Alberta Innovates

Emissions Reduction Alberta

Report: Study of Water Impacts of CCUS Development in Alberta

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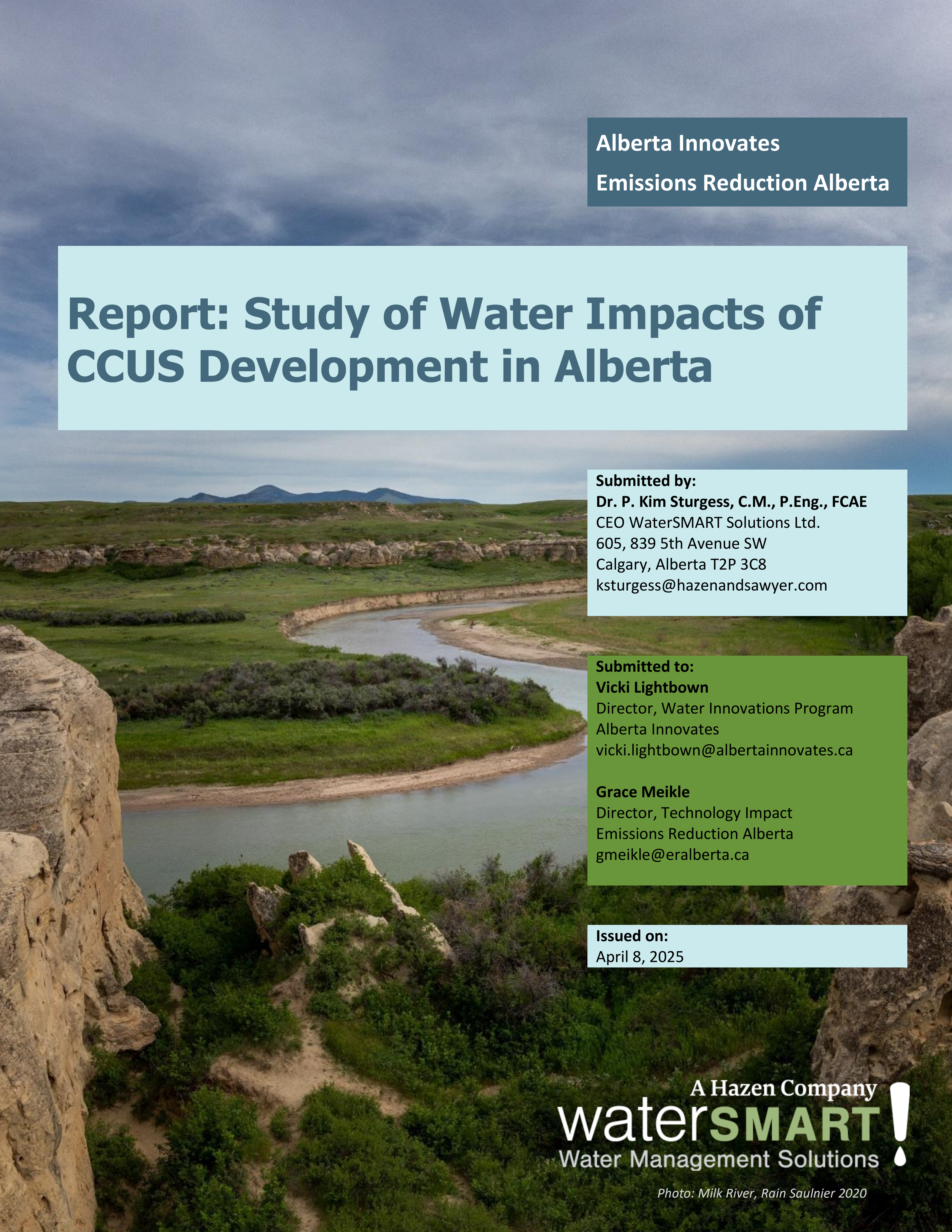

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Photo: Milk River, Rain Saulnier 2020

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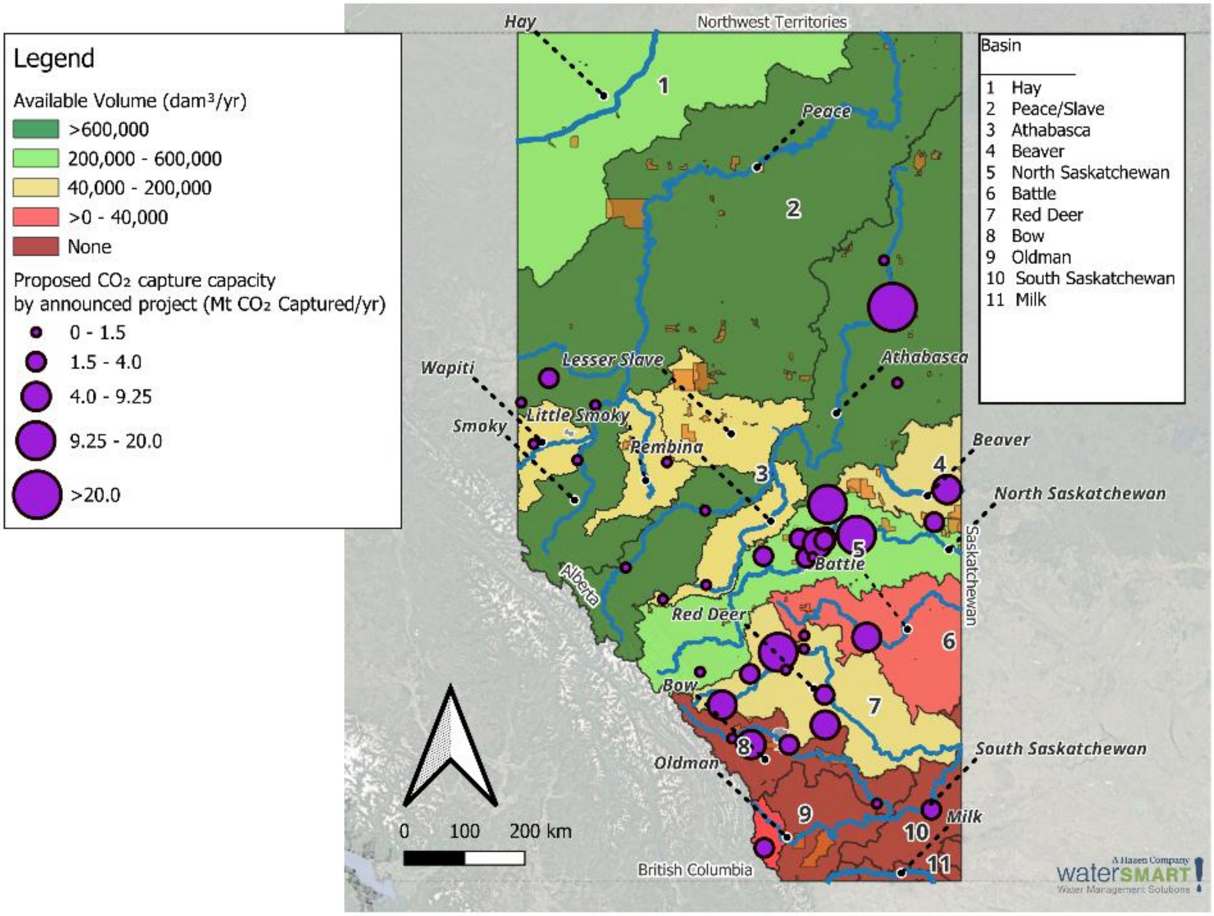
Photo: Siffleur Canyon, Rain Saulnier 2022

Executive Summary

In a rapidly evolving global geopolitical climate, emphasis continues to be placed by governments, institutions, companies, and individuals on reducing greenhouse gas emissions. In Alberta, carbon capture, utilization, and storage (CCUS) has been identified as integral to transitioning to a lower carbon economy, with the goal of leveraging the province's existing strengths while fostering new economic opportunities. A critical facet of the energy transition, including CCUS, is its potential water-related impacts and opportunities, and the constraints which water supply may place on its development.

In this report, WaterSMART Solutions Ltd., a Hazen Company (WaterSMART), has analyzed the anticipated water-related impacts of CCUS development in Alberta, the potential risks to CCUS development that water scarcity may present, and the possible water-energy-food nexus trade-offs that may arise from this development. The water-energy-food nexus describes the interconnectivity between the use and management of water, energy, and food, where decision-making for one resource impacts the others. This report is intended to inform policies, regulations, and investments that will best enable the CCUS sector's growth, while helping proponents and decision-makers identify competing interests and manage trade-offs within the water-energy-food nexus context. It builds on WaterSMART's 2023 Study of Water Impacts of Hydrogen Development in Alberta and considers the combined water impacts of CCUS and hydrogen development.

Using a 2050 time horizon, the following figure illustrates the anticipated carbon capture projects in Alberta, overlaid on a water availability heatmap for a median flow year. In some river basins, particularly in the south of the province, future water supply has the potential to constrain CCUS development. Conversely, numerous other locations are expected to have sufficient water supply to accommodate current CCUS development goals.



Low, Medium, and High water use scenarios were developed, assuming amine-based carbon capture, to reflect the range of potential water intensities for various CCUS projects. Several variables were adjusted to differentiate between each scenario, including the rate of water recovery from the flue gas, the cooling technology deployed, and the presence or absence of existing power generation to run the process. The Low, Medium, and High scenarios were calculated for several flue gas compositions representing the wide variety in planned CCUS projects in Alberta (i.e., natural gas combined cycle power generation, biomass combustion, cement manufacturing, auto-thermal reforming hydrogen/ammonia production, and oil sands). The water use scenarios were applied to all announced CCUS projects in Alberta to estimate the range of potential water demands for CCUS.

By comparing potential water demands for CCUS to water availability across Alberta in 2050, this report demonstrates that the full buildout of the CCUS sector in the province is likely to involve water supply risks and necessitate trade-offs within the water-energy-food nexus. These risks and trade-offs will vary across the province and location-specific efforts will be required to understand and manage them appropriately. For example, water supply challenges are expected to significantly increase project risks in river basins with current water supply constraints, especially where no new water diversion licences can be applied for (e.g., the Bow River Basin). Other basins, such as the North Saskatchewan and Red Deer, are not currently water constrained to the same extent as the southern basins, but this is subject to change in the future. In these locations, CCUS development may introduce water supply challenges, especially when considered in conjunction with other industrial development, such as hydrogen production. Within all basins in Alberta, individual tributaries may present water supply risks.

Although this figure highlights the locations where water supply may limit CCUS development, it is important to note that some carbon capture configurations actually generate more water than they consume. Specifically, water can be generated through highly water efficient, amine-based carbon capture applications in natural gas combined cycle power generation, cement manufacturing, biomass combustion, and the oil sands. This excess water, which is removed from the industrial flue gas during capture, can be reused within the capture process to reduce makeup water demands or reused in the adjoining industrial facility. By using this recovered water and offsetting other demands, some carbon capture projects can result in a net-neutral or even a net-positive impact to water availability at a basin level. Achieving this outcome requires the right combination of flue gas composition, carbon capture technology, and process design, as well as the associated treatment and logistics to beneficially use the recovered water. In cases where excess recovered water cannot be beneficially utilized, it will need to be appropriately managed, for example through disposal.

Given the potential for CCUS to either consume or generate water, on a net basis, it should not be concluded that CCUS development should be avoided within Alberta, or even within specific river basins. Rather, proponents, investors, policy makers, and other decision makers with influence on the sector should carefully consider the potential water risks and opportunities identified in this report. Through early identification and evaluation of water-related challenges, solutions can be identified and implemented to minimize the impacts of CCUS development in the water-energy-food nexus context. Specifically, the following recommendations are provided for project proponents and investors, with parallels to the recommendations provided in WaterSMART's 2023 hydrogen report:

1. Integrate water management into project planning at an early development stage:
    a. Conduct detailed analyses of the water available for a given project and how it will be impacted by hydrologic and environmental conditions, regulatory context, and other water users, now and into the future. Ideally, these analyses will occur before significant time and capital is spent on other project design efforts, regulatory applications, or land purchases.
    b. Consider regional water management plans and regulatory requirements.
2. Consider climate change risks:
    a. Assess the potential impacts of climate change on water availability, including changes in precipitation patterns, temperature increases, and the frequency and severity of droughts and floods.
3. Develop approaches to manage water supply risks, considering both project-level conditions and basin-level context. The following approaches may be applicable:
    a. Implement water storage with sufficient capacity to supply operations during low flow periods, such as building reservoirs or using natural water bodies for storage.
    b. Strengthen stakeholder engagement and collaboration by working with other water users to more effectively manage water on a basin-wide level.
    c. Seek opportunities to maximize water reuse within carbon capture and through

integration with other industrial processes, thereby reducing consumptive water requirements. For example, this could be achieved by implementing water-efficient technologies and practices (e.g., air cooling instead of cooling towers, novel capture technologies instead of traditional amine-based capture, etc.).

   d. Seek alternatives to non-saline surface water use, including groundwater (especially saline) and effluent from municipalities and industrial facilities (e.g., tailings water, treated brackish water).

While the preceding recommendations can effectively address specific projects, there are additional opportunities to improve water management across the entire Alberta CCUS ecosystem. To better understand and address water-related challenges for CCUS operations in Alberta, the following opportunities should be considered:

1. Use collaborative, data-driven processes to identify, understand, and manage water challenges on a river basin scale, while balancing water-energy-food nexus trade-offs and environmental considerations.
   a. Develop a collaborative roadmap for sustainable water management in the Peace and Athabasca River basins, where significant CCUS deployment is expected in parallel with other industrial development.
   b. Review and update current and existing basin-scale planning on an ongoing basis as CCUS develops within the context of the transition to a lower emissions economy (e.g., within the South Saskatchewan and North Saskatchewan river basins).
2. Foster a better province-wide understanding of Alberta's groundwater resources and enhance data collection and accessibility to help project proponents meaningfully evaluate sustainable groundwater use as an alternative to surface water use. This should leverage existing efforts to understand and responsibly manage groundwater resources and could include the development of a centralized database to store and share groundwater data.
3. Support the further development and deployment of technologies to enable the reuse of excess recovered water from CCUS projects. This will reduce the water consumption of CCUS broadly and has the potential to beneficially offset the demands of other industries (e.g., hydrogen) within a given river basin.
4. Conduct similar studies to evaluate emerging technologies and sectors (e.g., nuclear power generation, critical minerals, data centres, etc.) within Alberta and other jurisdictions. This will enable the estimation of new water demands and help guide decisions to balance trade-offs within the water-energy-food nexus as the transition to a lower emissions economy continues.

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Definitions

Acronym	Definition
ACO	Aboriginal Consultation Office
AER	Alberta Energy Regulator
BECCS	Bioenergy with Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
DAC	Direct Air Capture
EPA	Alberta Environment and Protected Areas
FNCIP	First Nation Capital Investment Partnership
HMB	Heat and Mass Balance
MEA	Monoethanolamine
NGCC	Natural Gas Combined Cycle
PACSH	Pathways Alliance Carbon Capture Storage Hub
SSP	Shared Socio-economic Pathway
SWAD	Surface Water Allocation Directive
WMP	Water Management Plan

1.0 Introduction

1.1 Carbon capture as part of the energy transition

In the current global, political, and social climate, there is an increasing focus on reducing greenhouse gas emissions by 2050. The International Energy Agency Energy Technology Perspectives 2020 report highlights carbon capture, utilization, and storage (CCUS) as one of the four pillars of the global energy transition, alongside renewable power generation, bioenergy, and hydrogen [1]. An explicit link between hydrogen development and CCUS is also made in the Alberta Hydrogen Roadmap report [2]. The Mandate Letter issued to the Minister of Energy and Minerals on July 10, 2023 also includes specific reference to CCUS as part of the development and implementation of an investment program for deployment of emissions-reducing technologies [3]. In addition, ongoing efforts to streamline regulatory processes associated with investment in clean energy and carbon-reduction technologies clearly signal the key role CCUS will play in the future energy make-up of Alberta.

Given this enthusiasm for CCUS, all Albertans will benefit from further dialogue on its environmental trade-offs, especially the potential impacts on the province's water resources and its role in the interconnection between water, energy, and food via the water-energy-food nexus. These dynamics must be explored to better understand the potential impacts of CCUS on water, as well as the limitations that water may place on CCUS projects.

In 2023, WaterSMART Solutions Ltd., a Hazen Company (WaterSMART), published a report examining the potential impacts of Alberta's evolving hydrogen industry on the province's water resources [4]. This report found that a variety of hydrogen production technologies are proposed in Alberta, each with different ranges of potential water demands. Upon comparing these demands with current and future water availability, it was determined that the capacity of Alberta's river basins to support additional hydrogen development varies and is location dependent. Some basins may face challenges, while others may not.

WaterSMART has prepared this report on the water impacts of CCUS development by building on the water availability assessment and risk identification framework established in the hydrogen study. This report is intended for policy makers, regulators, project developers, investors, and the interested public. It is acknowledged that to fully understand the impact of the energy transition on our shared water resources, other evolving sectors will also need to be studied in the future, such as critical mineral mining, new power generation using alternative energy sources (e.g., nuclear power generation, geothermal), and data centres.

1.2 Report scope

To prepare this report, WaterSMART undertook a project with funding and support from the parties identified in the Funding Acknowledgement. This project estimated both the water demands of CCUS development in Alberta by 2050 and the water supply which is likely to be available. By comparing the water demand for CCUS with the available water supply, this report highlights the potential for river basin-specific challenges, opportunities, and trade-offs within the water-energy-food nexus. These insights will be critical for project developers, policy makers, and decision-makers to consider when enabling large-scale CCUS projects in Alberta as part of the energy transition. See Figure 1 for a map of the study area, which delineates Alberta's major river basins. This report includes the following sections:

- **Section 2.0 Anticipated Carbon Capture, Utilization, and Storage Water Demands in Alberta** details the net-new water demands expected to arise from CCUS development in Alberta. It includes all currently identified carbon capture projects in the province, with deployment occurring between now and 2050. This section details project locations, estimated sizes (i.e., annual rate of carbon capture), and the range of per-unit water demands associated with the most widely available commercial carbon capture technology.
  - See *Appendix A: Details of Carbon Capture, Utilization, and Storage Water Demands* for a summary of current and emerging carbon capture technologies, details on the per-unit water demand calculations for CCUS, and a sensitivity analysis for key parameters of the calculations.
  - See *Appendix B: Carbon Capture, Utilization, and Storage Project Details* for further information on the projects included in this analysis.
- **Section 3.0 Alberta's Water Context** summarizes Alberta's present and future water context. This includes information on how water is regulated and managed within Alberta, as well as the results of water availability analyses completed in key areas throughout the province. A discussion on potential climate change impacts to water supply is also included.
  - See *Appendix C: Assessment of future water availability in Alberta* for a summary of the climate change impacts modelling.
- **Section 4.0 Comparing Carbon Capture, Utilization, and Storage Water Demands to Water Availability** presents the combined results of the preceding analyses on CCUS water demands and Alberta's water availability. Several river basins of interest, where multiple CCUS projects are anticipated, were analyzed in more detail as case studies. In addition, the potential cumulative impacts with hydrogen projects, based on 2023 hydrogen announcements and 2025 CCUS announcements in Alberta, are discussed, leveraging findings from WaterSMART's 2023 hydrogen report.
- **Section 5.0 Recommendations and Next Steps** provides recommendations for how the information contained in this report can support strategic decision making to manage the potential water-energy-food nexus trade-offs associated with CCUS development. Opportunities for further study within the energy transition context are also provided.

Note that this report is focused on surface water supply within Alberta, as historically many large-scale projects in the province have utilized surface water. While groundwater and various forms of water reuse can be significant and important water sources for a variety of existing and future uses, this report emphasizes surface water. This focus is expected to account for most of the new water use required for CCUS across the province, although it is recognized that some regions and industries make greater use of alternatives to surface water than others. Further investigation into groundwater supply and water reuse is an opportunity for future work.

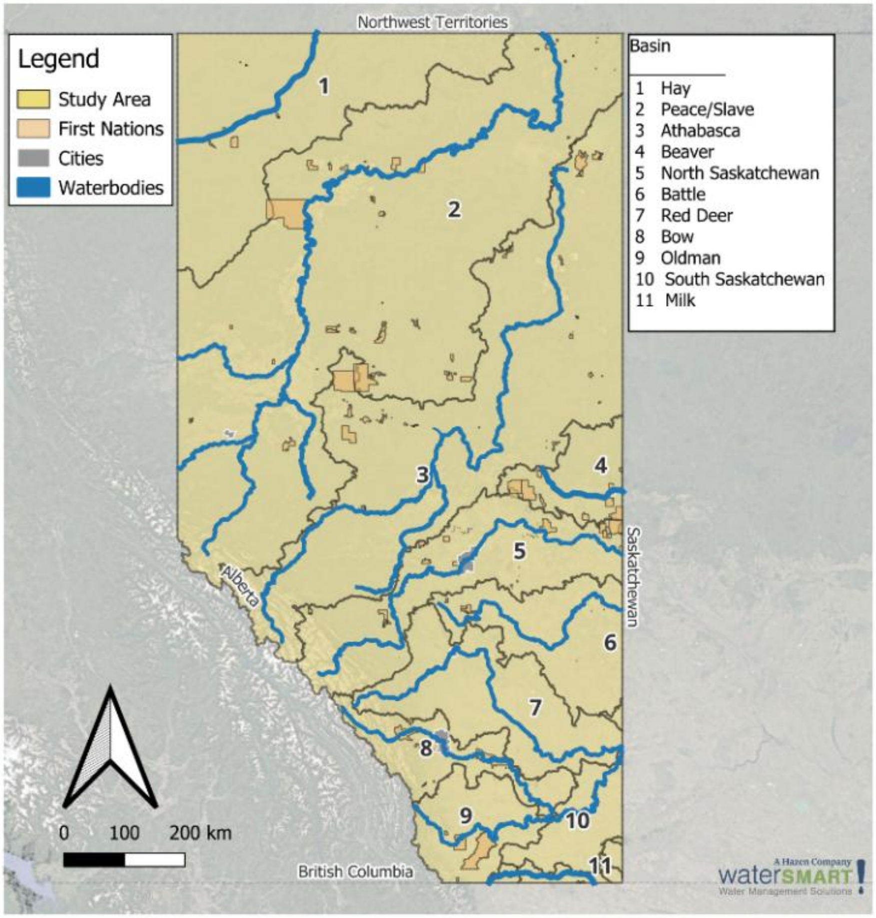

Figure 1. Map of the study area for this report, which covers all of Alberta.

1.2.1 Updates from the 2023 WaterSMART hydrogen report

WaterSMART's 2023 Study of Water Impacts of Hydrogen Development in Alberta examined the link between water demands for hydrogen development and surface water resources in Alberta. The hydrogen study was used for this new report as the model for assessing net water availability in Alberta and the potential water risks for the development of CCUS.

The key updates in this report compared to the 2023 hydrogen study include:

- Updates to the water availability assessments across all major basins in Alberta to account for the issuance of recent diversion licences and any other applicable hydrologic and regulatory changes.
- Additional water availability assessments for sub-basins with projected CCUS developments that were not previously considered for hydrogen development. Specifically, assessments have been added for the Lesser Slave River and Pembina River sub-basins within the Athabasca River basin.
- New climate change modelling to assess potential future changes to water availability on a major-basin scale across Alberta.
- Computation of the potential cumulative water demands for hydrogen, as planned in 2023, and CCUS developments announced as of March 2025.

2.0 Anticipated Water Demands for Carbon Capture, Utilization, and Storage Water in Alberta

This section documents the research completed to estimate the water use intensity of carbon capture technologies likely to be deployed in Alberta and to identify the associated projects within the province expected to implement these technologies by 2050. Section 2.1 provides background information on the carbon capture process, while Section 2.2 discusses the methodology for estimating the water demands associated with expected carbon capture projects in the province. These projects, and the approach for identifying them, are discussed in Section 2.3. Finally, Section 2.4 combines the findings from Sections 2.2 and 2.3 to present the estimated water demands of CCUS projects in Alberta. The information throughout Section 2.0 should be reviewed and updated regularly as new carbon capture projects emerge in the province.

Note that this report estimates water demands specifically for the **carbon capture** step of CCUS, as it is the most water-intensive process among commercially available technologies. Water requirements for carbon utilization, conveyance, and storage are considered negligible in comparison to those needed for the operation of the carbon capture process [5].

2.1 Background on carbon capture, utilization, and storage

Broadly, CCUS refers to a process involving:

- **Carbon capture:** capturing carbon dioxide (CO_2) primarily from large point sources, such as power generation or industrial facilities. Alternatives which do not rely on capture from a point source, such as direct air capture (DAC), are also available. As noted, the carbon capture step is the focus of this report.
- **Utilization:** using this captured CO_2 within the emitting facility's fence line or in an external industrial process. Compression and conveyance are typically required prior to utilization.
- **Storage:** storing the captured, un-utilized CO_2 in deep geological formations for permanent sequestration [6].

Carbon capture is typically classified based on two factors: 1) the point in the process where the fuel combustion or industrial by-product (i.e., CO_2) is removed, and 2) the mechanism used to separate CO_2 from the flue gas. These two dimensions of classification are summarized in Table 1. See *Appendix A1 – Current and emerging carbon capture technologies* for a more detailed breakdown of carbon capture technologies, sub-classifications, and examples.

Table 1. Definitions and classifications for carbon capture, utilization, and storage.

By the relative location of CO_2 capture unit	
Post-combustion	Removal of CO_2 from the flue gas or smokestack from an industrial point source [7].
Pre-combustion	Removal of CO_2 from fuels before combustion occurs, typically by the gasification of the fuel to a mixture of carbon monoxide (CO) and hydrogen (H_2). Steam is then added to shift the chemical equilibrium from CO to CO_2 [7].
Oxy-combustion	Removal of CO_2 from a concentrated flue gas stream which is the result of the complete combustion of a fuel or chemical synthesis [8].
Direct air capture (DAC)	Removal of CO_2 directly from the atmosphere, rather than at the point source of emissions. It is generally more energy intensive than other carbon capture methods due to the low concentration of CO_2 in air relative to flue gas.
Bioenergy with carbon capture and storage (BECCS)	Removal and sequestration of CO_2 associated with the conversion of biomass to energy. BECCS can include a variety of industries, biomass feedstocks, and methods of energy conversion [9, 10]. BECCS is a sub-category of post-combustion capture.
By the underlying mechanism for capture	
Absorption	Removal of CO_2 that uses physical, chemical, or combined solvents (e.g., monoethanolamine, ammonia, etc.) [11].
Adsorption	Removal of CO_2 molecules (adsorbate) diffused in the gaseous phase using an adjacent solid surface (sorbent) [12].
Membranes	Removal of CO_2 using permeable or semipermeable materials that allow for selective transport and separation of carbon from the flue gas [13].
Cryogenic distillation	Removal of CO_2 based on the different condensation temperatures of distinct gases mixed in the flue gas [14].
Chemical looping	Removal of CO_2 by the introduction of a metal oxide that supplies oxygen for complete combustion [15].
Microbial/algal systems	Removal of CO_2 from the atmosphere or a flue gas through the organic pathway of photosynthesis, generating biomass [16]. The biomass produced by this method can be burned to generate energy, and the associated carbon emissions can be captured through a different mechanism (i.e., BECCS) [9].

Post-combustion carbon capture, particularly through the chemical absorption mechanism, is generally regarded as one of the lower cost retrofit options for existing point source emissions. The low partial pressure of CO_2 means that chemical solvents like amines are currently preferred over physical solvents due to their stronger affinity. Monoethanolamine (MEA) is considered the benchmark for chemical absorption due to its commercial maturity and performance in the oxidizing nature of oxygen-rich flue gas [17].

