulative $CO_2$ storage resource density (Mt/km$^2$) for the seven studied aquifers highest in central Saskatchewan, where the Basal Cambrian thickness is the greatest.

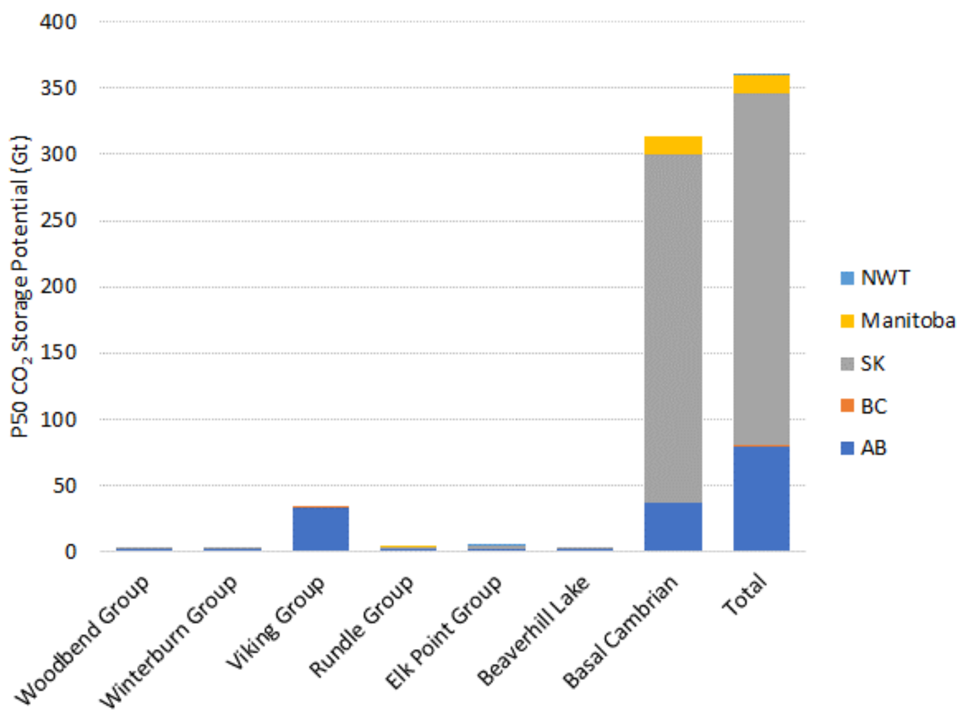



**Figure 5. Western Canada $CO_2$ storage prospective resource by aquifer and province. Data from 2017 PCOR Atlas [31].**

Storage studies and projects in Western Canada have focused on the Devonian (Leduc, Nisku formations) and Cambrian (Basal Cambrian Sandstone) aged units. The Basal Cambrian unit is the storage target of both operating Western Canadian $CO_2$ saline aquifer storage projects: Shell Quest in Alberta and Aquistore in Saskatchewan. Project and site-specific studies in Central Alberta such as the Wabamun Area $CO_2$ Sequestration Project (WASP), Heartland Area Redwater $CO_2$ Storage Project (HARP), and Alberta Saline Aquifer Project (ASAP) have also focused on the Basal Cambrian, as well as the Devonian Leduc and Nisku formations.

Aquifer suitability for $CO_2$ storage varies across Alberta. Bachu et al. reported in 2000 that Alberta could be divided into areas of suitability based on geological, geothermal, and hydrodynamic characteristics of the Alberta Basin. This study found that Southwestern and Central Alberta are most suitable for $CO_2$ storage in geological media, with the northeastern or Athabasca region of Alberta being the least suitable due to the shallowness of the basin [14].

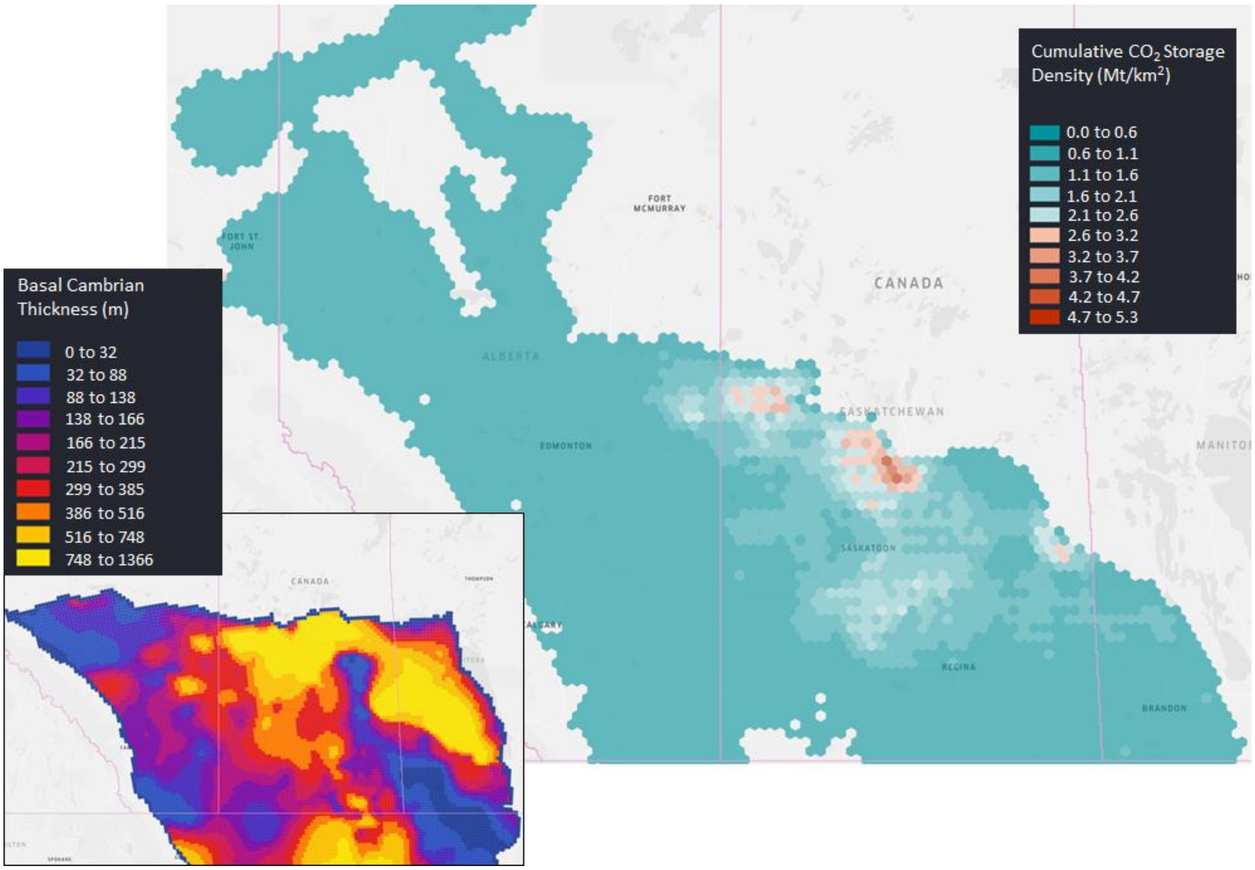



**Figure 6. Western Canada cumulative deep saline aquifer $CO_2$ storage density (Mt/km2) and Basal Cambrian thickness (m) in the inset figure. Data from PCOR 2017 Atlas [31].**

In Alberta, there are 78 Gt of prospective storage resources in the seven prioritized saline aquifers studied (**Figure 5**). If further investigation were to result in only 20% of this resource being proven as $CO_2$ storage capacity, this would be the equivalent of over 100 years of storage based on capture and storage of all current stationary $CO_2$ emissions in Alberta[4]. These values demonstrate the enormous magnitude of prospective $CO_2$ storage resources in Alberta alone. However, there is a high degree of uncertainty

[4] Calculated based on 2019 Alberta reported total emissions of 147 Mt from stationary emissions sources and assuming a 90% capture efficiency [55]

associated with these basin-scale volumetric estimates of resources and they should not be considered as a substitute for site-specific characterization and assessments.

## 3.2 Proven Storage Capacity and Project- and Site-Specific Storage

Despite the sizeable deep saline aquifer storage potential in Western Canada, there are only approximately 56 Mt of proven $CO_2$ capacity using the Storage Resource Management System (SRMS) definition[5] [57], [58]. This $CO_2$ resource capacity is dedicated storage, tied to existing specific emission sources and, at the time of writing, is not available for other $CO_2$ sources. In the example of Shell Quest, the storage site is tied to the Scotford upgrader, and Aquistore is tied to the Boundary Dam coal-fired power plant. These two current operating saline aquifer storage projects, Shell Quest and Aquistore, have 34 Mt and 22 Mt of remaining $CO_2$ storage capacity based on published estimates of their total capacity[6].

