A Long-Term Integrated Assessment of Cost, Water Consumption, and Greenhouse Gas Emissions of a Transition to a Low-Carbon Bitumen and Hydrogen Production

by

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Abstract

The growing demand for energy and the need for mitigation of greenhouse gas (GHG) emissions has led to increased interest from government, industry, and academia in the development of new low-carbon technologies for bitumen extraction and hydrogen production. In situ bitumen is a major contributor to Canada's economy. Hydrogen has the potential to play a critical role in the transition to a low-carbon economy. The production of these two important energy sources comes with significant environmental impacts related to GHG emissions and water consumption. While low-carbon technologies offer a promising solution to mitigate carbon emissions, there is a critical knowledge gap regarding their potential impacts on water. This research aims to investigate the environmental footprints related to water consumption, GHG emissions, and associated cost impacts with the adoption of new low-carbon technologies for bitumen extraction and hydrogen production.

Bitumen production from the Canadian oil sands made up 5.3% of the country's GDP in 2020. Canada exports 76% of the crude oil produced, and 97% of this is recovered in the oil sands. In the next 25 years, bitumen production is expected to increase by 2.5 million cubic meters per day because of expansions of in situ bitumen recovery projects. The oil sands sector is a significant emitter of greenhouse gases (GHGs), accounting for 11.3% of Canada's GHG emissions; therefore, advancing low-carbon oil sands extraction technologies is critical. While many strategies to mitigate GHG emissions from the oil sands sector have been proposed, there are few assessments of associated water-use impacts. To fill this knowledge gap, this research builds on a novel data-intensive and technology-specific model of the in situ bitumen extraction sector in

Canada developed to determine the long-term water and GHG footprints of the penetration of emerging low-carbon oil sands recovery technologies. The market penetration of seven novel low-carbon and three conventional in situ bitumen extraction techniques through four different technology mix scenarios between 2020 and 2050 were considered. The results show maximum water savings and GHG abatement potential in 2050 of 7% and 17%, respectively, at a \$59/m^3 water savings cost and a \$32/tCO_2e GHG abatement cost at a scenario of high carbon tax. Total water consumption and GHG emissions are projected to reach 43.8 million cubic meters and 49.9 million tonnes in 2050 under the scenario that best reduces water use and emissions. Although freshwater use from in situ recovery is low – 0.05% of the Athabasca River flow – projected annual emissions from the oil sands industry are significant, thus further efforts are needed to meet Canada's net-zero emissions target by 2050.

Hydrogen-based greenhouse gas (GHG) mitigation strategies can have multi-sector benefits and are considered necessary to reach net-zero emissions by 2050. Assessments of hydrogen scale-up have not included long-term implications for water resources. This work aims to fill this knowledge gap through a long-term integrated assessment of the water consumption, GHG emissions, and costs of conventional and low-carbon hydrogen scenarios to the year 2050. 120 long-term scenarios were developed for the large-scale deployment of low-carbon hydrogen in a prospective hydrogen-intensive economy (Alberta, Canada) and the economic impacts in terms of marginal abatement costs were determined. This study considered 15 different natural gas- and electrolysis-based hydrogen production technologies. The results obtained project a cumulative mitigation of 9 to 162 million tonnes of carbon emissions between 2026 and 2050 through the implementation of low-carbon hydrogen production scenarios compared to the business-as-usual scenario. However, cumulative water consumption increases considerably with the large-scale deployment of low-carbon hydrogen, reaching 8 to 3,815 million cubic meters. The adoption of green hydrogen technologies increases water consumption significantly. Depending on the jurisdiction of analysis and its water bodies, this increase may or may not be a long-term issue. Alberta's available water resources are sufficient to provide water to drive low-carbon hydrogen deployment while also providing water for other economic and social activities. Low-carbon hydrogen scenarios start becoming cost-effective as the carbon price rises to \$170/tCO_2e. The long-term water consumption projections add valuable information to the existing body of literature by providing details on the potential impacts on water resources associated with the implementation of low-carbon hydrogen.

Preface

This thesis contains material from two studies written by me as lead author and two others.

Chapter 2 will be submitted to the *Journal of Cleaner Production* as "Long-term integrated assessment of water, GHG, and cost impacts of a transition to a low-carbon unconventional oil extraction" by Gustavo Moraes Coraça, Matthew Davis, and Amit Kumar.

Chapter 3 will be submitted to *Applied Energy* as "Long-term integrated assessment of water, GHG, and cost impacts of a transition to a low-carbon hydrogen production" by Gustavo Moraes Coraça, Matthew Davis, and Amit Kumar.

Because of their pending publication status, Chapters 2 and 3 are presented in their entirety in the format in which they will be submitted to peer-reviewed journals. The supplementary information material to be submitted with Chapters 2 and 3 have been reorganized into the appendices of this thesis for the sake of consistency and logical order.

I was responsible for the literature review, data collection and processing, methods development, formal analysis, modelling, analysis and interpretation of results, and writing for all the material presented in this thesis. Matthew Davis provided input on the research program design, method development, and modelling. He also provided editorial input on all the content in this thesis. Dr. Amit Kumar directed the conceptual study design, provided overall supervision and editorial input on all content in this thesis, coordinated funding for the work, provided inputs to the designed scenarios and feedback on the results, and led discussions with key stakeholders from government, industry and academia.

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Table of Contents

List of Tables

List of Figures

List of Abbreviations

Abbreviations

AER	Alberta Energy Regulator
CAPX	Capital cost
CCS	Carbon capture and sequestration
CER	Canada Energy Regulator
CER-CP	Canada Energy Regulator Current Policies scenario
CER-EP	Canada Energy Regulator Evolving Policies scenario
CSS	Cyclic steam stimulation
EBRT	Enhanced Bitumen Recovery Technology
ESEIEH	Enhanced Solvent Extraction Incorporating Electromagnetic Heating
GHG	Greenhouse gas
LASER	Liquid Addition to Steam for Enhancing Recovery
LEAP	Low Emissions Analysis Platform
OPX	Operating cost
OSA	Oil sands area
RUST	Regression, Uncertainty, and Sensitivity Tool
SA	Solvent-aided
SAGD	Steam-assisted gravity drainage

SB	Solvent-based
SEGD	Steam environmentally generated drainage
WEAP	Water Evaluation and Planning

Quantities

Variables and parameters

AS	Additional share
BP	Yearly in situ bitumen production
CC	Capital cost
$CGHG$	Cumulative GHG abatement (Chapter 3 only)
Ct	Carbon cost
CtP	Carbon price
CWS	Cumulative water savings
EC	Energy cost
EI	Electricity intensity
EP	Electricity price
GHG	Yearly GHG emissions
$GHGI$	GHG intensity
HD	Hydrogen demand

HPC	Hydrogen production capacity
LCC	Life cycle cost
MAC	Marginal abatement cost
$MGHG$	Cumulative GHG abatement (Chapter 2 only)
MS	Market share
MSC	Marginal savings cost
MWS	Marginal water savings cost
n	Lifetime of in situ bitumen extraction technology (Chapter 2 only) or lifetime hydrogen production technology (Chapter 3 only)
NI	Natural gas intensity
NP	Natural gas price
OC	Operating cost
r	Interest rate
v	Cost variance (Chapter 2 only) or sensitivity to cost (Chapter 3 only)
WC	Yearly water consumption (Chapter 3 only)
WCI	Water consumption intensity (Chapter 3 only)
WR	Yearly water consumption (Chapter 2 only)
WRI	Water consumption intensity (Chapter 2 only)

Sets

C	Conventional in situ bitumen extraction technology
cp	Carbon policy environment
ds	Hydrogen demand scenario
j	In situ bitumen extraction technology (Chapter 2 only) or hydrogen production technology (Chapter 3 only)
ns	Novel scenario (Chapter 2 only)
nps	Novel production scenario (Chapter 3 only)
NR	Non-retiring hydrogen production capacity or technology
NT	Novel in situ bitumen extraction technology
OSA	Oil sands area
ps	Hydrogen production scenario
R	Retiring hydrogen production capacity or technology
REF	Reference scenario
s	Scenario (Chapter 2 only)
y	Year

1. Introduction

1.1 Research motivation

The increasing demand for energy over the last century has led to an unprecedented surge in greenhouse gas (GHG) emissions which is a major environmental concern. Bitumen is a major contributor to Canada's economy and energy sector. In-situ bitumen is extracted mostly through steam assisted gravity drainage (SAGD) process which is a GHG intensive process due to the use of large amounts of natural gas. There are a several new bitumen extraction technologies, which are in various stages of development, deployment and commercialization, which have lower environmental footprints compared to SAGD.

Hydrogen has the potential to play a critical role in the transition to a low-carbon economy by replacing fossil fuels in transportation and industrial applications. Currently, hydrogen is mostly used to upgrade bitumen to synthetic crude oil, which is further converted to fuel, lubricants, and other petrochemical products. However, the current production of hydrogen is also associated with significant GHG emissions as the majority of these are produced from fossil fuel.

In addition to GHG emissions, water consumption is a significant environmental issue associated with the production of bitumen and hydrogen. These energy sources require large amounts of water for production, processing, and transportation.

The Canadian oil sands represent the world's third-largest proven oil reserve and account for 97% of the country's oil deposits [1]. The oil sands are located in northern Alberta, Canada, and spread across three oil sands areas (OSAs): the Athabasca, Cold Lake, and Peace River deposits [2]. The oil sands consist of a mixture of sands (83%), bitumen (10-12%), water (4%), and clay (3%) [2]. Depending on how deep the oil sands are, bitumen can be extracted through in situ production or open pit mining. About 80% of Alberta's total proven oil sands reserves are located more than 75 meters below ground and are accessible only through in situ extraction. The remaining 20% can be recovered through open pit mining [3]. The recovery of bitumen from deep oil sands reserves is water and energy intensive. On average, 0.47 cubic meters of water and 13.9 GJ of energy are required to extract one cubic meter of bitumen from underground [4]. The energy is supplied by electricity and natural gas and is mainly used to treat water and convert it to steam. Water is a crucial resource used to separate bitumen from the oil sands mix, and most of the water used in this recovery process is recycled. Since 2016, the water recycling rate has increased and now makes up 88% of the total water used for in situ bitumen production [5]. However, the quality of the water decreases as the recycling process continually brings chemicals from the oil sands deposits into the steam, thus reducing the oil-water recovery rate over time [6]. The accelerated development of oil sands projects depend on the proper management of water resources [4]. In Alberta, the regulation of the oil sands industry falls under Alberta Energy Regulator (AER) directives. For example, Directive 081 [7] limits water use in oil sands activities by water type. In addition to water-use restrictions, emissions-related regulations apply. For example, the Government of Alberta limits oil sands emissions by 100 Mt in any year [8]. This is in line with Canada's target of net-zero GHG emissions by 2050 and Canada's 2030 Emissions Reduction Plan [9]. Especially for the in situ bitumen extraction sector, which is responsible for most (80%) of the bitumen extracted, the advancement of novel low-carbon bitumen recovery technologies is key to reducing GHG emissions.

As an alternative to fossil fuels, hydrogen plays an important role in the transition to a low-carbon economy by representing a clean fuel feedstock solution for a wide range of applications [10]. Hydrogen is a suitable component for energy-intensive applications where the electrification process is either challenging or limited and the use of high-energy-density fuels is preferred over low-cost natural gas [11]. Presently, the expansion of the hydrogen economy has remarkable momentum. Global hydrogen demand is expected to increase from 88.5 Mt in 2020 to 210.6 Mt in 2030 [12]. Hydrogen can be produced from fossil fuels and biomass, as well as by electrolysis, wherein oxygen and hydrogen are separated from the water molecule by electricity. Currently, more than 90% of global hydrogen production is from fossil fuels [10] and there is a significant interest in using low-carbon hydrogen production technologies.

With the growth in demand for bitumen and hydrogen, the environmental impacts associated with their production and consumption are likely to intensify. Given the importance of both bitumen and hydrogen in Canada's energy mix, it is essential to understand the long-term environmental impacts associated with low-carbon bitumen extraction technologies and hydrogen production technologies. The large-scale deployment of low-carbon technologies is one of the most promising and interesting strategies to mitigate GHG emissions; however, this option may increase production costs. This thesis will examine the environmental benefits (or burdens), focusing on GHG emissions and water consumption along with the associated cost impacts, related to the growth in demand and production of bitumen and hydrogen via low-carbon technologies with a focus on Canada's energy sector. By doing so, this research contributes to the development of sustainable energy policies and practices that will help decision-makers ensure a cleaner and healthier environment for future generations through a transition to a low-carbon economy.

1.2 Knowledge gaps

The study carried out in this research targets several knowledge gaps identified through a literature review. Chapters 2 and 3 present and discuss in more detail and with a more focused approach the most relevant gaps. This section provides a general overview of the knowledge gaps identified that will support the development of the thesis objectives.

Gap 1: Lack of integrated analysis that evaluates the long-term water consumption with the deployment of low-carbon technologies.

Radpour et al. [13] developed a data-intensive framework to assess the market penetration of emerging in situ oil sands recovery technologies and the associated GHG abatement potential in different carbon pricing environments. Janzen et al. [14] modelled the large-scale deployment of carbon capture and sequestration (CCS) in the Canadian oil sands through a cost-based market penetration model and evaluated long-term GHG mitigation opportunities and associated economic impacts. These same authors evaluated the long-term GHG mitigation potential and cost impacts of cogenerating electricity in the oil sands [15] and with the implementation of renewables as power generation options [16]. Katta et al. [17] studied energy demand-based GHG mitigation options for the oil sands sector, covering in situ extraction, surface mining, and bitumen upgrading processes. Janzen et al. [16] evaluated the GHG emissions reduction potential and cost impacts of integrating low-carbon and renewable energy technologies in the Canadian oil sands from 2019 to 2050. Davis et al. [18] assessed the GHG abatement potential and cost-effectiveness of blending and supplying low-carbon hydrogen with natural gas, specifically hythane, through 576 long-term scenarios from 2026 and 2050. Navas-Anguita et al. [19] studied the long-term potential of hydrogen production technologies with and without CCS in meeting the hydrogen demand by fuel cell electric vehicles in Spain from 2020 to 2050.

None of these studies considered the impacts on water resources of the large-scale deployment of low-carbon options.

Gap 2: Insufficient disaggregation of analysis and results.

Rosa et al. [20] estimated the actual and potential rates of water use in the Canadian oil sands deposits and in other major oil deposits worldwide, comparing surface mining activities with in situ drilling. Aggregated values were used for the estimations; the bitumen extraction oil sands area (OSA) deposits and the in situ recovery technologies considered were not differentiated.

Gap 3: Lack of a bottom-up model that considers techno-economic inputs.

Jordaan [21] discussed the impacts on land and water resources associated with oil sands production in Alberta. The author carried out a literature review and identified a need to develop better scientific knowledge on water use and quality implications, since the growth of the oil sands industry and potential impacts of climate change will lead to water availability limitations and more restrictions for water withdrawals. McKellar et al. [22] and Sleep et al. [23] projected GHG emissions from the Canadian oil sands over a short-term horizon. McKellar et al. [22] did this by interviewing thirteen experts in the oil sands industry to collect data on expected changes in the sector's GHG emissions intensity. Sleep et al. [23] used experts' information and knowledge to project the deployment and performance of novel in situ, surface mining, and upgrading methods. Lunn [24] and Wilson [25] reviewed facts on saline and freshwater use in the Canadian oil sands as well as projections for water consumption in 2030.

Gap 4: Lack of long-term analysis.