For this report, post-combustion, MEA-based absorption was selected as the reference carbon capture technology to estimate consumptive water demands, and it was assumed that this technology would be deployed for all projects discussed in Section 2.3. Despite the emergence of numerous new carbon capture technologies, many of which are nearing commercialization and likely deployment by 2050, MEA remains one of the most extensively researched and best understood methods for carbon capture. The decision to focus on post-combustion, MEA-based absorption was informed by the availability of data in the literature, as well as discussions with project supporters and industry contacts. It also reflects that MEA offers lower costs for retrofitting in older industrial facilities, a rapid absorption rate, high efficiency, and a substantial loading capacity [18]. Finally, using MEA-based carbon capture is relatively conservative, from a water balance perspective, since other technologies, including different amines used in lieu of MEA, are more water efficient.

A reference schematic for the MEA-based carbon capture process is shown in Figure 2 [19]. The flue gas enters the carbon capture system via a direct contact cooler (Step 1), where a substantial portion of its water vapor is condensed and recovered. Subsequently, the flue gas is directed to an MEA absorption column, where CO_2 is stripped from the gas stream (Step 2). The CO_2-rich amine solvent then undergoes regeneration using steam-sourced heat, releasing the captured CO_2 (Step 3). The released CO_2 is then cooled and compressed, further recovering water, before being conveyed to its destination (Step 4). See Section 2.2 for discussion on how the recovered water may be handled.

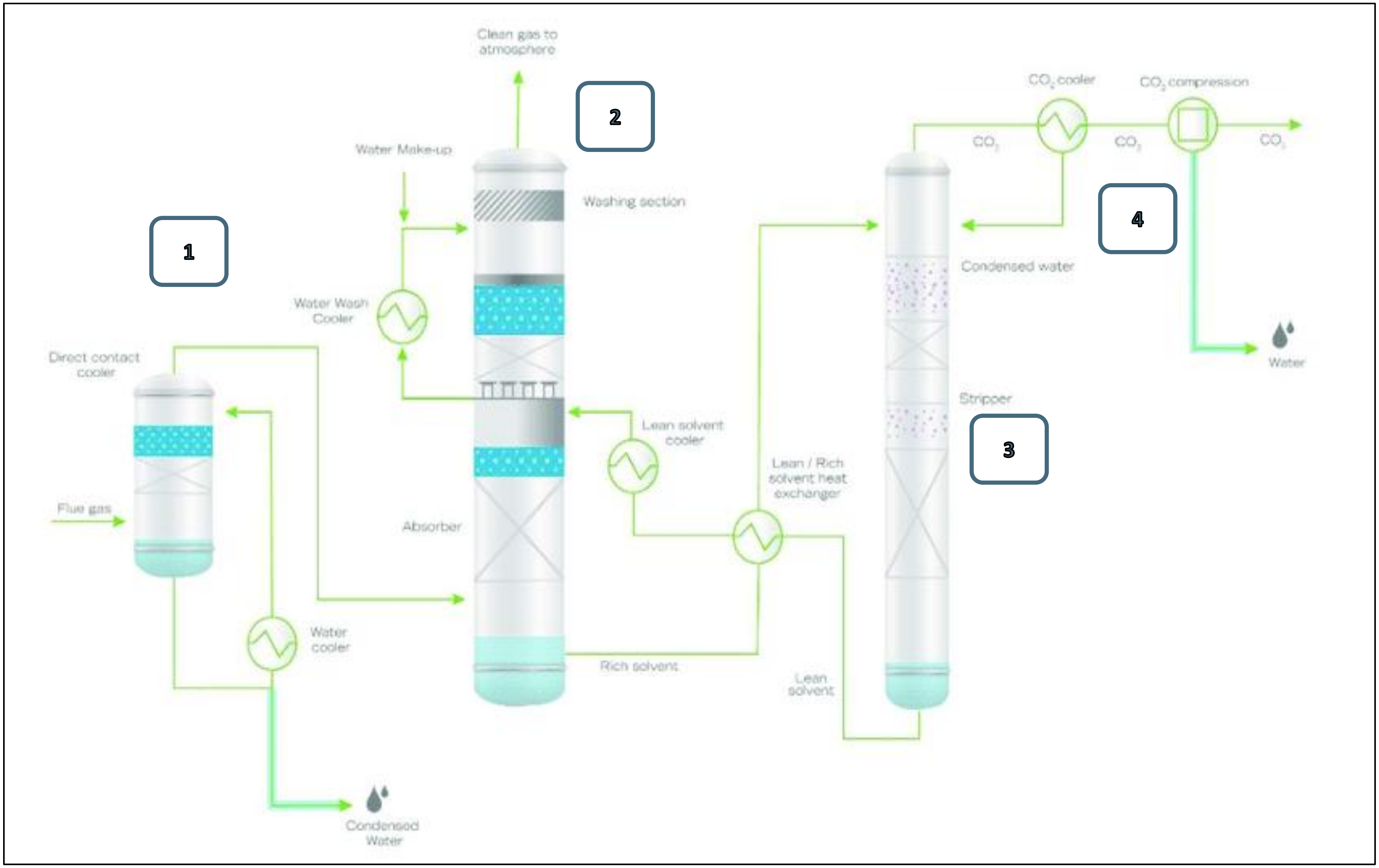

Figure 2. Process diagram for MEA-based carbon capture [19]. The steps labelled here correspond to the preceding text.

2.2 Per-unit water demands

This report focuses on consumptive water use for MEA-based carbon capture, which refers to the volume of water removed from a river basin and not returned. It is acknowledged that many industrial processes, including forms of carbon capture, return water to the hydrologic cycle as water vapor (e.g., from evaporative cooling). Although this water still exists, it will not be directly returned to the specific river basin from which it was removed. This net consumption can have material basin-level impacts (e.g., on aquatic species and habitats, for navigability, for water diversions by downstream users, etc.).

For this analysis, a heat and mass balance (HMB) was calculated for a nominal MEA-based carbon capture process as represented in Figure 2. The HMB was used to identify which parameters have the greatest influence on the results (i.e., net, per-unit water demand) and which have little influence. Several key parameters were identified through this analysis and a literature review was undertaken to identify suitable values for each. These findings were validated using data from this project's funders and other industry partners. This process revealed many unique designs for MEA-based carbon capture and the variability in water use between them.

Given the complexity of the MEA-based process and the potential variability in water use by application, three water use scenarios (i.e., Low, Medium, and High) were defined to capture the range of potential outcomes across the CCUS sector. Of the key parameters identified, several were held constant across all three scenarios, as described in Section 2.2.1. Other key parameters were varied between the scenarios to illustrate how design decisions can influence net, per-unit water demands. The Low, Medium, and High water use scenarios and the variable parameters are described in Section 2.2.2. The resulting net, per-unit water demands are documented in Section 2.2.3. Finally, the applicability and limitations of this modelling approach are summarized in Section 2.2.4. For more information, refer to *Appendix A2 - Estimation of water demands for MEA-based carbon capture.*

2.2.1 Key parameters held constant in the heat and mass balance

The following key parameters for the HMB were held constant in this analysis and are described below:

- Flue gas composition, including moisture content.
- Raw water treatment requirements.
- Purge rate.
- MEA absorption efficiency.

2.2.1.1 Flue gas composition

The water demands for carbon capture are heavily dependent on the composition of the incoming gas, as it directly affects the process's HMB. Specifically, higher CO_2 concentrations in the flue gas result in more efficient use of MEA-based solvents, resulting in lower demands for both energy and cooling per unit of CO_2 captured. The amount of water in the flue gas is also crucial, since any water recovered from the flue gas can be used within other steps of the process to reduce the need for additional make-up water (see Sections 2.2.2 and 2.2.3). Table 2 shows the approximate flue gas compositions for several common industrial developments, chosen to represent the largest industrial CO_2 sources in Alberta (see Section 2.3). Note that actual flue gas compositions are highly variable, and the values reported represent averages from the ranges which are available in literature and from project partners [20, 21, 22, 23, 24, 25].

Table 2. Approximate flue gas composition by process source, in percent by volume.

Component	Source of flue gas				
	Natural gas combined cycle power generation	Cement manufacturing	Biomass combustion - spruce chips	ATR hydrogen/ ammonia production*	Oil sands
CO_2	5.5%	17.8%	12.0%	60.0%	8.6%
O_2	11.0%	7.5%	8.2%	4.0%	2.6%
H_2O	8.2%	18.2%	28.3%	10.0%	16.3%
N_2	75.3%	56.5%	51.5%	26.0%	72.5%

**Ammonia production through the Haber-Bosch process typically uses hydrogen produced through a methane reforming process. The flue gas in this table assumes autothermal reforming (ATR), which has a higher CO_2 concentration in the flue gas compared to steam methane reforming (SMR). In Alberta, most major planned carbon capture projects coupled to hydrogen production facilities are based on ATR (e.g., Net-zero Hydrogen Energy Complex).*

2.2.1.2 Raw water treatment and purge rate

The requirement to treat water to a particular quality before utilizing it in the carbon capture process also plays a role in overall water use. This is primarily because some portion of the raw water is rejected during the treatment process, so more water must be withdrawn for treatment than is productively used. For MEA-based carbon capture, raw water treatment is required for the makeup water in the cooling loops, for steam generation, and for MEA solvent preparation. Although the treatment process has the potential to require the diversion of up to 50% more water than can be used, depending on the target quality, the impact to water use in the broader carbon capture process is low because the relevant makeup volumes are small [26]. As such, treatment requirements are accounted for via the purge rate used for the steam and amine solvent streams. The purge rate reflects that neither water nor MEA can be looped indefinitely without degradation of quality below acceptable limits. A purge rate of 3% was used in this analysis to account for losses from water treatment and to be on the conservative end of data provided by project partners and available in literature.

2.2.1.3 MEA absorption efficiency

The efficiency of the MEA absorption itself influences the overall water consumption of MEA-based carbon capture. This refers to how effectively the CO_2 is separated from the flue gas in Step 2 in Figure 2. Mathematically, it is the ratio of mass flow of CO_2 in the compressed CO_2 outlet stream compared to CO_2 entering the process in the flue gas stream. The efficiency of the MEA solvent for carbon capture depends on several factors, such as the operational temperature and pressure and the ratio of water to MEA in the mixture. The efficiency of MEA absorption selected for this report is 90%, which represents a typical value for the technology [27]. Note this efficiency is separate from the condensate recovery and reuse factor discussed in Section 2.2.2.3.

2.2.2 Water use scenarios and variable parameters in the heat and mass balance

The Low, Medium, and High water use scenarios, as summarized in Table 3, were developed through the adjustment of three key parameters, which are detailed below. These parameters are:

- Choice of cooling technology (e.g., evaporative compared to hybrid and air cooling).
- Presence or absence of new on-site power supply for operating the carbon capture process.
- Proportion of moisture in the flue gas which is captured as condensate and reused.

2.2.2.1 Cooling technology

Cooling is a critical step in the carbon capture process, both to condense water vapor from the hot flue gas stream and to achieve optimal MEA capture efficiency. Evaporative cooling is often used due to the high latent heat of water and because this type of cooling exists at many sites. Alternatively, mechanical, hybrid, and air-cooled systems can dissipate thermal energy while consuming comparatively less water than evaporative cooling, and in some instances, even less than the amount recovered as condensate from the flue gas. The choice of cooling technology can have significant implications for industrial projects, including capital and operating costs, facility footprint, total power demands, reliability, and more. Project proponents often need to balance several competing factors within the water-energy-food nexus when selecting the preferred cooling technology.

2.2.2.2 Power supply

Another important driver of water consumption for carbon capture is the presence or absence of new on-site power supply to operate the process (e.g., generate steam). For carbon capture relying on existing power production[1], the water consumed to produce this power has already been accounted for in existing water allocations and is already impacting the river basin. Conversely, if a project requires new on-site power generation to operate the carbon capture process, as is being considered by many CCUS projects, the overall consumptive water demands for the facility would likely increase compared to baseline to meet the additional requirements. Note that any water recovered as condensate from the on-site power generation process is outside of the scope of the analysis[2].

For this analysis, the consumptive water demands for new on-site power generation were estimated assuming the use of natural gas combined cycle (NGCC) technology, which traditionally consumes water

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[1] Existing power refers to electricity that is either:

- Sourced from on-site generation, where this generation normally exceeds the immediate needs at the point of capture and would otherwise be exported to the grid, or
- Procured from off-site sources (i.e., the grid), where that water use is accounted for elsewhere.

[2] Industrial facilities with on-site power generation that do reuse the flue gas condensate from the process will have a lower consumptive water demand for carbon capture.

for cooling and steam generation. This assumption, which is likely conservative from a water demand perspective, reflects the current predominance of NGCC-based power for industrial processes in Alberta.

2.2.2.3 Flue gas condensate recovery and reuse

The water consumption estimates prepared for this report assume a range of water recovery and reuse from the flue gas condensate (i.e., water outflows within Steps 1 and 4 in Figure 2). Available literature indicates that 80% condensate recovery is an achievable, albeit optimistic, benchmark in commercially available processes that recover water condensate from flue gas [28, 29, 30]. In contrast, a 0% use rate reflects a process where the condensate is not reused to decrease the make-up water demands.

2.2.2.4 Water use scenario summary

The Low, Medium, and High water use scenarios were prepared by varying the three parameters described in Section 2.2.2, while holding constant the parameters described in Section 2.2.1. The three scenarios were applied for each flue gas type.

Table 3. Water use scenarios

	Low water use	Medium water use	High water use
Description	Represents a highly water-efficient process	Represents a well-optimized process	Represents the least water-efficient process
Cooling technology	Air cooling	Hybrid cooling	Evaporative cooling
Power supply	Existing power generation	New on-site power generation	New on-site power generation
Flue gas condensate recovery and reuse factor	80%	50%	0%

2.2.3 Net, per-unit water demands

The results of the HMB calculations, accounting for constant parameters (Section 2.2.1) and variable parameters and water use scenarios (Section 2.2.2), are summarized in Table 4. These results, expressed as net, per-unit water demands with units of m^3 H_2O/tCO_2 captured, were validated using aggregated data from project funders, industry partners, and literature. They should be reviewed regularly as existing MEA-based capture projects are optimized and the technology evolves [31]. For example, some carbon capture projects currently in the pilot stage use oil instead of water as the heat transfer liquid of choice for MEA regeneration, reducing water demands for steam generation, albeit typically at a higher cost [32]. The use of Low, Medium, and High water use scenarios is intended to account for these and other uncertainties as MEA-based capture technologies are deployed and improved over the 2050 time horizon. See *Appendix A2 - Estimation of water demands for MEA-based carbon capture* for more details.

Table 4. Net, per-unit consumptive water demands of monoethanolamine-based carbon capture.

Source of flue gas	Net water demands (m^3/tCO_2)*		
	Low**	Medium	High***
Natural Gas Combined Cycle power generation	-0.48	0.39	1.39
Cement manufacturing	-0.31	0.32	0.94
Biomass combustion	-0.79	0.08	1.10
Hydrogen/ammonia production	0.003	0.45	0.77
Oil sands	-0.62	0.22	0.22

**Analysis of the HMB for the MEA-based carbon capture process for each type of flue gas helps to explain the differences between the net water demand in a given use scenario. For example, for ATR hydrogen/ammonia production, the CO_2 stream is more concentrated while the moisture content is relatively low, leading to less water recovery and higher net water consumption.*

***A negative net water demand indicates that more water is recovered from the carbon capture process than what is used.*

****The assumptions used for the modelling of the High use scenario are not applicable to projects in the oil sands. Front-end engineering design studies performed by industry, using commercially available technologies, indicate that carbon capture projects in the oil sands are expected to* ***produce*** *0.1 to 0.5 m^3/tCO_2, consistent with the Low use scenario. See the Devon Jackfish Report for a sample study* [25]. *To better reflect the potential water demands of the oil sands in a High use scenario, the net, per-unit water demand for Medium use scenario was used for both cases.*

As Table 4 indicates, the water demands for carbon capture are highly variable, both by use scenario (i.e., Low, Medium, and High) and by the source of the flue gas, ranging from -0.79 to 1.10 m^3/tCO_2 for biomass combustion flue gas, to -0.48 to 1.39 m^3/tCO_2 for NGCC power generation. This variability reflects the wide range of industrial processes which will deploy carbon capture technologies and the number of design choices available to optimize these processes for various outcomes. For example, optimizing to reduce water use will result in a different process design, and associated water consumption, compared to optimizing for a small land footprint or to minimize costs. For a more detailed overview of the variability of the results based on design, refer to *Appendix A3 - Sensitivity analysis.*

Another important takeaway from Table 4 is the potential for MEA-based carbon capture to generate more water than it consumes, indicated by the negative values in the Low water use scenario. As Figure 2 illustrates, water from the flue gas can be recovered during cooling (Step 1) and compression (Step 4). This water can be treated as needed, and beneficially utilized, for example, to offset the make-up water demands within the carbon capture process. It may also be possible to further utilize this recovered water within the adjoining industrial process, thereby reducing the water consumption normally required for the overall facility. In this scenario, referred to as Low, the addition of carbon capture to an industrial process would have a net positive impact on the river basin, from a water consumption perspective. However, for some developments and retrofit projects, fully utilizing the recovered water may not be practical due to treatment costs (e.g., pH correction, removing trace compounds carried over from the flue gas), logistics, or because this would introduce an unacceptable risk to the operations of the industrial process. Research and industry engagement completed for this report suggest that some operators would have the opportunity to achieve the Low scenario and the associated net benefits from offsetting their industrial make-up water demands, while others would not.

In cases where the excess recovered water cannot be fully utilized, it will need to be managed as a waste stream. Operators will need to evaluate various management options (e.g., deep well disposal) and the associated risks (e.g., constraints on nearby disposal capacity). If this excess recovered water were treated and returned to the river basin, it would be an alternative pathway to achieving the Low scenario. However, this approach would need to overcome technical, regulatory, and social acceptance barriers. See Section 4.4 for additional discussion on how excess recovered water can be managed.

2.2.4 Modelling approach applicability and limitations

It must be noted that the results in this report reflect a specific set of assumptions for the HMB associated with post-combustion, MEA-based carbon capture, based on the configuration and boundary conditions represented in Figure 2. As discussed, efforts have been made to capture a wide range of possible outcomes through the Low, Medium, and High water use scenarios, and to align the net, per-unit water demands for these scenarios with available data from literature and industry partners. As explored in *Appendix A2 - Estimation of water demands for MEA-based carbon capture* and *Appendix A3 - Sensitivity analysis*, many parameters can greatly influence the results, including but not limited to flue gas composition, raw water treatment requirements, purge rate, MEA absorption efficiency, cooling technology, power supply, and flue gas moisture recovery and reuse.

The methodology and results in this analysis have been validated through engagement with industry partners and review of available data. However, given the number of parameters involved in the HMB and the wide range of applications and optimization goals for industrial carbon capture, it is acknowledged that others may report values which differ from those in Table 4. Differences are also expected based on the boundary conditions of the HMB; if analysis is performed on a set of unit operations which does not match Figure 2, the results will diverge. For example, whether or not compression (Step 4) is included in the HMB is a common difference in approach observed in the literature. Finally, it is acknowledged that carbon capture technologies are evolving, including post-combustion amine capture itself. As MEA-based systems continue to be deployed and optimized and wholly new technologies are commercialized, it is expected that different net, per-unit water demands will be determined.

2.3 Alberta carbon capture projects

The projects considered in this study include carbon capture facilities and carbon hubs in Alberta that are currently operational, under construction, or in the planning phase as of March 2025. Publicly available data was used to identify project locations and the scale of each project, in terms of $MtCO_2$ per year, where available. Each individual project was assigned one of the identified flue gas types in Table 2, and the water demands for each were calculated for the river basin closest to its approximate location. Efforts were made to verify project details with multiple sources where possible and to compare projects on a consistent basis. Where data was not available for certain projects (e.g., project scale, location), assumptions were made using known values where practical. The most robust sources for this dataset were provided by the International Energy Agency, the Government of Alberta, and the Government of

Canada [33, 34, 35]. A detailed summary of this research and associated assumptions is shown *in Appendix B Carbon Capture, Utilization, and Storage Project Details.*

Figure 3 shows the approximate locations of existing and announced carbon capture facilities throughout Alberta. There are a total of 54 projects as of March 2025, with a maximum capture and sequestration capacity expected to exceed 205 Mt CO^2/yr by 2050. Variably sized circles indicate the projected carbon capture magnitude (i.e., MtCO_2/yr) for each facility in 2050. The following considerations were accounted for in preparing Figure 3:

- Some projects are classified as CCUS hubs, comprising capture, utilization, conveyance, and sequestration. For the purposes of this report, their reported maximum annual storage capacity is assumed to match the CO_2 capture rate at the source. This implies that for each tonne of CO_2 sequestered within a hub, an equivalent tonne was captured from a point source nearby (i.e., within the same river basin).
    - This represents a conservative estimate from a water consumption perspective, because it implies all the hubs will be fully utilized by 2050. Despite the CCUS infrastructure being designed for a specific sequestration capacity, the actual capture rate may be lower, particularly within the 2050 timeframe.
- Since 2015, existing CCUS projects have permanently sequestered approximately 13.6 Mt of CO_2. These include the Nutrien Redwater Fertilizer Facility and the Sturgeon Refinery (through the Alberta Carbon Trunk Line [ACTL]), and Shell Quest. In 2023, the estimated carbon sequestration rate in the province was 2.59 Mt CO_2/yr [36]. For this report, both Shell Quest and the ACTL are included in the list of projects expected to have net new water demands by 2050. This assumption reflects that the total volume of CO_2 sequestered to date represents a relatively small percentage of the overall capacity of these hubs, and that their current annual sequestration rate is smaller than the expected future capture rate of these projects and the rest of the province (i.e., 2.59 Mt CO_2/yr in 2023 compared to approximately 16.53 Mt CO_2/yr for Shell Quest and ACTL by 2050 and compared to 205 Mt CO_2/yr for all of Alberta by 2050).

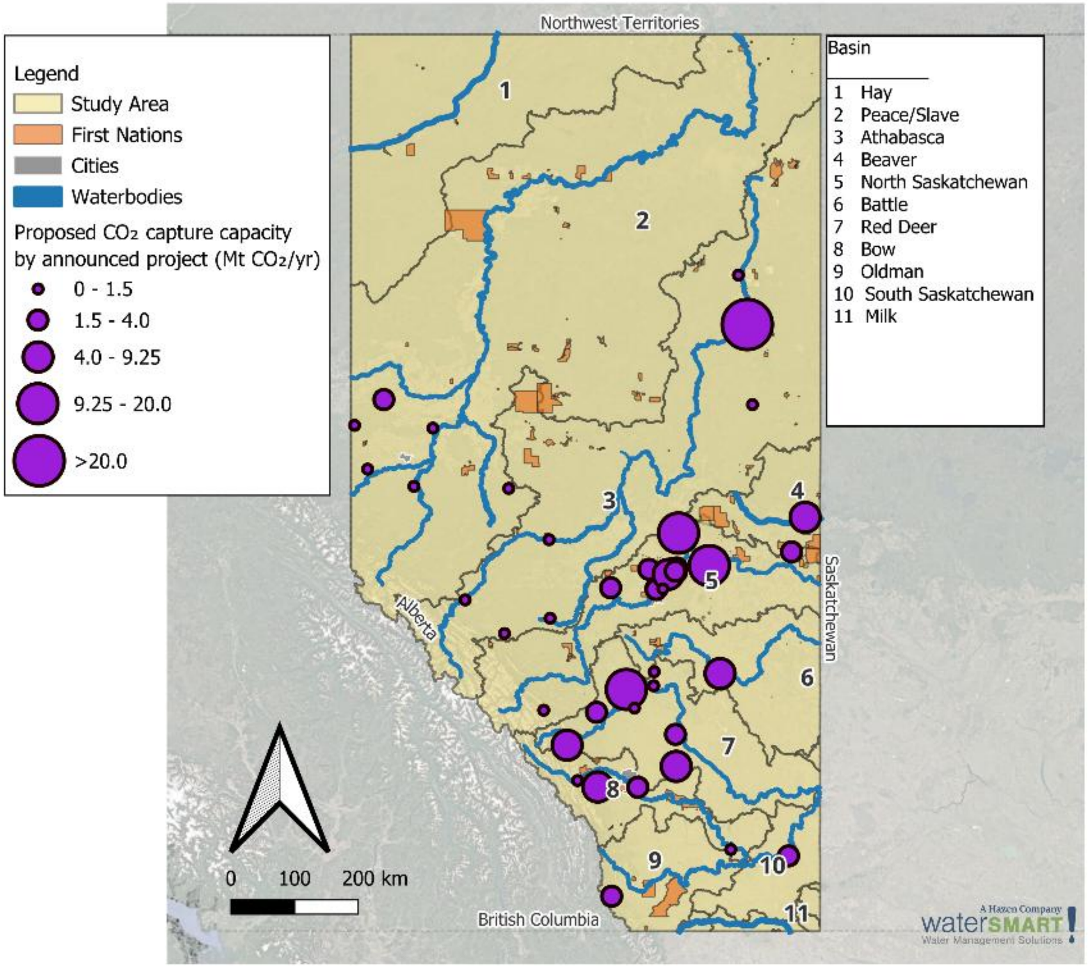

Figure 3. Approximate location and scale of announced CCUS projects throughout Alberta.

2.4 Potential water demands for carbon capture projects in Alberta

To estimate the water demands for CCUS throughout the province, the Low, Medium, and High ranges calculated in Section 2.2 were applied to the expected carbon capture capacity for announced projects in Section 2.3, based on the type of flue gas. Note that as per Section 2.3, the announced projects used for this analysis represent a snapshot of the expected projects operational in 2050 announced as of March 2025. Over time, as projects begin operating, new technologies are deployed, new projects are announced, and the water demands of all CCUS projects are better understood and optimized, the water demands across Alberta should be re-evaluated.

The results are summarized in a series of tables and figures to illustrate the various dynamics of flue gas type, water consumption scenario, and location. Table 5 and Figure 4 display the results on a province-wide basis, organized by type of flue gas. Table 6 and Figure 5 display the results by river basin, without segmentation by flue gas type. Note that there have been no annouced CCUS projects in the Hay and Milk River Basins as of March 2025. In all cases, the results reflect a wide range of possible outcomes, from -100,587 dam^3/yr (i.e., net water production) to 202,144 dam^3/yr (i.e., net water consumption) across the province.

Table 5. Estimated net water demands for carbon capture in Alberta per type of flue gas.