There have been several notable saline aquifer $CO_2$ storage projects proposed and studied in Western Canada. **Table 1** shows the list of the past studies, resource storage estimates, and type of assessment. Furthermore, it includes each study's storage potential and maturity of resource assessment. The storage potential associated with individual projects ranges from tens of millions of tonnes of storage to gigatonnes, often related to the size of the study area of interest. While undoubtedly large, the total storage potential of all those projects listed in **Table 1** is not a simple sum, as the studies are of different maturity levels and some studies overlap in terms of geographical areas and target formation.

Storage resource potential from most studies in Western Canada, apart from Quest and Aquistore, have not advanced past contingent resources classification to be considered capacity. The most mature of the other projects are **Project Pioneer**, proposed by TransAlta in the Wabamun Lake area of Alberta, and the **Spectra Fort Nelson CCS Project** in British Columbia. Both projects advanced to the point of completing dynamic reservoir modelling and simulation and drilling and testing of evaluation $CO_2$ injection wells. Project economics and uncertainty in the $CO_2$ market forced both projects to be suspended. Other saline aquifer storage studies in Western Canada include WASP, HARP, ASAP, and the Athabasca Saline Aquifer Project and have completed assessments ranging from static volumetric modelling based on the US-DOE-NETL volumetric methodology [47] to constructing detailed geological and reservoir numerical simulation models. As noted, some of these project areas overlap, such as those for Project Pioneer, (WASP), and the Alberta Saline Aquifer Project, which all studied the Nisku formation in the Wabamun Lake region of Alberta.

[5] Annual saline aquifer injection design capacity - Shell Quest: 1.2Mt per year [56]; Saskatchewan Aquistore: 0.7 Mt per year [57]. 2019 actual $CO_2$ injection - Shell Quest: 1.14 Mt per year; Saskatchewan Aquistore: 0.06 Mt per year.
[6] Calculated from Shell Quest's initial estimated $CO_2$ storage potential of 27 Mt and current $CO_2$ injected volume of 7.8 Mt and Aquistore's initial estimated $CO_2$ storage potential of 34 Mt and current $CO_2$ injected volume of 0.37 Mt. [58]–[60]

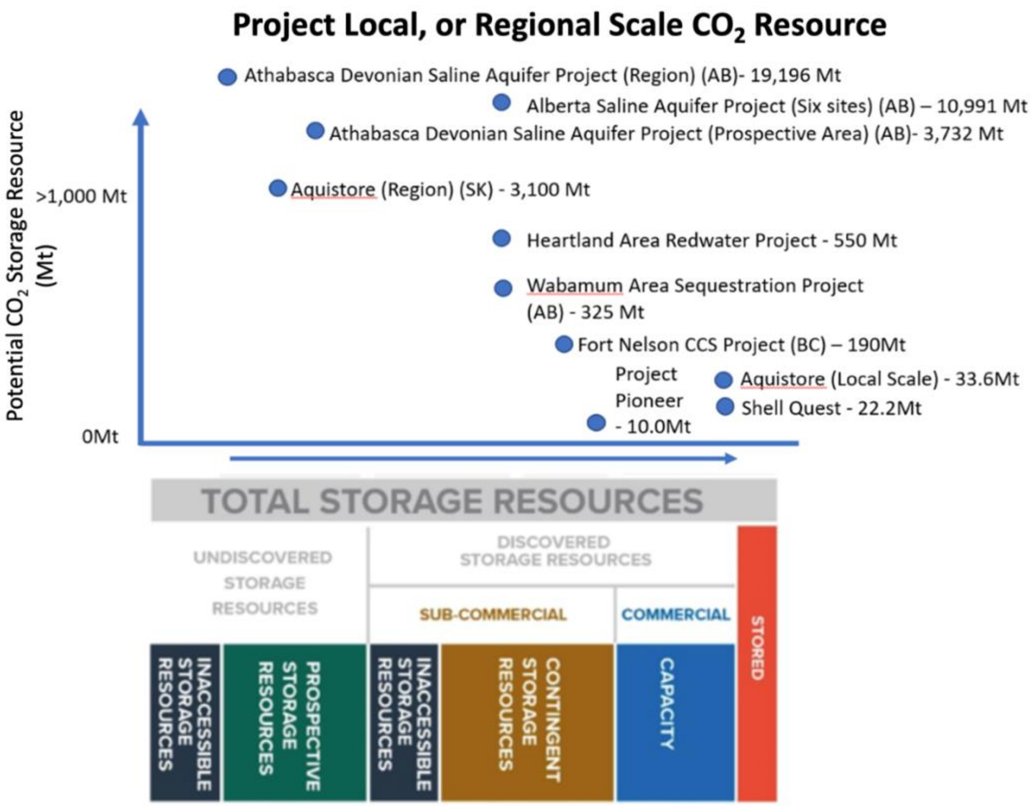



**Figure 7. Comparison of size and maturity of saline aquifer storage projects in Western Canada mapped against the SPE Storage Resource Management System (SRMS) system.**

The storage resource estimates in **Table 1** are presented in terms of cumulative capacity, rather than annual injection rates, as few of the projects (other than those operating) have developed reliable estimates of injectivity. That said, storing 200 $MtCO_2$ per year over a period of decades in support of the energy transition would certainly require many of these projects to be developed simultaneously. Moreover, pursuing a national (or provincial) strategy that involves large-scale use of hydrogen as an energy carrier means that there needs to be a robust portfolio of geologic storge options. Thus, further work is required to improve the certainty and commerciality of $CO_2$ storage resource in Western Canada. Future $CO_2$ storage studies should focus on deep saline aquifers in areas in proximity to future blue hydrogen production and focus on leveraging existing knowledge from Quest, WASP, HARP, ASAP, and other regional studies to enable accelerated project development.

**Table 1. Summary of project- and site-specific saline aquifer $CO_2$ storage studies in Western Canada.**

| Study or Status Year | Site/Regional Study Name | Oper-ating | Basin | Target Saline Aquifer(s) | Period/Age | Storage Estimate (Mt) | | | Storage Classification (SPE - SRMS) | Methodology | Ref. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Low | Mid | High | | | |
| 2009 | Central Alberta Study | No | Alberta | Nisku | Devonian | | 375 | | Prospective | Static/Analytical Model | [51] |
| 2009 | Alberta Saline Aquifer Project (ASAP) (Six Sites) | No | Alberta | Nisku, Beaverhill Lake, Leduc, Cooking Lake, Keg River | Devonian | | 10 991 | | Contingent | Dynamic Simulation | [61] |
| 2009 | Heartland Area Redwater Project (HARP) | No | Alberta | Leduc | Devonian | | 550 | | Contingent | Dynamic Simulation | [62] |
| 2010 | Wabamum Area Sequestration Project (WASP) | No | Alberta | Nisku | Devonian | 250 | 325 | 400 | Contingent | Dynamic Simulation | [63] |
| 2012 | Project Pioneer | No | Alberta | Nisku | Devonian | | 10 | | Contingent | Exploratory Well, Dynamic Simulation | [64] |
| 2014 | Fort Nelson CCS Project | No | Alberta | Slave Point, Sulphur Point, and Lower Keg River formations | Devonian | 140 | 190 | 240 | Contingent | Exploratory Well, Dynamic Simulation | [65] |
| 2014 | Athabasca Saline Aquifer Project | No | Alberta | Wabamun, Blueridge, Nisku, Grosmont, Leduc, Cooking Lake, Moberly, Calumet, Salve Point, Swan Hills, Gilwood, Keg River, Granite Wash | Devonian | | 19 196 | | Prospective | Adapted Volumetric (DOE) | [17] |
| 2014 | Athabasca Saline Aquifer Project - Prospective Storage Area | No | Alberta | Wabamun, Blueridge, Nisku, Grosmont, Leduc, Cooking Lake, Salve Point, Gilwood, Keg River, Granite Wash | Devonian | | 3732 | | Prospective | Adapted Volumetric (DOE) | [17] |
| 2014 | Saskatchewan Aquistore Storage Project | No | Williston | Deadwood, Black Island | Cambrian | 1600 | 3 100 | 5 300 | Contingent | Volumetric (DOE), Dynamic Simulation | [59] |
| 2014 | Saskatchewan Aquistore Storage Project - Local Scale | Yes | Williston | Deadwood, Black Island | Cambrian | | 34 | | Capacity | Volumetric (DOE), Dynamic Simulation | [59] |
| 2020 | Shell Quest | Yes | Albert | Basal Cambrian Sands | Cambrian | | 27 | | Capacity | Dynamic Simulation | [58] |

# 4 $CO_2$ STORAGE RESOURCES IN HYDROCARBON RESERVOIRS IN WESTERN CANADA

## 4.1 Is $CO_2$-Enhanced Oil Recovery the Solution?

$CO_2$-enhanced oil recovery and its $CO_2$ storage potential have been studied extensively in Western Canada on both a regional- and basin-scale and pool-scale. Regional $CO_2$-EOR studies apply a volumetric methodology to $CO_2$ storage assessment. This assessment methodology usually assumes that the storage potential equals the volume previously occupied by produced oil while considering secondary effects that limit the ability of $CO_2$ (and similar fluids) to effectively displace oil from the reservoir. This approach is also combined with screening or selection criteria to identify those oil pools most suited for $CO_2$-EOR.