Mehmeti et al. [26] studied the life cycle environmental performance of natural gas- and electrolysis-based hydrogen and included water consumption footprints. The authors did not carry out long-term projections on water consumption with the deployment of low-carbon hydrogen technologies. Woods et al. [27] quantified the different types of water in Australia, including waste, surface, ground, and desalinated water in different states across the country, and evaluated their potential to meet local hydrogen demand through water electrolysis production. No long-term projections on water consumption were provided. Shi et al. [28] quantified water consumption and scarcity footprints of hydrogen production from electrolysis-based options, specifically alkaline electrolysis cell (AEC), presenting the geographical distribution of the water footprints along the hydrogen supply chain. Grid and renewable-powered electrolysis were considered.

Gap 5: Insufficient consideration of multiple technologies/system boundaries.

Ali and Kumar [29] developed life cycle water footprints for bitumen extraction, upgrading, and refining processes. Only conventional in situ bitumen extraction technologies (SAGD, CSS, and primary) were considered. Ali [30] developed quantitative indicators for a comparative sustainability assessment of eighteen bitumen-producing pathways in Alberta, Canada, for the years 2009 to 2030. Water demand was one of the indicators assessed in the author's work; however, only conventional in situ bitumen extraction technologies were considered. Webber [31] analyzed the total water consumption of the transitional hydrogen economy by quantifying direct and indirect water requirements to produce 60 million tonnes of hydrogen per year through thermoelectrically powered electrolysis. The water requirements of different renewable electrolysis were not considered.

Although it is beyond the scope of this research to propose complete and accurate solutions for all the gaps listed above, acknowledging their existence is fundamental to shed light on the necessary work to be carried out to resolve them and address the environmental issues related to the continuous growth of the sectors of unconventional oil and hydrogen production.

1.3 Research objectives

The overall objective of this research is to investigate the impacts on hydrogen and bitumen production water use, GHG emissions, and costs associated with the large-scale deployment of low-carbon technologies over the long term. The specific objectives are to:

Objective 1: Develop feasible scenarios for hydrogen and bitumen production in Alberta that consider realistic applications of low-carbon technologies, their lifetime costs and energy requirements, and distinct energy and carbon pricing environments.

Objective 2: Develop a bottom-up cost-based market penetration model to project the market shares of conventional and low-carbon hydrogen- and unconventional oil-producing technologies up to 2050 for different technology-mix scenarios.

Objective 3: Estimate and compare total water consumption and GHG emissions up to 2050 for different hydrogen and bitumen production scenarios, and carbon pricing environments, thus determining the cumulative GHG abatement and water savings (or consumption) potential with the large-scale deployment of low-carbon technologies.

Objective 4: Evaluate the effectiveness of current and potential policies on supporting the large-scale deployment of low-carbon technologies and reducing GHG emissions, and the associated impacts on local water resources.

Objective 5: Compare the marginal GHG abatement and water savings costs for different technology-mixes and carbon pricing environments.

Objective 6: Evaluate how projected cumulative water savings and GHG abatement are affected by variations in techno-economic parameters through a sensitivity analysis and by how much these projections vary through an uncertainty analysis.

1.4 Organization of thesis

This thesis has four chapters and has been written in a paper-based format. Chapter 1 introduces the motivations for evaluating the long-term impacts on water consumption, GHG emissions, and costs with the large-scale deployment of low-carbon technologies on energy-intensive sectors, discusses the current knowledge gaps, and outlines the scope of this research through detailed objectives to be met.

Chapter 2 and Chapter 3 focus on the development of the bottom-up model to assess water consumption, GHG emissions, and cost impacts of integrating low-carbon technologies to produce unconventional oil and hydrogen, respectively. Both chapters are structured through the following sections: introduction, methods, results and discussion, and conclusions. These are supposed to be read independently.

Chapter 4 provides the conclusions of this research and summarizes the results. Throughout, the figures, tables, and equations are numbered according in sequential order. The appendices contain additional input data used and results obtained in this research.

2. Long-term integrated assessment of a transition to a low-carbon unconventional oil extraction

2.1. Introduction

The oil sands are found in multiple countries throughout the world, including Venezuela, the United States, Russia, and Canada [1]. The largest reserves are located within Cretaceous rocks in Venezuela and Canada [32]. The Canadian oil sands represent the world's third-largest proven oil reserve and account for 97% of the country's oil deposits [1]. The oil sands are located in northern Alberta, a western Canadian province, and spread across three oil sands areas (OSAs): the Athabasca, Cold Lake, and Peace River deposits [2]. The oil sands consist of a mixture of sands (83%), bitumen (10-12%), water (4%), and clay (3%) [2]. Bitumen consists of heavy crude oil, a thick, black, and viscous substance. Depending on how deep the oil sands are, bitumen can be extracted through in situ production or open pit mining. 80% of Alberta's total proven oil sands reserves are located more than 75 meters belowground and are accessible only through in situ extraction. The remaining 20% can be recovered through open pit mining [3]. The recovery of bitumen from deep oil sands reserves is water and energy intensive [4]. The energy is supplied by electricity and natural gas and is mainly used to treat water and convert it to steam. Water is a crucial resource used to separate bitumen from the oil sands mix, and most of the water used in this recovery process is recycled. Since 2016, the water recycling rate has increased and now makes up 88% of the total water used for in situ bitumen production [5]. However, the quality of the water decreases as the recycling process continually brings chemicals from the oil sands deposits into the steam, thus reducing the oil-water recovery rate over time [6]. The accelerated development of oil sands projects depend on the proper management of water resources [4]. In Alberta, the regulation of the oil sands industry falls under Alberta Energy Regulator (AER) directives. For example, Directive 081 [7] limits water use in oil sands activities by water type. In addition to water-use restrictions, emissions-related regulations apply. Especially for the in situ bitumen extraction sector, which is responsible for most (80%) of the bitumen extracted, the advancement of novel low-carbon bitumen recovery technologies is key to reducing GHG emissions.

Conventional in situ recovery technologies primarily rely on the injection of steam underground to reduce the viscosity of the bitumen to the point where it can flow into a producing well and be brought up to the surface. Steam-assisted gravity drainage (SAGD) [33], cyclic steam stimulation (CSS) [34], and primary [35, 36] are the three main conventional in situ extraction methods. Potential pathways for deep decarbonization of the oil sands consist of replacing conventional in situ bitumen extraction techniques with novel low-carbon recovery technologies. The use of heated solvents can significantly reduce GHG emissions by reducing the natural gas and electricity requirements of the oil recovery process [23, 37]. Using solvents in place of steam and other approaches to extract bitumen can also reduce the energy intensity of in situ recovery. Novel low-carbon bitumen extraction methods can be classified as solvent-aided (SA), solvent-based (SB), or "other" novel technologies. The SA methods co-inject a mixture of solvent and steam into the reservoir, with the solvent constituting approximately 20% of the volume of the mixture and ranging from light to more volatile hydrocarbons, like butane, propane, and naphtha [38]. SA technologies include solvent-assisted-SAGD (SA-SAGD) [39, 40] and Liquid Addition to Steam for Enhancing Recovery (LASER) [41, 42]. Steam-free technologies or in situ extraction methods that apply a mixture of solvent and steam with more than 90% in solvent volume are classified as SB-bitumen recovery technologies. Some emerging technologies already in various stages of development are Nsolv [43-45], Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH), [46-48], and Enhanced Bitumen Recovery Technology (EBRT) [49]. Technologies that do not fall into the SA or SB process categories are considered "other" novel in situ bitumen extraction methods and include steam environmentally generated drainage (SEGD) [50] and blowdown boiler [38, 51].

We reviewed studies that considered the GHG mitigation potential and/or associated water-use impacts with the implementation of conventional and novel low-carbon technologies in the oil sands sector. The main objective was to determine whether there are long-term projections on water consumption and GHG emissions for different industries, especially for the Canadian oil sands, and the modelling approach used. Radpour et al. [13] developed a data-intensive framework to assess the market penetration of emerging in situ oil sands recovery technologies and the associated GHG abatement potential in different carbon pricing environments. The authors found that cumulative GHG mitigation potential in the oil sands sector can be as high as 192.8 $MtCO_2e$

between 2018 and 2050 in a high carbon pricing scenario. Janzen et al. [14] modelled the large-scale deployment of carbon capture and sequestration (CCS) in the Canadian oil sands through a cost-based market penetration model and evaluated long-term GHG mitigation opportunities and associated economic impacts. The cumulative GHG abatement potential was found to be within the range of 3 and 232 $MtCO_2e$ at a marginal abatement cost of -28 and -\$42/tCO_2e. These same authors also evaluated the long-term GHG mitigation potential and cost impacts of cogenerating electricity in the oil sands [15] and with the implementation of renewables as power generation options [16]. Katta et al. [17] studied energy demand-based GHG mitigation options for the oil sands sector, covering in situ extraction, surface mining, and bitumen upgrading processes. Their evaluation of thirty energy-use reduction scenarios resulted in up to 86 $MtCO_2$ reduction potential by 2050. McKellar et al. [22] and Sleep et al. [23] projected GHG emissions from the Canadian oil sands over a short-term horizon. McKellar et al. [22] did this by interviewing thirteen experts in the oil sands industry to collect data on expected changes in the sector's GHG emissions intensity. The authors concluded that novel technology availability and more stringent GHG mitigation polices are required to lead to significant emissions reduction. Sleep et al. [23] used experts' information and knowledge to project the deployment and performance of novel in situ, surface mining, and upgrading methods. According to Sleep et al. [23], conventional bitumen extraction technologies or steam-solvent techniques will be used for most (60-98%) of the in situ bitumen production in 2034.

While long-term projections on GHG emissions, cumulative mitigation potential, and associated costs were carefully developed for the oil sands and other energy industries, the assessment of associated water-use implications is limited. Ali and Kumar [29] developed life cycle water footprints for bitumen extraction, upgrading, and refining processes. Only conventional in situ bitumen extraction technologies (SAGD, CSS, and primary) were considered. These same authors [52] later quantified the life cycle water demand coefficients of fuels produced from five different crude oil fields. The freshwater consumption coefficient found for the heavy crude oil produced in the Bow River oil field in Alberta was approximately 1.75 $m^3_{water}/m^3_{bitumen}$. Agrawal et al. [53] analyzed Canada's water intake, consumption, and discharge by disaggregating water use by regional subsectors. Water withdrawal and consumption from oil sands surface mining, in situ extraction, and upgrading were considered. Lunn [24] and Wilson [25] reviewed facts on saline and freshwater use in the Canadian oil sands as well as projections for water consumption in 2030. The authors stated that the increase in saline water use exceeded the increase in freshwater use between 2002 and 2010 for in situ bitumen recovery facilities. Based on this trend, the authors projected total water consumption of 38 million cubic meters in 2030 and a water intensity of 0.21 $m^3_{water}/m^3_{bitumen}$. This projection represents between 0.04 and 0.09% of the average water flows available in the Peace, Beaver, and Athabasca basins in Alberta. The authors did not make clear the assumptions made, such as the novel and conventional recovery technologies assumed to be used in 2030 and how the projections were obtained, that is, the modelling approach and the calculations performed. Novel low-carbon in situ bitumen extraction technologies were cited, such as LASER and SA-SAGD; however, the authors did not consider a quantitative analysis in water consumption implications due to the penetration of each technology. Rosa et al. [20] estimated the actual and potential rates of water use in the Canadian oil sands deposits and in other major oil deposits worldwide, comparing surface mining activities with in situ drilling. The authors found that the total water intensity for in situ bitumen extraction reaches 2.77 $m^3_{water}/m^3_{bitumen}$. Aggregated values were used for the estimations; the bitumen extraction OSA deposits and the in situ recovery technologies considered were not differentiated. Jordaan [21] discussed the impacts on land and water resources associated with oil sands production in Alberta. The author identified a need to develop better scientific knowledge on water use and quality implications, since the growth of the oil sands industry. Ali [30] developed quantitative indicators for a comparative sustainability assessment of eighteen bitumen-producing pathways in Alberta, Canada, for the years 2009 to 2030. Water demand was one of the indicators assessed in the author's work; however, only conventional in situ bitumen extraction technologies were considered. Specific to novel in situ bitumen extraction technologies, most studies focus on the analysis of technical performance and techno-economic feasibility without assessing the implications on water consumption [54-57]. None of these studies long term water demand due to the penetration of the new extraction technologies over a long term.

A study considering water-use implications and GHG emissions from the implementation of emerging in situ bitumen extraction technologies in a long-term analysis period is missing and this is a critical gap in literature. More specifically, there is a knowledge gap in the in situ bitumen extraction literature in that no single study framework assesses novel low-carbon technologies (i.e., SA, SB, and others); the value of this is effective technology scenario comparisons in terms of water consumption, GHG emissions, and abatement costs. Therefore, this study aims to fill this gap through integrated assessment by modelling and projecting the market penetration of emerging in situ extraction technologies through a set of scenarios along with their associated water consumption, GHG emissions, and corresponding costs for each cubic meter of water saved and tonne of CO_2-equivalent abated.

This analysis offers new information to support the transition to a low-carbon and less water-intensive in situ bitumen recovery industry by providing an outlook for policy- and decision-makers through long-term water and GHG abatement projections and commenting on whether the oil sands sector is on track to meet the net-zero emissions target by 2050 or should apply stricter policies and what the water-use impacts will be. The specific objectives of this work are to:

- Develop market penetration models to estimate the market shares of conventional and novel low-carbon in situ bitumen extraction technologies for different long-term scenarios.
- Develop a framework to integrate the GHG emissions, water footprint and costs for assessing the new bitumen extraction technologies.
- Conduct a case study for Canadian oil sands using the developed framework.
- Compare total water consumption and GHG emissions of each scenario over a long-term, i.e. up to 2050.
- Determine the net cost (or benefit) of saved water and abated GHGs with the adoption of novel low-carbon in situ bitumen extraction technologies in each scenario.
- Evaluate how projected cumulative water savings and water savings cost are affected by variations in input parameters through a global sensitivity and uncertainty analysis.

2.2. Method

2.2.1. Study framework

This study develops a novel framework to assess water consumption, GHG emissions, and marginal costs associated with the adoption of low-carbon in situ unconventional crude oil extraction technologies. Figure 2-1 shows the modelling framework. The initial stage involves two steps, the first one is data gathering, filtering and analysis, and the second one is scenario development. Five scenarios are considered, and they are described in Table 2-1. The market-share model is developed in the third stage. The model is used to project the market shares of the novel in situ bitumen recovery technologies in each scenario from 2020 to 2050. It is assumed that these technologies start competing for additional capacity of in situ oil production in 2020 and that only conventional facilities are used from 2005 to 2019. In the fourth and fifth stages, the GHG emissions and water consumption of each scenario are projected. The LEAP-Canada model is based on the Low Emissions Analysis Platform (LEAP) software [58], a modeling tool based on scenarios that designs and projects energy consumption, production, and resource extraction, accounting for both energy and non-energy sector GHG emissions sources and sinks. The WEAP-Canada model is based on the Water Evaluation and Planning (WEAP) software [59], which takes an integrated approach for water resources planning, providing an intuitive GIS-based graphical interface to model the supply and demand of water from different resources. The sixth stage is cost-benefit analysis, in which the water and GHG mitigation projections obtained through the WEAP- and LEAP-Canada models are used to determine the marginal water savings and GHG abatement costs of each decarbonization pathway compared to the reference scenario. The robustness of the results is improved through a sensitivity analysis in the seventh stage. The Regression, Uncertainty, and Sensitivity Tool (RUST) [60] developed is used to perform a Morris global sensitivity analysis and to calculate the Morris mean and standard deviation for the input variables analyzed. The RUST model is built on Rstudio and Excel VBA, and can be inserted into any Excel-based model to run sensitivity, uncertainty, and contribution to variance analysis. More details on the RUST model can be found in Di Lullo et al. [50]. The LEAP- and WEAP-Canada models were developed, validated, and used for previous GHG mitigation and water savings studies that considered different sectors across an economy. The studies focus on energy use [61, 62], water use [53], GHG emissions [63], power generation [64-66], residential and commercial [67, 68], oil sands [14-17], petroleum refining [69], chemical [70], mineral mining [71, 72], iron and steel [73], cement [74], and agricultural [75] sectors. The RUST model was also used as part of other studies to carry out global sensitivity and uncertainty analyses [76-84].