Source of flue gas	Net water demands by consumption scenario (dam^3/yr)*		
	Low	Medium	High
Natural Gas Combined Cycle power generation (125.1 $MtCO_2/yr$)**	-60,263	48,914	173,639
Cement manufacturing (1.8 $MtCO_2/yr$)	-548	573	1,680
Biomass combustion (1.43 $MtCO_2/yr$)	-1,135	117	1,577
Hydrogen/ammonia production (14.9 $MtCO_2/yr$)	48	6,679	11,497
Oil sands (62 $MtCO_2/yr$)	-38,690	13,752	13,752
Total (205.2 $MtCO_2/yr$)	***-100,587***	***70,035***	***202,144***

**One dam^3 (cubic decametre) is equal to 1,000 m^3 (cubic metre).*

*** For projects that do not specify the industry connecting to a carbon capture facility or hub, it is assumed that the flue gas from NGCC power generation will be captured, as many planned projects are considering new on-site power generation to operate the carbon capture process. Refer to Appendix B for more information.*

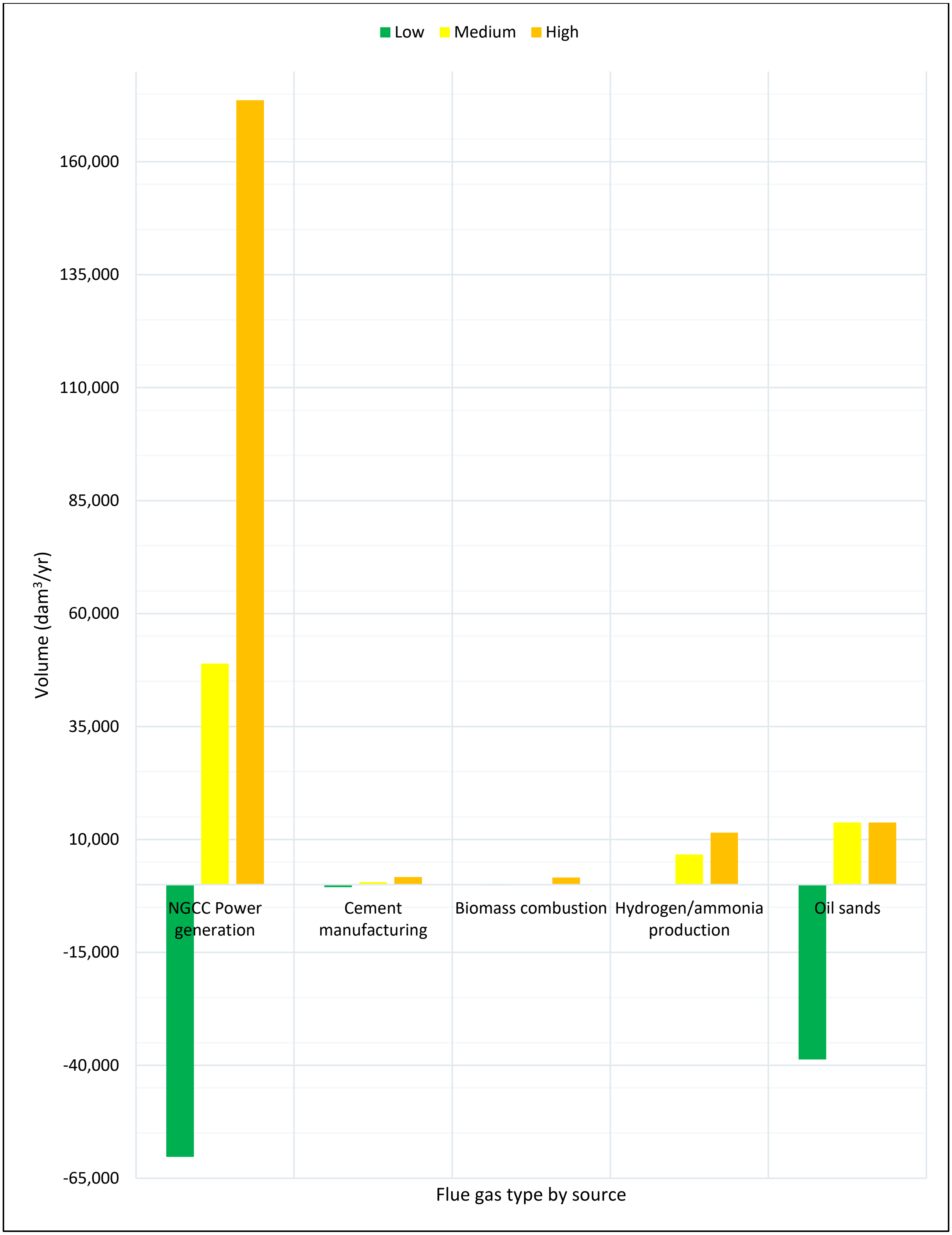

Figure 4. Estimated net water demands for carbon capture in Alberta per type of flue gas.

Table 6. Summary of estimated water demands for Low, Medium, and High use scenarios for carbon capture projects in Alberta, organized by river basin and sub-basin.

Basin	Sub-basin	Anticipated carbon capture (Mt CO_2/yr) projects	Anticipated water demand on the river basin (dam^3/yr)		
			Low*	Medium	High
Peace	Peace mainstem**	6.2	-2,978	2,417	8,581
	Smoky	2.7	-1,292	1,049	3,724
	Wapiti	0.18	-88	72	254
	Little Smoky	1.0	-482	391	1,388
Athabasca	Athabasca mainstem**	59.8	-36,894	13,841	19,648
	Lesser Slave	3.0	-1,456	1,181	4,194
	Pembina	0.53	-256	208	737
North Saskatchewan	North Saskatchewan	70.6	-26,674	28,325	88,338
	Battle	5.0	-2,408	1,955	6,939
South Saskatchewan	Red Deer	31.0	-14,951	12,162	43,126
	South Saskatchewan	3.0	-1,445	1,173	4,163
	Bow	16.7	-7,885	6,472	22,775
	Upper Oldman	2.7	-1,300	1,056	3,747
Hay		---	0	0	0
Beaver		10.2	-6,052	2,634	4,828
Milk		---	0	0	0
	Total	**205.2**	**3,918**	**56,526**	**201,718**

**A negative water demand indicates potential water production on a net basis.*

*** The Peace River data also includes data for the Wapiti, Smoky, and Little Smoky, which are tributaries to the major basin. Similarly, the Athabasca mainstem also includes data for its tributaries, the Lesser Slave and Pembina rivers.*

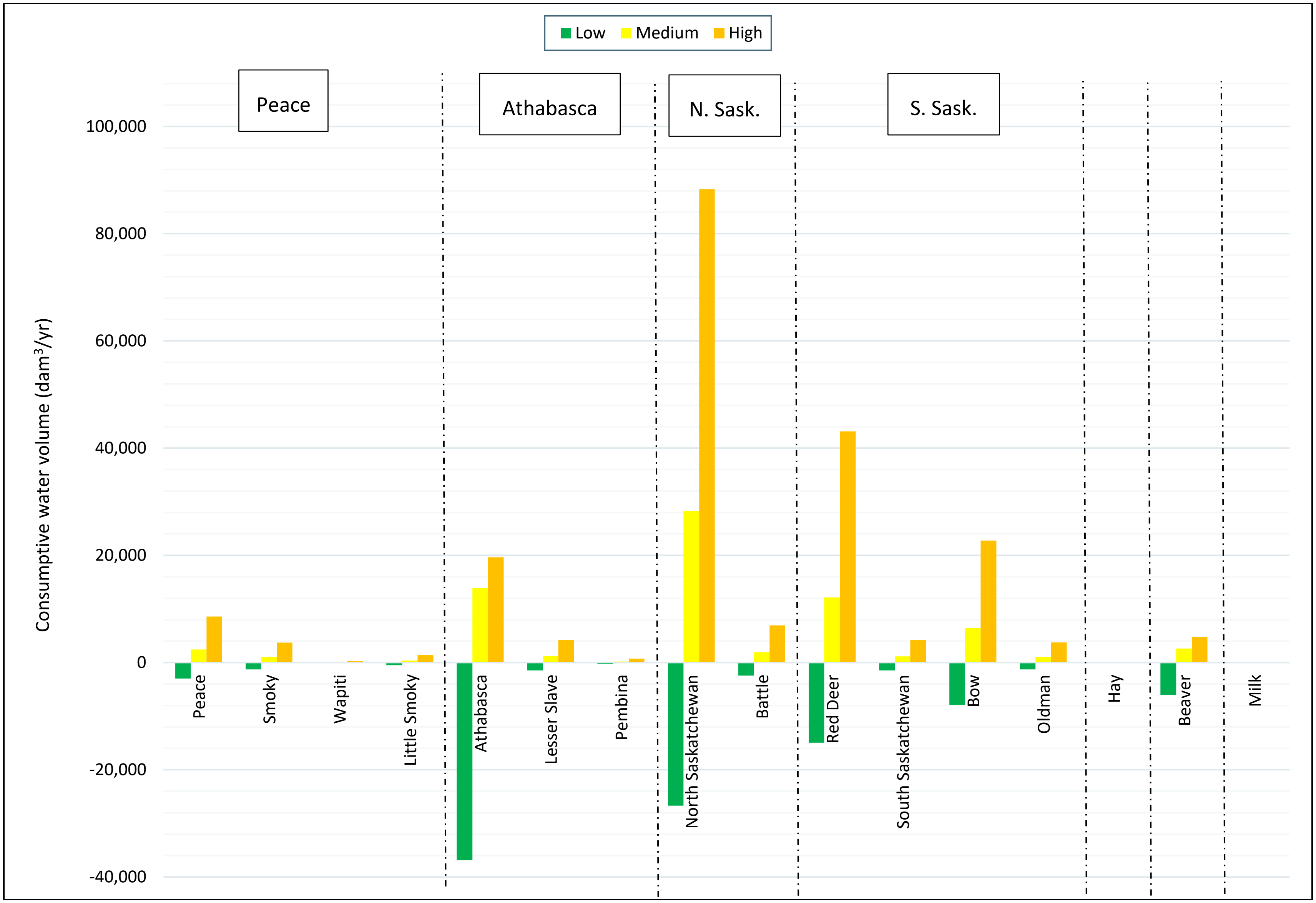

Figure 5. Net water demands for announced CCUS projects per river basin.

3.0 Alberta's Water Context

Across Alberta, available water volume varies significantly by location. This variability affects how regulators and users manage water to meet both ecological and human needs. For example, rivers in southern Alberta, which are generally smaller than some of their northern counterparts, flow through densely populated regions. Over time this has led to significant competition for water resources, particularly when compared to other regions in the province.

In addition to geographic variability, water users must contend with temporal variability of water supplies, both seasonally and year over year. This variability, explored further in Section 3.1, requires careful evaluation and management of water supply risks within the existing regulatory framework, irrespective of their location within the province (Section 3.2). This report provides a high-level water availability assessment (Section 3.3) for the rivers highlighted within the study area (Figure 6). These rivers were selected because they satisfied one or more of the following criteria:

- Likely to host CCUS projects as per Section 2.3 (e.g., the Beaver River).
- Located in a water-short region or an area with an allocation order that limits the issuance of new water licences (e.g., the Bow River).
- Likely to be a water-constrained region in the future, due to annual water availability and anticipated increases in demand from various users (e.g., the Red Deer River).

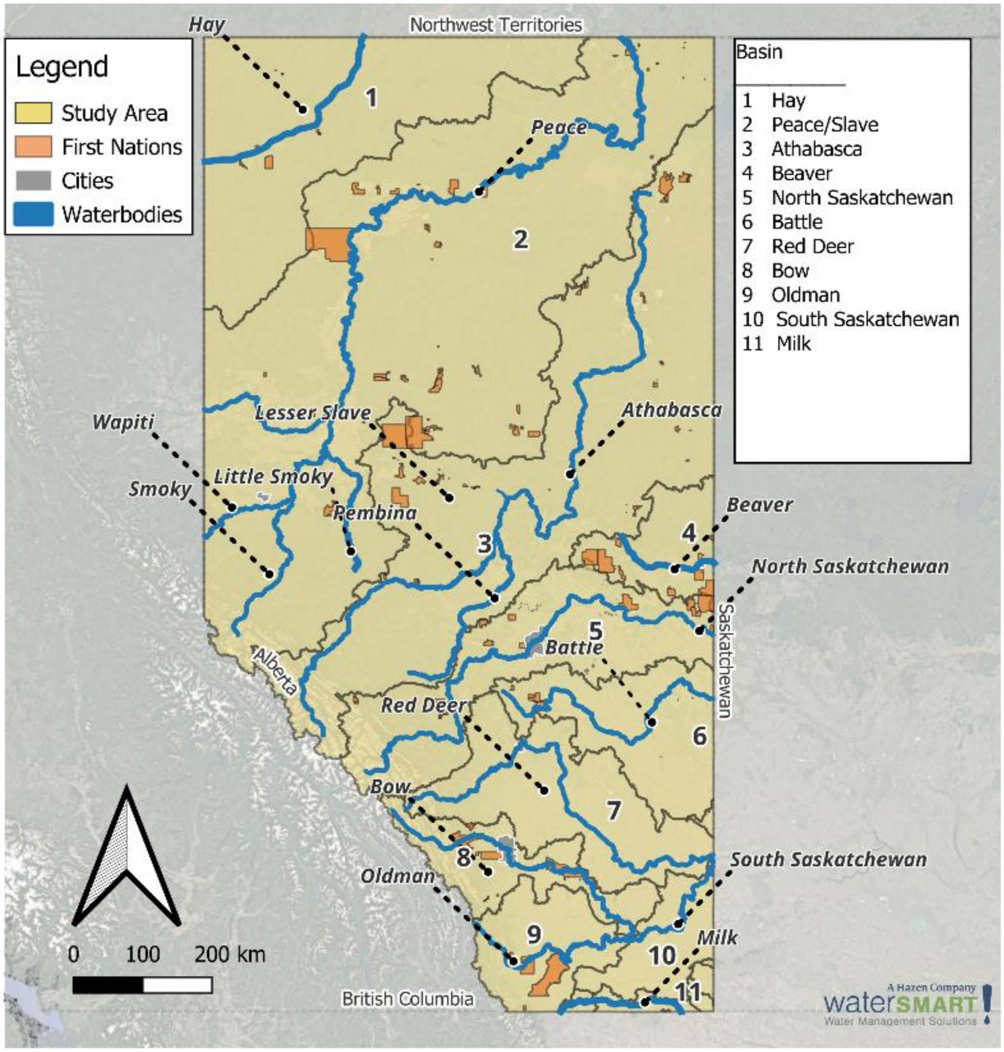

Figure 6. Map of the study area for this report, with specific rivers of interest highlighted.

3.1 Hydrology overview

Alberta’s water resources are generally grouped into three categories: groundwater, non-flowing surface water (e.g., lakes, ponds, sloughs, etc.), and flowing surface water (e.g., rivers, streams, and creeks). This report focuses on Alberta’s flowing surface water due to the significantly higher reliance on it compared to groundwater and non-flowing surface water. Groundwater availability is highly variable, and current data limitations can make it challenging for users to develop plans to obtain sufficient volumes from groundwater sources without conducting detailed fieldwork.

Alberta’s major river basins, as defined in the *Water Act* [37], have headwaters in the eastern slopes of the Rocky Mountains, with the exception of the Beaver River. These basins generally exhibit significant seasonal variations in water supply. River flows in Alberta typically peak between May and July, driven by snow melt from the Rockies (freshet), and are at their lowest between October and February, when there is limited contribution from snow melt. During these lower flow periods, glacier melt makes up a higher proportion of flows. This seasonal variability is illustrated in Figure 7. Another important aspect of water supply risk, not shown in Figure 7, is the potential for ice cover during winter months, which can hinder access to flowing surface water bodies depending on the water diversion infrastructure being used. Appendix C of WaterSMART's 2023 hydrogen report can be referenced for more information on the characteristics of Alberta's rivers [38].

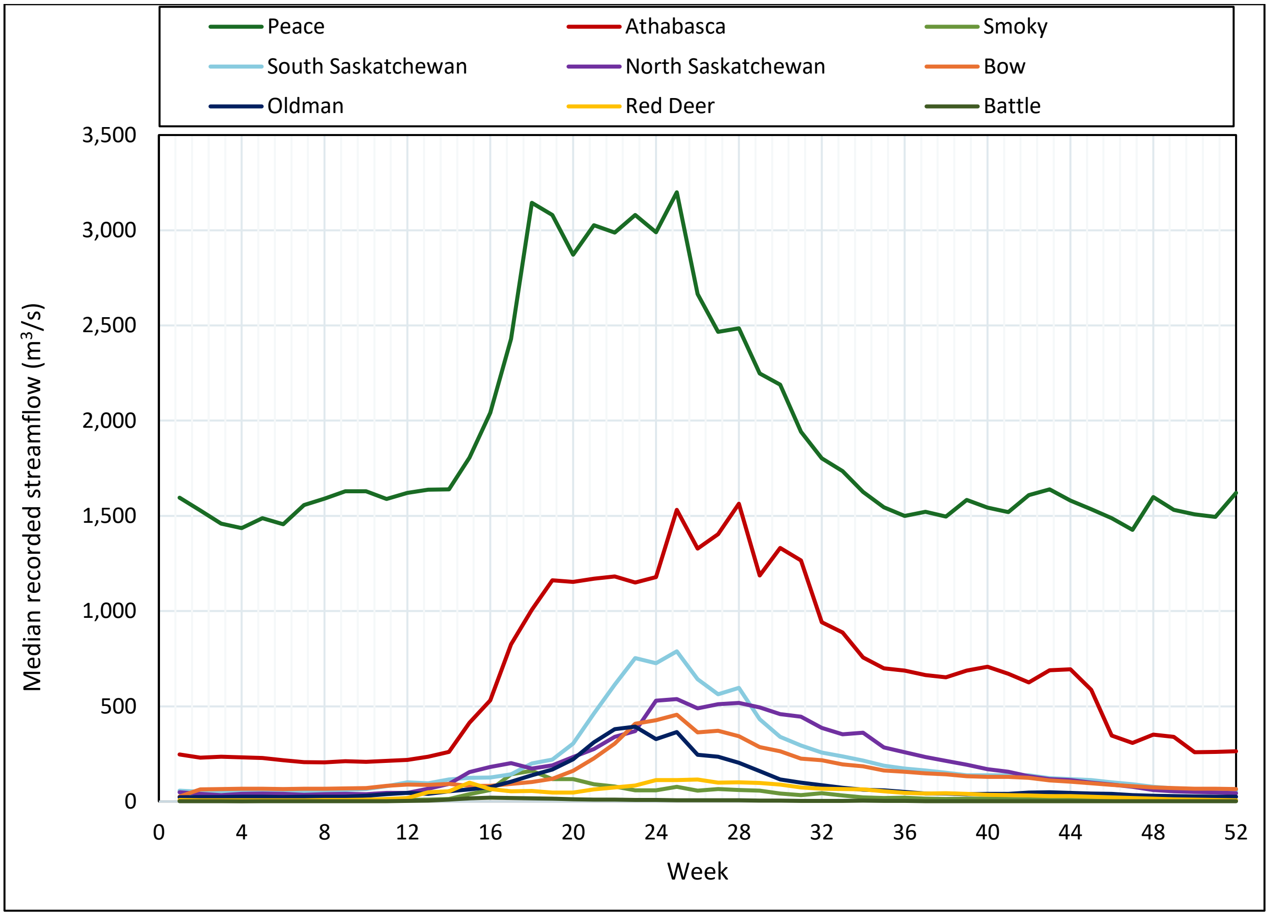

Figure 7. Illustrative median recorded streamflow hydrographs (1991-2020) for select rivers in Alberta, which demonstrate flow variability across seasons.

3.2 Water management and regulation

Note that Section 3.2 has been reproduced from WaterSMART's 2023 hydrogen study, with minor editorial changes and the addition of Section 3.2.1. It is included in this report for ease of reference and to provide context for readers who have not reviewed the 2023 study. While WaterSMART continues to closely monitor Alberta's regulatory environment for water, no significant changes have been observed that would necessitate edits to the information below.

Water resources in Alberta are governed through a suite of regulatory instruments, which vary in type, level of authority, and enforcing body. The *Water Act* is the primary statute for governing water resources in Alberta [37]. It seeks to balance the competing water needs of the environment, people (i.e., high quality drinking water), and industry by providing direction on water management planning, the right to divert water, issuance and administration of diversion licenses, construction of works, and conflict resolution, among other topics. The *Water Act* is enforced by the Alberta Energy Regulator (AER) for energy projects (i.e., oil, oil sands, natural gas, coal, geothermal, and brine-hosted mineral resources) and by Alberta Environment and Protected Areas (EPA) for all other (i.e., non-energy) uses. Hence, carbon capture projects can be regulated by one of the two entities, depending on the point source emitter that they are associated with [39].

Several key elements of the *Water Act* which may impact how a project accesses water include:

- **Inter-basin water transfers:** The *Water Act* stipulates that a licence cannot be issued which allows water transfer between major river basins unless it is authorized by a special Act of the Legislature. The major river basins named in the *Water Act* are the Peace/Slave, Athabasca, North Saskatchewan, South Saskatchewan, Milk, Beaver, and Hay River Basins. Hence, water resources are generally considered available for use only within the river basin in which they exist.

- **Environmental protection:** The *Water Act* provides mechanisms for determining the volume of water which should remain in a river for the sake of environmental protection (i.e., the volume which will not be licensed for people to utilize). These mechanisms include cabinet-approved Water Management Plans (WMPs), water conservation objectives, and others. The Surface Water Allocation Directive (SWAD), issued under the *Water Act*, provides direction for all rivers and lakes without pre-existing management approaches [40].

- **Diversion rights:** Water users receive a licence to divert a specified volume of water at a specified rate, commonly referred to as a water allocation. Alberta uses a priority-based allocation system, which means that older (i.e., senior) licenses have higher priority to withdraw water than newer (i.e., junior) licenses. This includes senior licence holders who are downstream of junior licence holders. In situations where water availability is low, the junior licence holders may have their water access restricted, while senior licence holders may continue diverting water. Generally, users engage in a collaborative process to develop strategies for optimizing water use and management during periods of low water availability (e.g., 2024 Water Sharing Memorandums of Understanding in the South Saskatchewan River Basin), and priorities are rarely called. Carbon capture projects which require new water diversion licenses (e.g., for new on-site power generation) will have a junior priority. Seniority of diversion rights can be an important component of overall water security for projects.

- **Demonstrated need for water**: Also known as a Development Plan, the *Water Act* requires that applicants for water licenses credibly demonstrate their anticipated water needs over the duration of the project. This requirement prevents speculation on the water resources in Alberta by ensuring only those with legitimate plans to use water can be granted a licence.

- **Construction of works:** The *Water Act* includes requirements and restrictions for the construction of water storage and intake works. Significant restrictions are placed on construction occurring within the river to minimize negative impacts to the aquatic environment.

- **Monitoring and reporting:** Water diversion licenses have requirements on them for monitoring and reporting, and it is expected that licence applicants will have a plan for monitoring quality and quantity criteria and reporting these to the regulator (e.g., annually).

- **Licence transfers:** The *Water Act* includes provisions to permanently transfer all, or a portion of, a water diversion licence from one user to another in basins with a cabinet approved WMP. Such transfers require that the original licence is in good standing, which typically requires that a substantial portion of the licence is currently being used. This restriction can make licence transfers challenging, since current licence holders may be unwilling to permanently transfer away the right to divert water which they currently use. In addition, in basins without an approved WMP, transfers can only be approved by an order of the Lieutenant Governor in Council, which can be difficult to secure.
- **Licence assignments:** As an alternative to licence transfers, the *Water Act* also allows for licence assignments, wherein a senior licence holder temporarily assigns their licence priority number to a junior licence holder, based on a contract negotiated between the parties. Functioning much like an insurance policy, this arrangement allows the junior licence holder to divert water during water-short periods, when they would not have otherwise been able to due to their junior priority. Assignments require that the assigned licence is in good standing.

Other provincial regulatory instruments which may be relevant to a project's water supply include the *Historical Resources Act,* the *Environmental Protection and Enhancement Act,* the *Public Lands Act,* the *Wildlife Act*, the Water (Ministerial) Regulation, the Wastewater and Storm Drainage Regulation, the Pipeline Rules, the Alberta Wetland Policy, and the Environmental Quality Guidelines for Alberta Surface Waters.

In addition, some elements of water access fall under federal jurisdiction, primarily through the *Fisheries Act* and the *Canadian Navigable Waters Act.* The *Fisheries Act* provides a framework for the conservation and protection of fish and fish habitat, with implications for water intake structure design and construction. The *Canadian Navigable Waters Act* provides rules for environmental protection and to promote the continued use of navigable water bodies within Canada by the public, which includes commercial or recreational vessels and Indigenous peoples exercising their Treaty rights. Other potentially relevant federal acts include the *Canadian Environmental Protection Act*, the *Species at Risk Act*, the *Migratory Birds Convention Act*¸ and the *Impacts Assessment Act*

An additional limitation on water use in Alberta is the 1969 Master Agreement on Apportionment, which requires Alberta to allow a volume of water to flow into Saskatchewan equal to half the natural flow in each river [41]. This requirement impacts the volume of water which is available for diversion from the rivers flowing into Saskatchewan. There is also an agreement through the International Joint Commission, which governs how water flows into the United States via the Milk River in Alberta's southeast [42, 43].

3.2.1 Indigenous engagement and First Nations Consultation

An important aspect of this regulatory framework is the need to engage with Indigenous communities and fulfil the statutory obligation for formal First Nations Consultation as outlined by the Aboriginal Consultation Office. This office provides direction on the regulatory requirements for Consultation in Alberta. Additionally, some federal departments have their own requirements and processes for projects with elements falling under their jurisdiction [44]. It is important for project proponents to consider whether their projects meet both the provincial and federal requirements for consultation and the extent to which they may adversely impact First Nations' Treaty rights or traditional uses and Métis settlement members' harvesting or traditional use activities.

Beyond regulatory obligations, meaningful engagement around water can also provide important opportunities for both project proponents and Indigenous communities, with links to economic reconciliation. There are many examples of Indigenous partnerships related to carbon capture and the net zero transition more broadly, some of which are receiving international attention. For example, former Enoch Cree Nation Chief Billy Morin traveled to the COP28 climate conference in Dubai to showcase Canada's Indigenous Advantage in carbon capture and storage [45]. In 2022, Enbridge Inc. and the First Nation Capital Investment Partnership (FNCIP) reached an agreement to advance the Open Access Wabamun Carbon Hub, a large-scale carbon transportation and storage project. Four Treaty 6 Nations —Alexander First Nation, Alexis Nakota Sioux Nation, Enoch Cree Nation, and Paul First Nation—formed the FNCIP to secure ownership in major infrastructure projects while ensuring that Indigenous values shape project development [46]. This collaboration is a model for equitable partnerships, demonstrating how Indigenous leadership can drive large-scale infrastructure development for reducing carbon emissions [47].

3.2.2 Impact of regulations on water availability

Within this suite of regulatory instruments, each water body within Alberta has a unique regulatory context, which directly influences how water is managed and how much water is available for new uses. For example, the *Bow, Oldman and South Saskatchewan River Basin Water Allocation Order* (2007) closed the Bow Basin, the Oldman Basin, and the South Saskatchewan Sub-Basin to new water diversion licence applications [48]. However, the *Oldman River Basin Water Allocation Order* (2003) reserves a small volume of water upstream of the Oldman Dam for specific uses [49]. In addition, several other basins have prescriptive, cabinet approved WMPs, and still other basins are managed through application of the SWAD. Project proponents must understand the regulatory context and how this impacts water availability in areas they are considering for development.

Figure 8 illustrates how the regulatory regime impacts water availability from a river, using the Little Smoky River as an example. The SWAD is applied to the Little Smoky River, meaning that water available for allocations is calculated as a variable percentage of total flow. As noted in Section 3.2, water withdrawals are managed to ensure adequate water remains in the river for healthy aquatic species and habitats. Therefore, the SWAD percentage is scaled to be lower when river flow is lower, such that proportionally more water stays in the river during low flow periods (e.g., winter months). For licence holders on the Little Smoky and elsewhere throughout Alberta, this means that, although a water licence is granted as an annual volume of water, there is no guarantee that a licensee will actually be able to divert that volume, and it is likely that their rate of diversion will need to vary throughout the year (i.e., lower in the winter, higher in the spring). These dynamics of intermittency and variability introduce water supply risks which must be managed (e.g., via water storage). See Section 3.3 for further discussion on water availability throughout the province.