Due to the complex reservoir production mechanisms involved in $CO_2$-EOR, numerical simulation is required to provide high-certainty estimates of both $CO_2$ sequestered and incremental oil recovery. The only publicly available large-scale study to perform pool-level detailed reservoir technical evaluation and utilize numerical modelling was conducted by the Alberta Research Council in 2009 [66]. Other studies have used analytical tools or statistical-based models to estimate $CO_2$ storage potential in $CO_2$-EOR operations and/or considered the reduction in storage potential due to aquifer effects [22], [34], [67].

The range in regional estimates for contingent $CO_2$ storage resources from enhanced oil recovery from past studies in Western Canada and Alberta have been consistent. The median (or P50) $CO_2$-EOR storage estimates range between 522 Mt [32] and 870 Mt [22] (**Figure 8**), with an associated incremental oil recovery of between 1,044 and 1,740 MMSTB[7]. Although the total cumulative $CO_2$ storage resource is large, **one of the challenges with storing a material volume of $CO_2$ through EOR is that most oil pools are small (measured by original oil in place) and, thus, have a small storage potential**. Also, smaller oil pools tend to have poorer economics.

[7] Calculated using a net $CO_2$ utilization factor of 0.5 tonne of $CO_2$ stored per barrel of incremental oil

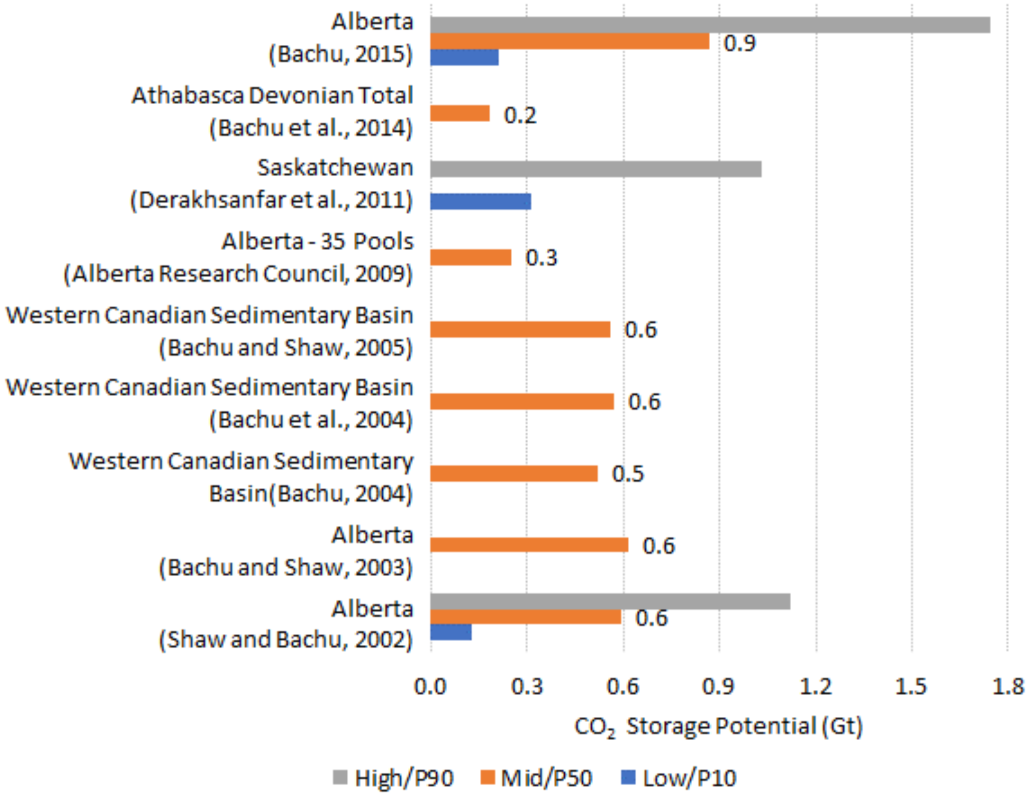



**Figure 8. Estimated contingent $CO_2$ storage resources from regional $CO_2$-enhanced oil recovery studies (Mt).**
P90 represents a 90th percentile estimate; P50 a 50th percentile (median); and, P10 represents a 10th percentile estimate.

> "...two fields, Pembina and Redwater, accounted for 80% of the $CO_2$ storage potential."

The average oil pool storage resource in Alberta is 120 kt $CO_2$ in $CO_2$-EOR cases, with most storage potential existing in a few number of pools [32]. A 2015 study found that of 85 fields identified as suitable for $CO_2$-EOR in Alberta, two fields, Pembina and Redwater, accounted for 80% of the $CO_2$ storage potential. The same study found that of the more than 14,000 pools in Alberta, there are only 136 pools suitable for $CO_2$-EOR based on the studies' screening methodologies [22]. $CO_2$ storage potential through $CO_2$-EOR is calculated by pool using the methodology from the Bachu et al. 2015 study [11]. The screened oil pools with greater than 1 Mt of $CO_2$ storage potential are shown in **Figure 9.**

Saskatchewan also offers $CO_2$ storage resources through $CO_2$-EOR, as demonstrated by the successful Weyburn and Midale $CO_2$-EOR projects. A 2011 study found, using screening criteria, that 239 oil pools are considered suitable for $CO_2$-EOR. All suitable pools are located in the southern part of the province in the Swift Current and Weyburn regions. These pools have storage potential between 314 and 1,030 Mt of $CO_2$ with an associated incremental oil recovery of between 689 and 2,299 MMbbls [68].

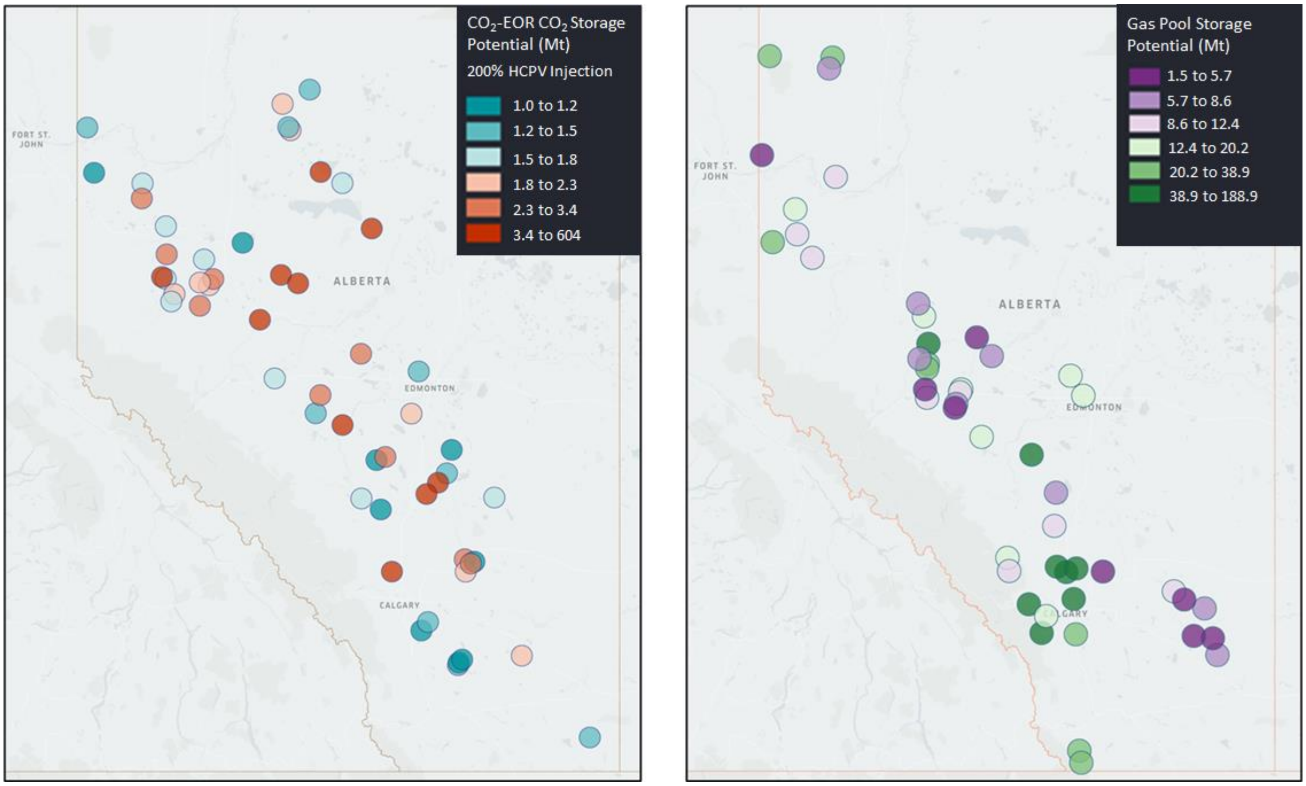



**Figure 9. Map of Alberta identifying oil pools suitable for $CO_2$-EOR and depleted gas pools and their $CO_2$ storage potential. Maps are created by the author using methodology from Bachu [22] and Bachu and Shaw [67] and filtered for pools with greater than 1Mt $CO_2$ storage potential.**