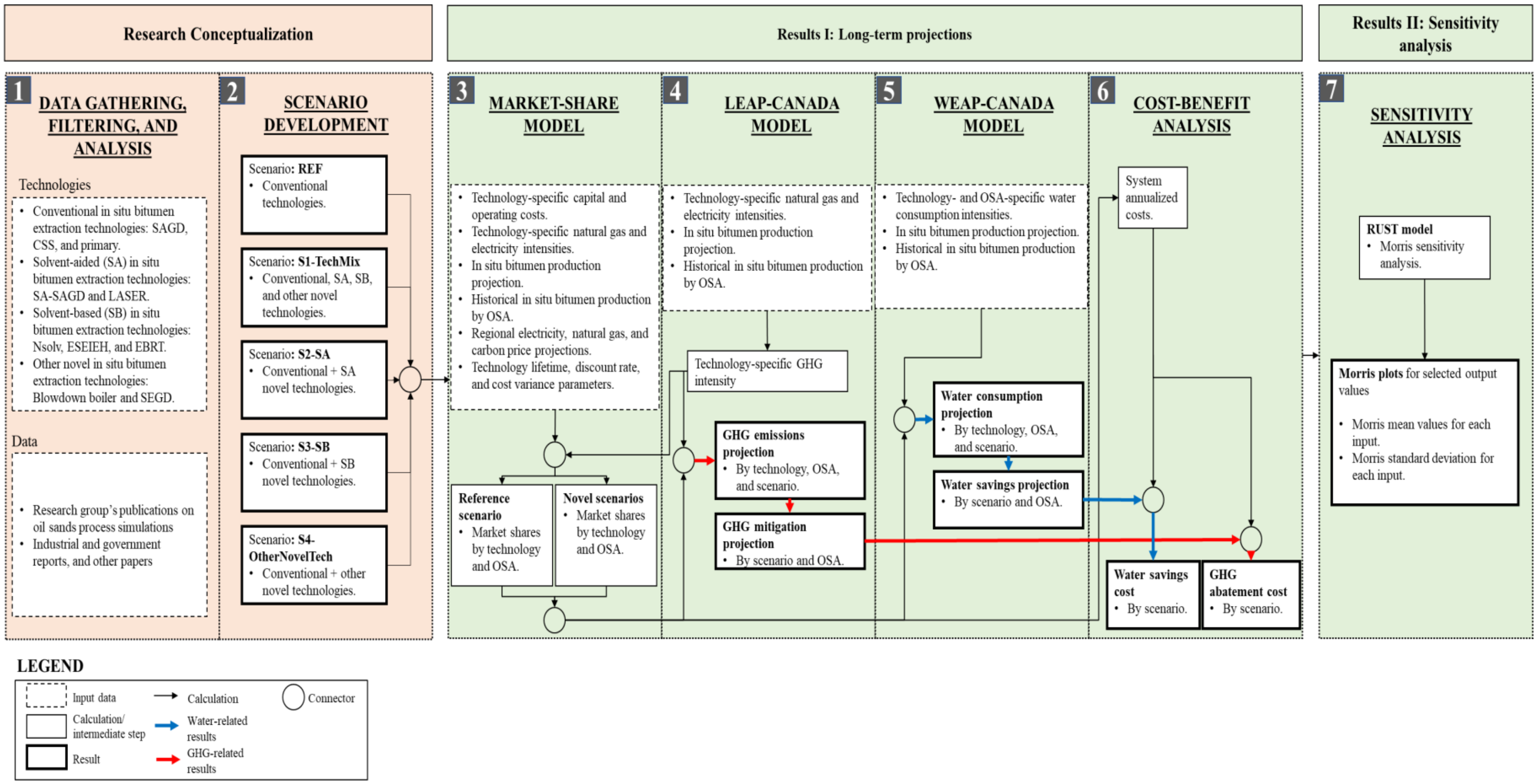


Figure 2-1: Integrated assessment framework for novel low-carbon in situ bitumen extraction technologies

2.2.2. Scenario development

The objective behind scenario development was to change the types and mixes of in situ bitumen extraction technologies used to transition to a low-carbon oil sands sector and to compare the water and GHG footprints, and abatement cost impacts of different decarbonization pathways. The conventional in situ bitumen extraction technologies considered are SAGD, CSS, and primary. The novel low-carbon technologies contemplated are classified as SA, SB, and other. The SA technologies include SA-SAGD and LASER. The SB technologies include Nsolv, ESEIEH, and EBRT. The other novel technologies include blowdown boiler and SEGD.

For each scenario considered, novel technologies compete with and replace conventional recovery methods with similar operating modes. SA-SAGD, Nsolv, ESEIEH, EBRT, blowdown boiler, and SEGD technologies compete with and replace conventional SAGD, and LASER technology competes with and replaces conventional CSS. The primary technology is not replaced by any novel in situ bitumen extraction technology, as primary production uses a recovery technology similar to conventional crude oil and is classified as a bitumen extraction method because of royalty regimes [35].

Table 2-1: Scenario descriptions

Scenario name	Description	In situ technologies used
REF	The reference scenario (REF) or business-as-usual scenario serves as a baseline for the water savings and GHG mitigation potential of the decarbonization scenarios and for the cost-benefit analysis. This scenario assumes that only conventional technologies will penetrate the market.	SAGD, CSS, and primary.
S1-TechMix	Effective 2020, all conventional and low-carbon in situ bitumen extraction technologies considered compete for new market shares. The objective is to assess whether all types of extraction technologies should compete for new market shares for larger water savings and GHG mitigation potential or whether specific types, such as SA and SB, should penetrate the market separately for better environmental performance. For the years 2005 to 2020, we assume that only conventional technologies were used to extract in situ bitumen.	SAGD, CSS, primary, SA-SAGD, LASER, Nsolv, ESEIEH, EBRT, blowdown boiler, and SEGD.
S2-SA	The assumption in this scenario is that effective 2020, conventional and SA technologies were used in the technology competition. This scenario aligns with CER-EP scenario that all new oil sands facilities post 2025 include SA extraction, with the adoption in existing facilities beginning in the latter half of the projection period (2035-2050) [85]. The objective is to assess whether the most optimistic scenario from the CER will lead to greater water savings and GHG mitigation potential than the other decarbonization scenarios. It is assumed that from 2005 to 2020, only conventional technologies were used to extract in situ bitumen.	SAGD, CSS, primary, SA-SAGD, and LASER.

Scenario name	Description	In situ technologies used
S3-SB	Effective 2020, we assume that conventional and SB technologies were used in the technology competition. This scenario simulates a more aggressive approach in which only less mature low-carbon technologies penetrate the market. The objective is to understand whether SB extraction technologies will lead to the maximum decarbonization potential and what the associated water impacts are. We assume that from 2005 to 2020, only conventional technologies were used to extract in situ bitumen.	SAGD, CSS, primary, Nsolv, ESEIEH, and EBRT.
S4-OtherNovelTech	We assumed that effective 2020, conventional and other novel low-carbon extraction technologies were used in the technology competition. This scenario simulates the penetration mix of a less mature low-carbon technology (SEGD) and a more mature and less water-intense recovery technology (blowdown boiler). The objective is to understand if this technology mix leads to significant reductions in water consumption and GHG emissions. For the years 2005 to 2020, we assume that only conventional technologies were used to extract in situ bitumen.	SAGD, CSS, primary, blowdown boiler, and SEGD.

2.2.3. Market-share model

The market-share model simulates technology competition from annualized lifetime costs of each technology and scenario considered, thus providing additional shares captured by individual in situ extraction technologies in a specific year. This modelling approach was adapted from Nyboer's dissertation [86] and used by Radpour et al. and Janzen et al. on oil sands [13, 16], Janzen et al. and Bataille et al. on CCS deployment [14, 87], and Radpour et al. on energy technology [88] studies, among others. Equation 1 is used to calculate the additional shares for a specific technology in a certain year for a given scenario.

$$AS_{j,y,s} = \frac{{LCC_{j,y}}^{-v}}{\sum_{j=1}^{J}\left({LCC_{j,y}}^{-v}\right)_s} \tag{1}$$

$$LCC_{j,y} = CC_j \frac{r}{1-(1+r)^{-n}} + OC_j + EC_{j,y} + Ct_{j,y} \tag{2}$$

$AS_{j,y,s}$ is the additional share calculated for technology j in year y for scenario s. $LCC_{j,y}$ is the annualized lifetime cost of technology j in year y. J represents the total number of in situ recovery technologies included in the scenario under analysis (s). CC_j and OC_j are the capital and operating costs, excluding energy consumption costs. Solvent-related costs are considered in total operating cost. The latter is represented by $EC_{j,y}$, which constitutes natural gas and electricity costs of technology j in year y. $Ct_{j,y}$ represents the carbon cost of technology j in year y and is obtained through the GHG intensity of technology j and the carbon price applied in year y. The carbon price is set by the Government of Alberta through the Technology Innovation and Emissions Reduction (TIER) regulation [89], which is in line with the Minimum National Carbon Pollution Price Schedule [90]. The TIER regulation limits the total amount of GHG emissions that can be emitted from the oil sands industry without any charge and adds a carbon price (\$/tCO_2e) to facilities that emit more than 100,000 tCO_2e as an economic stimulus to make the oil industry more innovative and environmentally friendly. Equations 3 and 4 present the breakdown of the energy and carbon cost terms, respectively. The interest rate is represented by the variable r, while n represents the lifetime of a technology. The cost variance parameter v is a measure of market heterogeneity, expressing non-uniformity in the system. A low cost variance value means that the price differential between the technologies competing for new market shares has less effect on decisions, and higher values for cost variance lead to market shares that more strongly favour the less costly technologies. A more comprehensive analysis of the cost variance parameter can be found in Nyboer's research [86].

$$EC_{j,y} = EP_y EI_j + NP_y NI_j \tag{3}$$

$$Ct_{j,y} = CtP_y GHGI_j \tag{4}$$

EP_y and NP_y represent the electricity and natural gas price in year y, and EI_j and NI_j represent the electricity and natural gas intensities of technology j. CtP_y represents the carbon price in year y and $GHGI_j$ represents the GHG intensity of technology j.

The market shares of conventional and novel technologies for a given scenario are calculated using Equations 5 and 6, respectively.

$$MS^{C}_{j,y,s} = \frac{BP_{y-1} MS^{C}_{j,y-1,s} + AS_{j,y,s}\left(\Delta BP_y + \frac{BP^{C}_{y-1}}{n}\right) - \frac{BP^{C}_{y-1}}{n}}{BP_y} \tag{5}$$

$$MS^{NT}_{j,y,s} = \frac{BP_{y-1} MS^{NT}_{j,y-1,s} + AS_{j,y,s}\left(\Delta BP_y + \frac{BP^{C}_{y-1}}{n}\right)}{BP_y} \tag{6}$$

$MS^{C}_{j,y,s}$ and $MS^{NT}_{j,y,s}$ represent the market shares of technology j, in year y, and for scenario s. The superscript notations C and NT indicate that the variable is specific to conventional and novel recovery technologies, respectively. No superscript indicates that the market share parameter works for either conventional or novel technologies. BP_y represents bitumen production in year y, while ΔBP_y represents the additional bitumen production in year y and is given by the difference in bitumen production in year y and $y-1$, $BP_y - BP_{y-1}$. Equations 5 and 6 consider that conventional technologies will retire, and the retired capacity will be added to the additional bitumen production to incorporate the technology competition. The retired capacity of the conventional technologies is represented by the fraction BP^{C}_{y-1}/n.

The market shares per OSA are given by Equation 7.

$$MS_{j,y,s,OSA} = \left(\frac{MS^C_{j,y,REF,OSA}}{\sum_{OSA=1}^{N} MS^C_{j,y,REF,OSA}}\right) MS_{j,y,s} \qquad 7$$

The market shares of conventional technologies (SAGD and CSS) by OSA and for the reference scenario are used to calculate the shares of the novel technologies, by OSA that are replacing conventional recovery methods. The market shares of conventional technologies by OSA are considered constant from 2020 to 2050. N represents the number of OSAs (in this case, three: Athabasca, Cold Lake, and Peace).

The interest rates were extracted from previous studies by our research group on long-term GHG and water projections [13, 64, 91, 92] and range from 5.0 and 10.0%. A median value of 7.5% was assumed to run the market-share model and perform the cost-benefit analysis. For the energy industry, the cost variance parameter is from 6 to 10, according to Nyboer [86]. A median value of 8 was assumed and assigned to run the model and obtain the technology shares for each scenario. Lastly, the lifetime of each in situ recovery pathway was assumed to be fixed and equal to 30 years [93]. A more pessimist case of a 20-year lifetime [93] was assessed in the sensitivity analysis.

The data for each in situ bitumen extraction technology used to calculate the annualized lifetime costs are presented in Table 2-2. Assumptions and adaptations were used for some input values when none were given in the literature. For instance, for LASER technology, Imperial Oil states that GHG emissions could be reduced by approximately 20-25% from its CSS application in the Cold Lake facility [42, 94] without mentioning how much electricity and/or natural gas will be required or how much energy will be saved compared to CSS technology. For the blowdown boiler, when make-up water is reduced by about half, operating costs will also drop because fewer chemicals are needed to treat the water for steam production. Nonetheless, electricity requirements will increase because of the introduction of a new evaporator into the system. None of these increases and decreases were quantitatively estimated or provided in studies [51, 95]; therefore, energy requirements were assumed to be the same as conventional SAGD technology. Despite the uncertainties related to the input data, the model can be easily adapted for future work as values related to energy intensities and costs become available for novel in situ bitumen extraction technologies.

Natural gas and electricity price projections were extracted from research by our colleagues Davis et al. [18], who obtained them from endogenous modelling that takes into account different carbon pricing environments. These projections are presented in Figure 2-2. For carbon price, the values are based on Alberta's TIER regulation [89] and Canada's National Carbon Pollution Price Schedule (2023-2030) [90], which projects carbon price to linearly increase from \$65/tCO_2e in 2023 to \$170/tCO_2e in 2030. From 2030-2050, carbon price is assumed to remain constant in \$170/tCO_2e. In this work, all monetary values are expressed in Canadian dollars.