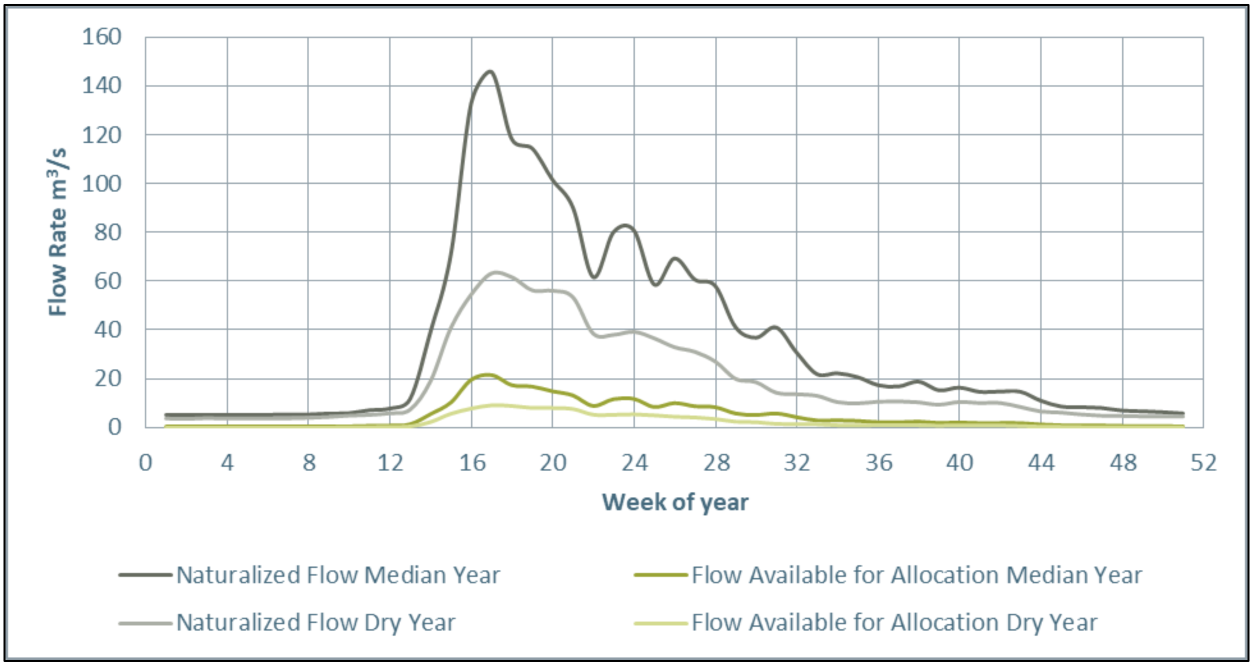

Figure 8. Hydrograph for the Little Smoky River, showing the seasonal variability of natural flow and how this impacts water available for allocation (1991-2020).

3.3 Water availability

3.3.1 Water availability analysis

The water available for new consumptive uses was analyzed for the rivers in the study area (Figure 6) with a 2050 time horizon. This accounts for estimated water usage in the year 2050, based on assumptions about historical water availability, current water usage in the various river basins, and a projected usage increase over the next 25 years. Future water use was projected assuming a 50% increase in currently allocated volumes. Additional work should be considered in the future to determine a more accurate scaling factor across different river basins.

The results presented below offer a high-level assessment of water risk across the study area, emphasizing comparative analysis rather than precise figures. It is recommended that project proponents conduct a more detailed, site-specific water supply risk analysis prior to proposing or developing new projects. River flow data was sourced from Water Survey of Canada gauge stations, while data on existing water allocations was provided by EPA. The appropriate regulatory framework (e.g., Approved WMP for the South Saskatchewan River Basin) was applied to estimate water availability for the river basins analyzed.

Two different statistical flow scenarios were selected to represent the annual variability of flow in Alberta's rivers: a median year (50th percentile of river flow) and a dry year (25th percentile of river flow). These flow scenarios were modelled based on the data for the historical record from 1991 to 2020. As discussed in Section 3.3.2.1, projections indicate that by 2050, the median water availability may shift towards a slightly drier scenario. For more details on the water availability methodology, refer to Appendix D in the Study of Water Impacts of Hydrogen Development in Alberta report [4].

Figure 9 displays the results of the water availability analysis in each basin across the province. The colours indicate how much water is available for new allocations (annually) based on a median year, and do not reflect inter-annual or seasonal flow variability. In addition to assessing the water availability of major river basins, select sub-basins (i.e., tributaries) were analyzed separately. This approach acknowledges that while a large river may have an abundant water supply, its tributaries may not. This is important in the CCUS context given that some of the projects discussed in Section 2.3 are expected to be situated within these sub-basins.

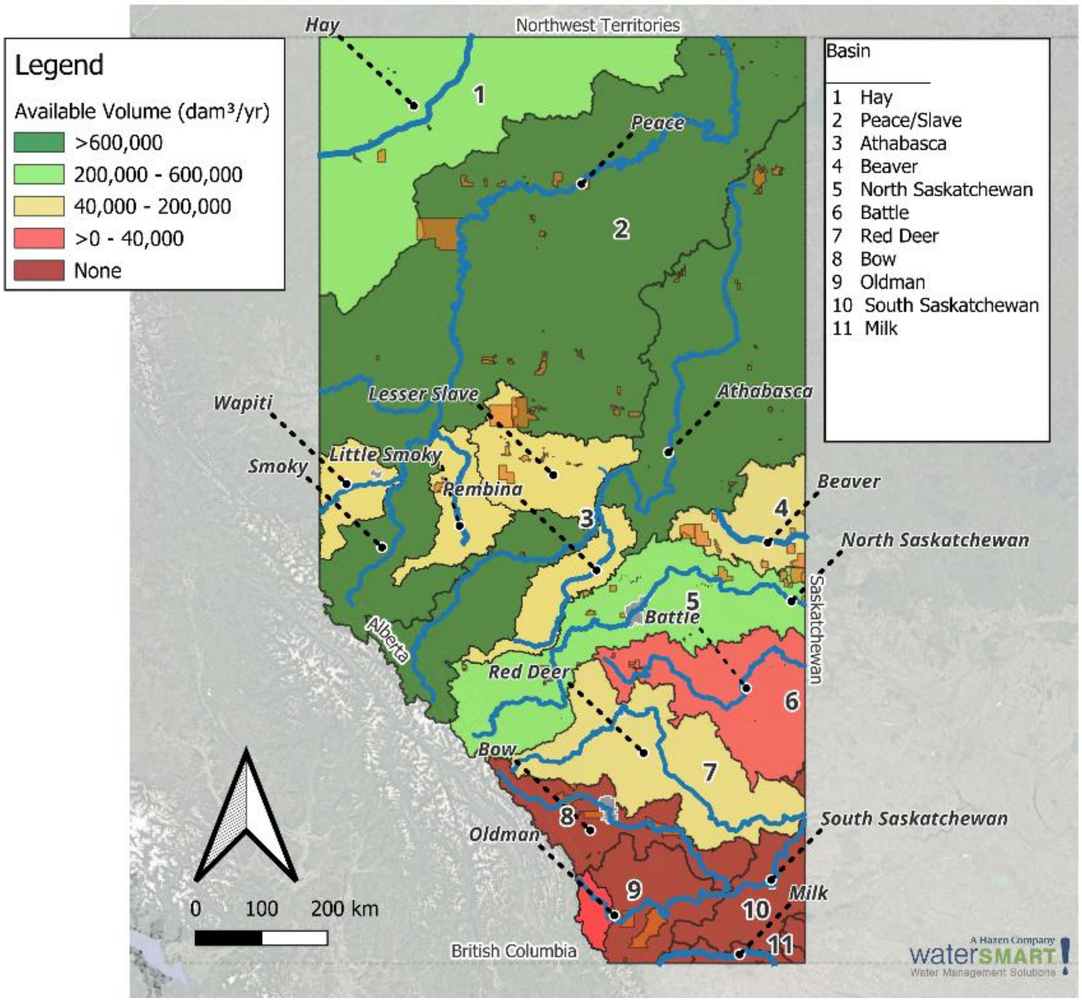

Figure 9. Heat map of water availability throughout Alberta in 2050, for a statistical median flow year.

Overall, river basins in the northern regions of Alberta have a higher annual water availability than their southern counterparts, although each river and its tributaries must be studied closely, and at a relevant hydrologic scale, before project development. Table 7 was prepared to accompany Figure 9. For both median and dry year scenarios, Table 7 compares the total water flow in each river to the volume which is available for new allocations. Rivers are listed in descending by volume. Note that while the heat map in Figure 9 provides a high-level comparison between river basins, a detailed analysis will be required to confirm the water supply dynamics of a specific project location. Figure 10 shows the estimated water availability from Table 7, in descending order of availability. The annual, aggregated data should be considered in combination with the river's seasonal and inter-annual variability.

Table 7. Summary of annual flow and water availability for the river basins and sub-basins of interest, ordered by approximate water availability.

Basin	Sub-basin	Approximate annual flow (dam^3/yr)		Approximate water availability in 2050 (dam^3/yr)	
		Median year	Dry year	Median year	Dry year
Peace	Peace	60,188,000	50,264,000	8,854,000	7,365,000
Athabasca	Athabasca	21,116,000	16,818,000	2,623,000	1,978,000
Peace	Smoky	8,910,000	6,605,000	1,235,000	889,000
Hay	Hay	3,491,000	1,578,000	520,000	233,000
North Saskatchewan	North Saskatchewan	6,194,000	5,011,000	383,000	252,000
Athabasca	Lesser Slave	1,195,000	687,000	158,000	82,000
Peace	Little Smoky	1,040,000	545,000	143,000	68,000
South Saskatchewan	Red Deer	1,392,000	957,000	97,000	97,000
Athabasca	Pembina	699,000	390,000	93,000	46,000
Peace	Wapiti	2,523,000	1,820,000	54,000	51,000
Beaver	Beaver	369,000	209,000	29,000	9,000
North Saskatchewan	Battle	153,000	103,000	5,000	4,000
South Saskatchewan	Oldman _____ Upper Oldman*	2,999,000	2,072,000	0 _____ 0 (Industrial) 9,936 (Irrigation) 1,450 (Commercial and other uses)	0 _____ 0 (Industrial) 9,936 (Irrigation) 1,450 (Commercial and other uses)
Milk	Milk**	267,000	318,000	0	0

Basin	Sub-basin	Approximate annual flow (dam^3/yr)		Approximate water availability in 2050 (dam^3/yr)	
		Median year	Dry year	Median year	Dry year
South Saskatchewan	South Saskatchewan Sub-Basin	6,713,000	5,189,000	0	0
South Saskatchewan	Bow	5,295,000	4,526,000	0	0

** There is a small volume of water available in the Upper Oldman River Basin. The Oldman River Basin Water Allocation Order which allocates this water has priority over the closure of the South Saskatchewan River Basin [50, 51].*

***The analysis for the Milk River reflects the rules of the WMP, which are enforced at the Milk River Gauge Station. Water is reserved under the WMP for very specific uses, which do not include CCUS [52].*

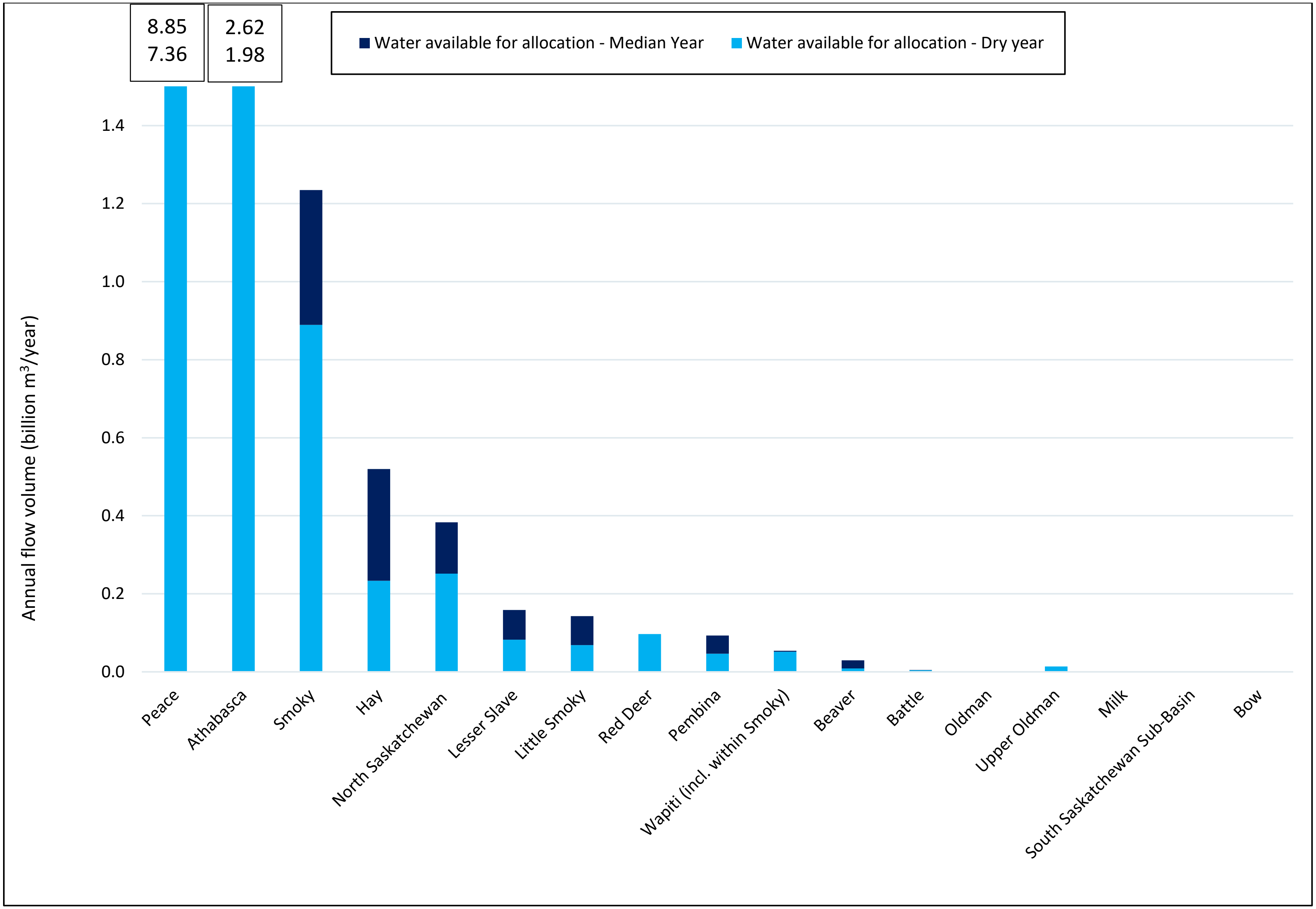

Figure 10. Relative water available for new allocations across the study area. The chart displays a stacked representation of water availability.

3.3.2 Water availability in a climate change affected future

In 2020, WaterSMART analyzed the projected impacts of climate change for the Prairie region, with a focus on changes in the form and seasonal timing of precipitation, among other factors [38]. One of this study's key findings was that, in a climate change affected future, Alberta is likely to experience increased variability of precipitation events, as well as changes to the seasonality of river streamflow. These findings have implications for the management of water supply risks, particularly given projections that the late summer periods are likely to become longer and drier in the future.

The 2020 study laid the groundwork for future investigation of how climate change may impact water availability and water security in Alberta. While regionally specific analyses have been completed since, this CCUS study provided the opportunity to update the climate impacts modelling on a provincial scale. Work was undertaken to estimate potential water availability (i.e., precipitation minus potential evapotranspiration), with a focus on how this measure may change under two future climate scenarios. The Raven Hydrological Modelling Framework[3] was used to assess water availability, incorporating spatially distributed air temperature data from DayMet (1990-2020) for historical climate conditions, as well as climate projections from Environment and Climate Change Canada's statistically downscaled Shared Socio-economic Pathways (SSPs) 2-4.5 and 5-8.5 for the period between 2021 and 2081. These future climate scenarios were chosen to represent two contrasting development pathways: SSP2-4.5 reflects a middle-of-the-road scenario, while SSP5-8.5 represents a future characterized by intensified fossil fuel development and use. See the full memo in *Appendix C Assessment of future water availability in Alberta.*

The key results from this analysis (i.e., changes to potential future water availability) are shown in Figure 11, split into the 2021 to 2050 and 2051 to 2080 timeframes. Through the analysis of changes to both precipitation and evapotranspiration, this modelling indicates that water availability is projected to decrease in all river basins. The largest projected decreases are in the south-eastern basins, whereas the Hay and Athabasca basins are projected to see minimal changes, as increased precipitation mostly offsets increased evapotranspiration. For projects with a multi-decade operational lifespan, this modelling suggests that planning should begin now to address the potential impacts of climate change on water availability (see Section 3.3.2.1).

The modelling and its results in Figure 11 provide directional indications of how water availability in Alberta could change in the future. While such analyses are useful to inform long-range risk management efforts, they are not guarantees of what will occur. Modelling the impacts of future climate scenarios is inherently uncertain, for example, with respect to which socio-economic pathway will be followed globally. Furthermore, the modelling completed for this report was necessarily high level to provide a province-wide view. More detailed, and location specific, modelling can be completed for individual

[3] The Raven Hydrological Modelling Framework (v3.8; Craig et al., 2020) was used to estimate water availability across Alberta. Raven is a mixed lumped/semi-distributed model that is typically used to simulate state variables and streamflow.

projects to better assess future water supply risks. Such modelling could account for factors such as the differences between tributary and mainstem, seasonal variability, other water users, flow regulation, and changes in water management, which were excluded from the analysis in this report. Note that because of these uncertainties, the water availability estimates presented in Section 3.3.1 do not explicitly include the impacts of future climate scenarios.

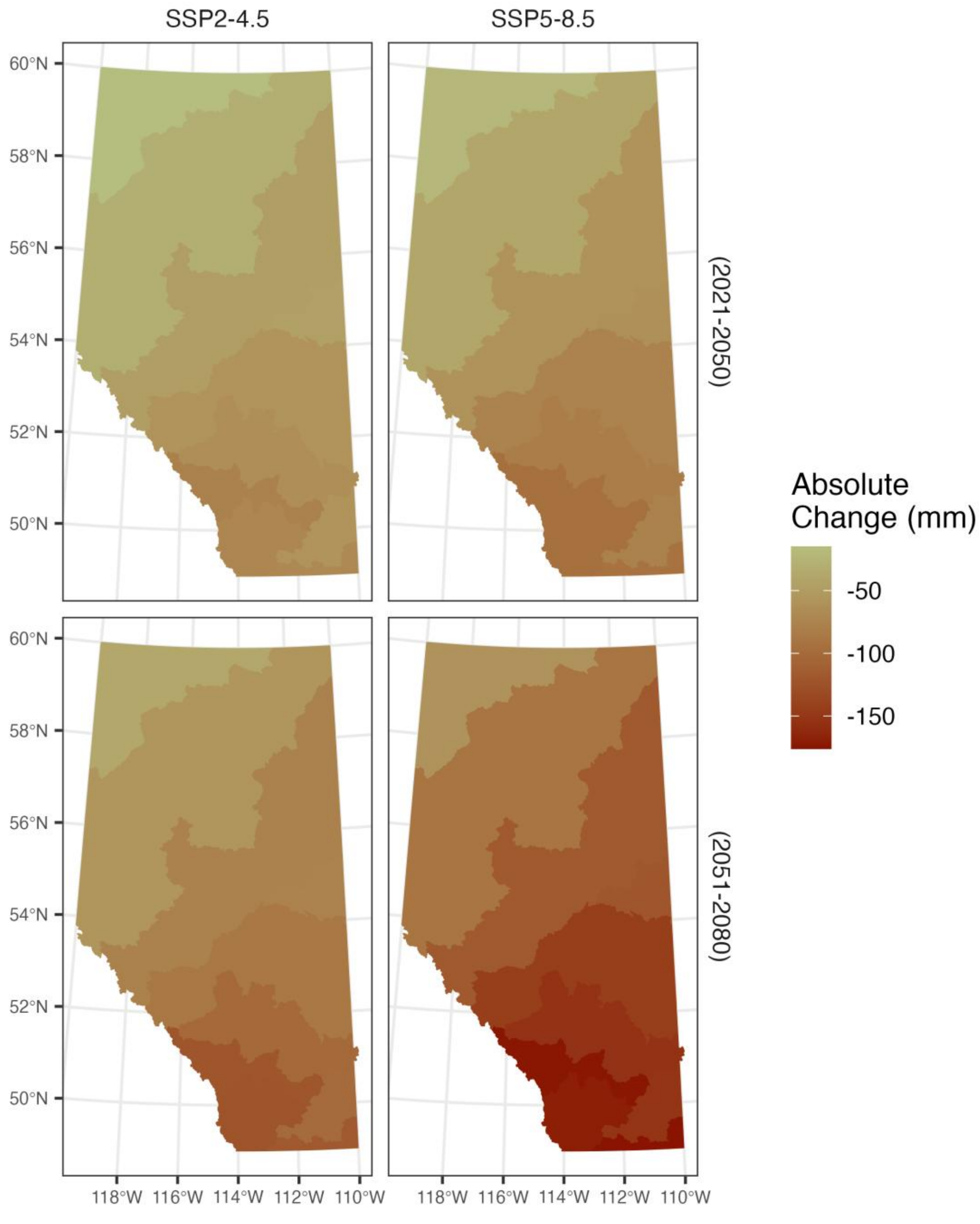

Figure 11. Absolute change in potential water availability for future periods (2021-2050 and 2051-2080) under climate change scenarios (SSP2-4.5 and SSP5-8.5) and from the historical scenario (historical climate forcings from 1990-2020).

3.3.2.1 Approaches to managing potential climate change impacts

As discussed in Section 3.3.2, the impacts of future climate scenarios are projected to result in decreased water availability throughout Alberta. Furthermore, previous work indicates that the effects of climate change, such as increased variability, will make it more difficult to predict future conditions based on historic data. Increases to variability, coupled with decreases to availability, can complicate the assessment and management of water risks for project proponents. However, several strategies exist to manage water supply risks in a changing climate. Project proponents and policy makers should consider strategies such as:

- Upgrades to, and development of, water storage capacity, which can enhance the reliability of water access amidst an increasingly variable supply. In the context of climate change, projects may necessitate larger storage capacities than historically required, and the value of centralized storage infrastructure may increase.
- Implementation of water reuse and recycling programs for users across Alberta.
- Collaboration with other water users, such as the use of water licence transfers and assignments under the Alberta *Water Act*, or water-sharing memorandums of understanding like the ones developed in 2024 in the South Saskatchewan River Basin in anticipation of drought conditions.

These strategies are generally applicable across Alberta, although it is critical to recognize that each basin is unique, with various drivers, risks, and opportunities. A comprehensive understanding of the local basin context and the existing regulatory framework will facilitate innovative solutions for managing future water risks.

4.0 Comparing Carbon Capture, Utilization, and Storage Water Demands to Water Availability

This section compares the estimated water demand for carbon capture in Alberta (Section 2.4) to the estimated water availability for new allocations with a 2050 horizon (Section 3.3.1). In Sections 4.1, 4.2, and 4.3, three case studies are presented for specific regions expected to host substantial carbon capture development. These are the East Calgary Region CCUS Hub, Athabasca River below Fort McMurray, and the North Saskatchewan River at Fort Saskatchewan, respectively. The goal of these case studies is to closely examine the potential trade-offs associated with carbon capture development within the water-energy-food nexus. Lastly, Section 4.4 examines the implications and potential interactions of combined hydrogen and carbon capture development in Alberta, leveraging the findings from WaterSMART's 2023 hydrogen study.

Figure 12 shows the estimated water availability for selected river basins in Alberta, compared to the potential consumptive water demands of known CCUS projects under Low, Medium, and High water use scenarios. Figure 12 is supplemented by Figure 13, which is the water availability heat map discussed in Section 3.3.1, overlaid with the identified projects from Section 2.3. These results indicate that the potential water availability for planned CCUS projects in Alberta will vary widely depending on the river basin. For example, the Peace and Athabasca River basins offer a relatively high water supply to support new projects along their mainstem, though some individual sub-basins, like the Wapiti and Pembina Rivers face greater water risk. In southern Alberta, however, water availability for new projects is much more constrained, particularly in the Battle, Milk, South Saskatchewan, Oldman, and Bow River basins. In some basins and sub-basins, the potential water demand for CCUS exceeds the availability of new water licences. In such scenarios, CCUS development may be constrained by water supply, and creative sourcing alternatives will be required (e.g., reuse, licence transfers, and water sharing agreements). It is also in these locations that potential trade-offs within the water-energy-food nexus will be most salient. Project proponents and water managers should carefully consider the highest and best use of constrained water resources while managing supply risks for individual projects and users.

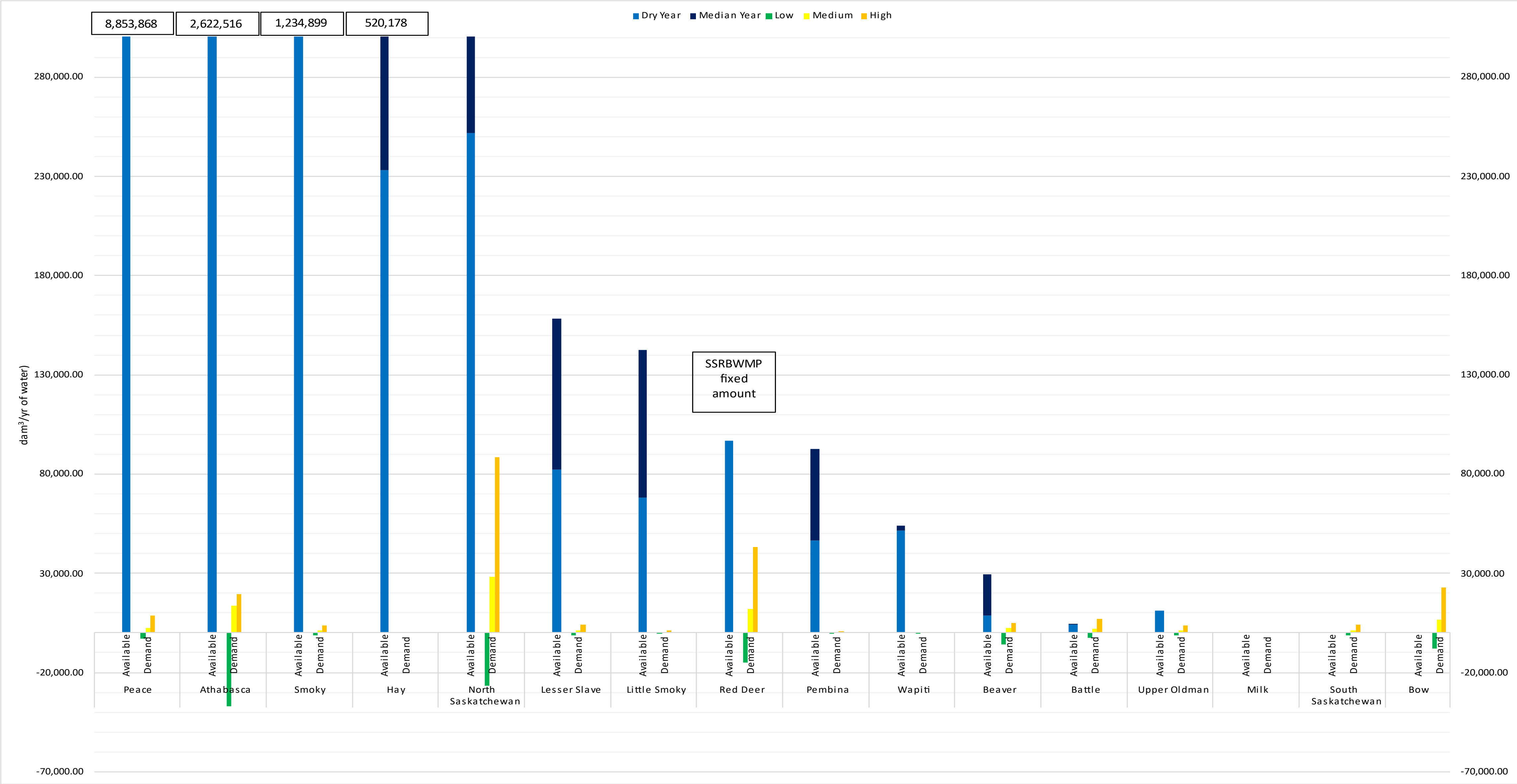

Figure 12. Available water in a median and dry flow year compared to the estimated water demand for the Low, Medium, and High use scenarios for CCUS.