There have been fewer than 20 $CO_2$-EOR pilot projects executed in Canada since 1980 [69]–[71]. **Table 2** shows the list of past and current pilot and commercial $CO_2$-EOR projects in Alberta and Saskatchewan. Three $CO_2$-EOR projects are operating in Alberta, Clive, Joffre, and Chigwell fields, and two operating in Saskatchewan, Weyburn and Midale [36]. The most recent $CO_2$-EOR storage project is the Clive EOR project, which is connected to the Alberta Carbon Trunk Line (ACTL), and stores $CO_2$ captured from upgrading and fertilizer production northeast of Edmonton [60]. The cumulative annual $CO_2$ sequestered in Western Canada through $CO_2$-EOR is 3.6 Mt per year (**Figure 10**), mainly attributed to Weyburn, which sequesters 2 Mt of $CO_2$ per year [60], [72], [73]. Storage through $CO_2$-EOR in Western Canada significantly exceeds the annual $CO_2$ storage through deep saline aquifers.

Given the magnitude of $CO_2$ emissions reduction required to reach net-zero targets and support blue hydrogen production, $CO_2$-EOR is unlikely to provide sufficient storage potential alone. Based on the range of resource estimates from past studies, storage through deep saline aquifer can provide 10 to 1,000 times more storage potential than $CO_2$-EOR. However, storage resources associated with $CO_2$-EOR are, today, better defined than those in saline aquifers and—depending on the business models involved—could be seen to be lower risk and have better economics than development of relatively uncertain deep saline aquifer storage. From this perspective, $CO_2$-EOR could be a catalyst and help underpin future saline storage project success through providing short-term revenue generated from oil recovery and build-out of required complementary infrastructure. Both the TransAlta Project Pioneer and Heartland Area Redwater Project considered integrating $CO_2$-EOR, in the Pembina and Redwater fields, respectively, in their project proposals.

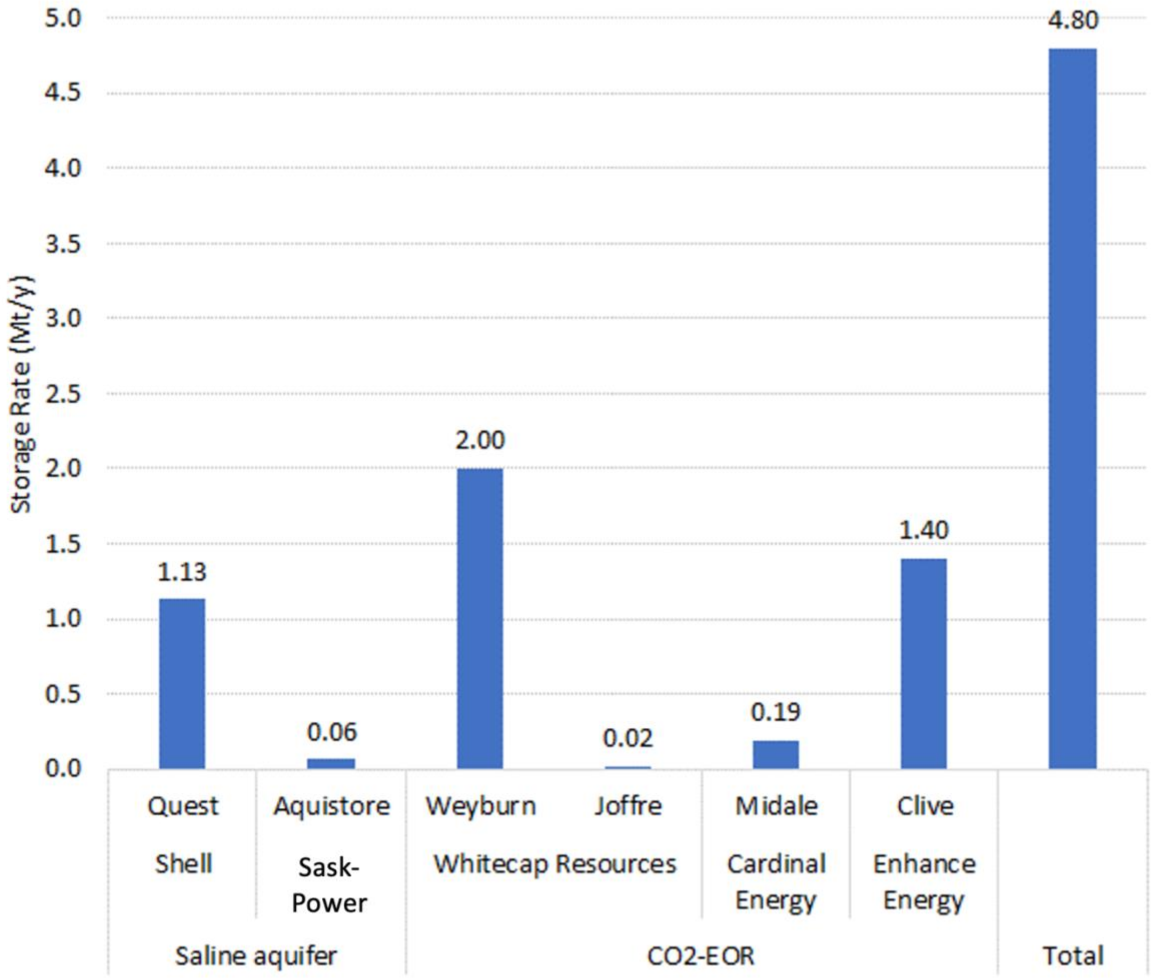



**Figure 10. Annual $CO_2$ stored (Mt/yr) through current projects in Western Canada. Annual CO2 stored based on corporate reports, presentations, press releases, and other publicly available data. The Chigwell field, operated by AlphaBow Energy, is excluded from the chart due to the lack of available data.**

Table 2. Pilot and commercial $CO_2$-enhanced oil recovery projects in Western Canada Data from BMO [69] and Gunter and Longworth [70].

| Field | Pool | OOIP (mmbbl) | API | Pilot | Type | $CO_2$ Start Year | Current R.F. (%) | Cum. Oil Prod. (mmbbl) | $CO_2$ Storage Capacity (Mt) | Est. $CO_2$ Stored 2021 (Mt) | Status | Ref. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pembina | Cardium | 10,576 | 38 | X | Miscible | 2005 | 14% | 1,431 | | | Discontinued 2010 - Technical Success | [69], [70] |
| Swan Hills | Beaverhill Lake A & B | 2,900 | 41 | X | Miscible | 2004 | 32% | 929 | | | Discontinued 2007 - Technical Success | [69], [70] |
| Weyburn/Estevan | Weyburn Midale | 1,500 | 30 | | Miscible | 2000 | 35% | 521 | 55 | 34 | Operating - Saskatchewan | [69], [70], [74], [75] |
| Redwater | D-3 | 1,300 | 36 | X | Immsible | 2008 | 65% | 847 | | | Discontinued 2010 – Technical Success | [69], [70] |
| Swan Hills South | Beaverhill Lake A | 1,084 | 41 | X | Miscible | 2008 | 37% | 400 | | | Discontinued 2010 – Technical Success | [69], [70] |
| Judy Creek | Beaverhill Lake A & B | 1,020 | 42 | X | Miscible | 2007 | 49% | 500 | | | Discontinued n.d. - Technical Success | [69], [70] |
| Weyburn/Estevan | Midale Central Midale | 730 | 30 | | Miscible | 2005 | 22% | 158 | 32 | 5 | Operating - Saskatchewan | [69], [70], [73] |
| Clive | D-3A | 97 | 40 | | Miscible | 2019/2020 | 48% | 47 | 18.8 | 1 | Operating - Alberta | [60], [69], [70], [76] |
| Joffre | Viking | 89 | 38 | | Miscible | 1984 | 48% | 43 | 5† | 1.5 | Operating - Alberta | [69], [70] |
| Chigwell | Viking I & E | 64 | 33 | | Miscible | 2007 | 11% | 7 | | | Operating - Alberta | [69], [70] |
| Zama | Keg River (X2X, etc.) | 24 | 35-39 | X | Miscible | 2004 | 33% | 8 | | | Discontinued 2007 - Technical Success | [69], [70] |
| Enchant | Arcs A & B | 11 | 26 | X | Miscible | 2004 | 37% | 4 | | | Disconintued 2008 - Unsuccessful <MMP | [69], [70] |

†Storage capacity estimated based on Azzolina et al. [25] correlation assuming 200% hydrocarbon pore volume injected $CO_2$ and Joffre and Chigwell OOIP of 88.8 MMbbls and 63.9 MMbbls respectively [36]

## 4.2 Finding Storage Opportunities in Depleted Gas Pools

Depleted gas reservoirs once contained commercial accumulations of natural gas and, through production, they have been depleted. Unlike for storage in oil reservoirs, injection of $CO_2$ would not likely be used to enhance hydrocarbon recovery. The $CO_2$ storage opportunity in depleted gas pools has been studied in past regional and province-specific studies. The aggregate $CO_2$ storage resource in depleted gas pools is several times larger than that of $CO_2$-EOR— estimated at 8 Gt of contingent storage resources in the WCSB.