Table 2-2: Unit cost, energy, and GHG intensity data of in situ extraction technologies

Technology type	Technology	Capital cost (CC) (2020$/ $m^3_{bitumen}$)	Operating cost (OC) (2020$/ $m^3_{bitumen}$)	Natural gas intensity (GJ/ $m^3_{bitumen}$)	Electricity intensity (kWh/ $m^3_{bitumen}$)	GHG intensity[1] (tCO_2/ $m^3_{bitumen}$)	Source
Conventional	SAGD	59.8	72.3	7.00	100	0.457	Nimana et al. [96]
	CSS	65.7	79.8	8.05	115	0.545	Nimana et al. [96]
SA	SA-SAGD	56.8	103.5	4.55	100	0.295	CC and OC adapted from Toro Monsalve et al. [76] Natural gas and electricity intensity adapted from Umeozor et al. and Radpour et al. [13, 38]
	LASER	98.2	114.2	5.20	115	0.405	Adapted from Toro Monsalve et al. [76] and Nimana et al. [96]
SB	Nsolv	48.0	207.0	0.51	124	0.078	CC and OC from Toro Monsalve et al. [76] Natural gas and electricity intensity from Soiket et al. [45]

Technology type	Technology	Capital cost (CC) (2020$/ $m^3_{bitumen}$)	Operating cost (OC) (2020$/ $m^3_{bitumen}$)	Natural gas intensity (GJ/ $m^3_{bitumen}$)	Electricity intensity (kWh/ $m^3_{bitumen}$)	GHG intensity[1] (tCO_2/ $m^3_{bitumen}$)	Source
	ESEIEH	100.7	140.2	0.79	591	0.281	CC and OC from Toro Monsalve et al. [98] Natural gas & electricity intensity adapted from Safaei et al. [48]
	EBRT	48.0	207.0	2.10	100	0.158	CC and OC assumed the same as Nsolv. Natural gas and electricity intensity adapted from Imperial Oil and Radpour et al. [13, 49]
Other novel technologies	SEGD	100.7	140.2	5.25	100	0.334	CC and OC assumed the same as ESEIEH. Natural gas and electricity intensity adapted from Nduagu et al. and Radpour et al. [13, 51]
	Blowdown boiler	59.8	72.3	7.00	100	0.457	Assumed to be the same as SAGD technology, except CC

Technology type	Technology	Capital cost (CC) (2020$/ $m^3_{bitumen}$)	Operating cost (OC) (2020$/ $m^3_{bitumen}$)	Natural gas intensity (GJ/ $m^3_{bitumen}$)	Electricity intensity (kWh/ $m^3_{bitumen}$)	GHG intensity[1] (tCO_2/ $m^3_{bitumen}$)	Source
							which was considered 25% more expensive than SAGD [51]

[1]GHG intensity data obtained from the natural gas and electricity intensity through the LEAP-Canada model

2.2.4. LEAP-Canada model

The novel in situ bitumen extraction technologies were incorporated into the LEAP-Canada model to project their GHG emissions intensities in tonnes of CO_2 emitted per cubic meter of bitumen produced from the technologies' electricity and natural gas intensities. The emission factors are based on the values provided in LEAP's Technology and Environmental Database (TED), which applies IPCC emission factors [99]. The GHG intensity of each technology is used as an input to run the market-share model and project the market shares of novel low-carbon technologies (see Section 2.3 Market-share model). The projected market shares and GHG intensities are used as inputs in the LEAP-Canada model to project disaggregated GHG emissions and mitigation potential by technology, OSA, and scenario according to Equations 8 and 9, respectively.

$$GHG_{j,y,s,OSA} = BP_y MS_{j,y,s,OSA} GHGI_j \tag{8}$$

$$MGHG_{ns,OSA} = \sum_{y=2020}^{2050} \left(\sum_{j=1}^{J_{REF}} GHG_{j,y,REF,OSA} - \sum_{j=1}^{J_{ns}} GHG_{j,y,ns,OSA} \right) \tag{9}$$

$GHG_{j,y,s,OSA}$ is the projected GHG emissions from technology j, in year y, for scenario s, and oil sands area OSA. $MGHG_{ns,OSA}$ represents the cumulative GHG mitigation potential of novel scenario ns segregated by oil sands area OSA. J_{REF} and J_{ns} represent the total number of technologies considered in the REF and novel scenarios, respectively.

The in situ bitumen production projection used as input in the market-share model was obtained from the LEAP-Canada model [100], which was calculated from historical crude oil prices and annual capital investments for in situ extraction technologies. The projection for in situ production is presented in Figure 2-2 together with CER-current policies (CER-CP) and -evolving policies (CER-EP) scenarios' projections for comparison [101].

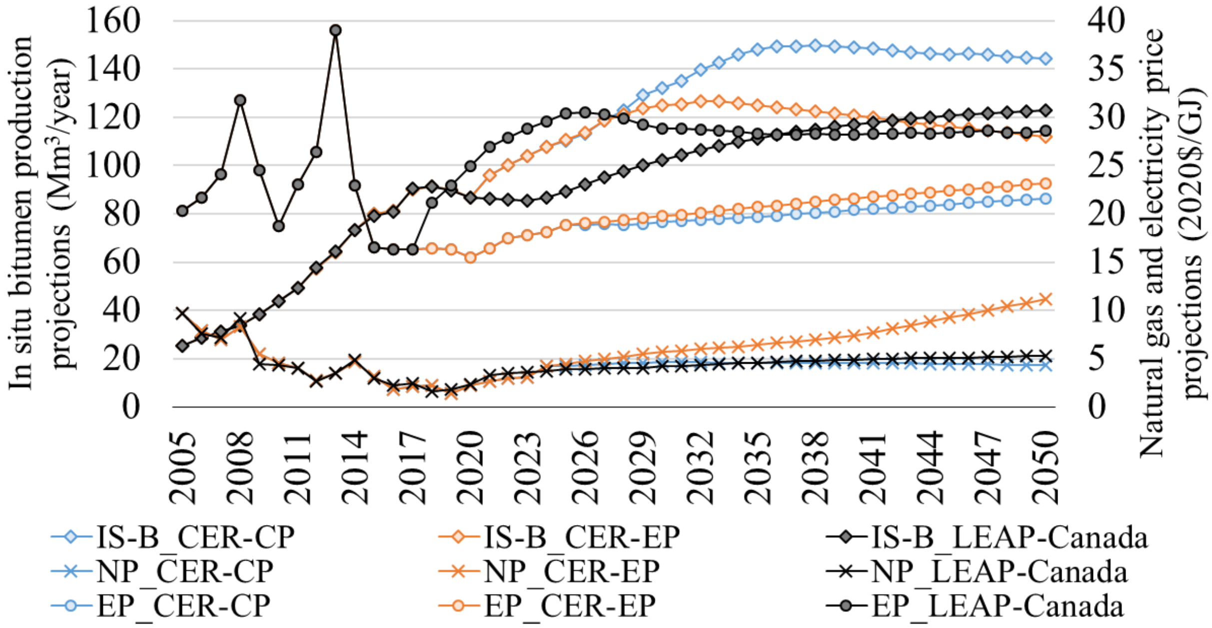


Figure 2-2: In situ bitumen production, natural gas, and electricity price projections from CER-CP and -EP scenarios [101] and the LEAP-Canada model [100]

The acronyms "IS-B_," "NP_," and "EP_" stand for in situ bitumen production, natural gas, and electricity price projections. The CER projections are higher than the LEAP-Canada projection between 2020 and 2042 for in situ bitumen production. The LEAP-Canada projection for in situ bitumen production is higher than CER-EV after 2042 but remains lower than the projected values of the CER-CP scenario. The LEAP-Canada projection for 2050 is 122.9 $Mm^3_{bitumen}$, and the CER-CP and CER-EP projections are 144.2 and 111.9 $Mm^3_{bitumen}$, respectively. For natural gas price, LEAP-Canada's projection is similar to CER-CP's values. For electricity price, LEAP-Canada's projections are considerably higher than CER-CP and -EP values.

2.2.5. WEAP-Canada model

The novel in situ bitumen extraction technologies and scenarios were added to the WEAP-Canada model to calculate yearly water consumption. A schematic of the WEAP-Canada model is presented in Figure 2-3, highlighting the water supply-demand sites in the province of Alberta. Even though not all of WEAP's features are necessary to obtain the results for this work, WEAP provides a robust framework to assess multiple scenarios and technologies disaggregated by river basins.

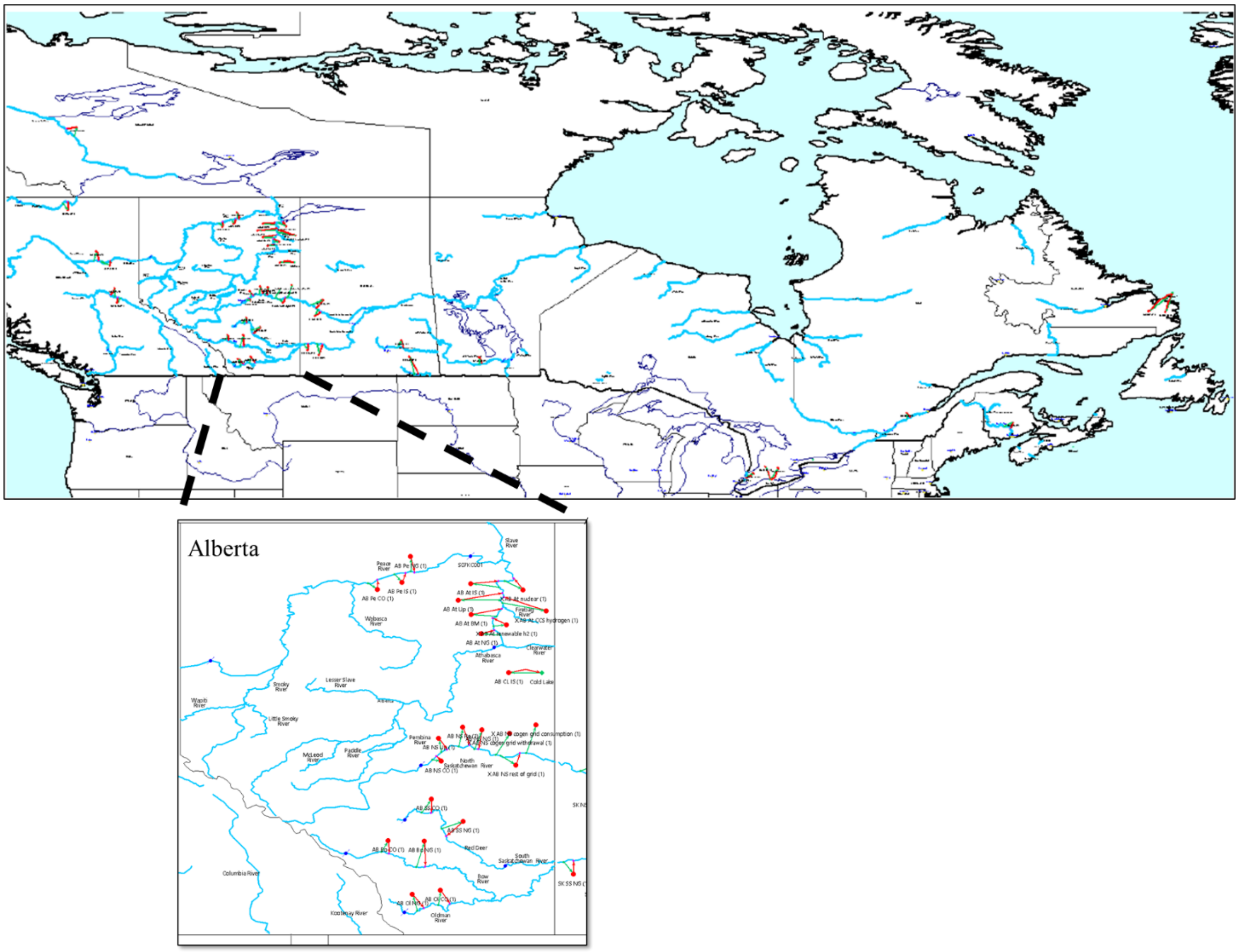


Figure 2-3: Schematic of the WEAP-Canada model highlighting the province of Alberta adapted from Gupta et al. [66]

The projected market shares and water intensities are used as inputs in the WEAP-Canada model to project disaggregated water consumption and cumulative savings potential by technology, OSA, and scenario, as described in Equations 10 and 11, respectively. Table 2-3 presents the 2020 water intensity values in cubic meters of water consumed per cubic meters of bitumen produced for each in situ extraction technology and by OSA. A more detailed yearly breakdown of water intensities is in the Appendices.

$$WR_{j,y,s,OSA} = BP_y MS_{j,y,s,OSA} WRI_j \quad 10$$

$$MWR_{ns,OSA} = \sum_{y=2020}^{2050} \left(\sum_{j=1}^{J_{REF}} WR_{j,y,REF,OSA} - \sum_{j=1}^{J_{ns}} WR_{j,y,ns,OSA} \right) \quad 11$$

$WR_{j,y,s,OSA}$ is the projected water consumption from technology j in year y for scenario s and oil sands area OSA. $MWR_{ns,OSA}$ represents the cumulative water savings potential of novel scenario ns and segregated by oil sands area OSA.

For conventional technologies, all water intensity values, WRI, were extracted from our research colleagues' WEAP-Canada model [53], which uses actual industrial water-use data for SAGD and CSS facilities in Alberta from AER's Thermal In Situ (TIS) Water Publication [102]. The water demand of primary production is not available from industry and therefore we used Ali and Kumar's values [29]. For the novel low-carbon in situ extraction technologies, water-use data is also limited. The water intensity data was estimated from industrial reports (for SA-SAGD, LASER, EBRT, and blowdown boiler) and process simulations (for Nsolv, ESEIEH, and SEGD). Linear interpolations were made to adjust the water intensity values from one OSA to another whenever data was unavailable. The water intensities for the conventional and novel technologies were assumed to remain constant from 2022 to 2050. A dash was placed in the cells of recovery technologies that do not operate in the OSA listed.

Table 2-3: 2020 water intensity ($m^3_{water}/m^3_{bitumen}$) data of in situ extraction technologies by OSA

Technology type	Technology	OSA			Source
		Athabasca	Cold Lake	Peace	
Conventional	SAGD	0.216	0.296	-	[102]
	CSS	-	0.752	6.463	[102]
	Primary	0.650	0.650	0.650	[29]
SA	SA-SAGD	0.255	0.349	-	Cold Lake [39] Athabasca: adapted from SAGD Athabasca/Cold

Technology type	Technology	OSA			Source
		Athabasca	Cold Lake	Peace	
					Lake and SA-SAGD Cold Lake values
	LASER	-	0.564	4.847	[103]
SB	Nsolv	0.209	0.286	-	Cold Lake [45] Athabasca: adapted from SAGD Athabasca/Cold Lake and Nsolv Cold Lake values
	ESEIEH	0.088	0.120	-	Cold Lake [48] Athabasca: adapted from SAGD Athabasca/Cold Lake and ESEIEH Cold Lake values
	EBRT	0.058	0.079	-	Cold Lake [49] Athabasca: adapted from SAGD Athabasca/Cold Lake and ERBT Cold Lake values
Other novel technologies	SEGD	0.200	0.274	-	Athabasca [51] Cold Lake: adapted from SAGD Athabasca/Cold Lake and SEGD Athabasca values
	Blowdown boiler	0.108	0.148	-	[38]

2.2.6. Cost-benefit analysis

A cost-benefit analysis was performed to understand the cost-effectiveness of the decarbonization scenarios in terms of marginal GHG abatement and water savings costs. The marginal GHG abatement and water savings costs for each scenario were obtained with Equation 12 and 13, respectively.

$$MAC_{ns} = \frac{\sum_{y=2020}^{2050} BP_y\left[\left(\sum_{OSA=1}^{N}\sum_{j=1}^{J_{ns}} MS_{j,y,ns}LCC_{j,y}\right) - \left(\sum_{OSA=1}^{N}\sum_{j=1}^{J_{REF}} MS_{j,y,REF}LCC_{j,y}\right)\right]}{\sum_{OSA=1}^{N} MGHG_{ns,OSA}} \tag{12}$$

$$MSC_{ns} = \frac{\sum_{y=2020}^{2050} BP_y\left[\left(\sum_{OSA=1}^{N}\sum_{j=1}^{J_{ns}} MS_{j,y,ns}LCC_{j,y}\right) - \left(\sum_{OSA=1}^{N}\sum_{j=1}^{J_{REF}} MS_{j,y,REF}LCC_{j,y}\right)\right]}{\sum_{OSA=1}^{N} MWR_{ns,OSA}} \tag{13}$$

MAC_{ns} represents the marginal cost of each tonne of CO_2 abated in the novel scenario ns and MSC_{ns} is the marginal cost of each cubic meter of water saved in scenario ns. The total annualized costs are brought to the present value, discounted at a rate of 7.5%. The numerator of Equations 12 and 13 represents the total system cost difference between the novel scenario and the reference scenario, while the denominator represents the cumulative GHG abated and water savings. The units of the marginal abatement and savings costs are in 2020 Canadian dollars per tonne of CO_2 abated and per cubic meter of water saved, respectively. The marginal costs are broken down into marginal capital, operating, energy, and carbon costs.