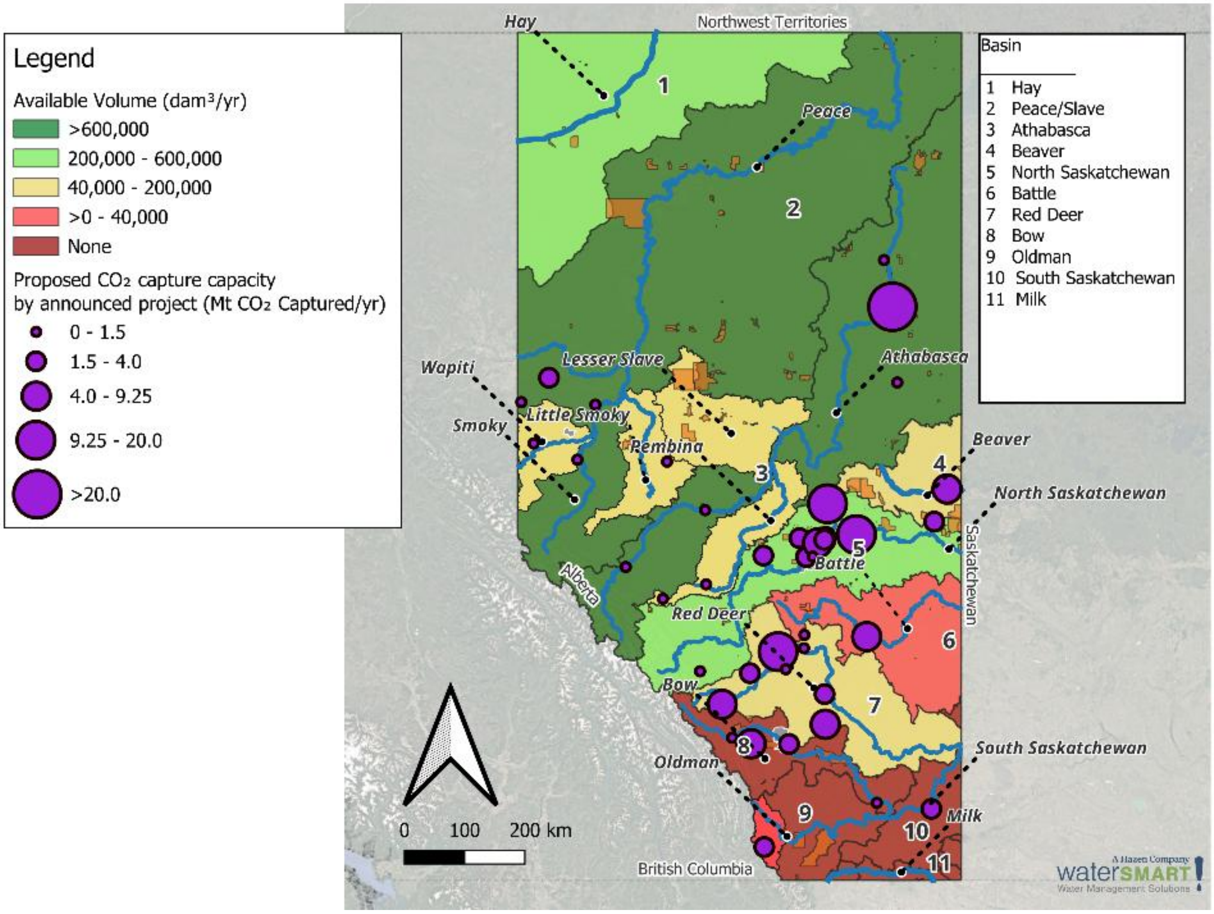

Figure 13. Announced CCUS projects on top of a median flow year water availability heat map, to provide visual context of demand per basin and water available in that basin.

As noted and illustrated in Figure 12 and Figure 13, there are likely to be some CCUS projects which encounter water supply challenges within the 2050 timeframe and beyond. The risks on an annual basis are readily apparent from these figures, but water supply variability seasonally and year over year (per Section 3.0) should also be considered. The dynamics of junior and senior licence priorities within Alberta's priority-based water rights system (Section 3.2) will also impact water supply risks. It is also important to consider how CCUS development may compete with other future uses, for example from sectors supporting the transition to a lower carbon economy (e.g., hydrogen development, critical mineral mining, and nuclear power generation) and from traditional uses (e.g., municipal growth, industry, and irrigation).

Figure 14 illustrates a modified version of the heat map presented in Figure 13, updated to show a potential future scenario where all identified CCUS projects have been fully developed under a Medium water use scenario. The Medium water use scenario was selected as representative of many planned projects which are known to be considering well-optimized systems which incorporate a level of water recovery and reuse, along with a hybrid cooling system. Figure 14 shows the remaining water supply during a statistical dry year, assuming this build out. The quantities visualized in Figure 14 are reported in Table 8 for reference. Due to the large annual flows in the Peace and Athabasca River basins, they remain relatively unimpacted. Conversely, higher water demands associated with CCUS development in the North

Saskatchewan, Beaver, Battle, and Upper Oldman River Basins could significantly impact water availability, particularly in years of lower streamflow. This could lead to trade-offs within the water-energy-food nexus.

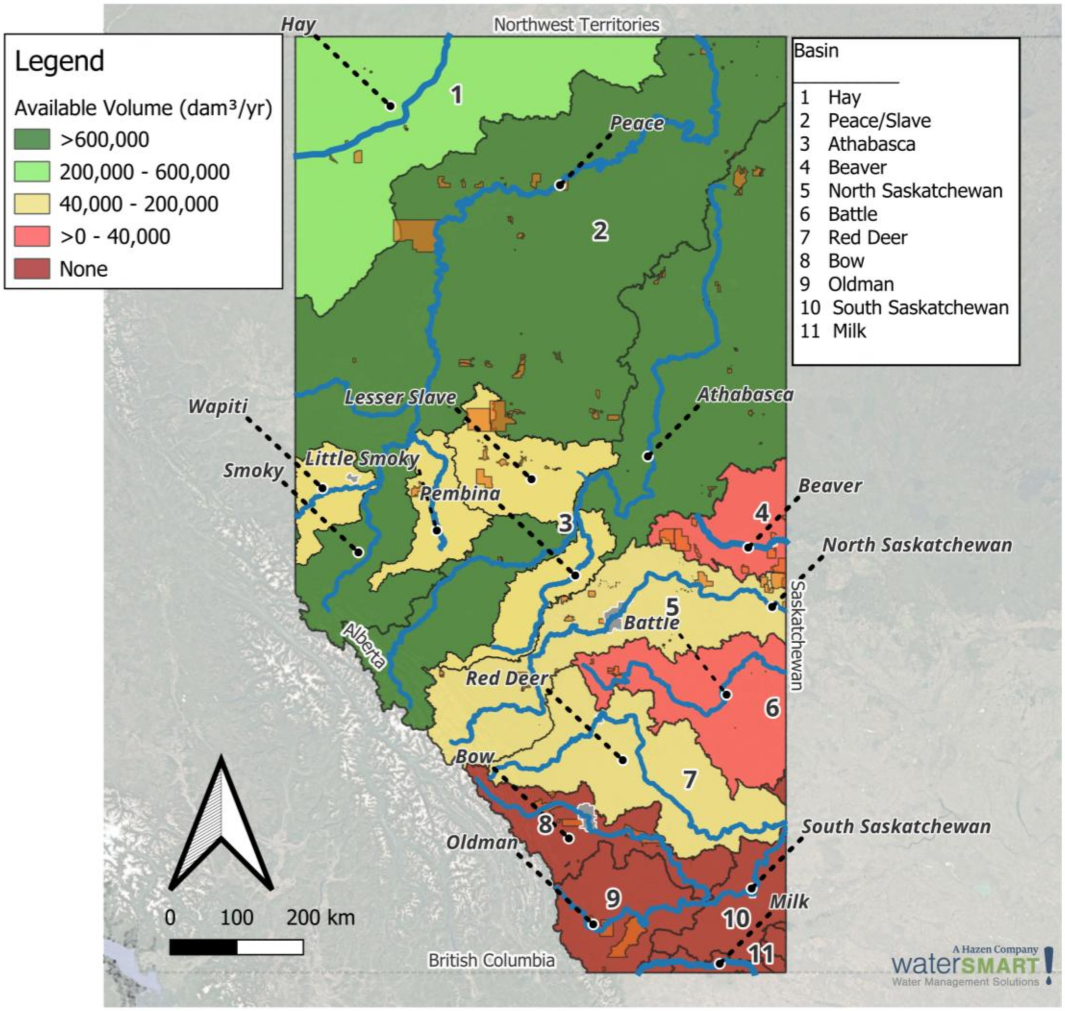

Figure 14. Annual water availability per basin in the case of Medium CCUS demands in a statistical dry year.

Table 8. Annual water availability in a statistical dry year after Medium water use demands for CCUS projects.

Basin	Sub-basin	*Medium use demand for CCUS (dam^3/yr)**	*Water available in a dry year after CCUS demands (dam^3/yr)**
Peace	Peace	2,417	7,363,000
Athabasca	Athabasca	13,841	1,964,000
Peace	Smoky	1,512	888,000
Hay	Hay	---	233,000
North Saskatchewan	North Saskatchewan	28,325	224,000
South Saskatchewan	Red Deer	12,162	85,000
Athabasca	Lesser Slave	1,181	81,000
Peace	Little Smoky	391	68,000
Peace	Wapiti	72	51,000
Athabasca	Pembina	208	46,000
Beaver	Beaver	2,634	6,000
North Saskatchewan	Battle	1,955	2,000
South Saskatchewan	Oldman Upper Oldman	0 1,055	0 0 (For industrial use)
Milk	Milk	---	0
South Saskatchewan	South Saskatchewan Sub-Basin	1,173	0
South Saskatchewan	Bow	6,472	0

** A value of zero in this case indicates that water demands for CCUS exceed water availability, and there is no further water available for use.*

4.1 Case study: East Calgary Region Carbon Capture, Utilization, and Storage Hub

The Bow River Basin is expected to host significant CCUS developments, despite the closure to new licence applications noted in Section 3.2.2. As documented in Section 2.3 (Figure 3), several developments in the basin are planned near the City of Calgary, including the East Calgary Region CCUS Hub (the Hub) [33]. Although the geological formation suitable for sequestration of CO_2 associated with the Hub is primarily within the Red Deer River Basin, the carbon capture points are closer to Calgary and are assumed to source water from the Bow River Basin. Currently, many industrial facilities in the area rely on water from the City of Calgary's existing water licences [53]. Although there is no certainty that this practice will continue in the future, for the purpose of this case study, it is assumed the Hub will source water from the City of Calgary.

The City of Calgary holds a cumulative annual allowable diversion of 461,645,481 m^3 across various licences, and it is licensed to return approximately 80% of this diversion to the environment. This results in a maximum consumptive allocation of 90,669,355 m^3/yr, some of which is already in use. As Table 9 and Figure 15 indicate, the development of the Hub could require up to 11.5% of the City of Calgary's total consumptive allocation under a High water use scenario. For comparison, the average Calgarian uses 0.17 m^3/day (170 L/day) [54]. At a 20% consumptive ratio, the Hub's annual High water use scenario would equate to the water demand of approximately 800,000 people. Conversely, under a Low water demand scenario, the Hub's development could result in no net-new water consumption, or even the net generation of water to offset existing consumptive water demands in the Bow River Basin.

Table 9. Estimated consumptive water demands for the East Calgary Region Carbon Capture, Utilization, and Storage Hub as a percentage of the City of Calgary's existing consumptive water allocation.

CCUS water use scenario	East Calgary Region CCUS Hub		
	Annual consumptive water demand (dam^3/yr)	Equivalent % of total City of Calgary licensed consumptive volume	Approximate equivalent population*
Low	-3,612	0%	-300,000
Medium	2,932	3.2%	230,000
High	10,408	11.5%	800,000

**A negative value in this case indicates a net reduction in water use equivalent to a given population.*

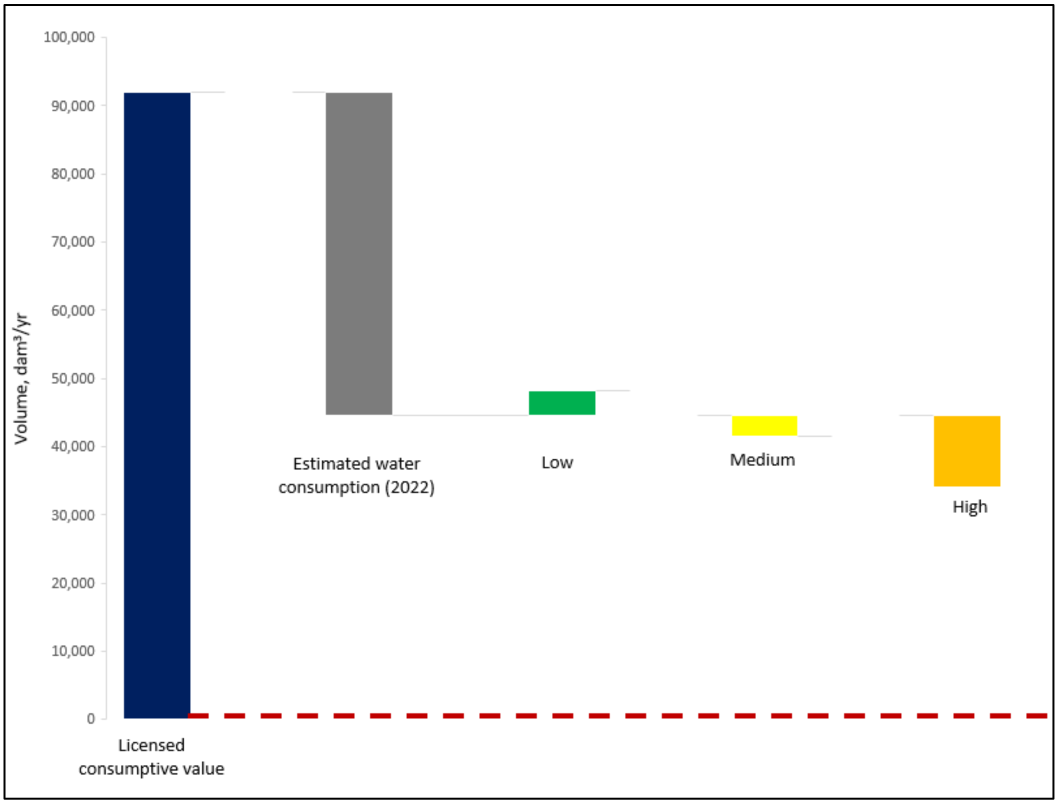

Figure 15. City of Calgary's consumptive water allocations compared to estimated demands for current use and CCUS.

Another important consideration is whether the Hub will be accompanied by hydrogen development, such as through the Calgary Hydrogen Production Hub [55]. According to WaterSMART's 2023 report, hydrogen development within the City of Calgary, as proposed in 2023, could consume 11 – 51% of the City's total consumptive water allocation, which would be incremental to the demands for CCUS. As discussed in Section 4.4, it will be critical for both water managers and project proponents to understand the water consumption dynamics of combined carbon capture and hydrogen production, as well as the interactions with other new technologies and facilities under consideration.

The variability in potential future water demands highlights the need for both the City of Calgary and proponents of the Hub to carefully assess the water demands associated with carbon capture for this development. This evaluation would provide insights on potential trade-offs within the water-energy-food nexus and support informed decision making. For example, in a High water use scenario, the Hub may directly compete for water with future domestic, commercial, and industrial users in Calgary. Alternatively, it may be possible for the capture facilities that connect to the Hub to align with the Low water demand scenario, if other considerations, such as economic and operational factors (e.g., cooling technology), can be managed accordingly. In this scenario, excess water recovered from the Hub could be used to reduce the overall consumptive demands on the Bow River basin, which would increase the water supply reliability in a basin closed to new water allocations. Alternative water sources, such as groundwater and reuse, could also be considered to further manage water supply risks and reduce the overall water impacts of the Hub.

4.2 Case study: Athabasca River

The Athabasca River Basin generally has high water availability, in part due to its extensive network of tributaries and its relatively high annual flow compared to demands and to other river basins in Alberta, as seen in Figure 7. The Athabasca River plays a critical role in supporting various industrial activities, including oil sands operations, which are a major component of Alberta's energy sector. Although oil sands operations incorporate a high degree of internal water recycling, most still rely, to some extent, on surface water and connected groundwater from the Athabasca River and its tributaries. This makes it essential to understand how water availability may influence, and be influenced by, CCUS development in the basin, most of which is associated with the oil sands.

The Athabasca River Basin is expected to host one of the largest CCUS projects in the world, the Pathways Alliance Carbon Capture Storage Hub (PACSH) [56]. The 400-km-long CO_2 conveyance project is designed to capture carbon emissions from over 20 oil sands facilities, mainly located within the Athabasca River basin[4]. By 2050, it is expected to capture up to 62 Mt CO_2/yr [57], representing approximately 30% of Alberta's announced sequestration capacity. The water availability assessment for the Athabasca River assumes that approximately 90% of PACSH's capacity, and the associated consumptive water demands, will be specific to the Athabasca River Basin. Based on this assumption, the proposed CCUS capacity for all projects in the basin by 2050, including non-oil sands related facilities (as shown in *Appendix B*) is approximately 60 Mt CO_2/yr. Note that the facilities connected to the PACSH are expected to fall within the Low use scenario, based on engineering studies completed to date which assume air cooling, as discussed in Section 2.2.

The Athabasca River Basin is generally well positioned for CCUS and other types of industrial activities, from a water availability perspective, as shown in Figure 16 and Table 10. However, while these results indicate ample water is available on an annual basis, seasonal and year over year variability must also be considered. Figure 16 demonstrates the potential seasonal variability within the Athabasca River mainstem, with the potential for river flows to change by a factor of eight between winter and summer. This variability is echoed within the tributaries of the Athabasca River, some of which demonstrate even higher seasonal swings and greater sensitivity to storm events.

CCUS proponents within the Athabasca River Basin should complete site-specific evaluations to quantify their water supply risks, as well as to better understand the potential impacts of CCUS development on water access for other uses. These assessments will be especially valuable on the Athabasca River's tributaries, which can sometimes experience low water availability during the winter season and in low flow years. Low water availability periods can pose serious challenges for CCUS and other industrial operations, which should be accounted for in comprehensive plans to mitigate the impacts of these conditions. For example, the decision by proponents of the PACSH to utilize air cooling instead of

[4] The Pathways Alliance Carbon Capture Storage Hub is projected to connect to facilities in the Athabasca and Beaver River Basins, with the majority located in the Athabasca.

evaporative cooling reflects a planned response to potential water supply challenges. The reuse of excess recovered water from the capture process is another avenue through which projects in the Athabasca can mitigate their water supply risks and water impacts.

While project-level planning is important, there is also value in regional collaborative approaches, such as those undertaken in the South Saskatchewan and North Saskatchewan River Basins [58]. This type of project would bring together communities, water managers, environmental experts, and industry leaders to identify priority water issues across the basin. Supported by quantitative tools, this group could then identify opportunities to mitigate and adapt to these water challenges, with the goal of improving water management for sustainable future use and desired environmental outcomes. Such a project in the Athabasca River Basin could also incorporate the Peace River Basin and account for the interactions in the Peace-Athabasca Delta.

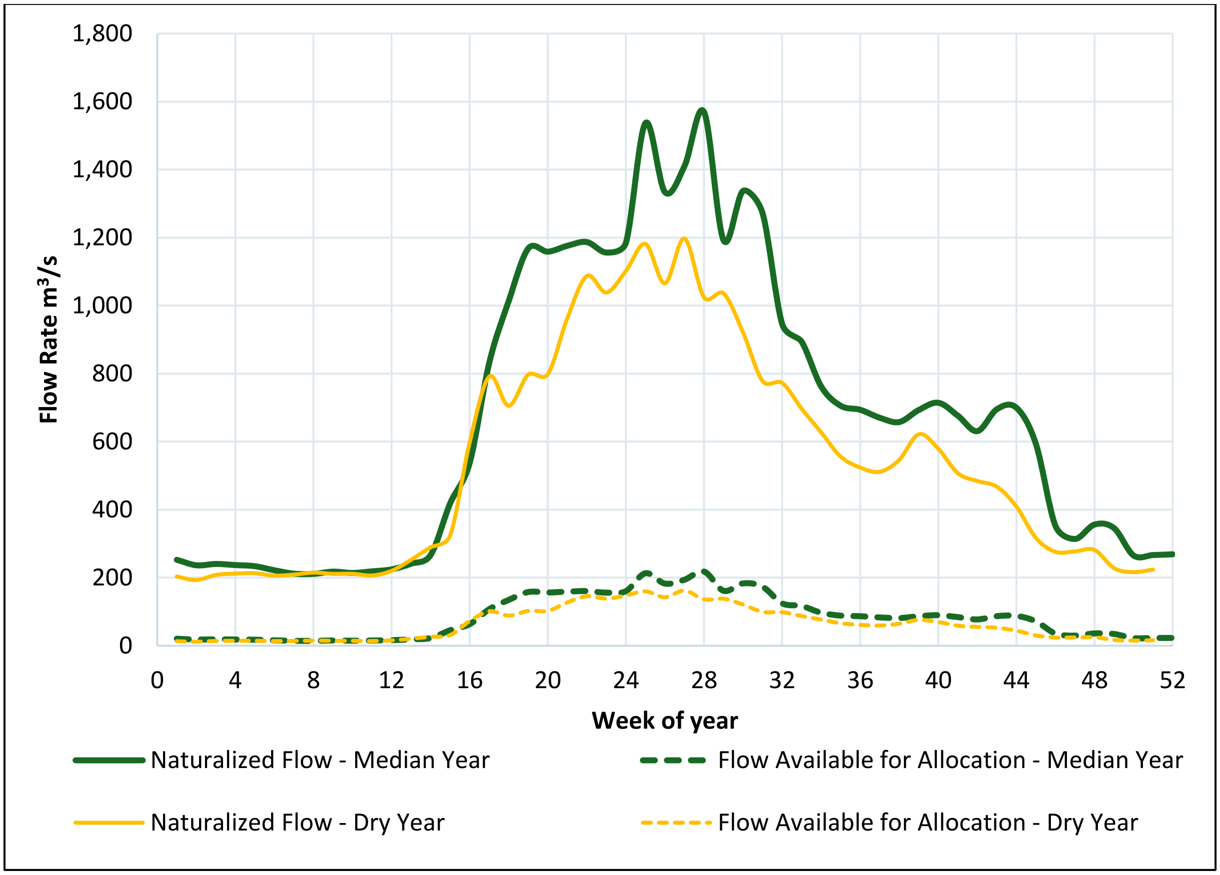

Figure 16. Comparison of naturalized flow and water availability under the SWAD for the Athabasca River below Fort McMurray, in dry and median years (1991-2020).

Table 10. Estimated consumptive water demands for CCUS development in the Athabasca River.

CCUS water demand scenario	Water available in a dry year (dam³/yr) before CCUS demands	Annual consumptive water demand (dam³/yr)	Water available in a dry year (dam³/yr) after CCUS demands	Equivalent use % of total water available in a dry year *
Low	1,978,000	-36,894	2,015,000	-1.9%
Medium		13,841	1,964000	0.7%
High**		19,648	1,958,000	1.0%

** A negative value indicates that more water is generated than is consumed.*

*** The High Use scenario encompasses all announced projects within the Athabasca River Basin, including those unrelated to the oil sands. Refer to Appendix B Carbon Capture, Utilization, and Storage Project Details for more details.*

4.3 Case study: North Saskatchewan River at Fort Saskatchewan – Edmonton Region

This case study for the North Saskatchewan River Basin focuses on the City of Edmonton and surrounding areas (e.g., Fort Saskatchewan and the Alberta Industrial Heartland). This area is projected to be one of Alberta's leading regions in terms of total carbon capture capacity, with an estimated capture rate of 66 Mt CO_2/yr by 2050. As shown in *Appendix B*, the potential annual consumptive water demands for CCUS projects in the Edmonton region range from -26,408 dam^3/yr to 87,573 dam^3/yr.

It is understood that the North Saskatchewan River does not have a cabinet-approved WMP in place, nor are there specific regulatory guidelines dictating how water should be allocated (e.g., water conservation objectives). In addition, the SWAD does not directly apply because the river is regulated by the upstream Big Horn and Brazeau dams, which mute the peak spring flows while increasing winter flows, relative to natural conditions. For this report, a modified version of the SWAD has been applied, which accounts for the higher than natural winter flows in the North Saskatchewan River. Should the regulatory environment change in the future, for example through a WMP or other mechanism, the water availability estimate should be updated.

In a dry year scenario, the High water use case for CCUS could account for a significant portion of water available for allocation in the North Saskatchewan River as it flows through the Edmonton Region. Conversely, the net water production associated with the Low scenario could help offset some of the water demands for existing industrial processes or future hydrogen development (see Section 4.4 for further discussion).

Although the upstream dams on the North Saskatchewan River help to reduce the seasonal variability in flows compared to some other Albertan rivers, seasonal variability remains, in addition to year over year variability (see Figure 17). As discussed in Section 3.3.2, there is also the potential for greater variability in a climate change affected future. Given this potential for variability, as well as the extensive development planned for the region, project proponents should carefully assess their long-term water security risks. As part of this assessment, consideration should also be given to how raw water will be physically accessed, given existing constraints on water diversion infrastructure within the river. It is understood that shared infrastructure (e.g., new river intakes) is being explored to manage cumulative impacts while enabling water access.

In addition to localized assessments of water supply risks and opportunities, basin-wide collaboration among water users and managers will be essential to identify and address long-term water-related challenges. As of March 2025, WaterSMART is completing a collaborative watershed modelling project with many participants from the basin. The results of this work, in the form of an adaptation roadmap, should be considered by CCUS proponents and decision makers and updated over time.