Depleted gas pools have relatively low technical risk compared to saline aquifers. They are generally well characterized and delineated through years of study and production, have demonstrated their ability to contain buoyant fluids, and have produced a measured volume of gas, establishing a known storage volume. As a result, gas pools can provide greater containment assurance, unlike large regional saline aquifers where there is uncertainty as to $CO_2$ migration pathways. Most depleted gas storage potential is, however, located in smaller sized pools. Studies have found that most gas pools could only store a small amount of $CO_2$, with a typical storage resource of between 60–332 kt$CO_2$ per pool, making most single depleted gas reservoirs likely impractical or uneconomic for $CO_2$ storage [32], [67]. Aggregated or clustered gas pools or fields offer much greater storage potential.

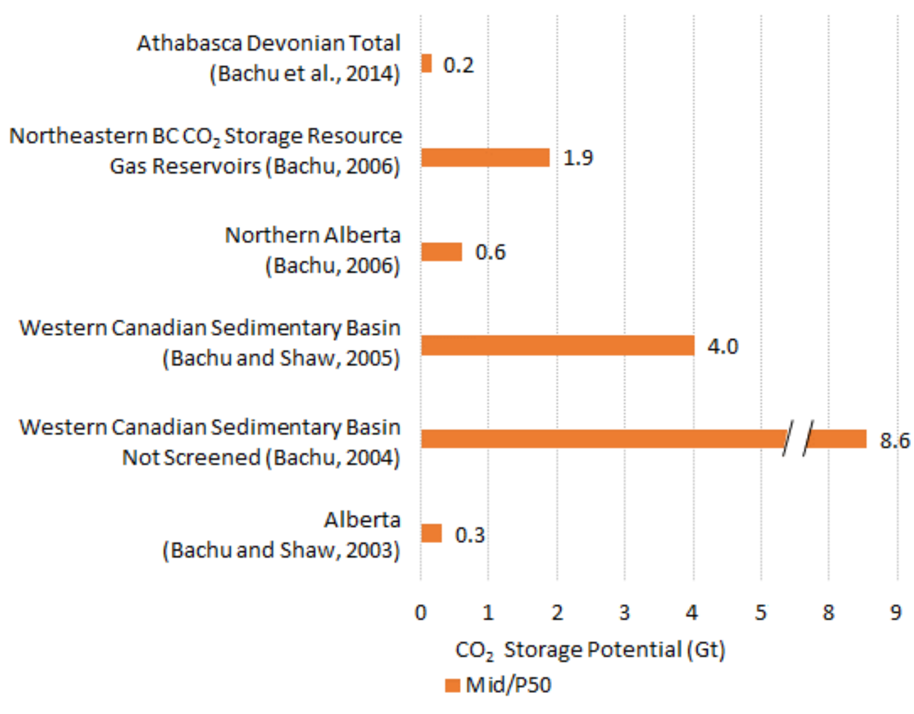



**Figure 11. Data labels report the central, or where specified, 50th percentile (P50) estimate for each study. P90 represents a 90th percentile estimate and, P10 represents a 10th percentile estimate. Note the broken axis in order to show the large estimate for the Western Canadian Sedimentary Basin by Bachu [32].**

The Western Canadian depleted gas pool $CO_2$ storage resource estimates shown in **Figure 11** vary based on size of area of study and the screening criteria applied to identify available or suitable pools. Pool size and depth are often used to screen depleted gas pools. **Shallow gas pools are inefficient for $CO_2$ storage** due to the low-density state of $CO_2$ and ultimate storage capacity. Other screening criteria can include the effects of the underlying aquifer on $CO_2$ storage potential. Water invasion from underlying aquifers in depleted gas pools has been shown to reduce $CO_2$ storage resource on average by 28% [67].

Depleted gas pools with low pressures and weak aquifer invasion offer attractive $CO_2$ storage potential. **Both individually and in aggregate, there are many gas pools and fields with $CO_2$ storage potential greater than 10 Mt**, near current and future $CO_2$ sources, as shown in **Figure 9**. While this distribution of resources is promising, more investigation is required into flow-assurance issues resulting from injecting dense phase supercritical $CO_2$ into depleted reservoirs and associated risk assessment strategies and optimal operational management practices.

## Summary of Findings: Hydrocarbon Reservoir Storage Potential

- Median values of past estimates for storage potential in Western Canada through $CO_2$-enhanced oil recovery range between 500–870 Mt of $CO_2$
- Most oil pools and depleted gas reservoirs have a small $CO_2$ sequestration capacity relative to emissions captured from even one large emitter, making $CO_2$ storage economics challenging
- There are some individual oil pools and depleted gas reservoirs that have a cumulative storage potential greater than a few Mt of $CO_2$, and may be viable for $CO_2$ storage
- Notably, Pembina Cardium and Redwater Leduc offer large $CO_2$-EOR storage potential in Central Alberta, accounting for more than 80% of $CO_2$ storage through $CO_2$ EOR from fields suitable for $CO_2$-EOR [15]
- Current commercial $CO_2$-EOR projects in both Alberta and Saskatchewan are sequestering a total of 3.6 Mt of $CO_2$ per year
- **$CO_2$-EOR can provide revenue from incremental oil recovery** and can advance deep saline storage development
- Technical challenges require further R&D to manage risks associated with injection of $CO_2$ into depleted, low pressure gas reservoirs

# 5 $CO_2$ STORAGE RESOURCES IN THE ALBERTA INDUSTRIAL HEARTLAND

Central Alberta and Alberta's Industrial Heartland (AIH) are ideally positioned to underpin future CCUS projects. Alberta's Industrial Heartland is located northeast of Edmonton and represents a large industrial complex with large point sources of $CO_2$ emissions. The AIH is adjacent to some of the most material $CO_2$ storage opportunities in the province, and is strategically located to produce, use, and export blue hydrogen [6].

Central Alberta and the Alberta Industrial Heartland have been the focus of numerous reservoir characterization and site-specific $CO_2$ storage studies over the past couple decades. This was driven in large part because of the coal-fired power generation and other industrial $CO_2$ sources in the area, minimizing the transportation cost to storage site.

"Alberta's Industrial Heartland is adjacent to some of the most material $CO_2$ storage opportunities in the province, and is strategically located to produce, use, and export blue hydrogen."

**Error! Reference source not found.** shows current and past $CO_2$ storage project study areas, size of estimated $CO_2$ storage resources, and proximity to central Alberta and $CO_2$ emissions sources. Studies have focused primarily on the Devonian and Cambrian aged saline formations targeting the Leduc and Basal Cambrian in the Fort Saskatchewan area, and the Nisku in the Wabamun Lake area southwest of Edmonton. These studies are often tied to specific emission sources of $CO_2$, such as TransAlta Project Pioneer tied to the Keephills 3 power plant, and/or coupled with $CO_2$-EOR project proposals. The central Alberta studies demonstrate a $CO_2$ storage resource of hundreds of millions of tonnes.

The Wabamun–Lake Devonian–Nisku area has been the subject of four separate project- and site-specific studies:

- Sequestration Project (WASP);
- TransAlta's Project Pioneer;
- The Alberta Saline Aquifer Project (ASAP); and
- A 2009 Central Alberta Storage Study [51].

The Devonian Nisku has excellent $CO_2$ storage potential. It is large, has favourable geology, and benefits from a large amount of data on stratigraphy and lithology, fluid compositions, and rock properties [51].

Wabamun Lake is also strategically located near a number of mature oil fields with EOR opportunities including the large Pembina Cardium oil pool location just south of the Wabamun Lake area [63]. The Wabamun–Nisku area's cumulative $CO_2$ storage resource ranges between 10 and 400 Mt of $CO_2$, or 1 to 12.5 Mt per year [51], [63], [64].