2.2.7. Sensitivity analysis

Sensitivity analysis is performed to investigate the output parameter sensitivity to variation of individual input parameters. In this work, the Morris sensitivity analysis was performed with the help of RUST to assess the sensitivity of the cumulative water savings and GHG abatement, and the marginal GHG abatement and water savings cost to variations in input values. The Morris sensitivity method is not a one-at-a-time approach; instead, it considers the interactions between the input parameters by examining the sensitivity of the output variables across the entire parameter domain. This is done by calculating several partial derivatives for each selected input in different locations of the parameter space. The mean and standard deviation of the absolute values of the partial derivatives are obtained and used to obtain the Morris plot for each output analyzed. In the Morris plot, the sensitive inputs are located at the top right of the chart and insensitive variables on the bottom left [104].

Table 2-4 gives the input parameters used in the sensitivity analysis, the baseline values, the variation of the baseline, and the justification of each variation assumed.

Table 2-4: Sensitivity analysis input parameters

Input variable	Baseline value	Variation	Comment
Discount rate	7.5%	± 2.5%	Based on values used in previous studies by our research group on long-term GHG emissions and water consumption projections [13, 64, 91, 92].
Cost variance	8.0	± 2	Based on different values for the energy industry from Nyboer [86].
Technology lifetime	30	- 10	Based on values used in industry [93].
Technology-specific capital and operating costs	See Table 2-2	*(1±0.25)	An arbitrary 25% variation from the baseline values was assumed, as capital and operating costs data are limited in the literature. All novel technologies were considered.
Technology-specific electricity, natural gas, and carbon intensities	See Table 2-2	*(1±0.25)	An arbitrary 25% variation from the baseline values was assumed. The variation rate is equal to the value used for the technology-specific capital and operating costs since the technology-specific energy intensities and costs are used with the same weight in the market-share model to obtain the market shares of the novel scenarios. All novel technologies were considered.

2.3. Results and Discussion

2.3.1. Model validation

To validate the water consumption and GHG emission values obtained with the WEAP- and LEAP-Canada models, the historical results captured between 2005 and 2020 were compared with the in situ bitumen recovery industry values obtained from AER's Thermal In Situ (TIS) Water Publication [102] and Environment and Climate Change Canada [105]. The values are presented in Figure 2-4.

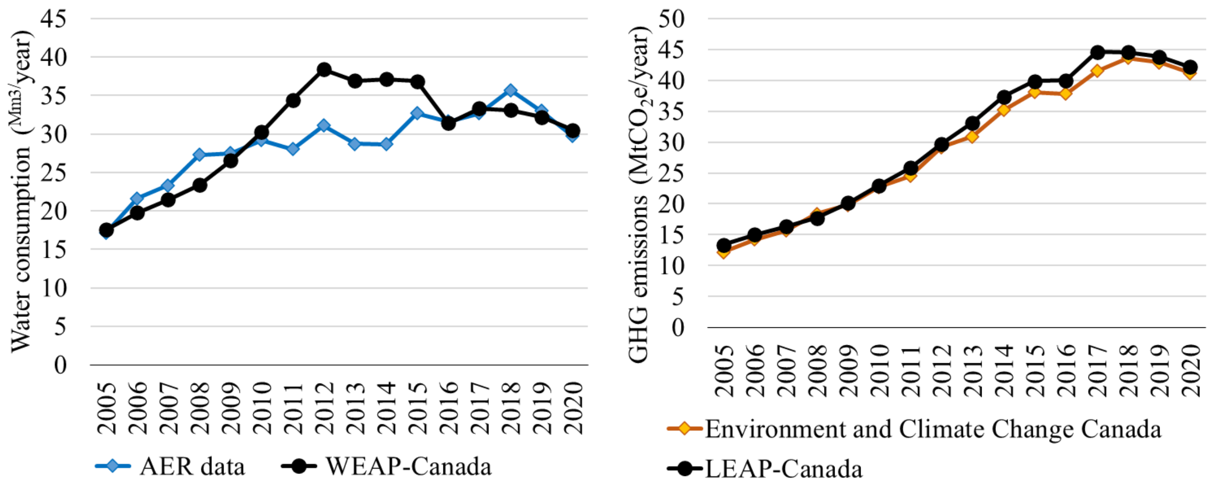


Figure 2-4: Validation of the results of the WEAP- and LEAP-Canada models in compared to literature [102, 105]

The results obtained with the WEAP- and LEAP-Canada models are in good agreement with the historical values for the in situ bitumen production industry. The water consumption and GHG emissions obtained vary by a maximum of 23% and 8.5% and an average of 3.5% and 3.8% from the historical values used in the analysis. For water consumption, the highest variation (23%) is observed for the year 2014 and for GHG emissions, the highest variation (8.5%) is observed for the year 2005. The historical values provided by Environment and Climate Change Canada present the GHG emissions data in an aggregated format for the in situ oil sands industry. The AER publication considers freshwater and alternative water used by SAGD and CSS operations across the three OSAs in Alberta. The large differences in water consumption may be due to not considering primary bitumen production water consumption. AER considers SAGD and CSS facilities across Alberta, and it is unclear whether primary bitumen production sites are considered. In this study, historical water consumption of primary recovery is considered, and although primary technology has lower production shares than conventional bitumen recovery, the water intensity of the former is three times higher than the water intensity of conventional SAGD.

2.3.2. Market share results

The market shares projections of each technology and scenario are presented in Figure 2-5. The in situ bitumen production projection of each technology and scenario is given in the Appendices.

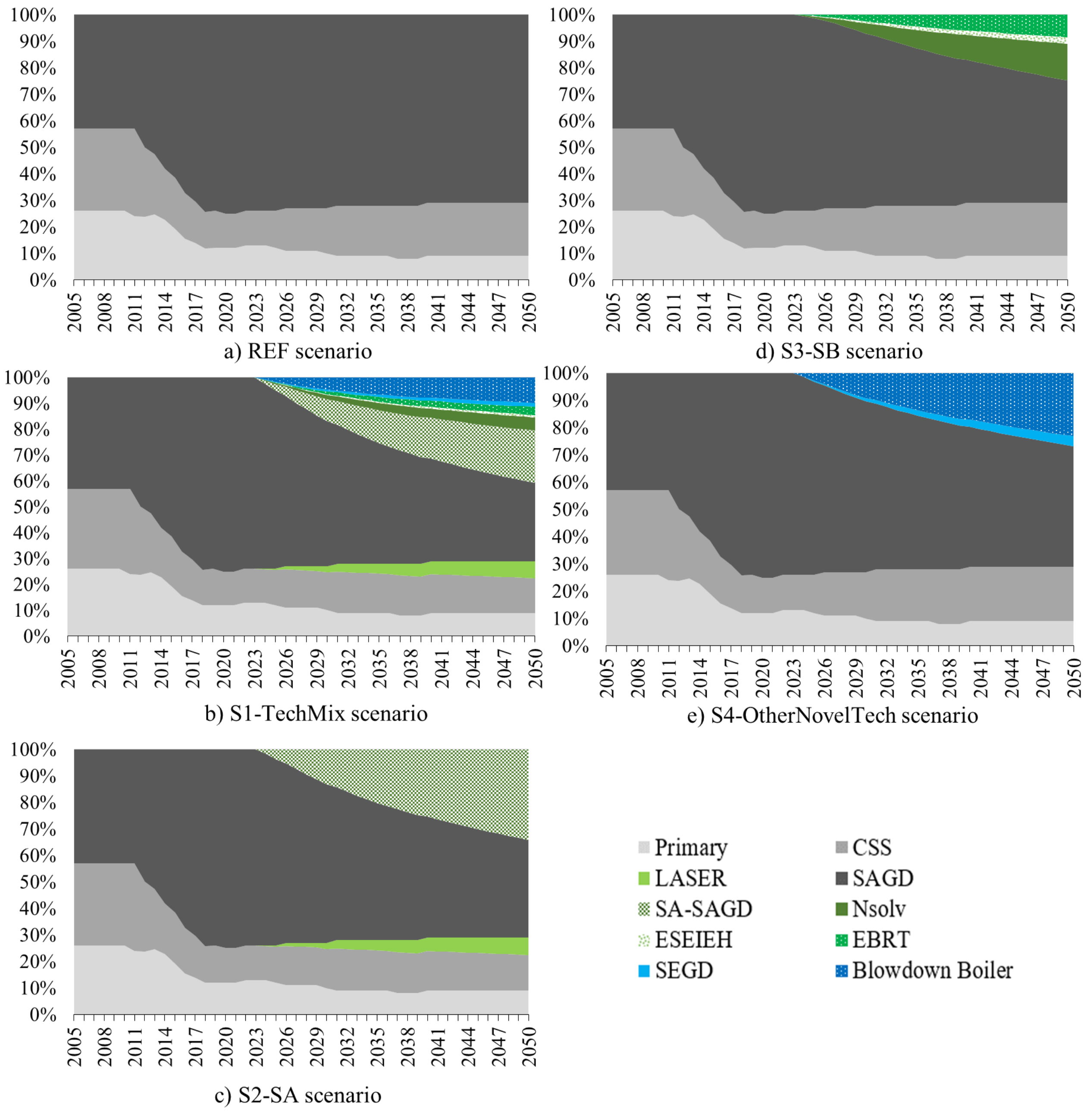


Figure 2-5: Market share projections for each scenario

In general, the market share model favors the penetration of less expensive options. For the S1-TechMix scenario, SA technologies penetrate the market more aggressively than SB and other novel recovery pathways. The SB technologies do not play an important role in bitumen production compared to SA and other novel low-carbon extraction options; this is explained by the higher unit costs (all the cost reported in this paper are in base year 2020) of the former – \$283/$m^3_{bitumen}$ for on average for SB technologies, and \$218/$m^3_{bitumen}$ and \$229/$m^3_{bitumen}$ on average for SA and other novel low-carbon technologies, respectively.

For the S2-SA scenario the market shares of LASER and SA-SAGD technologies increase steadily because they are less energy- and carbon-intense than conventional recovery. As natural gas, electricity, and carbon prices are projected to grow, the total costs of the novel technologies will decrease and favour market penetration. For the S3-SB scenario, EBRT and Nsolv penetrate the market aggressively, with bitumen production shares in 2050 of 13% for Nsolv and 8% for EBRT. As shown in Figure 2-5, ESEIEH penetrates the market only slightly, with an in situ bitumen production share in 2050 of just 2%; the low penetration is due to the high electricity demand (591 kWh/$m^3_{bitumen}$), which leads to high energy costs, thus negatively impacting the market penetration of this novel technology. Lastly, for the S4-OtherNovelTech scenario, the blowdown boiler technology predominately penetrates the market after SAGD, largely because it is \$86/$m^3_{bitumen}$ less expensive than SEGD and \$15/$m^3_{bitumen}$ more expensive than conventional SAGD in 2020. Even though the blowdown boiler and SEGD are more expensive than SAGD, the novel low-carbon technologies still increase their market penetration year over year as conventional SAGD capacity retires and is added to the technology competition in the market share modelling.

The market penetration projections show that novel low-carbon technologies will take between 25 and 47% of the in situ bitumen production shares by 2050. S3-SB is the most conservative scenario, accounting for 25% of the in situ bitumen produced in 2050 by novel recovery technologies. A higher penetration of low-carbon technologies is seen in the S1-TechMix scenario, with 47% of bitumen shares from novel recovery pathways, followed by the S2-SA and S4-OtherNovelTech scenarios with 41% and 27% of the in situ bitumen produced in 2050 by emerging low-carbon extraction technologies, respectively. The shares of novel technologies in the S3-SB scenario are lower than in the S2-SB scenario, since the emerging technologies considered in the former are more expensive than any other novel low-carbon option and only compete with SAGD, while the S2-SA scenario considers the LASER technology that replaces conventional CSS.

2.3.3. GHG emissions results

The yearly projections for total GHG emissions, in millions of tonnes of CO_2-equivalent, for each scenario from 2005 to 2050 are presented in Figure 2-6, and a more detailed breakdown of the results by scenario and technology is presented in Figure 2-7.