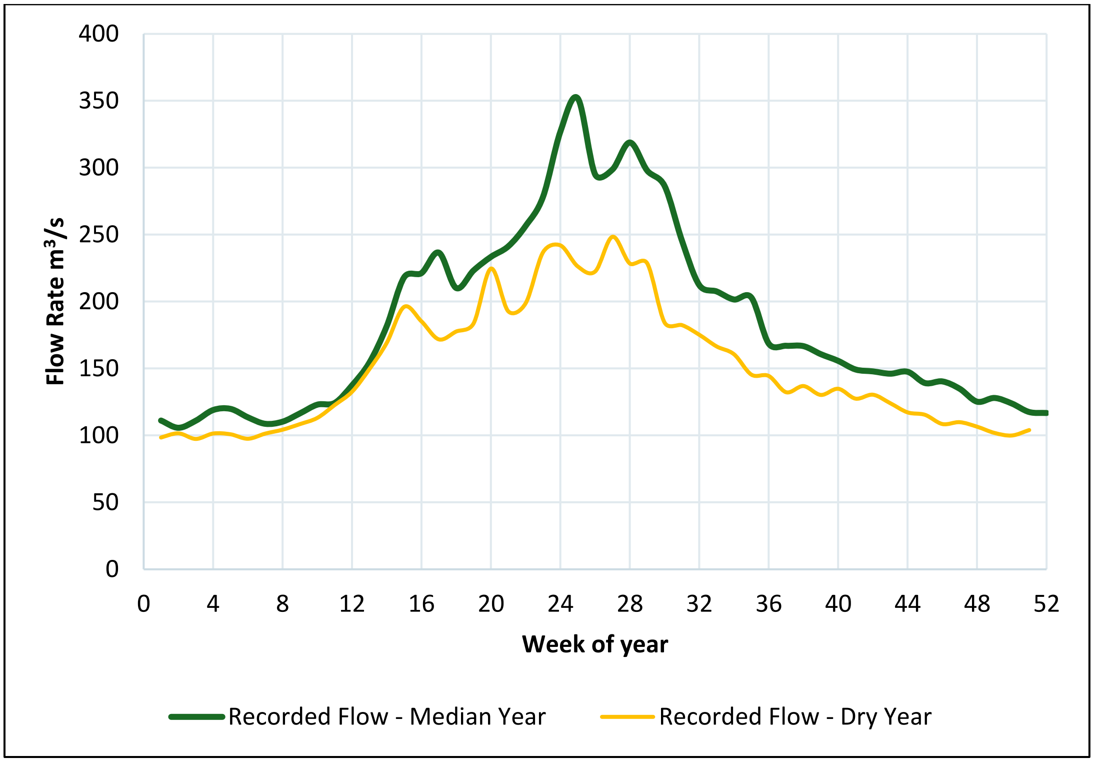

Figure 17. Comparison of recorded flow for the North Saskatchewan River in Edmonton, in dry and median years.

4.4 Layering carbon capture and hydrogen water demands

As noted in Section 1.0, there is an explicit link in Alberta between hydrogen development and CCUS. This is primarily driven by the expected use of natural gas for much of Alberta's hydrogen development and the associated need to capture the associated emissions (e.g., as noted in the Alberta Hydrogen Roadmap). It is therefore important to consider how the two sectors may together impact Alberta's water resources and drive trade-offs within the water-energy-food-nexus. Leveraging the findings from WaterSMART's 2023 study of hydrogen's water impacts, this section explores the intersection of hydrogen and CCUS development in Alberta, from a water consumption perspective.

Both the hydrogen and CCUS studies consider Low, Medium, and High water consumption scenarios, accounting for various technologies and process designs. The 2023 hydrogen study identified potential water consumption significantly higher than that for CCUS described in Section 4.0. The hydrogen study findings are replicated in Table 11 for ease of reference, with potential Alberta-wide water consumption estimated to be between 121,100 and 503,360 dam^3/yr. Note these values have not been revised since 2023 and may not be reflective of current plans for development.

Figure 18 illustrates how the water demands for CCUS and hydrogen could compound. Interestingly, there is the potential for CCUS development to reduce the net water consumption for hydrogen, assuming that the Low water consumption scenario can be achieved on carbon capture projects associated with hydrogen production. Figure 18 demonstrates this outcome, where the total water consumption for hydrogen plus CCUS is less than that of just hydrogen alone. It is estimated that water consumption for CCUS and hydrogen projects in Alberta will range from 20,513 dam^3/year (i.e., Low use scenarios for hydrogen and CCUS) to 705,504 dam^3/year (i.e., High use scenarios for hydrogen and CCUS).

As discussed throughout this report, not all CCUS facilities will achieve the Low use scenario. Indeed, as Section 2.2 discusses, NGCC power, oil sands, and biomass-related CCUS project have the most potential to produce water on a net basis, rather than the CCUS associated with hydrogen production using ATRs. For both hydrogen and CCUS development, the precise impacts and risks of water use should be analyzed on a location- and project-specific basis.

Table 11. Summary of the Low, Medium, and High hydrogen production water demand cases from WaterSMART's 2023 study [4]. This analysis has not been updated since the 2023 publish date.

Basin	Sub-basin	H_2 Projects	Anticipated water demand on the river basin (dam^3/yr)		
			Low	Medium	High
Peace	Smoky	2	17,090	29,350	47,110
	Wapiti (incl. within Smoky)	1	1,650	3,910	7,520
	Little Smoky	0	0	0	0
Athabasca		0	0	0	0
North Saskatchewan Battle	North Saskatchewan	7	52,660	111,400	220,740
	Battle	1	1,430	3,390	6,520
South Saskatchewan	Red Deer	1	20	50	90
	South Saskatchewan Sub-Basin	1	28,470	52,660	128,650
	Bow	3	21,290	47,780	96,620

Basin	Sub-basin	H_2 Projects	Anticipated water demand on the river basin (dam³/yr)		
			Low	Medium	High
	Oldman	0	0	0	0
	Upper Oldman	1	140	210	630
Hay		0	0	0	0
Beaver		0	0	0	0
Milk		0	0	0	0
Total		**17**	**121,100**	**244,840**	**503,360**

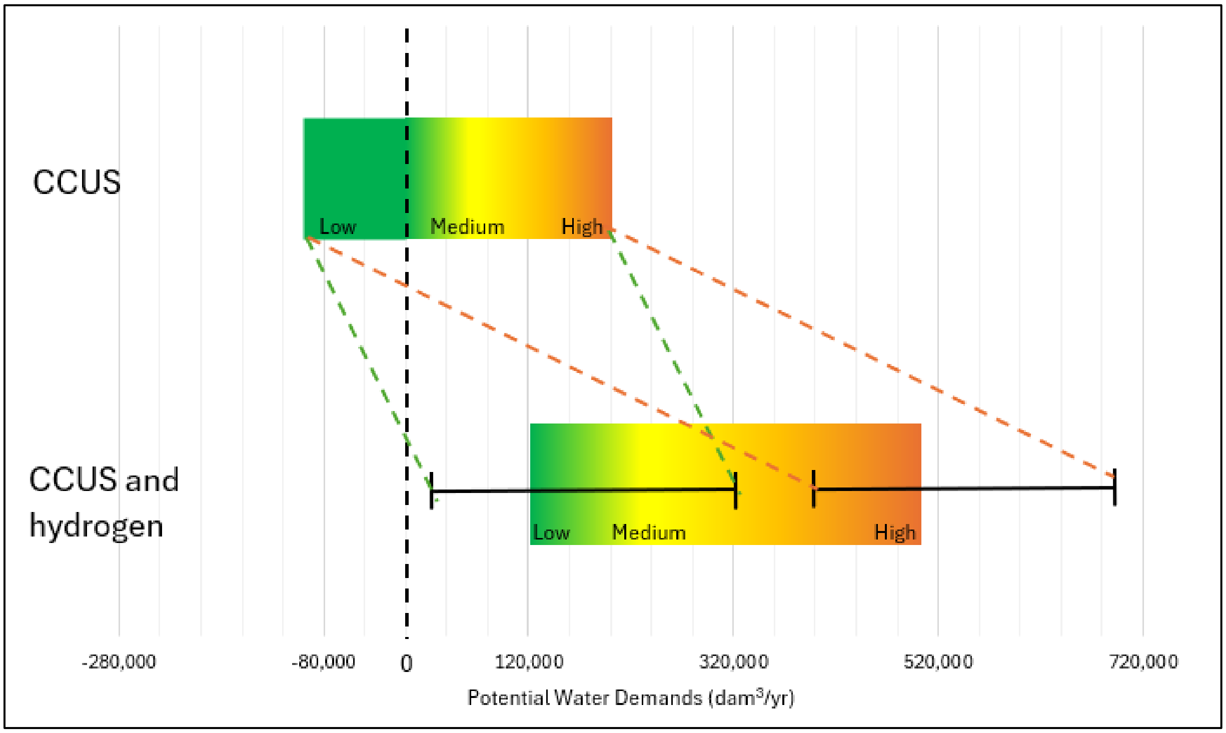

Figure 18. Water demands for CCUS and hydrogen development. Note that the range extensions represent the potential cumulative demand of CCUS overlaid on the Low and High water use scenarios for hydrogen development.

5.0 Recommendations and Next Steps

Through comparison of potential water demands for CCUS to water availability across Alberta in 2050, this report demonstrates that the full build out of the CCUS sector in the province is likely to necessitate trade-offs within the water-energy-food nexus. Specifically, there may be water supply risks under the Medium and High water use scenarios, while the Low water use scenario has the potential to beneficially offset other water demands if the excess recovered water can be appropriately managed. These risks, trade-offs, and opportunities will be variable across the province, and location-specific efforts will be required to understand and manage them appropriately. For example, water supply challenges are expected to introduce greater project risks in river basins with current water supply constraints and no access to new water diversion licences (e.g., the Bow River Basins). In other basins which do not currently face these types of constraints, such as the North Saskatchewan and Red Deer River basins, CCUS development may introduce water supply challenges, especially when considered in conjunction with other industrial development, such as hydrogen.

Given the potential for CCUS to either consume or generate water, on a net basis, it should not be concluded that CCUS development should be avoided within Alberta, or even within specific river basins. Rather, proponents, investors, policy makers, and other decision makers with influence on the sector should carefully consider the potential water risks and opportunities identified in this report. Through early identification and evaluation of the water-related challenges, solutions can be identified and implemented to minimize the impacts of CCUS development in the water-energy-food nexus context. Specifically, the following recommendations are provided for project proponents and investors, with parallels to the recommendations provided in WaterSMART's 2023 hydrogen report:

1. Integrate water management into project planning at an early development stage:
    a. Conduct detailed analyses of the water available for a given project and how it will be impacted by hydrologic and environmental conditions, regulatory context, and other water users, now and into the future. Ideally, these analyses will occur before significant time and capital is spent on other project design efforts, regulatory applications, or land purchases.
    b. Consider regional water management plans and regulatory requirements.
2. Consider climate change risks:
    a. Assess the potential impacts of climate change on water availability, including changes in precipitation patterns, temperature increases, and the frequency and severity of droughts and floods.
3. Develop approaches to manage water supply risks, considering both project-level conditions and basin-level context. The following approaches may be applicable:
    a. Implement water storage with sufficient capacity to supply operations during low flow periods, such as building reservoirs or using natural water bodies for storage.
    b. Strengthen stakeholder engagement and collaboration by working with other water users to more effectively manage water on a basin-wide level.
    c. Seek opportunities to maximize water reuse within carbon capture and through

integration with other industrial processes, thereby reducing consumptive water requirements. For example, this could be achieved by implementing water-efficient technologies and practices (e.g., air cooling instead of cooling towers, novel capture technologies instead of traditional amine-based capture, etc.).

d. Seek alternatives to non-saline surface water use, including groundwater (especially saline) and effluent from municipalities and industrial facilities (e.g., tailings water, treated brackish water).

While the preceding recommendations can effectively address specific projects, there are additional opportunities to improve water management across the entire Alberta CCUS ecosystem. To better understand and address water-related challenges for CCUS operations in Alberta, the following opportunities should be considered:

1. Use collaborative, data-driven processes to identify, understand, and manage water challenges on a river basin scale, while balancing water-energy-food nexus trade-offs and environmental considerations.
    a. Develop a collaborative roadmap for sustainable water management in the Peace and Athabasca River basins, where significant CCUS deployment is expected in parallel with other industrial development.
    b. Review and update current and existing basin-scale planning on an ongoing basis as CCUS develops within the context of the transition to a lower emissions economy (e.g., within the South Saskatchewan and North Saskatchewan river basins).
2. Foster a better province-wide understanding of Alberta's groundwater resources and enhance data collection and accessibility to help project proponents meaningfully evaluate sustainable groundwater use as an alternative to surface water use. This should leverage existing efforts to understand and responsibly manage groundwater resources and could include the development of a centralized database to store and share groundwater data.
3. Support the further development and deployment of technologies to enable the reuse of excess recovered water from CCUS projects. This will reduce the water consumption of CCUS broadly and has the potential to beneficially offset the demands of other industries (e.g., hydrogen) within a given river basin.
4. Conduct similar studies to evaluate emerging technologies and sectors (e.g., nuclear power generation, critical minerals, data centres, etc.) within Alberta and other jurisdictions. This will enable the estimation of new water demands and help guide decisions to balance trade-offs within the water-energy-food nexus as the transition to a lower emissions economy continues.

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Appendix A Details of Carbon Capture, Utilization, and Storage Water Demands

This appendix is a companion to Section 2.0 within the main report, and in particular Section 2.2. It consists of the following sub-appendices:

- A1 – Current and emerging carbon capture technologies
- A2 - Estimation of water demands for MEA-based carbon capture
- A3 - Sensitivity analysis

A1 – Current and emerging carbon capture technologies

Although post-combustion MEA-based carbon capture is the focus of this report, it is only one of a host of current and emerging technologies for extracting carbon from a source. Below is a brief overview of several capture technologies, organized according to the mechanism of capture documented in Table 1. Note that this is not a detailed assessment of each technology and its benefits and drawbacks.

- **Absorption**: Carbon capture through absorption is the general process of removing CO_2 via physical or chemical methods. In the latter, combined solvents are utilized, and these can include, but are not limited to, MEA, aqueous ammonia, and dual alkali. Carbon capture through absorption methods has been explored due to high processing capacity, adaptability, and reliability. [11]
    - **Chemical**: Carbon capture via chemical absorption is a method used to remove CO_2 from a range of gas streams. It utilizes a liquid solvent which selectively dissolves and absorbs CO_2 from the gas mixture, leaving the other gasses in the mixture behind. It is then transferred to a unit where the solvent is heated, and the CO_2 is released for compression and storage or utilization. After the CO_2 is collected, the solvent is regenerated and can be used again. Many different solvents have been tested and used in this process, with various results [11].
        - **MEA**: Monoethanolamine is a versatile compound which plays a crucial role in a number of industrial processes. It is a widely used solvent, able to dissolve both polar and non-polar substances. Its chemical structure contains the properties of amines and alcohols, lending to its versatility. It is utilized in cosmetics and pharmaceuticals, cleaning products, natural gas purification, and CO_2 capture. [59]. It has been highlighted as one of the key solvents used for chemical absorption of CO_2 and was selected as the reference case for the modelling in the report.
        - **Aqueous ammonia:** In recent years, aqueous ammonia has emerged as a promising solvent for carbon capture from industrial emissions. It has a high CO_2 loading capacity, low cost, and is resistant to degradation. It does, however, have a slow absorption rate, limiting its current industrial application, and efforts are ongoing to improve this absorption rate to allow for greater industrial utilization.

It can remove multiple pollutants at once, including carbon-based, nitrogen-based, and sulfur-based pollutants. Experiments have shown that optimized aqueous ammonia could have a removal efficiency of up to 98.4%, which would improve on current commercial efficiencies [60].

- **Dual alkali:** This approach to carbon capture is built upon the Solvay process, in which two alkalis are used sequentially to convert CO_2 into sodium carbonate. The dual alkali approach takes this process and builds on it by replacing the original bases with other compounds to improve CO_2 capture. In the original process, ammonia is used to produce the sodium carbonate, and in this process, it is replaced by amines in aqueous solutions of salts, plus a chloride. One of the key benefits of this process is the ability to convert CO_2 to carbonate salts that can be safely returned to the environment. Additionally, it is possible through this process to regenerate ammonia using activated carbon, and that activated carbon can be regenerated by using water to extract hydrochloric acid. [61]

- **Physical**: Physical absorption is a well-established method for isolating CO_2 from other gases at relatively low cost. It is based on Henry's law, which dictates CO_2 solubility into a solution without a chemical reaction. This process is simpler than chemical absorption, requiring only a single gas liquid contactor plus flash tanks to regenerate the solvent. It is operated at high pressure and low temperature to optimize CO_2 solubility [62]. Since physical absorption is most effective at high CO_2 partial pressures, the capture process is less efficient for low-concentration sources such as flue gas, and it has higher energy requirements to maintain the operational pressure and temperature of the process compared to chemical absorption.

- **Adsorption**: Adsorption is the process of separating and concentrating CO_2 from gas inputs using solid adsorbents that have a particularly high affinity for CO_2. These CO_2 molecules adhere to the solid surface, removing them from the gas mixture. Some of the most used adsorbents are alumina, zeolites, and activated carbon. [11]
  - **Adsorber Beds**: Adsorption beds are systems where a fluid containing contaminants passes through a packed column filled with adsorbent materials. These materials capture impurities through physical or chemical interactions, purifying the fluid. Due to its low cost and efficiency, this method is widely used in water treatment, air purification, and industrial processes to remove unwanted substances. For carbon capture specifically, adsorption beds can utilize alumina-based, zeolite-based, or activated carbon-based adsorption, which possess high surface areas and porosity, allowing them to trap CO_2 molecules through either physical adsorption (physisorption) or chemical adsorption (chemisorption) [63].
    - **Alumina**: Alumina based adsorption uses activated alumina (Al_2O_3) as the main component in the adsorber bed. Activated alumina may be chosen due to its high porosity and its ability to operate in and withstand high temperatures, fitting for a number of industrial applications. In comparison to other adsorbents, alumina is particularly well suited for removing contaminants that are polar in nature [64].
    - **Zeolite**: Zeolite-based adsorption utilizes inorganic polymers (crystalline

aluminosilicates) and the mechanism of molecular sieving to differentiate molecules based on their physical size, allowing molecules smaller than their pores to be adsorbed while larger molecules are excluded. It is utilized in both CO_2 capture and hydrogen purification with high selectivity for both [65].

- **Activated Carbon**: Activated carbon has a very high surface area to volume ratio, lending to its adsorption capabilities. While being less selective for CO_2 than zeolite-based or alumina-based adsorption, it is still commonly used for water and air purification, solvent recovery, and other broad-spectrum adsorptions [66].

- **Regeneration**: Following their use in adsorption separation, adsorbents need to be recharged for reuse. There are a number of methods used to regenerate adsorbents, including pressure swing, thermal/temperature swing, and electrical swing washing regeneration.
  - **Pressure swing**: During pressure swing adsorption, the process operates at an ambient, stable temperature while the pressure is being manipulated. During the adsorption phase of the process, the pressure is increased and compounds with a higher affinity for the particular adsorbent material are adsorbed onto its surface. During the regeneration phase, the pressure is reduced to atmospheric levels, causing the adsorbed gases to desorb, allowing them to be collected. This leaves a regenerated adsorbent bed to be reused. This process is highly energy efficient, as it utilizes ambient temperatures with little to no heating involved. It is also time efficient and can run multiple cycles within minutes [67].
  - **Temperature swing**: In contrast to pressure swing adsorption, temperature swing adsorption involves manipulating the temperature of the process. In the first phase, the temperature of the flue gas is decreased before it passes through the absorbent bed. The adsorbent captures the target molecules from the gas, allowing the other molecules to pass through. In the regenerative phase, the temperature of the adsorbent bed is increased, lowering the affinity of the adsorbent for the target molecules, and they desorb and are collected. The adsorbent bed is then cooled for reuse. Temperature swing is often used with adsorbates that have high adsorption enthalpies, such as activated alumina. However, is more energy demanding than a pressure swing method. [68]
  - **Electrical swing**: In electrical swing adsorption, the gas mixture passes through the adsorbent bed at ambient or low temperatures where the species of interest are captured. During the regeneration phase, an electrical current is applied to the adsorbent bed, causing a rapid increase in temperature, in turn causing desorption of the target molecules. The bed is then cooled for reuse. This can be a more energy efficient alternative to temperature swing adsorption, as only the adsorbent beds are heated, because the input gas is kept at a lower temperature.

- **Membranes:** Membrane capture involves the use of a selectively permeable membrane to separate CO_2 from a gas mixture. The membranes are typically constructed of either polymeric or ceramic materials. The three steps of membrane capture include CO_2 adsorption to the high-pressure side of the membrane, diffusion through the membrane, and CO_2 desorption to the membrane's low-pressure side [11].

  - **Ceramic based membranes:** An emerging method of CO_2 capture is the use of ceramic membranes. They are being explored due to their high thermal stability and both chemical and mechanical resilience. Ceramic membranes may be applicable in situations that are high-temperature and high-pressure in the place of a polymeric membrane which would normally fail under these conditions [69]. Ceramic membranes may also improve water recovery from the flue gas [30, 70]. Development of the technology is continuing to address challenges related to cost and brittleness.

- **Cryogenics:** Cryogenic separation utilizes differing boiling points of gases in a mixture, cooling the mixture to a very low temperature where CO_2 becomes solid and can be isolated. It is then reheated to its gaseous form once collected. This process can energy intensive, although it can yield high purity CO_2 which can be required in some utilization scenarios. Additionally, this process does not require any chemical reagents [11].
- **Microbial/algal**: CO_2 capture utilizing microalgae leverages photosynthesis to remove CO_2 from air and produce biomass. The biomass can in turn be used in applications such as biodiesel and fertilizer. This process is in the early stages of development [11].
- **Chemical looping**: Chemical looping is a type of combustion that uses an oxygen carrier species, typically a metal oxide, to efficiently burn hydrocarbon fuels, producing a highly concentrated carbon dioxide stream [15].

As discussed in Table 1, carbon capture can also be classified by the relative location of the CO_2 capture unit.

- **Post-combustion**: Post-combustion methods include absorption, membrane separation, and adsorption, described earlier in the appendix [71].
  - **Bioenergy with carbon capture and storage (BECCS):** BECCS is a type of post-combustion. Similarly to microbial/algal carbon capture, BECCS involves the removal of CO_2 from the atmosphere using the growth of biomass. The biomass is then used as a fuel source, paired with post-combustion carbon capture. There is no single definition for BECCS as it includes a variety of industries, biomass feedstocks, and methods of energy conversion.
  - The overall BECCS process is divided into a few key steps:
    1. Biomass feedstock draws CO_2 from the atmosphere through photosynthesis.
    2. Biomass is transported to the end-user and combusted for energy or transformed to biofuel through fermentation.
    3. The CO_2 which is produced is then captured through one the mechanisms discussed earlier in the appendix [10].
- **Pre-combustion**: Pre-combustion is a technique where fuel is mixed with air, oxygen, or steam to produce CO and H_2. From this, the CO is reacted with steam to produce CO_2, which is then separated by either chemical or physical absorption that can produce fuel to be utilized in other industrial processes [71].
- **Oxy-combustion**: Oxy-combustion is the process in which fuel is combusted in an atmosphere comprised of oxygen and recycled CO_2 or steam to produce a CO_2 and water rich stream. The CO_2 is

then separated via condensation [71].

- **Direct air capture (DAC):** DAC is defined as the capture of CO_2 directly from the atmosphere. A typical DAC process usually has an air contacting medium containing a sorbent absorption or adsorption and a regeneration segment [72].

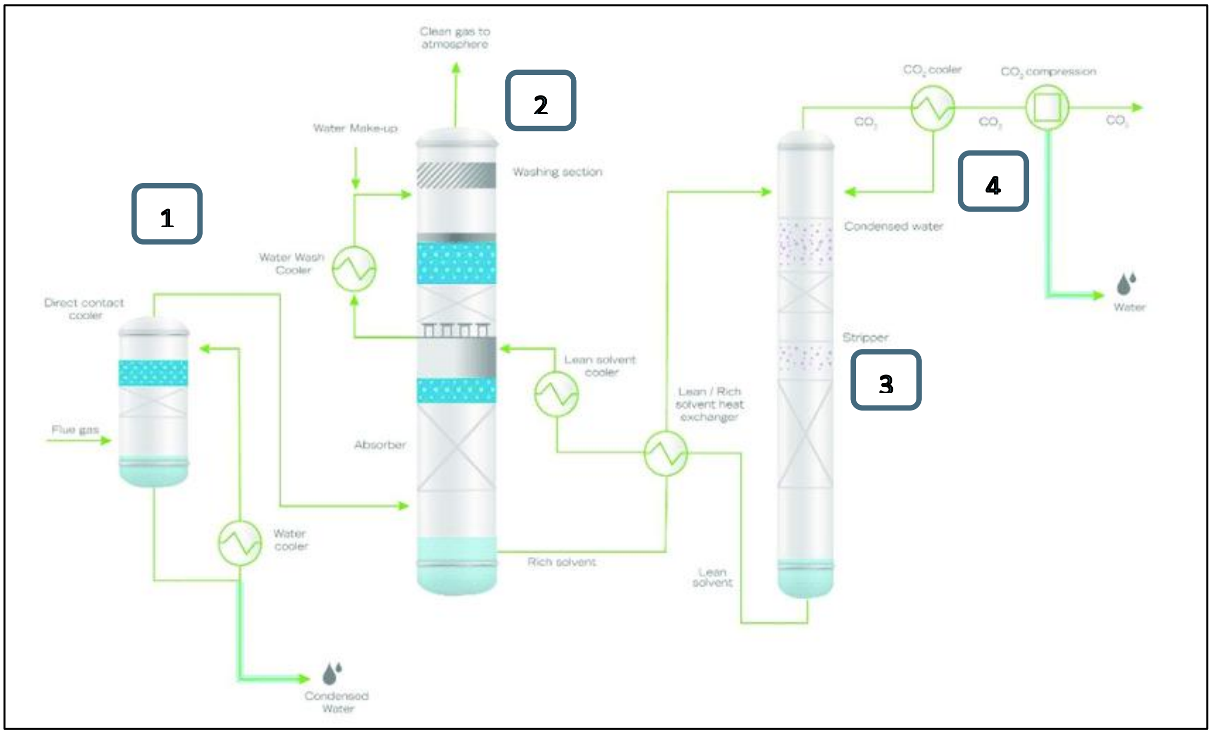
Examples of CCUS in North America:

- **Carbon capture by adsorption: Cvictus Tech – Low carbon syngas (EHR).**
  - Enhanced Hydrogen Recovery™ (EHR™) is Cv̄ictus's patented technology that produces syngas (H_2 and CO) which can then be reused for other industrial purposes. Additionally, by extracting hydrogen from coal, enough space is created to sequester all the CO_2 from the process and additional CO_2 from other sources [73].
- **Carbon capture by oxy-fuel combustion: Innova Hydrogen Pyrolysis Oxyfuel CCS.**
  - Innova Hydrogen is a Canadian startup developing a carbon-free hydrogen technology [74]. This is done via methane thermal pyrolysis, where thermal energy is applied to methane (CH_4) to break apart the bonded carbon and hydrogen. The carbon is removed and recovered as a solid, while the hydrogen can be used as an energy source [75].
- **Bioenergy with carbon capture and storage: Hinton Bioenergy Carbon Capture and Sequestration (BECCS) project.**
  - The Hinton BECCS project, led by Vault 44.01 in collaboration TorchLight Resources and West Fraser, aims to capture and store 1.3 million tonnes of biogenic CO_2 annually using an amine absorption system at West Fraser's Hinton Pulp Mill [76].
- **Carbon capture by MEA absorption: Alberta Carbon Conversion Technology Centre (ACCTC).**
  - The ACCTC is a facility built to research and validate prototypes for carbon capture, located next to the Shepard Energy Centre in Calgary, Alberta. The MEA-based carbon capture facility is capable of treating up to 25 tonnes of flue gas from the Shepard Energy Centre per day, to produce up to 6 tonnes of CO_2 per day [77].
- **DAC: Deep Sky Labs – Canadian carbon removal project.**
  - The Deep Sky Labs Canadian carbon removal project in Innisfail, Alberta, is a proposed facility to pilot 10 different DAC technologies to validate their operational efficiency in Canada before commercial deployment. It will have the capacity to capture up to 3,000 tonnes of CO_2 per year, with room for future expansion [78].

A2 - Estimation of water demands for MEA-based carbon capture

The calculation of the water demands in MEA-based carbon capture processes involves several key parameters and assumptions, as detailed in Section 2.2 of the report. This appendix further details on the data which was used in the HMB for this report, and provides a sample calculation for the net, per-unit water demands associated with biomass flue gas.