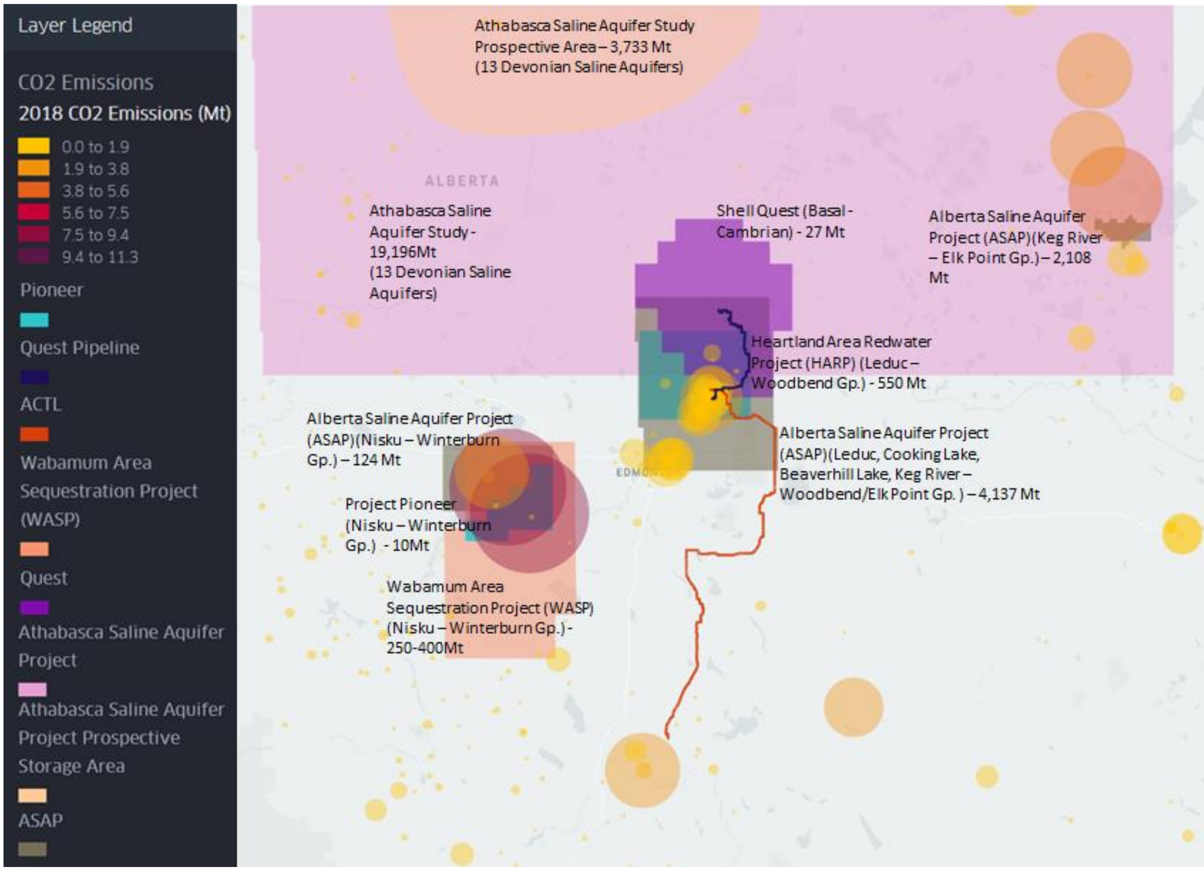



**Figure 12. Saline aquifer storage studies and projects surrounding the Alberta Industrial Heartland**

Other project- or site-specific studies in the area have targeted the Devonian Leduc reef aquifer surrounding Fort Saskatchewan. These include the Heartland Area Redwater Project (HARP), proposed by ARC Resources, and the Alberta Saline Aquifer Project (ASAP), proposed by Enbridge. Both studies concluded that the Redwater Leduc Reef is a good candidate for $CO_2$ storage, with $CO_2$ storage estimates ranging from 550 Mt, from HARP study dynamic modelling, to over a gigatonne [61], [62].

$CO_2$-EOR has also been implemented in the past in the Redwater Leduc area, and prior studies have identified the opportunity for optimizing $CO_2$-EOR and $CO_2$ storage improving oil recovery by 5–15% [62]. The Redwater field is one of the largest oil fields in Alberta, with almost 2 billion barrels of oil in place, and has a $CO_2$-EOR storage potential of 34 Mt [17], [22]. Other Devonian targets, such as Cooking Lake, Beaverhill Lake, and Keg River have also been studied in some detail as part of the ASAP.

The Shell Quest project injects approximately 1.2 Mt/yr of $CO_2$ into the Basal Cambrian Sandstone from the Scotford Upgrader (**Error! Reference source not found.**). The Basal Cambrian in the area is an excellent candidate for $CO_2$ storage, given its seal integrity, depth, and size. Given that Quest is dedicated storage for the Scotford Upgrader and was designed with a 25-year life, it is unclear whether this capacity could be available for third-party use. However, there is an opportunity to leverage prior knowledge from the Quest project to further the understanding of the Basal Cambrian in the Central Alberta area. In fact, Shell has leveraged this knowledge in proposing the Polaris project, in which $CO_2$ captured from the Scotford Refinery (and potentially that from third-parties) would be geologically stored at a location further south in the Basial Cambrian [77].

Total annual $CO_2$ storage resources, based on past site-specific studies for saline aquifers in central Alberta (**Table 1**), is large, but likely to less than the potential demand for $CO_2$ storage of 200 Mt per year by 2050. Further $CO_2$ storage needs to be de-risked in central Alberta and or $CO_2$ storage projects outside of central Alberta need to be pursued. The Basal Cambrian Sandstone, for example, offers storage capability in the Wabamun Lake area; however, it has not been studied in detail and suffers from a lack of well penetrations and associated data [63].

# 6 THE FUTURE OF $CO_2$ STORAGE

As evidenced by this review, $CO_2$ storage resource in geological media in the Western Canadian Sedimentary Basin has been studied extensively. Past studies' storage resource estimates range in quality and certainty as well as size. Generally, they paint a picture of gigatonnes of $CO_2$ storage opportunity, demonstrating that Western Canada theoretically contains enough $CO_2$ storage to meet future emissions reduction targets and support blue hydrogen production. However, the quality and completeness of past $CO_2$ storage resource estimates needs to be improved to provide higher certainty storage estimates that industry (and government) can use to make important strategic decisions. There are areas of study that need revising or further work to advance the knowledge base, improve the certainty of estimates, and provide tools to unlock and accelerate $CO_2$ storage development.

Regarding the regional saline aquifers studies in Western Canada, there is potential for expanding on the current work in several areas:

- Basal Cambrian is the only saline aquifer with a complete dataset in the National and PCOR Partnership Atlas submission for Western Canada [31]. Data for the other six aquifers needs to be aggregated, and saline aquifer properties calculated, to close gaps in the Western Canadian $CO_2$ Storage National and PCOR Partnership Atlas dataset.
- Other shallower aquifers, higher up the sedimentary succession, should be evaluated for $CO_2$ storage potential. This includes the Upper and Lower Cretaceous targets such as the Cardium and Mannville groups that were not the focus of earlier regional studies. Future assessments should follow a similar methodology to that of the Geological Survey of Canada (GSC) and Alberta Innovates studies and consider implementing recommendations provided to the GSC in 2011 [54].
- The PCOR and Alberta Innovates Basal Cambrian 2017 geological model should be refined. Taking a thorough look at and updating the Basal Cambrian modelling is justified based on the prolific storage potential previously identified. There is an opportunity to complete local-scale modelling in areas of Western Canada with the highest storage potential and lowest $CO_2$ storage risk.
- Consider applying methods in regional-scale assessments that resolve $CO_2$ plume development and consider injectivity limitations that will determine the required number of injection wells and influence the storage development plan [47]. To date, only site-specific studies considered storage development limitations related to plume size and injectivity. This should include an evaluation of these aquifers' heterogeneity and permeability because of the influence on injectivity.

- Understand the impact of large-scale storage across the WCSB and potential for pressure management approaches and $CO_2$ saturation management of the injection plume. $CO_2$ storage potential is dependent on pressure management, which could become important with large rates of injection across the WCSB,and could be affected through brine extraction.
- Future regional-scale assessments should encompass a broad set of suitability criteria beyond just storage resource potential. Future assessments should consider other risk factors such as containment risk incorporating the lateral continuity of the seal and seal thickness, number of seals or aquitards, wellbore leakage potential, faulting, and fracturing, as well as surface risk considerations. A ranking and weighting methodology could be applied to evaluate storage potential based on all suitability criteria. This methodology will help provide a more complete evaluation to define the more or less prospective $CO_2$ storage areas and sites in Western Canada.
- Future storage assessments should include an economic assessment to identify economically viable $CO_2$ storage potential. These cost models can then be used to identify low-cost storage opportunities near current and future emissions sources and refine Western Canadian blue hydrogen cost models.
- Given the magnitude of $CO_2$ storage capacity required from 2050 blue hydrogen production, there is a need to develop a complete CCUS strategy tied to supporting blue hydrogen production. This includes infrastructure requirements, operations management, and risk mitigation strategy in alignment with the Hydrogen Strategy for Canada.