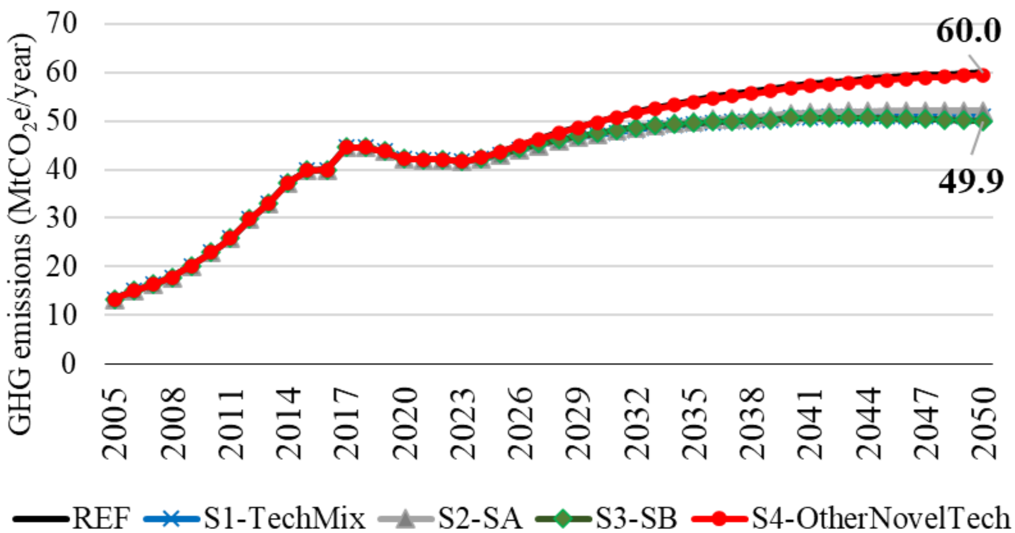


Figure 2-6: Total yearly GHG emissions projection by scenario

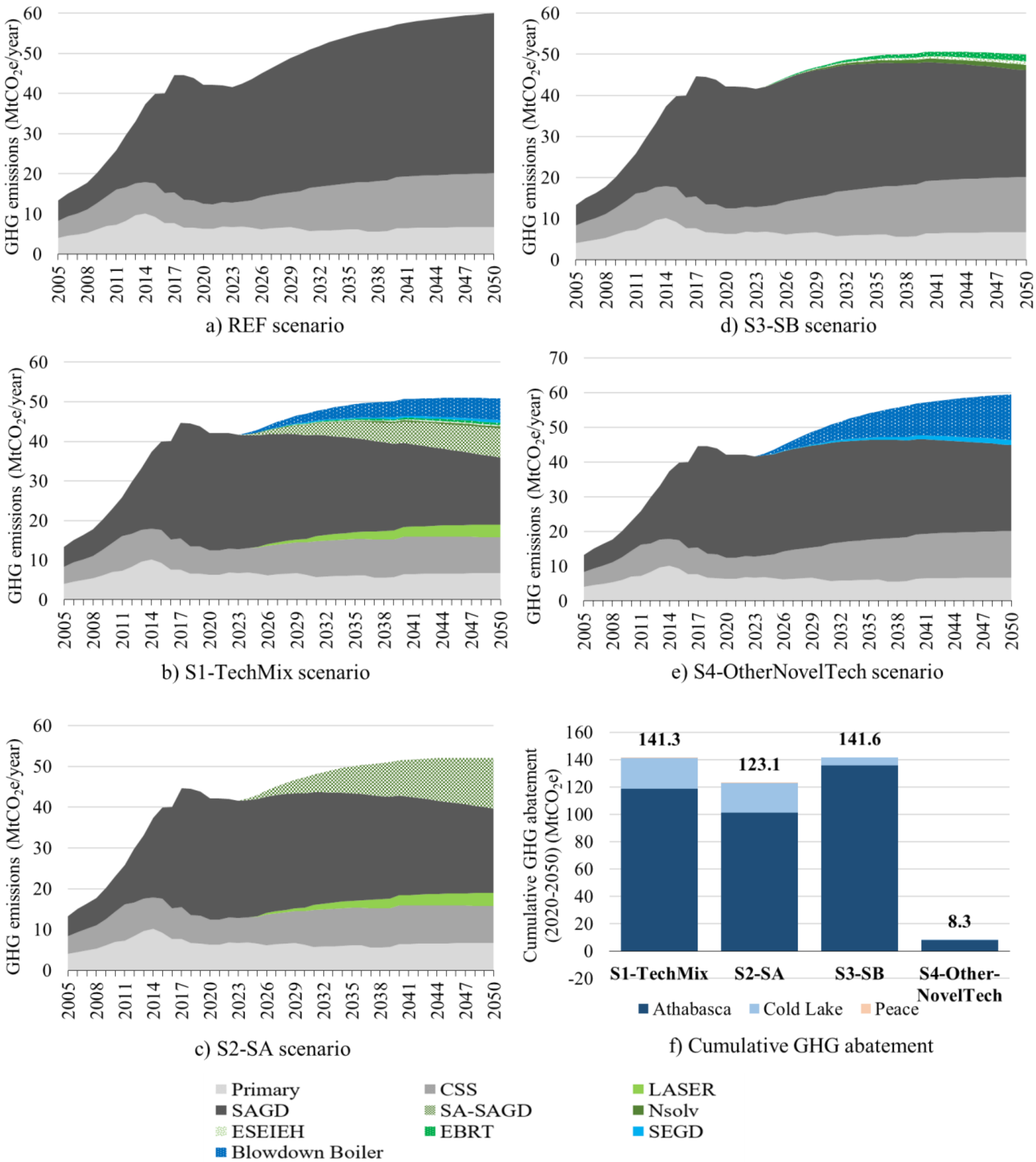


Figure 2-7: Yearly GHG emissions projection by scenario and technology and cumulative GHG abatement between 2020 and 2050 by scenario

For all novel scenarios, GHG emissions projections are lower than the reference case. In 2030 and 2050, the yearly total GHG emissions for the reference scenario are 49.9 and 60 $MtCO_2e$, respectively, which are close to Canada's GHG gas and air pollutant emissions projections for 2030 [106] of 55 $MtCO_2e$. The highest GHG abatement potential is observed for S3-SB. For this scenario, the GHG emissions are 47.5 $MtCO_2e$ in 2030 and 49.9 $MtCO_2e$ in 2050, 5% and 17% lower than the reference scenario in those years. The lower emissions in 2050 are due to the retirement of existing conventional facilities and an increase in energy and carbon price that favours the market penetration of low-carbon recovery technologies. The highest GHG emissions of 59.5 $MtCO_2e$, observed for S4-OtherNovelTech in 2050, are expected, as the blowdown boiler recovery technology has the same natural gas and electricity intensities as conventional SAGD, thus leading to the same GHG intensity. The slightly lower GHG emissions of S4-OtherNovelTech compared to the reference case is due to the penetration of SEGD technology, which is 27% less GHG-intense than conventional SAGD. For the S3-SB scenario, even though the ESEIEH recovery technology penetrates the market only slightly, the total GHG emissions projected for 2050 are 17% lower than the emissions from the reference case. The projected GHG emissions from S3-SB could be less than 49.9 $MtCO_2e$ in 2050 if novel low-carbon SB technologies replace CSS installations, as this conventional recovery technology represents 27% of the total GHG emissions from S3-SB in 2050.

The shares of GHG emissions differ by OSA. For the S1-TechMix scenario, the Athabasca-OSA is responsible for most of the emissions from in situ bitumen extraction, accounting for 66% of the cumulative GHG emissions between 2005 and 2050, with the Cold Lake-OSA accounting for 30% and the Peace-OSA the remaining 4%. Since the GHG intensity of each recovery technology is the same in each OSA, the GHG emissions will be higher in the OSA where most of the in situ bitumen is produced, the Athabasca-OSA. If the emissions cap is defined differently by OSA, the shares of GHG emissions per OSA represent relevant information for policy-makers. The cumulative GHG abatement potential of the decarbonization scenarios from 2020 to 2050 are presented in Figure 2-7.

The S3-SB scenario presents the highest cumulative GHG abatement potential of 142 $MtCO_2e$. The S1-TechMix decarbonization pathway presents a similar projected cumulative GHG abatement of 141 $MtCO_2e$ by 2050. Although the S3-SB scenario shows the potential of novel in situ recovery methods with low technology readiness level to replace conventional SAGD, it does not consider a low-carbon technology capable of replacing CSS. CSS is a major contributor to S3-

SB GHG emissions, indicating significant potential for greater GHG abatement with the development and implementation of emerging SB technologies. The GHG abatement potential of the S4-OtherNovelTech scenario differs considerably from the cumulative GHG abatement of the other three novel scenarios, accounting for a cumulative 8.6 $MtCO_2e$ GHG mitigation due to savings from the penetration of SEGD technology. As shown in Figure 2-7, the cumulative GHG abatement primarily comes from the Athabasca-OSA. This OSA accounts for 87.7% of the GHG abated, followed by the Cold Lake-OSA with 12.1% and the Peace-OSA with the remaining 0.2%. As pointed out previously, the larger abatement potential of the Athabasca-OSA is due to the larger bitumen production shares in this region.

2.3.4. Water use results

The yearly projections for total water consumption, in millions of cubic meters of water, for each scenario from 2005 to 2050 are presented in Figure 2-8. A more detailed breakdown of the results by scenario and technology is presented in Figure 2-9.

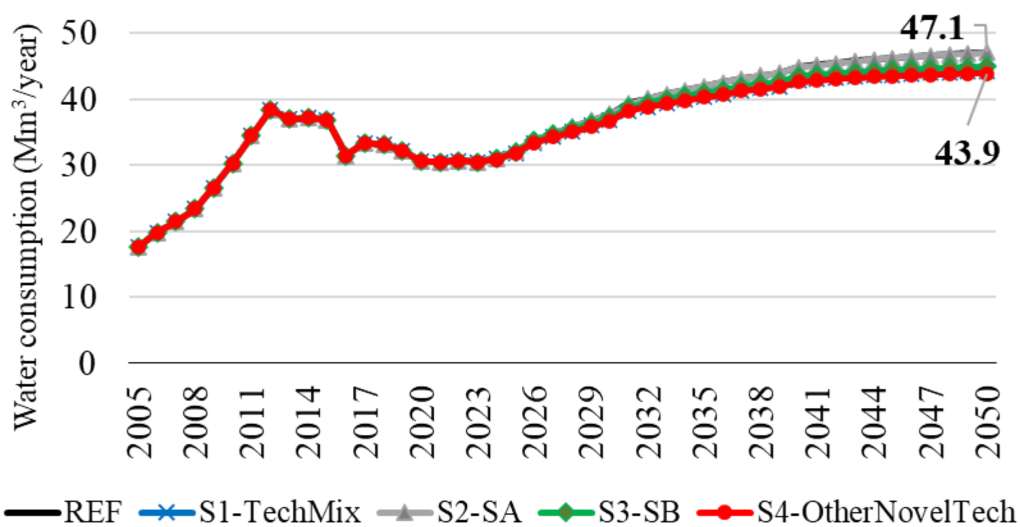


Figure 2-8: Total yearly water consumption projection by scenario

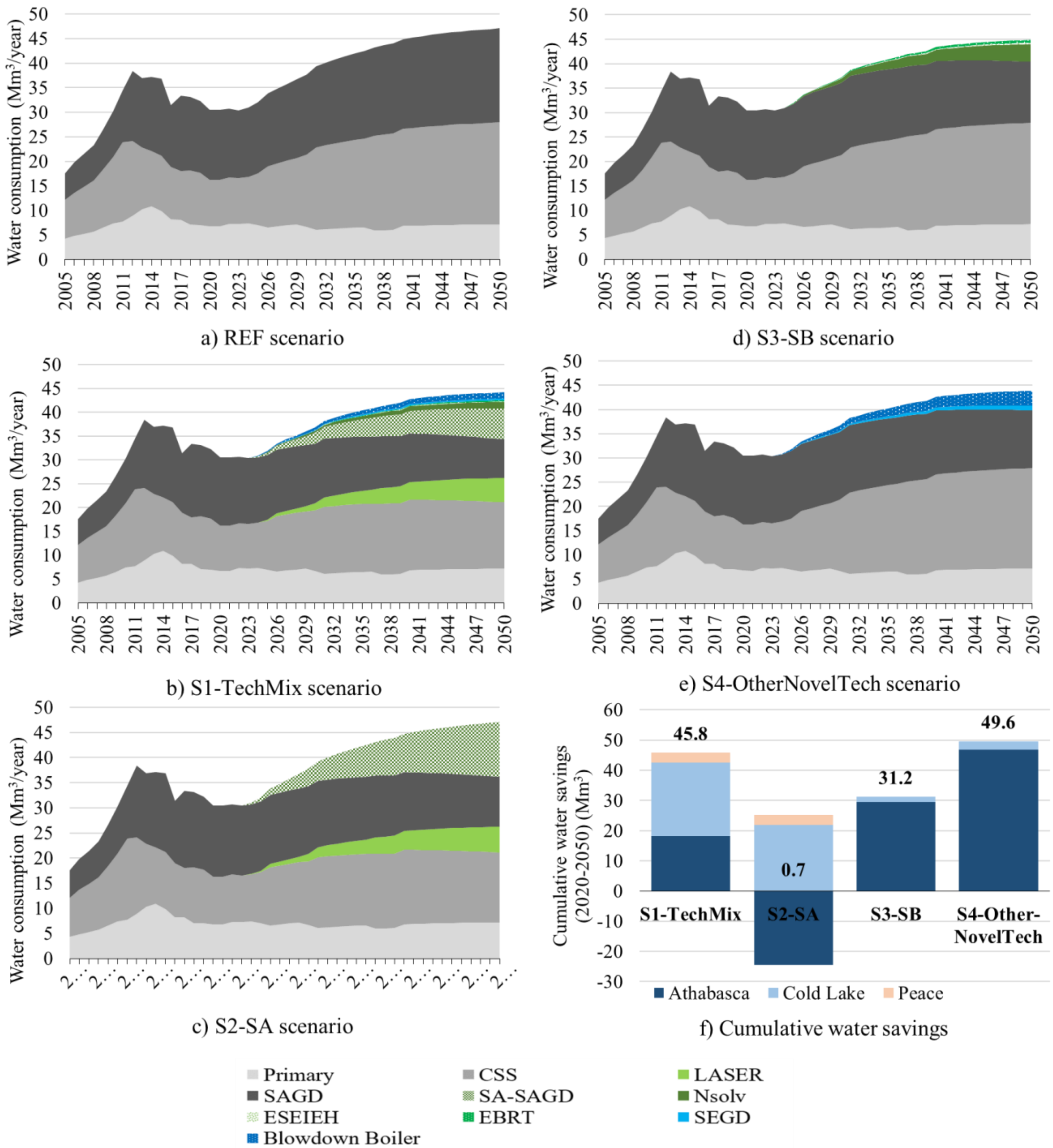


Figure 2-9: Yearly water consumption projection by scenario and technology and cumulative water savings between 2020 and 2050 by scenario

The water consumption results are in good agreement with the projections in the literature [20, 24]. Previous studies projected a total water consumption of 38 Mm^3 in 2030, and the results in this study range from 36.7 to 37.8 Mm^3 for the same year. All scenarios lead to lower water consumption; however, differently from the GHG emissions, S4-OtherNovelTech has the best performance in reducing water consumption. The projection for 2050 shows that water consumption will be 43.9 Mm^3 for this scenario, 7% less than the reference case. The worst performance in terms of reducing water consumption is observed for S2-SA. The projected water consumption in 2050 for this scenario is 47.0 Mm^3, only 0.8% lower than the reference case. For S2-SA, even though LASER technology is 25% less water intense than conventional CSS, the SA-SAGD recovery method consumes 18% more water than SAGD. It is important to point out that the difference in water consumption between the reference case and the S2-SA scenario in 2050 will not be equal to the difference in the percentage of water intensities from LASER and SA-SAGD technologies, once these recovery methods penetrate the market at different rates (see Figure 2-5). For S3-SB, the total water consumption is only lower than for S2-SA. CSS technology accounts for 41% of S3-SB scenario water consumption, showing the potential for further water savings with the implementation of novel SB technologies capable of replacing conventional CSS. SA technologies demand more water than SB technologies because of the higher water intensity values of the former; for example, SA-SAGD consumes 0.05 and 0.20 cubic meters more of water per cubic meter of bitumen than Nsolv and EBRT, respectively. For S4-OtherNovelTech, the lower amount of water consumption is related to the fact that the blowdown boiler technology and SEGD are 50% and 7% less water intense than conventional SAGD, respectively.

For total water use, the Athabasca- and Cold Lake-OSAs account for 45.6 and 45.9% of the total water consumption between 2005 and 2050, respectively, and the Peace-OSA the remaining 8.5%. Despite the higher bitumen production shares for the Athabasca-OSA, the high water consumption of the Cold Lake-OSA is mainly due to the higher water intensities associated with the recovery technologies used in this OSA. This information is crucial for projecting the water demand of different watersheds in Alberta and being able to evaluate how water stress levels will change in the long term for different water bodies.

The cumulative water savings between 2020 and 2050 are shown in Figure 2-9 based on the yearly projections for water consumption in each scenario. These results are also key for the cost-benefit analysis and directly influence the water savings costs.