Per Figure 2, reproduced below, the flue gas enters the carbon capture system via a direct contact cooler (Step 1). Subsequently, the flue gas is directed to an MEA absorption column (Step 2) and then the CO_2-rich amine solvent is then subjected to regeneration using steam-sourced heat, releasing the captured CO_2 (Step 3). The released CO_2 is then cooled and compressed before being conveyed to its destination (Step 4).



Data collection

Data values and ranges for the following parameters were gathered from publicly available sources, available literature, and collaborating partners [20, 21, 22, 23, 24]:

- Flue gas water recovery and reuse factor (80%).
- Composition of different types of flue gas, in % by volume/mole and % by mass (See Table A-1 and A-2).

Table A - 1. Flue gas compositions by volume/mole.

Component	Source of flue gas				
	NGCC power generation (% vol)	Cement manufacturing (% vol)	Biomass combustion - Spruce chips (% vol)	Hydrogen/ ammonia production (% vol)	Oil sands (% vol)
CO_2	5.5%	17.8%	12.0%	60.0%	8.6%
O_2	11.0%	7.5%	8.2%	4.0%	2.6%
H_2O	8.2%	18.2%	28.3%	10.0%	16.3%
N_2	75.3%	56.5%	51.5%	26.0%	72.5%

Table A - 2. Flue gas compositions by mass.

Component	Source of flue gas				
	NGCC power generation (% mass)	Cement manufacturing (% mass)	Biomass combustion - Spruce chips (% mass)	Hydrogen/ ammonia production (% mass)	Oil sands (% mass)
CO_2	8.5%	26.7%	19.2%	71.8%	13.6%
O_2	12.4%	8.2%	9.6%	3.5%	3.0%
H_2O	5.2%	11.2%	18.6%	4.9%	10.5%
N_2	73.9%	53.9%	52.7%	19.8%	72.9%

- Total CO_2 capture efficiency factor by MEA (90%).
- Temperature at different steps of the CO_2 capture process.
    - Flue gas before Step 1: T = 140°C
    - Flue gas after Step 1: T = 37°C.
    - MEA solvent temperature in Step 2: T = 37°C.
    - MEA solvent temperature in Step 3: T = 130°C.

Constants and engineering empirical guidelines used in the modelling were determined from literature review. These include [79, 29, 28, 80, 81, 82, 83]:

- Constant – Specific heat and enthalpy of each compound present in the flue gas.
- Constant – Specific heat and enthalpy of saturated steam at P = 3 bar.
- Constant – Average specific heat of aqueous MEA at T = 80°C (average between 37 and 130°C).

- $Cp_{MEA,l}$ at 80°C = 2,979 J/kgK.
- $Cp_{water,l}$ at 80°C = 4,184 J/kgK.
- $Cp_{,30\% \ MEA \ mixture,l}$ at 80°C = 3,822.5 J/kgK.

- Constant - CO_2 absorption capacity of MEA for a 30 %w/w aqueous concentration (i.e., 480 g CO_2 /kg MEA).
- Empirical guideline - NGCC new power generation consumptive water use.
- Empirical guideline - Evaporative cooling losses factor (cooling tower).

To perform a high-level analysis of the consumptive water demands of carbon capture, several assumptions were required to simplify complex variables. These include:

- Inlet and outlet temperature of direct contact cooler water in Step 1 (Ti = 10°C, Tf = 30°C).
- Steam and aqueous amine solvent purge rate in Step 3 (i.e., 3%).
    - Typical values for steam purge rate range between 2 and 3%.
    - The aqueous amine solvent is subject to thermal and oxidative degradation. 3% was selected as a conservative estimate.
- Negligible water demands for the compression of the CO_2 stream.
- Heat exchange efficiency of the steam boiler and power generation (75%).

Step-by-step example: Low Water Use for Biomass Combustion Flue Gas

The methodology described in this subsection outlines the approach used to estimate the Low water use scenario for the biomass combustion flue gas category (i.e., -0.79 m^3/tCO_2), for all stages of the MEA-based carbon capture process. As stated in the report, Low water use assumes existing power generation, 90% CO_2 capture (absorption) efficiency, 80% water recovery and reuse from the flue gas, and air-cooling (i.e., no evaporative water losses).

Heat and Mass balance

MEA aqueous solvent regeneration and steam generation requirements

1. The HMB was set to a fixed CO_2 capture target of 100 tCO_2/day (1.157 kg/s). This was used as a reference to estimate the consumptive water demands per tonne of CO_2.

As stated in section: Data collection	
MEA concentration in aqueous solution (kg/kg)	**Mass of CO_2 captured per unit mass of amine solvent (kg/kg)**
0.3	0.48

2. The mass flow rate of water and MEA required for the aqueous solvent mixture were based on the target CO_2 capture rate and the MEA concentration, as shown:

$$Total\ Mass\ Flow\ of\ MEA\ in\ the\ Aqueous\ Solvent\ Mixture = \frac{1.157\ kg\frac{CO_2}{s}\left(0.3\ kg\frac{MEA}{H_2O}\right)}{0.48\ kg\frac{CO_2}{Aqueous\ MEA}(90\%\ Absorption\ Efficiency)} = 0.8\frac{kg\ MEA}{s}$$

$$Total\ Mass\ of\ Water\ in\ the\ Aqueous\ Solvent\ Mixture = \frac{0.8\frac{kg}{s}MEA}{0.3\ kg\frac{MEA}{H_2O}}(1-0.3) = 1.9\frac{kg}{s} + \ 0.8\frac{kg}{s}$$

$$= 2.7\frac{kg}{s}\ Aqueous\ Solvent\ Total\ Mass\ of\ the\ Aqueous\ Solvent\ Mixture = 1.9\frac{kg\ H_2O}{s}$$

3. The consumptive water demand for the aqueous solvent mixture was then estimated based on the 3% purge rate noted above.

$$Aqueous\ Solvent\ Mixture\ Water\ Purge\ = 1.9\frac{kg}{s}\ H_2O\ (3\%\ Purge) = 0.056\frac{kg\ H_2O}{s}purge\ \text{(Consumptive Water Demand)}$$

4. The steam requirements for the solvent regeneration were estimated based on the mass flow rate of the aqueous solvent mixture.

$$Minimum\ Heat\ Required\ for\ the\ Regeneration\ of\ the\ Aqueous\ Solvent\ Mixture = \left(2.7\frac{kg}{s}\ Aqueous\ Solvent\right) * 3{,}822.5\frac{J}{kg°C} * (130-37°C) = 952{,}430\ J/s$$

$$\dot{Q} = \dot{m}_{\text{amine}} \cdot C_p(\text{amine mixture}) \cdot (T_{\text{fin}} - T_{\text{init}}) - T_{\text{init}})$$

As stated in section: Data collection

Minimum Heat required for regen (J/s)	3% amine solvent purge (kg/s)	Amine in solvent stream (kg/s)	Water in amine solvent stream	Cp of amine mixture (J/kg*K)	Final temperature amine solvent (°C)	Initial temperature amine solvent (°C)
952,430	0.056	0.8	1.9	3822.5	37	130

Consumptive Water for steam cycle (m^3/tCO_2) - Without New Power	Heat provided by steam boiler (J/s)	$\dot{Q} = \dot{m}_{\text{steam}}(h_g - h_l)$ Steam mass flow rate (kg/s)	Water for steam cycle (kg/s) 3% purge	Heat exhanger efficiency η	Enthalpy, h_g (3bar) J/kg	Enthalpy, h_l (3bar) J/kg
0.064	1,269,906	0.587	0.018	75%	2,724,660	561,440

$$Heat\ Required\ for\ the\ Regeneration\ of\ the\ Aqueous\ Solvent\ Mixture, provided\ by\ saturated\ steam, 3\ bar\ = \frac{952{,}430\,\frac{J}{s}}{75\%\ (heat\ exchange\ efficiency)} = 1{,}269{,}906\ J/s$$

$$Saturated\ Steam\ Flow, 3\ bar = \frac{1{,}269{,}906\frac{J}{s}}{\left(2{,}724{,}660\frac{J}{kg\ H_2O} - 561{,}440\frac{J}{kg\ H_2O}\right)} = 0.587\,\frac{kg\ H_2O}{s}$$

5. The consumptive water demand for the steam stream was based on the 3% purge noted above.

$$Saturated\ steam\ purge = 0.587\,\frac{kg}{s}\,(3\%\ Purge) = 0.018\,\frac{kg\ H_2O}{s}\,purge\ \text{(Consumptive Water Demand)}$$

6. The total consumptive water requirements for this step are then aggregated and converted to the reference units (i.e., $m^3\ H_2O/tCO_2$). Note that since the Low water use scenario assumes air cooling, the consumptive water demands for cooling are considered negligible.

$$Consumptive\ water\ demand\ for\ purge\ streams\ = \frac{(0.018 + 0.056)\,\frac{kg\ H_2O}{s}}{1.157\ kg\,\frac{CO_2}{s}} = \frac{(0.074)\,\frac{kg\ H_2O}{s}}{1.157\ kg\,\frac{CO_2}{s}} = 0.064\ kg\,\frac{H_2O}{CO_2} = 0.064\,\frac{m^3 H_2O}{tCO_2}$$

Flue gas cooling and product stream water recovery

1. The mass flow rate of the input flue gas to the CCUS process was calculated based on the average composition of the biomass combustion flue gas and the overall efficiency of the carbon capture process.

$$Total\ Mass\ of\ Input\ Flue\ Gas = \frac{1.157\frac{kg}{s}CO_2\ \ (Capture\ target)}{(90\%\ Capture\ efficiency)(19.2\%\ CO_2 in\ Flue\ Gas)} = 6.69\frac{kg}{s}of\ Flue\ Gas$$

	CO_2		
Total Mass Flow of Flue Gas (kg/s)	Total Mass Flow Rate of CO_2 captured (kg/s)	Total Mass Flow Rate of CO_2 not captured (kg/s)	Percentage by Mass of CO_2 in the Flue Gas (%)
6.69	1.157	0.13	19.2%

2. The mass flow rate of the water in the flue gas was estimated based on the average composition of the biomass combustion flue gas. Note that based on the assumptions, established above, the Low use scenario assumes that 80% of this water is recovered for use (see #4 below).

ass Flow Rate (kg/s)	Flue Gas Mass Flow Rate (kg/s)	Total water content in flue gas (usable and non usable) [kg/s]	Direct contact cooler heat removed (J/s)	Water necessary to remove heat (kg/s)	Evaporative cooling loss to cool down water (kg/s)	Net Consumptive Water Demands (kg/s)	Total Usable Recovered Water (kg/s)
1.29	6.69	1.242	- 1,091,015	13.0	0.00	0.00	0.99

$$Total\ Water\ Contentn\ the\ Flue\ Gas =\ 6.69\frac{kg}{s}Flue\ Gas *\ (18.6\%\ Water\ by\ Mass) = 1.24\frac{kg}{s}H_2O$$

3. The average specific heat capacity at a constant pressure for the flue gas was estimated using a weighted average (mass percentage), along with the heat removed from the flue gas using the direct contact cooler.

Biomass Combustion	
Spruce Chips Flue Gas	**Cp (J/kgK)**
CO2	849
O2	956
H2O	4184
N2	1049
Weighted Cp	1584

$$Weighted\ Cp = 849\frac{J}{kgK} * (19.2\%) + 956\frac{J}{kgK} * (9.6\%) + 4{,}184\frac{J}{kgK} * (18.6\%) + 1{,}049\frac{J}{kgK} * (52.7\%) = 1{,}584\frac{J}{kgK} = 1{,}584\frac{\mathrm{J}}{\mathrm{kg}}°\mathrm{C}$$

$$Heat\ Removed\ with\ Direct\ Contact\ Cooler = 6.69\frac{kg}{s} of\ Flue\ Gas * 1{,}584\frac{J}{kg°C} * (140 - 37)°C = -1{,}091{,}015\ J/s$$

4. The water required for decreasing the temperature of the flue gas with the Direct Contact Cooler was estimated. Note that since the process is air-cooled, the consumptive water demands associated with this cooling load of the direct contact cooler are assumed to be negligible.

$$Direct\ Contact\ Cooler\ Water\ Mass\ Flow\ Required = \frac{-1{,}091{,}015\frac{J}{s}}{4{,}184\frac{J}{kg°C} * (10 - 30)°C} = 13.0\frac{kg}{s}H_2O$$

$$Consumptive\ Water\ Requirement\ for\ Flue\ Gas\ Cooling = 0\ \frac{kg}{s}H_2O\ (Air\ cooled\ system) = 0\ \frac{m^3H_2O}{tCO_2}$$

5. The Low water use scenario was assumed to recover 80% of the condensed water of the flue gas to use in-process, thus the total consumptive water demands for the process are calculated as:

Demands Summary	Net consumptive water (m^3/tCO_2)
Biomass - Spruce chips	-0.79

$$Total\ Usable\ Water\ with\ 80\%\ use\ factor = \frac{1.24\frac{kg}{s}H_2O*80\%\ use\ factor}{1.157\frac{kg}{s}captured\ CO_2} == \frac{0.99\frac{kg}{s}H_2O}{1.157\frac{kg}{s}captured\ CO_2} = 0.86\ kg\frac{kg\ H_2O}{kg\ CO_2} = 0.86\ \frac{m^3H_2O}{tCO_2}$$

$$Net\ Water\ Balance\ = 0.064\ \frac{m^3H_2O}{tCO_2}(Consumptive\ water\ demands\ in\ all\ stages) - \ 0.86\ \frac{m^3H_2O}{tCO_2}\ (Water\ recovered\ in\ all\ stages) = -0.79\ \frac{m^3H_2O}{tCO_2}$$

A3 - Sensitivity analysis

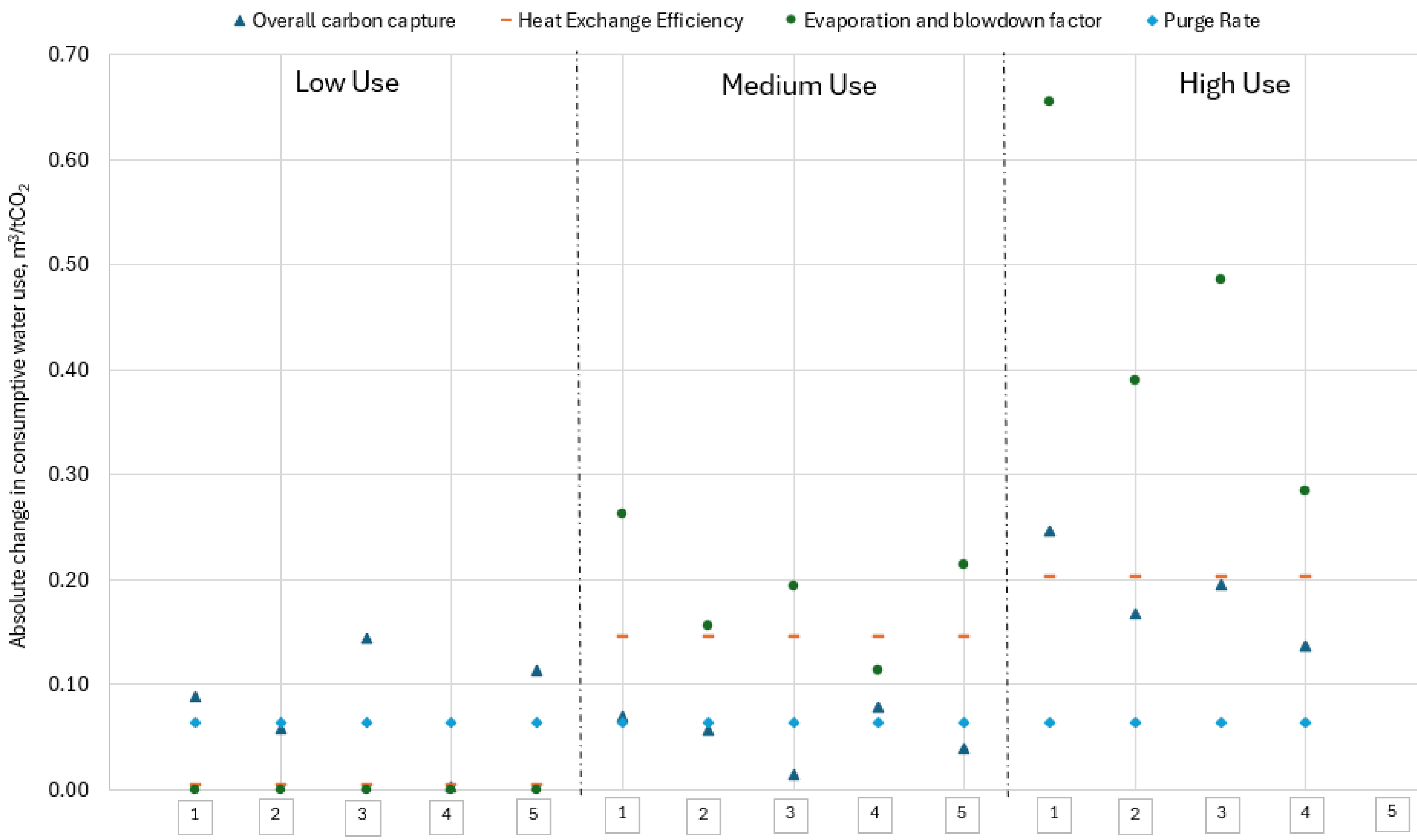
As noted in the body of the report, there are several key parameters which have a significant influence on the results (i.e., net, per-unit water demands). This appendix explores the influence of several impactful parameters to illustrate both the sensitivity of the HMB to change and to illustrate how design choices can be expected to impact the outcomes of future projects. These parameters, which were tested at typical operational ranges (based on input from industry and project partners) include:

- MEA-capture efficiency: Between 80 and 95%, based on industrial MEA-based carbon capture typical efficiency.
- Heat exchanger efficiency: Between 70 and 90%.
  - This heat exchange efficiency variance acknowledges that not all the thermal energy contained by the heating streams for amine regeneration and power generation is transferred between different media.
- Evaporative cooling and blowdown factor: Between 0.7 and 1.3%.
  - This empirical evaporative cooling and blowdown factor is highly dependent on the ambient temperature and type of cooling technology used on-site.
- Steam and MEA solvent purge rates: Between 2 and 5%.
  - As discussed in *Appendix A2 - Estimation of water demands for MEA-based carbon capture,* this range is facility-dependent.

In the sensitivity analysis plot below, the vertical axis represents the magnitude of the absolute change of the net, per-unit water demands of each type of flue gas (m^3/tCO2), for the Low, Medium and High use scenarios. The horizontal axis labels the type of flue gas as follows:

1. NGCC power generation.
2. Cement manufacturing.
3. Biomass combustion (spruce chips).
4. Hydrogen/ammonia production (ATR).
5. Oil sands.

Based on the scope of this report, the sensitivity analysis does not account for correlation and interaction between variables, which may be considerable. The MEA-based carbon capture system is most sensitive to variations in the evaporation cooling and blowdown factor, followed by the heat exchange efficiency factor in the Medium and High use scenarios, regardless of the flue gas source. Notably, changes in the heat exchanger efficiency and evaporative cooling and blowdown factors do not impact the Low use scenario due to assumptions of off-site (existing) power generation and air-cooling. The purge rate consistently affects the consumptive water demands across all use scenarios. Based on this analysis, the most effective strategies to decrease net, per-unit water demands in MEA-based carbon capture systems are to implement alternative cooling methods distinct from evaporative cooling (e.g., air cooling) and to optimize the overall system efficiency (capture and heat).



1. NGCC power generation.
2. Cement manufacturing.
3. Biomass combustion (spruce chips).
4. Hydrogen/ammonia production (ATR).
5. Oil sands.

Appendix B Carbon Capture, Utilization, and Storage Project Details

This appendix summarizes all the projects included in this study, in alphabetical order. As noted throughout the report, the analysis focused on projects representing the carbon capture capacity in Alberta with a 2050 horizon. For all the projects, water demand estimates were based on the water use ranges presented in Section 2.2 and the target capture or sequestration rate for each project[5].

The assumptions required to overcome limitations in publicly available data include:

- The reported maximum annual storage capacity for CCUS hubs is assumed to match the CO_2 capture rate at the same location.
  - For certain CCUS hubs, while their planned capacity is known, the specific projects and facilities that will link to them remain unidentified. The unaccounted capture for CCUS Hubs (Projects #34-37) represents the gap between the hubs' nominal capture capacity and the capture rate of the facilities that have confirmed their connection to the hub.
- For projects that do not specify the industry connecting to a carbon capture facility or hub, it is assumed that the flue gas is from NGCC power generation. This reflects that many planned projects are considering new on-site power generation to operate the carbon capture process, and NGCC is a common option in Alberta.
- For some projects, a CO_2 capture target has not been announced, but the power generation capacity or production rate of hydrogen and ammonia is known (e.g., Edmonton Varme Facility). For projects like this, the production rate is estimated to be similar to other comparable projects.

[5] Although water use for individual projects will differ from the specific scenario estimates in this appendix due to unique operational variables like flue gas composition, process temperature and pressure, overall carbon capture rate, alternative cooling technology, and in some instances, non-MEA based carbon capture, water use is likely to be within the Low to High range.

Legend: Blue = Estimated CO_2 capture rate based on comparable projects. **Bold water use estimate** = Net water production

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
1	Athabasca Leismer project (ALB)	Athabasca	Athabasca	Entropy Inc, Athabasca Oil Corporation	-	NGCC Power Gen.	440,000	**-211,916**	172,009	610,607
2	Bow River Carbon Hub	South Saskatchewan	Bow	Inter Pipeline Ltd. and Entropy Inc.	Bow River Carbon Hub	NGCC Power Gen.	5,000,000	**-2,408,136**	1,954,649	6,938,719
3	Brazeau Carbon Sequestration Hub	Athabasca	Pembina	Tidewater Midstream & Infrastructure Ltd	Brazeau Carbon Sequestration Hub	NGCC Power Gen.	31,000	**-14,930**	12,119	43,020
4	CCUS hub at Strathcona Resources Cold Lake Lindbergh, Orion, and Tucker SAGD facilities (x 3 projects) (ALB)	Beaver	Beaver	Strathcona Resources Ltd.	-	NGCC Power Gen.	2,200,000	**-1,059,580**	860,045	3,053,036
5	Chigwell	South Saskatchewan	Red Deer	Alphabow	-	Hydrogen/ Ammonia	60,000	193	26,753	46,054
6	Deep Sky's new centre in Innisfail	South Saskatchewan	Red Deer	Deep Sky Labs	-	NGCC Power Gen.	3,000	**-1,445**	1,173	4,163

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
7	Dow Fort Saskatchewan Path2Zero (ALB)	North Saskatchewan	North Saskatchewan	Dow Chemical, Linde, Fluor, Wolf Midstream	Alberta Carbon TrunkLine (ACTL)	Hydrogen/ Ammonia	1,000,000	3,221	445,887	767,562
8	East Calgary Region Carbon Sequestration Hub	South Saskatchewan	Bow	Reconciliation Energy Transition Inc. (RETI), Sumitomo	East Calgary Region Carbon Sequestration Hub	NGCC Power Gen.	7,500,000	**-3,612,204**	2,931,973	10,408,078
9	Edmonton Blue Hydrogen plant (ALB)	North Saskatchewan	North Saskatchewan	Mitsubishi Corporation, Shell Canada	Atlas Carbon Sequestration Hub	Hydrogen/ Ammonia	3,630,000	11,693	1,618,572	2,786,251
10	Edmonton Varme facility	North Saskatchewan	North Saskatchewan	Varme Energy, City of Edmonton	-	Biomass Combustion	128,250	**-101,876**	10,518	141,599
11	Elmworth Gas Plant	Peace	Wapiti	Cenovus	-	NGCC Power Gen.	183,330	**-88,297**	71,669	254,415
12	Exshaw Cement Carbon Capture	South Saskatchewan	Bow	Lafarge Canada (Holcim group)	-	Cement Manuf.	1,000,000	**-307,981**	321,828	943,668
13	Glacier Gas Plant CCS full capacity (ALB)	Peace	Peace	Entropy Inc. ABC Engineering, University of Regina	-	NGCC Power Gen.	200,000	**-96,325**	78,186	277,549

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
14	Grande Prairie Net Zero Gateway	Peace	Peace	NorthRiver Midstream Inc., Keyera Corp., and Entropy Inc.	Grande Prairie Net Zero Gateway	NGCC Power Gen.	3,300,000	**-1,589,370**	1,290,068	4,579,554
15	Greenview Region CCS Project	Peace	Smoky	ARC Resources Ltd.	Greenview Region CCS Project	NGCC Power Gen.	500,000	**-240,814**	195,465	693,872
16	Hays	South Saskatchewan	Bow	CNRL	-	NGCC Power Gen.	16,000	**-7,706**	6,255	22,204
17	Heartland hydrogen hub	North Saskatchewan	North Saskatchewan	Suncor, ATCO	Atlas Carbon Sequestration Hub	NGCC Power Gen.	2,000,000	**-963,254**	781,859	2,775,487
18	Hinton Bioenergy Carbon Capture and Storage Project	Athabasca	Athabasca	Vault 44.01	Rocky Mountain Carbon Vault	Biomass Combustion	1,300,000	**-1,032,661**	106,617	1,435,316
19	Horizon mine tailings	Athabasca	Athabasca	Canadian Natural Resources Ltd	-	NGCC Power Gen.	400,000	**-192,651**	156,372	555,097
20	Innovative Integration of Carbon Capture for Clean Power (ALB)	North Saskatchewan	Battle	Heartland Generation Ltd	Battle River Carbon Hub	NGCC Power Gen.	5,000,000	**-2,408,136**	1,954,649	6,938,719

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
21	Itochu/Petronas ammonia project (ALB)	North Saskatchewan	North Saskatchewan	Itochu Corporation, Petronas Energy Canada Ltd, and Inter Pipeline Ltd.	-	Hydrogen/ Ammonia	3,494,118	11,255	1,557,983	2,681,953
22	Joffre Pilot Plant	South Saskatchewan	Red Deer	Inventys	-	NGCC Power Gen.	40,000	**-19,265**	15,637	55,510
23	Lamont Carbon Hub (ALB)	North Saskatchewan	North Saskatchewan	Wolf Midstream, Whitecap Resources	Alberta Carbon Trunk Line (Transport), Lamont Carbon Hub (Storage)	NGCC Power Gen.	3,000,000	**-1,444,882**	1,172,789	4,163,231
24	Lehigh Cement Plant	North Saskatchewan	North Saskatchewan	Lehigh Cement Company (Heidelberg)	Open Access Wabamun Carbon Hub	Cement Manuf.	780,000	**-240,225**	251,026	736,061
25	Maskwa Project	Athabasca	Lesser Slave	Kiwetinohk Energy Corp.	Maskwa Project	NGCC Power Gen.	3,022,200	**-1,455,574**	1,181,468	4,194,039
26	Meadowbrook Hub Project	North Saskatchewan	North Saskatchewan	Bison Low Carbon Ventures , Enerflex, PrairieSky Royalty, IRC Enterprises, Marubeni Corporation	Meadowbrook storage hub	NGCC Power Gen.	3,000,000	**-1,444,882**	1,172,789	4,163,231

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
27	Moraine (GE) Power Generation (ALB)	Athabasca	Athabasca	Moraine Initiative Ltd (GE)	Athabasca Banks Carbon Hub	NGCC Power Gen.	100,000	**-48,163**	39,093	138,774
28	Net zero Hydrogen Energy Complex (ALB)	North Saskatchewan	North Saskatchewan	Air Products, Baker Hughes	Alberta Carbon TrunkLine (ACTL)	Hydrogen/ Ammonia	3,000,000	9,664	1,337,662	2,302,687
29	North Drumheller Hub	South Saskatchewan	Red Deer	Bison Low Carbon Ventures Inc.	North Drumheller Hub	NGCC Power Gen.	3,000,000	**-1,444,882**	1,172,789	4,163,231
30	Nutrien Redwater Fertilizer (ALB) phase 1 & 2 Operational	North Saskatchewan	North Saskatchewan	Nutrien (formerly Agrium)	Alberta Carbon Trunk Line (ACTL)/Enhance Clive Sequestration Facility	Hydrogen/ Ammonia	300,000	966	133,766	230,269
31	NWR Sturgeon Refinery (ALB) Operational	North Saskatchewan	North Saskatchewan	Northwest Redwater Partnership, CNRL	Alberta Carbon Trunk Line (ACTL)/Enhance Clive Sequestration Facility	NGCC Power Gen.	1,300,000	**-626,115**	508,209	1,804,067
32	Opal Carbon Hub	Peace	Little Smoky	Kiwetinohk Energy Corp.	Opal Carbon Hub	NGCC Power Gen.	1,000,000	**-481,627**	390,930	1,387,744
33	Origins Project	South Saskatchewan	Red Deer	Enhance Energy Inc.	Origins Project	NGCC Power Gen.	20,000,000	**-9,632,545**	7,818,595	27,754,875

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
34	Outstanding Capture for ACTL (not accounted for in individual projects)	North Saskatchewan	North Saskatchewan	-	Alberta Carbon TrunkLine (ACTL)	NGCC Power Gen.	13,000,000	**-6,261,154**	5,082,087	18,040,669
35	Outstanding Capture for Alberta Carbon Grid	North Saskatchewan	North Saskatchewan	Pembina Pipeline Corporation, TC Energy	Alberta Carbon Grid	NGCC Power Gen.	16,505,882	**-7,949,683**	6,452,640	22,905,935
36	Outstanding Capture for Atlas Carbon Sequestration Hub	North Saskatchewan	North Saskatchewan	Shell Canada Limited, ATCO Energy Solutions, Suncor Energy	Atlas Carbon Sequestration Hub	NGCC Power Gen.	3,620,000	**-1,743,491**	1,415,166	5,023,632
37	Outstanding Capture for Open Access Wabamun	North Saskatchewan	North Saskatchewan	Capital Power & Lehigh Cement	Open Access Wabamun Carbon Hub	NGCC Power Gen.	3,220,000	**-1,550,840**	1,258,794	4,468,535
38	Pathways Alliance (Phases I, II, III)	Beaver	Beaver	Pathways Alliance (CNRL, Cenovus Energy, ConocoPhilips, Imperial, MEG Energy, and Suncor)	Pathways Alliance (T&S)	Oil Sands	8,000,000	**-4,992,209**	1,774,461	1,774,461

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
39	Pathways Alliance (Phases I, II, III)[6]	Athabasca	Athabasca	Pathways Alliance (CNRL, Cenovus Energy, ConocoPhilips, Imperial, MEG Energy, and Suncor)	Pathways Alliance (T&S)	Oil Sands	54,000,000	**-33,697,413**	11,977,610	11,977,610
40	Pembina low carbon complex	North Saskatchewan	North Saskatchewan	Pembina Pipeline Corporation, Marubeni	Alberta Carbon Grid (Phase 1 & 2)	Hydrogen/ Ammonia	3,494,118	11,255	1,557,983	2,681,953
41	Pieridae Caroline Carbon Capture Power Complex Phase 1 (ALB)	South Saskatchewan	Red Deer	Pieridae Energy Ltd.	-	NGCC Power Gen.	1,000,000	**-481,627**	390,930	1,387,744
42	Pieridae Caroline Carbon Capture Power Complex Phase 2 (ALB)	South Saskatchewan	Red Deer	Pieridae Energy Ltd.	-	NGCC Power Gen.	2,000,000	**-963,254**	781,859	2,775,487

[6] The Pathways Alliance Hub assumes 54 $MtCO_2$/yr of capture capacity within the Athabasca River Basin, and 8 $MtCO_2$/yr in the Beaver River Basin.