> "Until evaluation wells are drilled to test, validate, and confirm $CO_2$ storage resource estimates, uncertainty in $CO_2$ storage resources cannot be reduced to a level needed to support future carbon capture projects and blue hydrogen production."

Many of the above recommendations could be incorporated into a tool that facilitates evaluation of $CO_2$ storage prospects based on a complete set of storage suitability criteria. This would go a long way to improve the quality and certainty of the regional storage estimates. Ultimately, however, storage evaluation wells need to be drilled targeting the most prospective $CO_2$ storage areas to obtain information required to further de-risk the storage potential in Western Canada. Evaluation wells allow direct testing and evaluation of saline aquifers, collection of core samples from caprocks, and collection of a comprehensive suite of logs, amongst other things. This well and formation data is required to validate geological models and dynamic simulations and confirm $CO_2$ storage estimates. Until evaluation wells are drilled to test, validate, and confirm $CO_2$ storage resource estimates, uncertainty in $CO_2$ storage resources cannot be reduced to a level needed to support future carbon capture projects and blue hydrogen production. This presents a "chicken or the egg" problem, as large investments in blue hydrogen production capacity require high probability storage capacity, and development of high probability storage capacity requires investment from blue hydrogen (or other emitters).

Finally, there is an opportunity to create a public repository for data related to $CO_2$ storage studies and projects in Western Canada. Industry and regulatory bodies can benefit from the vast amount of data in past studies. Utilizing all available data ensures the implementation of future storage projects to be more accurate and cost-effective for industry and government. Also, having more complete and accurate data, particularly on performance of existing projects, can support more effective management of risk for future projects.

# Appendix A. Current and Past Projects and Studies

## A.1 Deep Saline Aquifer Projects

### A.1.1 Wabamun Area $CO_2$ Sequestration Project (WASP)

WASP was conducted by a group of 16 University of Calgary researchers between March 2008 and August 2009. The project's objectives were to estimate the storage capacity, determine $CO_2$ plume movement and pressure distribution, and investigate long-term fate of injected $CO_2$ of the Devonian Nisku aquifer of the Winterburn Group in the Wabamun Lake area of Alberta, Canada. The study area was selected due to its proximity to four large coal-fired generating plants—which are now being retired or slated for conversion to natural gas—that were producing up to 6 Mt/yr of $CO_2$ [63].

The study concluded estimating a conservative cumulative $CO_2$ storage potential of between 0.25 and 0.40 Gt if no reservoir pressure maintenance is considered and two to three times higher if aquifer pressure maintenance is considered through net brine withdrawal [63]. The WASP study is one of the only studies that considers brine removal from the Nisku to increase the overall storage capacity. The study found that managing reservoir pressure by removing brine from the Nisku formation may substantially increase overall storage capacity.

The final report identified that there are other geological formations in the Wabamun area that have $CO_2$ storage capability; however, the Nisku formation was selected because of its depth, good reservoir quality, and lack of oil and gas development in the area of interest. The initial phase of WASP focused on establishing the viability of the Devonian Nisku aquifer and did not advance to the point of identifying site locations and drilling a test well and further reservoir characterization [63] .

### A.1.2. Project Pioneer

Project Pioneer was a CCS project that proposed to capture 1 million tonnes $CO_2$ annually for ten years from the Keephills 3 coal-fired power plant. The project proponents were TransAlta Corporation (TransAlta), and its partners, Capital Power L.P. (CPLP) and Enbridge Inc. (Enbridge), with financial support from the Alberta provincial and Canadian federal government. The components of the project included the capture facility and transport of the $CO_2$ by pipeline to both a storage site in the Wabamun Lake area and injected in the Nisku formation and a $CO_2$-enhanced oil recovery field in the Pembina oilfield 80 km southwest of the Keephills plant [64].

Schlumberger Carbon Services drilled, cased, and tested an evaluation well, 100/08-17-051-03W5/0. The well testing program confirmed excellent storage potential, and the evaluation well was assess to be capable of receiving 1.17 million tonnes of $CO_2$ per year and demonstrating good caprock at the site location [64].

In April 2012, TransAlta announced the decision not to proceed with the project due to the uncertainty of the market for $CO_2$ sales and the value of emission reduction in Alberta and Canada being insufficient [64].

The Project Pioneer study area is within the area of interest defined in the WASP study. The results of the WASP study confirmed that the Nisku Formation was a prospective target in the Wabamun Lake area and helped identify the general prospective locations for $CO_2$ storage within the WASP study area.

### A.1.3 Heartland Area Redwater $CO_2$ Storage Project (HARP)

The Heartland Area Redwater $CO_2$ Storage Project (HARP), developed by ARC Resources Ltd., proposed storing $CO_2$ in the Redwater Leduc Formation carbonate reef from sources in the Industrial Heartland of Alberta, Canada. The Redwater Reef, part of Woodbend Group, is approximately 600 $km^2$, is over 1,000 m deep, and up to 275 meters thick [20]. Phase 1 of the study was completed in 2009, which focused on the site characterization and evaluation of the Redwater Reef as a potential $CO_2$ saline aquifer storage site [62].

Phase 1 of the project characterization concluded that the Redwater Reef has the necessary capacity and injectivity for storing several hundred million tonnes of $CO_2$ and is confirmed to have primary and secondary barriers to prevent upward leakage. Historical high water injectivity into the reef indicated the potential for $CO_2$ injectivity of greater than 1,000 tonnes of $CO_2$ a day per well. The reservoir simulation model completed targeted total injection rates of 50,000 tonnes per day for 30 years with a total cumulative $CO_2$ stored of 550 Mt [20].

Phase II of the study included selecting a test site, drilling one injection and two monitoring wells, and the construction of surface facilities. The project was stopped prior to reaching Phase II planned for the last quarter of 2010 [62].

### A.1.4 Quest

The Quest project is a fully integrated capture, transport, and storage (CCS) project and is operated by Shell on behalf of the Athabasca Oil Sands Project (ASOP). The project captures emissions $CO_2$ from the hydrogen manufacturing units within Scotford upgrading facility in Fort Saskatchewan, Alberta. The $CO_2$ is then compressed and transported 65 km north to the injection site where more than 1 Mt per year of $CO_2$ is injected into the Basal Cambrian Storage Complex (BCSC). Design, construction, and start-up began in 2009, with $CO_2$ injection commencing in 2015 [58]. In 2020, Shell Canada announced Quest had surpassed 5 Mt in cumulative $CO_2$ injected through three injection wells [78]. The estimated total storage capacity, based on reservoir modelling of the Quest project, is 27 Mt [58]. The Quest project is the only commercial deep saline aquifer storage project in Alberta.

## A.1.5 Alberta Saline Aquifer Project

The Alberta Saline Aquifer Project (ASAP) was initiated by Enbridge in 2008 and concluded in 2009 and was a collaboration of 38 industry, government, and academic participants. The Phase 1 project goal was to identify the top deep saline aquifer storage sites and $CO_2$ pipeline routes to EOR projects and establish design and costs for large-scale storage.

ASAP Phase 1 was a comprehensive study that included site selection, risk assessment, reservoir simulation, preliminary well drilling and completion design, measurement, monitoring and verification (MMV) program development, compression, and pipeline design, as well as legal, regulatory, and stakeholder engagement overviews.

Twenty-nine aquifer formations were analyzed through interpreting geological, geophysical, and core data and logs and mapping from the Western Canadian Sedimentary Basin Atlas. Six $CO_2$ storage areas were identified through ASAP: Nisku Formation in the Wabamun Lake Area, Beaverhill Lake North, Beaverhill Lake South, Leduc, Keg River North, and Keg River South. The combined $CO_2$ storage potential of the six selected sites was estimated to be 10,911 Mt. The project concluded before the start of Phase II– the construction of a $CO_2$ injection pilot project – in advance of full-scale commercial development [61].

## A.1.6 Saskatchewan Aquistore

The Aquistore is an ongoing demonstration $CO_2$ storage project in southeast Saskatchewan managed and operated by SaskPower. The objective of the Aquistore project is to demonstrate the scientific and economic feasibility of deep saline aquifer storage and contribute evidence-based knowledge in support of the safe and effective implementation of the geological storage of $CO_2$ [79]. The project takes captured $CO_2$ emissions from the SaskPower Boundary Dam Unit 3 coal-fired power plant near Estevan, Saskatchewan, located 2.8 km away. The majority of captured emissions are sold to the Weyburn oilfield for enhanced oil recovery operations.

The Aquistore storage site location is in the northern part of the Williston Basin. The storage reservoir comprises the Deadwood and Winnipeg Formations, part of the Basal Cambrian Group, and is 3.4 km deep. The storage site was chosen due to its proximity to the capture facility, and the formations due to their sufficient thickness, porosity, and permeability to achieve the desired injectivity. The Aquistore project was initiated in 2009, with detailed investigation starting in 2012 [57]. Injection commenced in 2015, with more than 370,000 tonnes of $CO_2$ having been injected to date [80]. There is one injection well and one monitoring well.