The greatest cumulative water savings are observed for the S4-OtherNovelTech scenario, 49.6 Mm^3_{water}. As pointed out before, the S4-OtherNovelTech scenario combines the blowdown boiler technology, which is 50% less water intense than conventional SAGD, and SEGD, which consumes 7% less water than SAGD. The S1-TechMix scenario presents the second-best performance in terms of water savings. The cumulative 45.8 Mm^3_{water} savings are due to the combined savings that come from novel low-carbon technologies replacing SAGD and CSS. The cumulative 31.2 Mm^3_{water} savings for S3-SB could be higher if conventional CSS were replaced with SB-type technology. This is highlighted by the fact that most of the water savings in the S3-SB scenario comes from the Athabasca-OSA, with small water savings from the Cold-Lake-OSA – from which the market shares of CSS-type technologies are higher. For S2-SA, the Athabasca-OSA does not contribute to water savings; instead, water consumption is higher than in the reference case. This is because SA-SAGD replaces conventional SAGD and is 18% more water intense than the latter.

2.3.5. Integrated cost-benefit assessment

The marginal GHG abatement and water savings costs of each novel scenario are presented in Figure 2-10. The marginal costs are discounted at a rate of 7.5% to give the net present value in the first year of the market penetration period (2020).

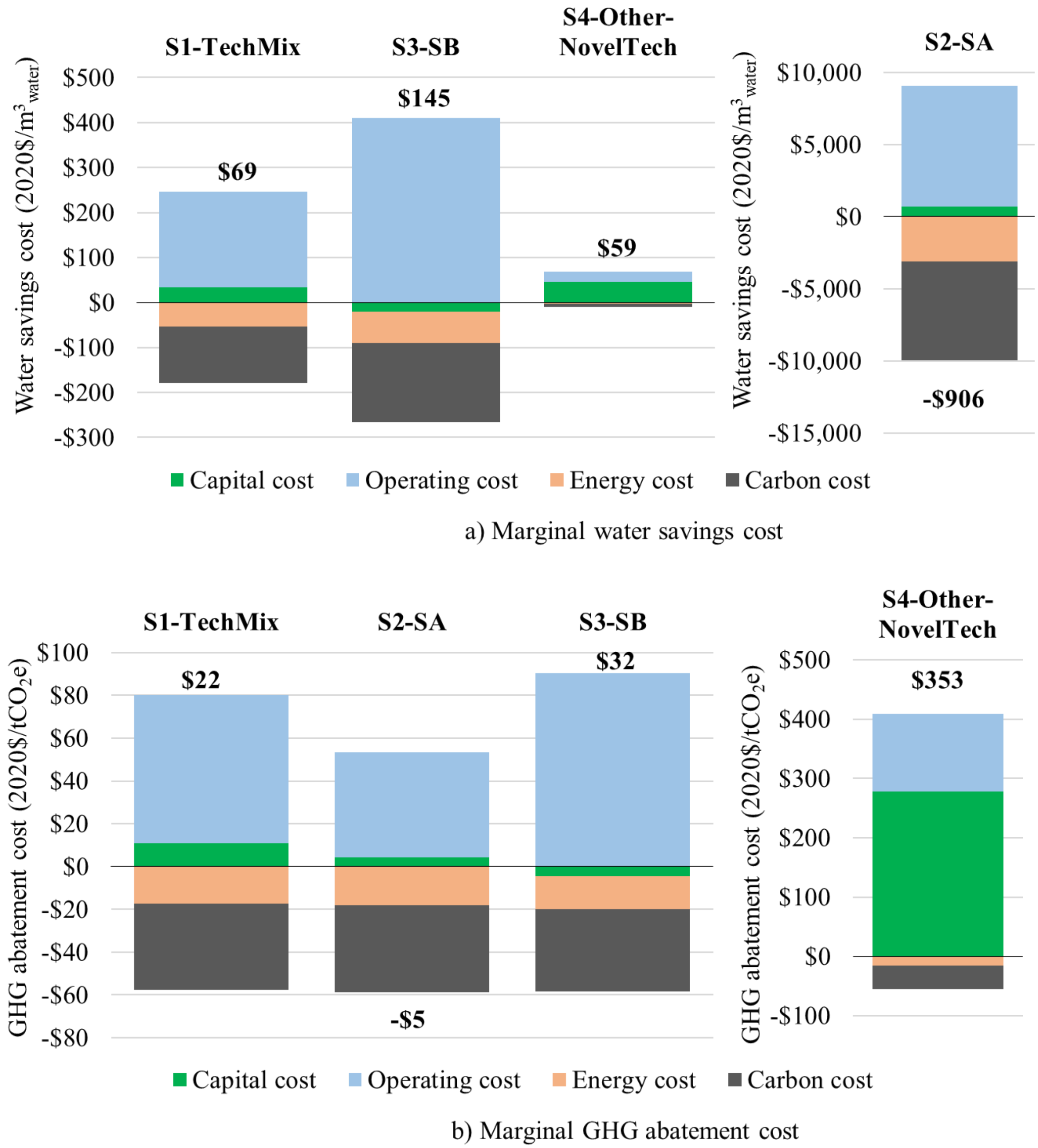


Figure 2-10: Water savings and GHG abatement costs for each scenario

The marginal costs are either negative or positive values. Energy and carbon costs reduce the overall GHG abatement and water savings cost of each scenario because novel low-carbon technologies are less energy and carbon intense than conventional SAGD and CSS. Nevertheless, the higher capital and operating costs of the emerging technologies are still dominant in leading to costs instead of benefits.

The financial benefit in terms of water savings for S2-SA and increased cost in terms of GHG abatement for S4-OtherNovelTech are explained by the cumulative water savings and GHG abatement of each scenario, respectively. For S2-SA, the cost difference between the novel SA technologies and conventional SAGD and CSS is negative, which means that this scenario will lead to cost savings (or benefits) as far as cumulative water savings and GHG abatement are concerned. Since the cumulative water savings for S2-SA is considerably small (0.7 Mm^3 of water savings from 2020 to 2050), the denominator of the Equation **13** becomes small and lead to a high water savings benefit. A similar interpretation is given to the GHG abatement cost of S4-OtherNovelTech. As the capital and operating costs of the blowdown boiler and SEGD technologies drive the cost difference between the novel and reference scenario to a positive number, the lower cumulative GHG abatement of 8.3 $MtCO_2e$ between 2020 and 2050 (consequently representing a small number in the denominator of Equation **12** becomes) lead to a higher GHG abatement cost of S4-OtherNovelTech compared to the other low-carbon scenarios.

Even though S1-TechMix does not present the lowest GHG abatement and water savings costs, these costs are lower than the numbers for S3-SB, and still not considerably high as the GHG abatement cost for S4-OtherNovelTech. Furthermore, the cumulative water savings and GHG abatement between 2020 and 2050 for S1-TechMix are second highest among the other novel low-carbon scenarios. The water savings and GHG abatement costs for S3-SB if a novel SB technology were to replace conventional CSS.

Energy and carbon costs are the main drivers of cost savings, as the low-carbon technologies reduce overall energy consumption and GHG emissions compared to conventional bitumen extraction options. Optimizing the energy efficiency of the novel recovery technologies is key to further savings as electricity and natural gas prices are expected to increase. Moreover, if carbon price were to increase relative to current projections (\$170/tCO_2e in 2030), the GHG abatement and water savings costs would reduce as the savings from carbon costs would be larger with the higher market penetration of low-carbon technologies.

A bubble chart (Figure 2-11) is used to better understand how each novel scenario performs in terms of saving water, abating GHG emissions, and the cost impacts to save one cubic meter of water and abate one tonne of CO_2. When we considered the relevance of energy and carbon costs to the novel scenarios' marginal savings and abatement cost, we obtained new results in a zero carbon price environment with the market share model. The results obtained for the scenarios with the current carbon pricing environment, \$170/tCO_2e in 2030 and onwards, are labeled by the scenario name followed by "CP170," and the results obtained considering a zero carbon pricing environment are labeled with the scenario name followed by "CP0."

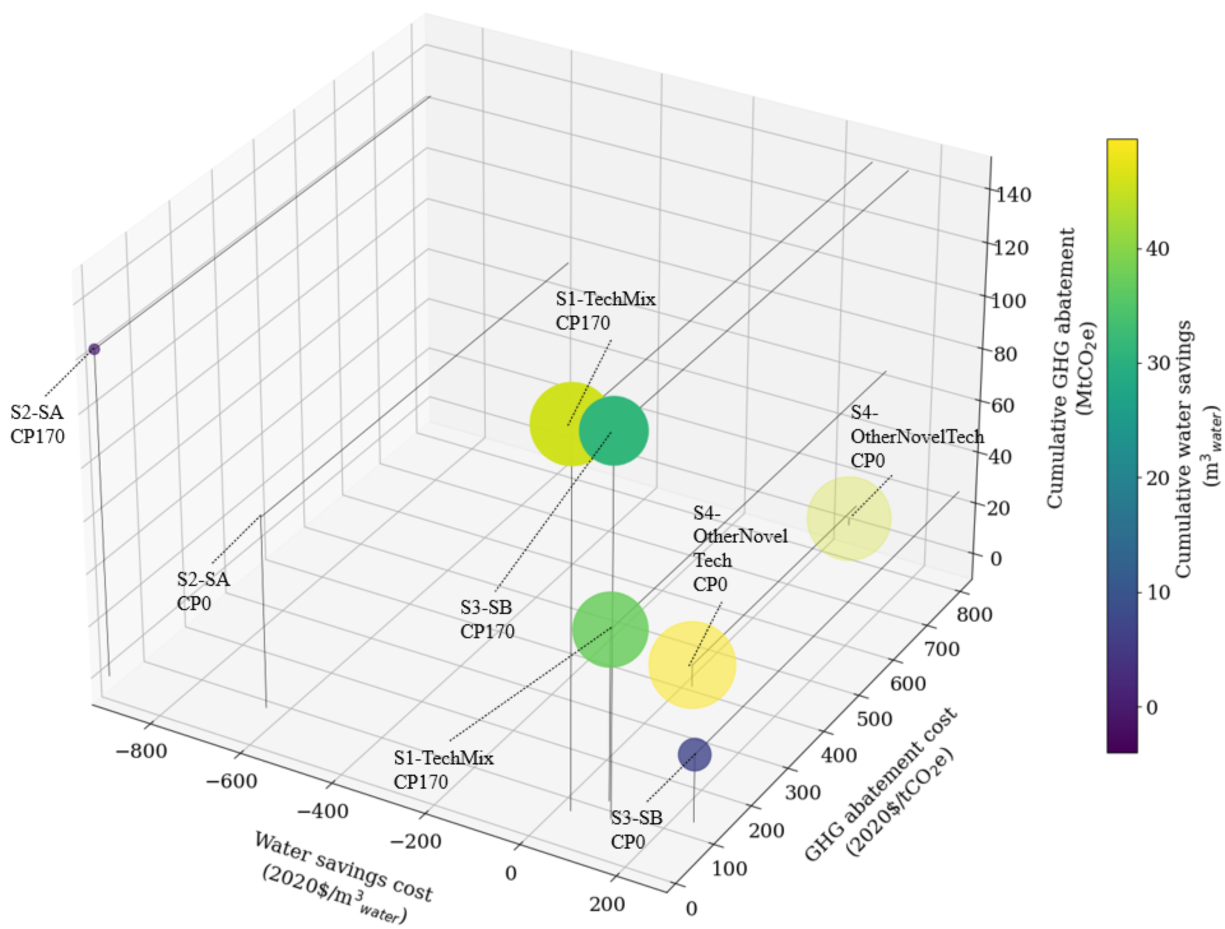


Figure 2-11: Bubble chart showing cumulative water and GHG savings between 2020 and 2050 and water savings and GHG abatement costs for each novel scenario. The coordinates of the center of each bubble represent the water savings and GHG abatement costs and the

cumulative GHG abatement potential of each scenario. The cumulative water savings are indicated by the size and color of each bubble.

S2-SA, as shown in Figure 2-11, has the poorest performance among the novel scenario options when considering cumulative water savings potential, presenting a total 0.7 and -4.0 Mm^3 of water saved between 2020 and 2050 for CP170 and CP0, respectively. The negative value indicates that this scenario at a zero carbon pricing environment does not lead to cumulative water savings, instead, it consumes more water than the reference case in the long term. The lower (negative) water savings costs of S2-SA are due to this scenario presenting a small water savings over the years. S1-TechMix and S3-SB scenarios present the best performance in terms of saving water and abating GHG emissions at CP170. For S4-OtherNovelTech, the increase in carbon price from CP0 to CP170 reduces the GHG abatement cost in \$466/tCO_2e as SEGD penetrates the market more aggressively and the overall GHG intensity of the scenario reduces. The cumulative water savings of approximately 49 Mm^3 are still due to the market penetration of the blowdown boiler technology that reduces by 50% the water intensity of the bitumen production process when compared to conventional SAGD.

The carbon price environment is relevant in increasing the benefits associated with the implementation of the novel scenarios and in abating more GHG emissions. The shift from a zero carbon price to \$170/tCO_2e in 2030 increases cumulative water savings and GHG abatement, but also reduces the water savings (slightly) and GHG abatement (significantly) costs of each novel scenario by 0.5%% and 57% on average, respectively. The cumulative GHG abatement and water savings potential increase by 151% and 47%, respectively.

The results from the cost-benefit analysis do not show the best performing scenario and/or technology but do provide decision-makers with information from the environmental and economic aspects of each decarbonization pathway, shedding some light on the pros and cons of specific options. The results show the gaps that need to be filled for further water consumption, GHG emissions, and cost reductions. The replacement of conventional CSS with SB-type technologies could significantly reduce water consumption and GHG emissions in the S3-SB scenario and also increase the economic benefit. The high energy cost savings show that the optimization of energy efficiencies, namely reducing natural gas and electricity intensities, would significantly reduce energy and carbon costs of novel technologies and make them more cost-effective options. Still, reducing capital and operating costs of the novel low-carbon technologies is imperative to incentive the market penetration of these emerging bitumen production options, and lead to GHG abatement and water savings in the long term.

2.3.6. Sensitivity analysis

The Morris sensitivity analysis results are presented in Figure 2-12. The results are in terms of the percentage variation in the Morris mean and standard deviation. The cumulative water savings and GHG abatement as well as marginal water savings and GHG abatement costs are relative to the S1-TechMix scenario. This scenario was chosen because it combines all the available novel technologies considered in this study.