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
43	Pincher Creek Carbon Sequestration Hub	South Saskatchewan	Oldman	West Lake Energy Corp.	Pincher Creek Carbon Sequestration Hub	NGCC Power Gen.	2,700,000	**-1,300,394**	1,055,510	3,746,908
44	Polaris	North Saskatchewan	North Saskatchewan	Shell Canada	Atlas Carbon Sequestration Hub	NGCC Power Gen.	650,000	**-313,058**	254,104	902,033
45	Project Clear Horizon	South Saskatchewan	South Saskatchewan	City of Medicine Hat	Project Clear Horizon	NGCC Power Gen.	3,000,000	**-1,444,882**	1,172,789	4,163,231
46	Quest	North Saskatchewan	North Saskatchewan	Canadian Natural Resources Limited, Shell, Chevron Canada	-	NGCC Power Gen.	1,100,000	**-529,790**	430,023	1,526,518
47	Ram River Carbon Sequestration Hub	North Saskatchewan	North Saskatchewan	Tidewater Midstream & Infrastructure Ltd.	Ram River Carbon Sequestration Hub	NGCC Power Gen.	550,943	**-265,349**	215,380	764,568
48	Rockpoint and Inter Pipeline Carbon Sequestration Hub	North Saskatchewan	North Saskatchewan	Inter Pipeline and Rockpoint Gas Storage	-	NGCC Power Gen.	6,000,000	**-2,889,763**	2,345,578	8,326,462

#	Name	Watershed	Sub-watershed	Proponents	Carbon hub	Flue Gas Source	CO_2 capture rate (tCO_2/yr)	Water Use Scenario (m^3/year)		
								Low	Medium	High
49	Rolling Hills Carbon Sequestration Hub	South Saskatchewan	Red Deer	AltaGas Ltd. and Whitecap Resources Inc.	Rolling Hills Carbon Sequestration Hub	NGCC Power Gen.	5,000,000	**-2,408,136**	1,954,649	6,938,719
50	Shell Quest Expansion	North Saskatchewan	North Saskatchewan	Shell Canada	-	NGCC Power Gen.	825,000	**-397,342**	322,517	1,144,889
51	Shepard Energy Centre (SEC) (ALB)	South Saskatchewan	Bow	Enmax Energy Corporation	-	NGCC Power Gen.	3,215,650	**-1,548,745**	1,257,093	4,462,498
52	Suncor Edmonton Refinery - Fluid Catalytic Cracker Capture (ALB)[7]	North Saskatchewan	North Saskatchewan	Suncor, Svante	-	NGCC Power Gen.	-	**-**	-	-
53	The Grande Prairie CCS Hub	Peace	Smoky	Enhance Energy Inc.	The Grande Prairie CCS Hub	NGCC Power Gen.	1,000,000	**-481,627**	390,930	1,387,744
54	Tourmaline Clearwater CCUS	Athabasca	Pembina	Tourmaline Oil Corp.	Tourmaline Clearwater CCUS	NGCC Power Gen.	500,000	**-240,814**	195,465	693,872

[7] Unknown project capacity.

Appendix C Assessment of future water availability in Alberta

March 10, 2025

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Assessment of future changes in potential water availability in Alberta

1. Introduction

WaterSMART Solutions Ltd. (WaterSMART) has been engaged, through funding from Alberta Innovates and Emissions Reductions Alberta, to examine the future potential available water for the Carbon, Capture Utilization and Storage (CCUS). MacDonald Hydrology Consultants Ltd. (MacHydro) were retained by WaterSMART to provide guidance on how water availability may change in Alberta in the future from anthropogenic climate change. This memo documents the methods used to estimate potential water availability (precipitation minus potential evapotranspiration) and provides estimates of the projected change under two future climate scenarios relative to historical conditions. Discussion of the context and limitations for these estimates are provided along with an analysis of the potential drivers to future hydrologic change in Alberta and its effects on the timing and magnitude of water availability.

2. Methods

Study Area

This study evaluates the projected change in precipitation, potential evapotranspiration, and water availability across the province of Alberta. The study area encompasses the entire province of Alberta. The province was split into major watersheds and the scale and extent of each basin was provided by WaterSMART. This delineation consists of varying sizes and does not consider upstream areas outside of the province (i.e. the headwaters of the Peace River are in British Columbia).

Hydrological Modelling

The Raven Hydrological Modelling Framework (v3.8; Craig et al., 2020) was used to estimate water availability across Alberta. Raven is a mixed lumped/semi-distributed model that is typically used to simulate state variables and streamflow. Raven allows users to determine the degree of model complexity from lumped (single subbasin models) to semi-distributed (routing). Each watershed is assembled from several subbasins, which are assembled from contiguous or non-contiguous hydrological response units. These are defined as areas that are hydrological unique responses to precipitation events. Each HRU can be defined by elevation, land use type, vegetation cover and terrain type, which is underlain by a soil profile. The model then solves the 1-dimensional water balance problem for each HRU where it can be later redistributed amongst surface water channels if semi-distributed.

Model Setup

Meteorological Forcing Datasets

The model requires spatially distributed daily minimum and maximum air temperature to simulate state variables and fluxes. The forcing dataset used for the historical climate scenario (1980-2024) daily air temperature (maximum and minimum, °C), precipitation (mm/day) and relative humidity were collected from DayMet (Thornton et al., 2018). DayMet points were extracted at a regular grid pattern of approximately 1 degree resolution. While the meteorological forcing dataset used for future climate change (2021-2080) was obtained from Environment and Climate Change Canada (ECCC, 2021) statistically downscaled under Shared Socio-economic Pathways (SSPs). These data collected used the daily median projection from an equal-weighting ensemble forecast of 26 General Circulation Models (GCM) from the Coupled Model Inter-comparison Project Phase 6 (CMIP6) from 2021 – 2080. For this work, two SSP median ensembles were chosen: SSP 2-4.5 which represents a middle-of-the-road pathway of development, and SSP 5-8.5 which represents a scenario with intensified exploitation of fossil fuel resources.

The daily future meteorological variables from ECCC daily median project were first bias-corrected using the simulated future air temperature and precipitation and historical (simulated). Each future month and year were then matched with a proxy month from the historical period. These scaling factors for each month and year (i.e., fractional difference in precipitation and absolute difference in air temperature between the proxy and scenario) were then used to correct the daily observed record for each climate scenario.

Conceptual Overview

The water balance problem is defined by the conservation equation whereby a conservative quantity entering a control volume during a defined period, minus the amount of the quantity leaving the volume during the period, equals the change in the amount of quantity stored in the volume during the time period (Dingman, 2015).

$$dS = Input - Outputs \quad (1)$$

Given the objectives and scope of this study, the hydrological model was set up as a lumped model whereby a water balance is calculated for each basin without surface water redistribution or routing. In this model, we defined the water balance as the annual sum of Inputs (i.e. the amount of water entering; precipitation (*P*) expressed in mm), minus Outputs (i.e. the amount leaving; potential evapotranspiration (*PET*) expressed in mm), is equal to the amount of water storage in each basin (eq. 1).

In this case, we assume the change in storage is negligible dS=0 at an annual timescale. Therefore, the potential available water (*PWA*, mm) can be defined as:

$$PWA = P - PET \quad (2)$$

As a result, estimates of precipitation and potential evapotranspiration are required to determine the potential water availability for each sub-basin and are discussed in the following sections.

Precipitation

Precipitation (rainfall and snowfall) were interpolated directly from the DayMet gauges using the inverse distance weighting interpolation method to generate a gridded product.

Potential Evapotranspiration

Potential Evapotranspiration (PET) was determined using the Priestley and Taylor (1972) relationship, whereby net radiation (calculated via model) derives daily PET, and a correction factor PET is driven by the vapor deficit.

$$PET = 1.26\frac{1}{\rho_w \lambda_v}\left[\frac{\Delta}{\Delta + \gamma} R_n\right] \quad (3)$$

Where R_n is the net radiation. The default scaling factor of 1.26 is used to scale the radiation-driven PET for the vapor deficient driven PET. The saturated vapor pressure is determined by the air temperature:

$$e_s(T) = 0.6108\, exp\, exp\left(\frac{17.23T}{T + 237.3}\right) \quad (4)$$

And the slope of this curve, $\Delta(T) = de_s/dT$,

$$\Delta = \frac{4.98}{T + 273.3} e_s T \quad (5)$$

Where the latent heat of vaporization of water, λ_v, is calculated by:

$$\lambda_v = 2.495 - 0.002361 * T \quad (6)$$

Where T is the temperature and the psychometric constant is λ_v.

Potential Water Availability

The outputs of daily average precipitation, P (mm), and potential evapotranspiration, PET (mm), in each subbasin were summarised each year (mm/year) and averaged across a historical (1991-2020) and two future periods (2021-2050, 2051-2080). Outputs of PET and precipitation were then used to evaluate potential water availability, PWA, which we used as a proxy to assess the state of water in each basin. For each future period, the change in PWA was estimated as the future value relative to the historical (1991-2020) period. When the change in PWA is negative this indicates more water is loss than gained in the basin. The absolute change from the historical scenario in the period (1991-2020) and climate scenario (historical) were then used as a metric to calculate change and project near future and long-term influence of climate change on water availability in the province.

3. Results

Figure 1 shows the absolute change of precipitation to historical driving data which we will refer to as historical conditions. This figure shows that precipitation in northern Alberta is projected to increase under both SSP2-4.5 and SSP5-8.5 climate change scenarios in the near-term and long-term future periods. These trends are amplified near the end of the century under both climate forcing scenarios where they increase 70 mm in the northern basins, particularly the Hay and the Athabasca watersheds. The basins in central and southern Alberta such as the North Saskatchewan River watershed, the subbasins of the South Saskatchewan River Basin (Red Deer, Bow and Oldman) and the Milk River watershed are projected to increase in precipitation albeit lesser than the north with only 20-40 mm increase under both scenarios and in near-term and long-term future periods.

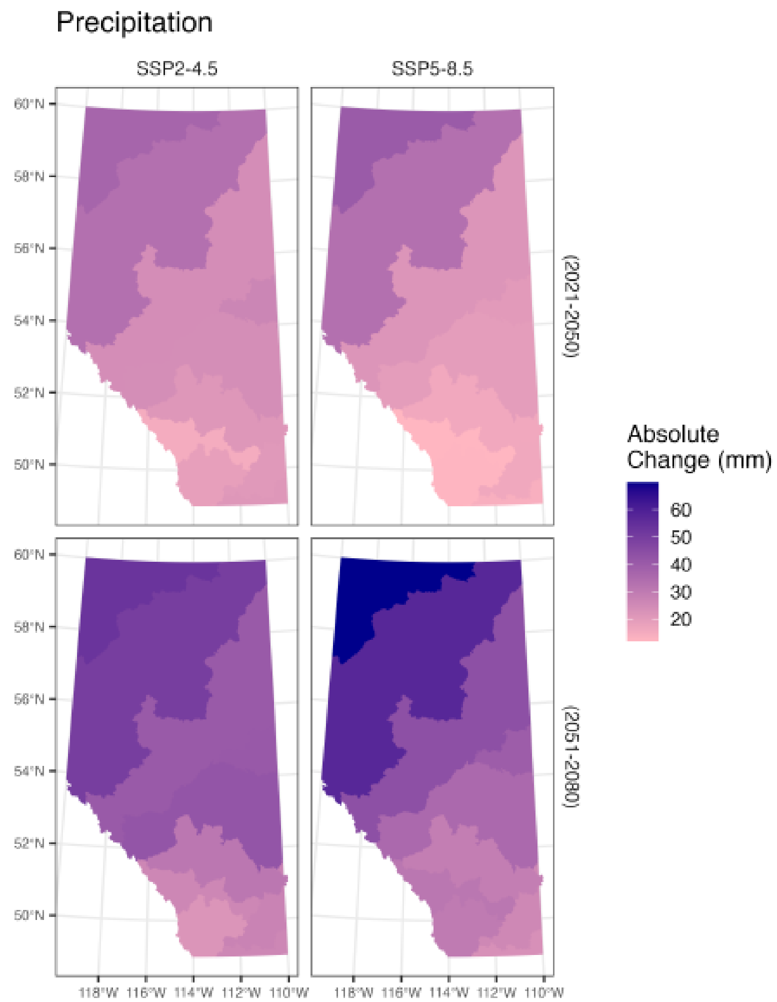

Figure 1: Absolute change of precipitation(mm/year) under future periods (2021-2050 and 2051-2081) under climate change scenarios (SSP2-4.5 and SSP5-8.5) relative to the historical period (1991-2020).

Potential Evapotranspiration

Figure 2 displays the absolute change of PET relative to the historical period. These results show that PET rates are projected to increase across Alberta in the future. The absolute increase in PET over the next 30 years is projected to range from 50 mm to 200 mm. However, in 2051-2080 these relative changes increased from 100 mm to 150 mm across the entire basins. These effects are greater more arid southeasterly basins such as the Milk River Basin and South Saskatchewan River Basins subbasins of the Red Deer Basin, Bow Basin and the Oldman Basin.

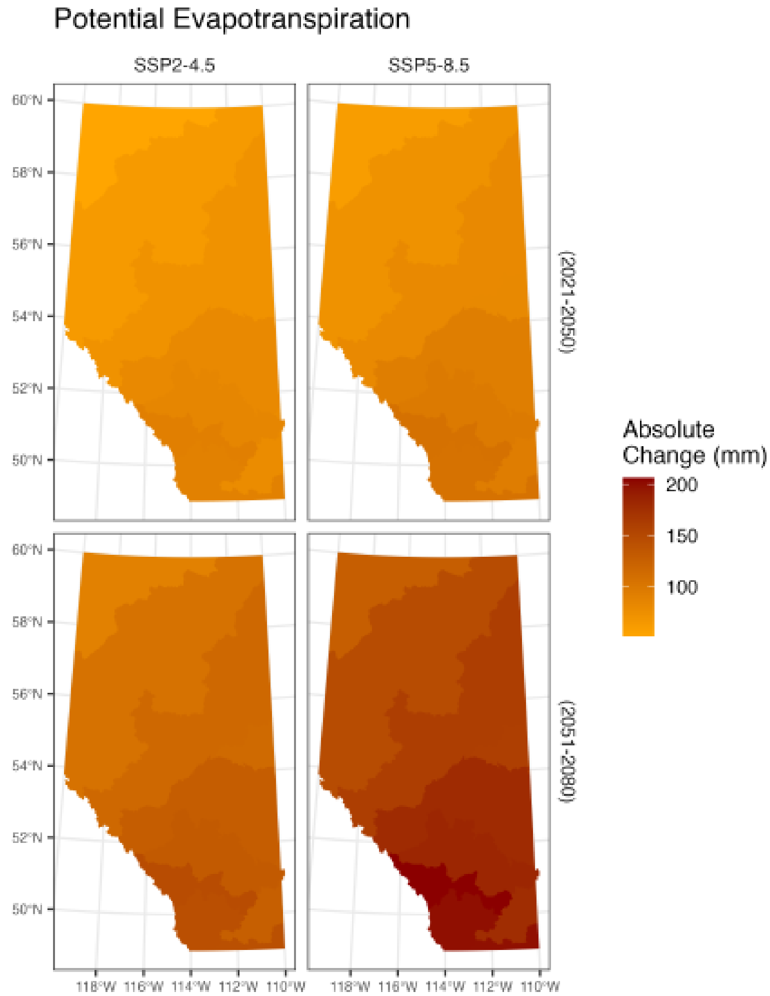

Figure 2: Absolute change of potential evapotranspiration (mm/year) under future periods (2021-2050 and 2051-2081) under climate change scenarios (SSP2-4.5 and SSP5-8.5) relative to the historical period (1991-2020).

Potential Water Availability

Figure 3 displays the absolute change of potential water availability in each basin relative to historical conditions. In all basins, water availability is projected to decrease under both climate change scenarios and both future periods as increases in PET outpace increases in precipitation. These plots show that the largest decrease in potential water availability is in the more arid south-eastern basins. These basins see greater changes of water loss from historical conditions to future scenarios in the next future period from 2051-2080. In the southernmost Oldman River and Milk River watersheds, water availability is projected to lose over 150 mm relative to historical conditions. While the centrally located basins the North Saskatchewan, Upper Churchill and the Battle watersheds show the same trend of increased water loss under in current and future periods but to a lesser degree than the southern basins. The Hay and Athabasca basins are projected to have less severe decreases in potential water availability, as increases in precipitation are projected to mostly offset the increase in potential evapotranspiration in these more northern basins.

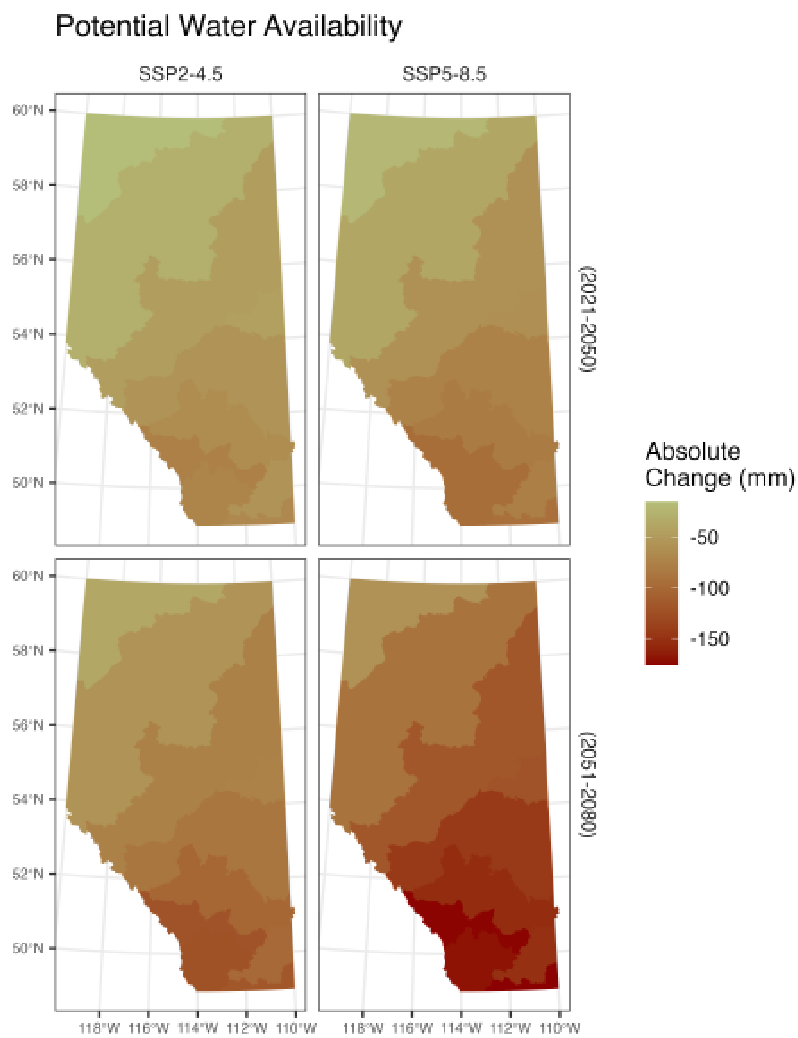

Figure 3: Absolute change of potential water availability (mm/year) under future periods (2021-2050 and 2051-2081) under climate change scenarios (SSP2-4.5 and SSP5-8.5) relative to the historical scenario (1991-2020).

4. Discussion and Limitations

This work provides a first order estimate of how water availability is projected to change across major river basins in Alberta under two future climate change scenarios. The results show that generally precipitation in northern Alberta is projected to increase while the southern half of the province is likely to stay relatively the same. Potential Evapotranspiration is projected to increase across the province. As a result, the more arid southern portion of the province is projected to experience decreases in potential water availability. In more northern basins, increases in precipitation are projected to mostly offset increases in potential evapotranspiration and lead to negligible/small decreases in potential water availability.

This work provides insights into the water availability of Alberta under two future climate change scenarios, yet certain limitations must be considered to contextualize these results. First, this modelling approach used PET, as opposed to ET, to estimate the rate of water loss. While this is an appropriate coarse proxy, PET represents the rate of evapotranspiration that would occur given unlimited water availability without advection of heat storage and therefore does not consider soil water processes. We chose PET as a proxy for water loss, because actual ET would involve considerably more detailed modelling, including accounting for soil water processes, as well as land cover and soil cover characteristics.

Likewise, this model does not consider how water moves on the landscape or the amount of water within a given stream. A more detailed model would account for water storage occurring in both the snowpack and soils. These processes influence water availability both temporally and spatially, such as the seasonality of water availability (including snowmelt timing and seasonal precipitation patterns) and how it's partitioned on the landscape (including soil water storage and release). A more detailed model would also account for more complex processes such as glacier contributions and attenuation lakes have on streamflow which influences the seasonality of water availability. Seasonality of water availability is particularly important for water users, since most of the watersheds in Alberta have a strongly seasonal pattern; flows are highest during the spring and early summer months, and can be very low during late summer, fall, and throughout the winter months.

This model does not account for flow regulation, water diversions, or changes in water management, which has considerable implications on water availability in several basins. Streamflow is regulated by major dams in several major basins, including the South Saskatchewan, North Saskatchewan, and Peace basins. Likewise, water licensing and use is considerable in many basins, especially in southern Alberta. Water management as well as changes in consumptive use, could impact the water availability in the future, especially in response to changing climatic conditions, but is beyond the scope of this work.

Lastly, the choice of spatial discretization (i.e. the selection of basin delineation) could have important implications for findings. We highlight that the size of basins selected for this study varied throughout the province, and notably some contain greater or lesser headwater areas, while some basins headwaters are neglected since they are outside the province (i.e. Peace River). As a result, the spatial outputs of precipitation reflect the fact that the larger basins encompass wetter mountainous headwater tributaries and more arid subbasins, which average out the total precipitation amounts. A strong precipitation gradient exists between the Rockies and the Prairies which leads to considerably greater precipitation in mountainous headwaters than in arid prairie areas. This dynamic is also reflected in PET results, where warmer, more arid environments have considerably higher rates than in cool, moist alpine environments.

In addition, this basin discretization implies that "water availability" is defined based on the mainstem outlet of this spatial unit and not off-stream or on smaller tributaries. In terms of assessing water availability, most major basins in the province receive much of their water from their western-most headwaters, where precipitation and winter snowpacks are greatest and water availability is considerably lower in further east (and south) regions of the province. Consequently, changing patterns of water availability in response to climate change on mainstem systems may not be represented by this spatial averaging, since in absolute terms, water availability is largely dictated by relatively small spatial headwater areas.

5. Conclusion

This memo documents the methods used to estimate potential water availability (precipitation minus potential evapotranspiration) and provides estimates of the projected change under two future climate scenarios relative to historical conditions. Results demonstrate that while precipitation is projected to increase under both climate change scenarios, in most cases an increase in potential evapotranspiration is projected to lead to a decrease in potential water availability in the coming decades. This reduction is projected to be greater in the southern and eastern regions of Alberta while portions of northern Alberta are projected to see small and/or negligible decreases in water availability. This work provides a broad estimate over a large spatial domain and does not consider changes in seasonality (i.e. changing timing in water availability), differentiate between tributaries and major basin rivers, explicitly model soil water and vegetation processes, or account for water management; all factors which could be important and should be considered if more detailed water availability assessment is needed.

6. Closing

MacHydro prepared this document for the account of WaterSMART. The material in it reflects the judgment of MacHydro staff considering the information available to MacHydro at the time of document preparation. Any use which a third party makes of this document or any reliance on decisions to be based on is the responsibility of such third parties. MacHydro accepts no responsibility for damages, if any, suffered by any third party because of decisions made or actions based on this document.

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Thank you for the opportunity to complete this work. Please do not hesitate to contact us if you have additional questions or concerns.

Sincerely,

Morgan Braaten, MES., GIT

Matthew Chernos, MSc., P.Geo.