Two simulation models, a local-scale and regional-scale, were completed for the Aquistore project through the Plains $CO_2$ Reduction Partnership (PCOR) and the Energy and Environment Research Center (EERC) collaborating with PTRC. The static $CO_2$ capacity of the local-scale model ranges from 8.4 Mt to 27.1 Mt for the P10 and P90 confidence intervals, with the simulation model estimating a maximum storage potential of 34 Mt over 50 years from a single injector. The Aquistore regional-scale model $CO_2$ storage potential from the Black Island and Deadwood Formations in the Basal Cambrian P10, P50, and P90 estimates are 1.6 Gt, 3.1 Gt, and 5.3 Gt [59].

### A.1.7 Fort Nelson

The Fort Nelson Carbon Capture and Storage project was proposed to capture and store $CO_2$ emissions from the Spectra Energy Transmission's (Spectra) Fort Nelson Gas Plant located in North-eastern British Columbia. The purpose of this project was to investigate the feasibility that $CO_2$ separated by gas processing at the gas plant can be safely and cost-effectively stored in the Devonian-age Presqu'ile reef carbonate saline complex [31].

The study was performed between 2009 and 2012 by the PCOR Partnership through the Energy and Environmental Research Center (EERC) in collaboration with Spectra. The study included extensive geological characterization, modeling, risk assessment, and included the drilling of the project test well. The results of the study suggested that the commercial-scale CCS project in the Fort Nelson area would be technically feasible with an estimated storage capacity of 140 Mt to 240 million Mt at an injection rate up to 2.2 Mt of $CO_2$ per year [44], [65], [81]. Spectra suspended the project in 2015 due to low-price environment for natural gas [31].

## A.2 Commercial $CO_2$-Enhanced Oil Recovery Projects

### A.2.1 Weyburn – Saskatchewan

The Weyburn Unit is located on the northeast flank of the Williston Basin in southeast Saskatchewan and was discovered in 1954. The Weyburn Unit has over twenty unit owners, with the majority interest owner and operator being Whitecap Resources with 65.3% working interest [69], [75]. The sources of $CO_2$ are SaskPower's Boundary Dam Power Station 3 located 68km southeast of the Unit, and the Great Plains Synfuels Plant in North Dakota. The combined maximum capture capacity of the two facilities is 4 Mt per year.

The target reservoir formation, the Mississippian aged Midale carbonate, contains a sizeable high-quality resource with 1.5 Billion barrels of original oil in place (OOIP) of light 30 API oil. The miscible carbon dioxide flood was initiated in October 2000 to enhance oil recovery. The Midale carbonate formation is separated into the distinctive zones, the Marly, Vuggy Intershoal, and Vuggy Shoal. The original target was the permeable Vuggy Shoal, while more recent drilling and $CO_2$ flooding has targeted the unswept Marly dolomite zones. The Midale Marly and Vuggy Shoal average permeability is 10 mD and 20 mD, and average porosity is 26% and 10%. The Vuggy Intershoal deposits have much poorer reservoir characteristics with considerably smaller pore size and lower permeability. The field is currently producing 22,150 bbls/d and has recovered a total of 525 MMbbls of oil. The Weyburn field stored 2 Mt of $CO_2$ in 2020, bringing the total volume of $CO_2$ sequestered to 36 Mt over the 20 years of operation [74], [82]. The Weyburn and Midale Unit $CO_2$-EOR projects together are the largest anthropogenic CCUS project globally, having stored over 40 Mt.

The Weyburn Unit and the Midale Unit were the subjects of an International Energy Agency (IEA) GHG project, led by the PTRC, that started in 2000 and continued to 2014, studying whether $CO_2$ could be securely and economically stored. The research resulted in a Best Practices Manual published in 2012 providing guidance on validating safe storage of $CO_2$ [83].

### A.2.2 Midale – Saskatchewan

The Midale Unit is located adjacent to the Weyburn Unit, directly to the east in Saskatchewan with the same source $CO_2$ and infrastructure. The Midale Unit, like the Weyburn Unit, has over twenty unit owners, with the majority interest owner and operator being Cardinal Energy with 77.2% working interest [69]. The Midale Unit produces from the same Midale reservoir formation as the Weyburn Unit. The OOIP of the Midale Unit is estimated to be 730 MMbbls, with 161 MMbbls recovered to date. Primary oil production started in 1953, with waterflooding implemented in 1962. The commercial miscible $CO_2$ flood commenced in 2005 and only one-third of the unit is currently flooded. Approximately 0.2 Mt of $CO_2$ stored in 2020 and 5 Mt of $CO_2$ to date, with an estimated total storage resource potential of 32 Mt [73].

### A.2.3 Clive – Alberta

The Enhance Energy Clive $CO_2$-EOR project is part of the Alberta Carbon Trunk Line (ACTL) joint partnership between Enhance Energy Inc., North West Redwater Partnership (NWR), and Wolf Carbon Solutions in Alberta. The project involves capturing up to 1.7 Mt per year of $CO_2$ from the existing Nutrien Redwater fertilizer plant and NWR Sturgeon Refinery located approximately 45 kilometres northwest of Edmonton. The $CO_2$ is compressed and transported down a 240 km pipeline, owned and operated by Wolf Carbon Solutions, south to the Enhance Energy Clive $CO_2$-EOR oil field located 32 km east of Red Deer, Alberta [60], [69]. The Clive field commenced injection in June 2020 has stored 1 Mt of $CO_2$ as of March 2021 [76]. ACTL currently has excess capacity and was designed for up to 14.6 Mt per year, making it the largest anthropogenic $CO_2$ transportation system in the world [60], [69]. The Clive field target reservoirs are the Devonian Leduc and Nisku formations and have a total OOIP of 166mmbbl, 97 MMbbls OOIP for the Leduc and 69 MMbbls for the Nisku [60]. The Clive reservoirs are mature waterflooded reservoirs, having been in operation for over 50 years, providing confidence for containment, injectivity and capacity for $CO_2$ storage. The average porosity for the Clive Leduc and Nisku formations is 6%, with an average permeability between 245 and 290mD. The initial reservoir pressures of the two formations were approximately 16,600kPa. Reservoir pressures have since fallen to around 12,500-13,000kPa after years of production [60], [69]. The $CO_2$ storage resource potential at Clive is 12.4 Mt at current reservoir pressure of 1,813 psi or up to 18.8 MT at initial reservoir pressure[60].

### A.2.4 Joffre – Alberta

Joffre Viking was one of the first commercial $CO_2$-EOR projects in Western Canada. Primary oil production commenced in 1953, with waterflooding starting in 1957 and the miscible $CO_2$ flood starting in 1982. Joffre Viking pool is currently owned and operated by Whitecap Resources.

$CO_2$ is delivered to site from the nearby NOVA chemical Ethylene Plant in Joffre, Alberta. The target cretaceous Viking sandstone reservoir has an OOIP of 88 mmbls and has produced 43 MMbbls to the end of 2019 [36]. Current oil production from the pool is approximately 500 bbl/d. The average porosity and permeability are 13% and 349mD, respectively, at an average depth of 1,400m. The initial reservoir pressure was 6,616 kPa, which was below the minimum miscible pressure; however, the reservoir has since been pressured up to above 13 MPa, allowing the $CO_2$ to be miscible [69], [70]. Joffre Viking field has stored an estimated 1.5 Mt of $CO_2$, based on an average net $CO_2$ utilization factor of 4 mscf per bbl of incremental oil and a total CO2 storage resource of 5Mt [66], [70]. The pool stored 21,500 tonnes of $CO_2$ in 2020, with Whitecap Resources recently announcing this could double to store 45,000 tonnes per year [84].

### A.2.5 Chigwell – Alberta

Chigwell Viking consists of two pools Chigwell Viking I and Viking E. The Chigwell Viking $CO_2$-EOR project is currently owned and operated by a private company Alpha Bow Energy. $CO_2$ is transported by pipeline from the MEGlobal Prentiss 2 Ethylene Glycol Production facility. The current oil production from the two pools is approximately 1000 bbls/d, producing a total cumulative oil of 7MMbbls up to the end of 2019. The combined OOIP is 63.9 MMbbls [36].

The Chigwell Viking E and Viking I pools reservoir properties are similar to Joffre Viking, with an average depth of approximately 1400m, porosity of 13% and average permeability in the range of 44 to 73mD [36], [69], [70]. $CO_2$ flooding was initiated in E pool in 2007, and the I pool in 2006. Following the $CO_2$ injection, both pools exhibited strong production responses and an increase in oil rates. More recently, CO2 injection has been intermittent in both pools, but has been more consistent over the past year [69], [70]. The estimated total $CO_2$ stored is 1.6Mt to the end of 2019 based on a generic net utilization factor of 6 mscf per bbl of incremental oil [36]. The total $CO_2$ storage resource potential is estimated to be 3.65 Mt $CO_2$.

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