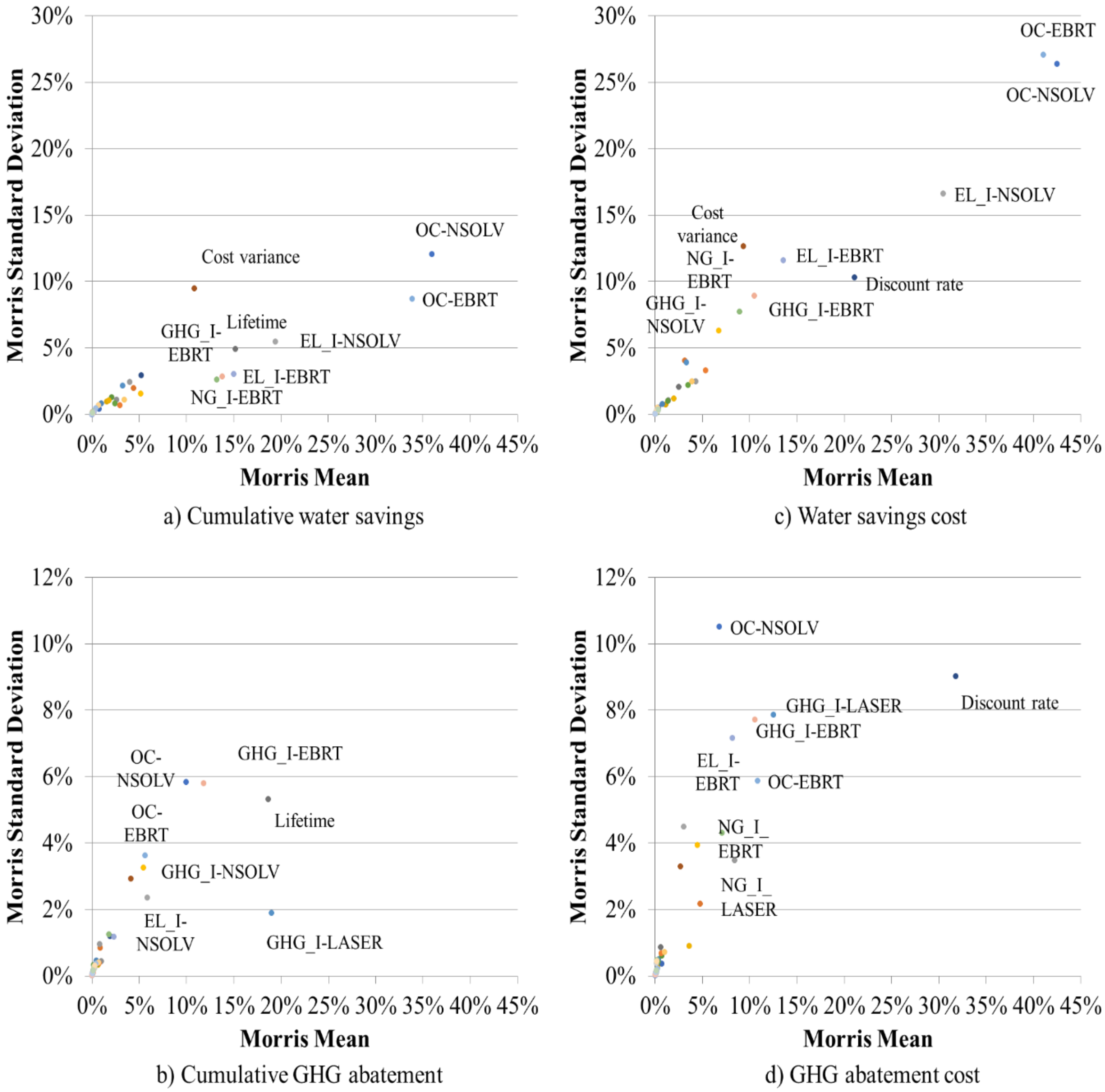


Figure 2-12: Morris sensitivity analysis results for cumulative water savings and GHG abatement between 2020 and 2050 as well as water savings and GHG abatement costs

The inputs used to perform the Morris sensitivity analysis are shown as circles on Figure 2-12. The input parameters change the output variables in different ways. Given that the most sensitive input parameters show a Morris mean of 10% or higher, we can say that the electricity, natural gas, and carbon intensity of SB Nsolv and EBRT, SA LASER, discount rate, and technology lifetime are the most sensitive inputs. The operating costs of SB technologies are also relevant to the Morris sensitivity analysis. In Figure 2-12, “EL_I-,” “NG_I-,” and “GHG_I-” are the electricity, natural gas, and GHG intensity of each specific technology. These inputs play an important role in determining market share values and, consequently, water savings and GHG abatement potential. Other novel technologies, SA-SAGD, ESEIEH data, and cost variance do not significantly alter the selected outputs.

Energy and carbon intensities of the process can be sufficiently determined through development of process simulation models that considers in detail the physical and chemical aspects of each specific technology; however, accurate operating cost data relies on input from industry and/or government. It is necessary to have reliable cost data to accurately model the market penetration of novel technologies over the long term and simulate technology competition over the years.

2.3.7. Policy implications

The total water consumption and GHG emissions projections obtained in this study are key to assessing whether current federal and provincial policies applied in the oil sands are enough to meet Canada's net-zero emissions target by 2050 [107]. The 2030 Emissions Reduction Plan [9] outlines a sector-by-sector path for Canada to reach its target of 40% below 2005 levels by 2030 and net-zero emissions by 2050. The Emissions Reduction Plan also notes the oil and gas sector's absolute emissions increase of 31% in 2030 from 2005 levels [108]. This study's results indicate that despite overall GHG intensity decreases of 7% for the best-performing scenario (S3-SB) in 2030 from 2005 levels, the projected absolute GHG emissions increase from 13.3 MtCO_2e in 2005 to 47.5 MtCO_2e in 2030 (a 257% increase) in the same decarbonization pathway. This shows that, despite the increase in bitumen extraction from 2005 to 2030, the projection of emissions growth for this recovery activity cannot be ignored. The representation of GHG emissions from in situ production in total oil and gas emissions is projected to grow. In situ CO_2e emissions share accounted for 8% of the total oil and gas sector emissions in 2005 and are expected to increase to 43% in 2030, according to this study's projections for the S3-SB scenario. Given the growth in total emissions of the oil and gas sector, replacing steam by different solvents for in situ bitumen extraction, even though extramally important in reducing GHG emissions, is clearly not enough to achieve Canada's net-zero emissions target by 2050. The advancement of CCS technologies, the use of more energy-efficient equipment, and the implementation of strong carbon pricing environments are essential to deeply decarbonize the oil and gas sector and more specifically the in situ bitumen recovery industry. Moreover, the Government of Alberta limits the emissions of the oil sands sector by imposing a maximum of 100 $MtCO_2e$ emissions in any year with provisions for cogeneration and new upgrading capacity [8]. From the yearly GHG emission projections (Figure 2-6), even without considering emissions from oil sands mining recovery activities (representing approximately 20% of the recoverable bitumen), the CO_2e emissions projection for 2050 is between 49.9 and 59.5 $MtCO_2e$, between 40% to 50% below the Alberta emissions cap. This limit should be regularly reviewed to consider technology improvement and the replacement of conventional bitumen extraction facilities by low-carbon extraction methods, thus guaranteeing and leveraging technology competition and the penetration of novel decarbonization pathways.

Regarding water withdraw limits, the Government of Alberta limits water withdrawals by oil sands companies to up to 3% of the Athabasca River flow [109]. According to the weekly flow estimates for the Athabasca River in the year 2021 [110], the annual average flow rate was 521.8 m^3/s, or 16,455 Mm^3/year. For the worst performing scenario in terms of water use in 2050 (S2-SA), the total water consumption projected for the Athabasca-OSA is 22.5 Mm^3/year, which represents 0.05% of the Athabasca's average annual flow rate, considering that 38% of the total water consumption is freshwater. Therefore, although the total water consumption shows an increase, as in situ bitumen production is projected to grow from 86.1 Mm^3/year in 2022 to 122.9 Mm^3/year in 2050, the total water withdrawal is considerably lower than the limit of 3%. Furthermore, even though the addition of other decarbonization options for in situ bitumen recovery might increase the total water consumption projected in this study – such as the implementation of CCS systems – oil sands industries are constantly working to increase the amount of alternative water used, thus off-setting any increase in water withdrawal rates from freshwater resources, as regulated by Directive 081 [7]. According AER data for 26 thermal in situ bitumen conventional extraction facilities for the period of January 2018 – July 2022 [102], high-quality nonsaline make-up water represents 38% of the total water consumed by in situ extraction facilities and alternative water types the remaining 62% – i.e., industrial runoff, treated wastewater, recyclable produced water, and deep nonsaline groundwater that lies more than 150 m underground. Freshwater withdrawal limits could be reduced over the years, as in situ oil sands industries continuously reduce high-quality nonsaline water intake.

The oil and gas sector in Canada is, for the most part, private; thus, data that is essential and useful to this work is not available. A more accurate breakdown of in situ bitumen extraction technology costs, water intake by site and OSA, and yearly energy intensities would lead to more precise results for total water consumption, GHG emissions, and marginal water savings and GHG abatement costs. Nonetheless, while these limitations have affected the results of this work, leaving clear areas of improvement for future work and research as data becomes available, they have not prevented the fulfillment of the objectives laid out.

Other factors not considered in this work, such as potential implications to land, air, and water bodies with the addition of solvent in the bitumen extraction process; the effects of technology readiness levels on total costs of different novel low-carbon pathways in the projection of market shares; and differences in water and GHG intensities over the analysis period could affect this study's water consumption and GHG emissions results. These factors and others are interesting topics to be examined in future work.

2.4. Conclusion

A decentralized study framework by oil sands area was developed to assess the water-GHG nexus with the implementation of seven novel and three conventional in situ bitumen extraction technologies in four distinct technology mix scenarios. The water consumption and GHG emissions for a 2020-2050 analysis period were projected using the Water Evaluation and Planning Model (WEAP) and the Low Emissions Analysis Platform (LEAP) Model. Bitumen production, water consumption, and GHG emissions curves were developed for each scenario and technology, hence favoring the projection of cumulative water savings and GHG abatement potential with the adoption of novel in situ extraction methods. Marginal abatement cost values were obtained to compare water savings, GHG abatement potential, and marginal costs. The robustness of the results was improved by performing a global Morris sensitivity analysis, thus assessing how cumulative water savings and GHG abatement, as well as marginal costs, change as input parameters change. This study represents a novel contribution to the literature by assessing the water consumption and GHG emissions of several in situ bitumen extraction technologies within a single study framework, thus providing information on the limits on water consumption and GHG emissions required to develop a more sustainable oil sands in situ bitumen recovery industry.

It was found that all novel in situ bitumen extraction scenarios lead to water savings and GHG abatement with positive net costs per tonne of GHG abated and cubic meter of water saved compared to the baseline case, which assumes only conventional bitumen recovery pathways are used in the long term. The only exception is for the scenario that assumes only solvent-assisted technologies to penetrate the market in the long term (S2-SA), in which costs become negative as the benefits from the reduced carbon and energy costs become larger than the higher capital and operating costs of the novel low-carbon technologies. The scenario that considers that all novel in situ bitumen extraction technologies compete to penetrate the market, the S1-TechMix scenario, shows the best combined water and GHG emissions reduction performance, with reductions of 6% and 15% in water consumption and GHG emissions in 2050 from the reference case. The results show that the novel technologies are more expensive in unit values (Canadian dollars per cubic meter of bitumen produced) than conventional extraction pathways, but their market penetration is related to both reductions in water consumption and GHG emissions. Each scenario can be improved as new in situ bitumen extraction technologies are developed and incorporated into the analysis, as capital and operating costs get reduced, and as carbon price increases. The water consumption and GHG emissions projections lead to the conclusion that implementing novel low-carbon in situ production technologies contribute to reducing the water-use intensity of the oil sands industry and that water withdrawal limits should be reduced to stimulate industry to replace steam or continually increase the use of alternative water types. The results obtained in this study can inform decision- and policy-makers of what in situ bitumen extraction technology mixes would be the most cost-effective options in the transition to a more environmentally friendly oil sands industry.

3. Long-term integrated assessment of impacts of a transition to low-carbon hydrogen production

3.1. Introduction

As an alternative to fossil fuels, hydrogen plays an important role in the transition to a low-carbon economy by representing a clean fuel feedstock solution for a wide range of applications [10]. Hydrogen is a suitable component for energy-intensive applications where the electrification process is either challenging or limited and the use of high-energy-density fuels is preferred over low-cost natural gas [11]. Presently, the expansion of the hydrogen economy has remarkable momentum. Global hydrogen demand is expected to increase from 88.5 Mt in 2020 to 210.6 Mt in 2030 [12]. Hydrogen can be produced from fossil fuels and biomass, as well as by electrolysis, wherein oxygen and hydrogen are separated from the water molecule by electricity. Currently, more than 90% of global hydrogen production is from fossil fuels [10] and there is a significant interest in using low-carbon hydrogen production technologies.

Among the available approaches for a cleaner hydrogen industry, water electrolysis powered by renewable energy and natural gas-based hydrogen tied to carbon capture and sequestration (CCS) are the two most promising paths, as they can enable energy conversion and low-carbon hydrogen production on a large scale [111]. Canada is one of the top ten global hydrogen producers, supplying approximately three million tonnes of hydrogen annually [112]. Under the Canada Energy Regulator's (CER) Evolving Policies (EP) Scenario [85], Canadian hydrogen demand in 2030 and 2050 is projected to be 0.12 and 4.7 Mt, respectively. Natural gas-based hydrogen with CCS accounts for 92% and 57% of this hydrogen production projection in 2030 and 2050, grid-powered electrolysis 8% and 34%, and dedicated renewable powered-electrolysis the remaining 9% in 2050 [85]. The western province of Alberta plays a key role in the country's hydrogen production and has been identified as a key player in Canada's transition to a low-carbon hydrogen economy [11]. The province was responsible for 92% and 53% of the total hydrogen production in the CER-EP scenario in 2030 and 2050 and produced approximately 2.49 Mt of hydrogen in 2021 [113].

The hydrogen-producing technologies differ in energy and water requirements and technology readiness levels. For electrolysis-based hydrogen, there are three different commercially available technologies: alkaline electrolysis cell (AEC), solid oxide electrolysis cell (SOEC), and polymer electrolyte membrane electrolysis cell (PEM). AEC is the most mature and commercially extended technology for hydrogen production through water electrolysis, followed by PEM [114, 115]. SOEC is a more recent technology, and it is still in the development stage. Its main difference from AEC and PEM is that it operates at higher temperatures, commonly between 500 and 850 °C [116]. Despite the enormous deployment potential in Canada [117], further research is still needed to improve the efficiency of the different electrolysis technologies to make them cost-competitive with conventional natural gas-based hydrogen [118]. Natural gas reforming by conventional steam methane reforming (SMR) is the most common and cost-effective hydrogen production method. Autothermal reforming (ATR) of natural gas is another well-established steam reforming process that is steadily gaining traction. It has been commercialized by Topsoe as Syncor^{TM} [119] and was selected as the method to produce low-carbon hydrogen by large chemical plants in Japan [120] and Canada [121] and elsewhere.

Natural gas decomposition (NGD) and chemical looping and partial oxidation of methane (CL-POM) are two emerging low-carbon technologies for hydrogen production that could be viable for large-scale deployment in the medium to long term [122]. The integration of CCS into natural gas-based hydrogen technologies to reduce greenhouse gas (GHG) emissions is already being explored and is seen as more relevant by industry and government [111, 123]. Depending on the technology, CCS can be used to capture different emissions levels. For SMR, CCS can be linked to 52% and 85% of emissions, ATR 91%, and NGD 61% [124]. Still, hydrogen production through electrolysis and natural gas reforming are water- and energy-intensive processes. Natural gas and water are used as feedstock for hydrogen production of natural gas-based technologies, but also as an energy source for heating and cooling purposes. The implementation of a CCS unit introduces a parasitic load to the system, which increases the amount of water used for cooling and capturing, transporting, and sequestrating CO_2 emissions [125]. Electrolysis technologies consume water as a feedstock for hydrogen production and indirectly to produce electrical energy to support the electrolysis process [26]. Understanding the energy and water requirements as well as emissions over the long term provides a comprehensive picture of the environmental benefits (or burdens) associated with the large-scale deployment of low-carbon hydrogen.

Studies that considered the GHG mitigation potential and/or the associated water-use impacts with the deployment of low-carbon hydrogen production technologies were identified and reviewed. The primary objective was to understand whether there are long-term projections on water consumption and GHG emissions with the large-scale deployment of low-carbon hydrogen and identify the modelling approach used. Seventeen studies were found relevant to the scope of this study. Our research group colleagues Janzen et al. [16] evaluated the GHG emissions reduction potential and cost impacts of integrating low-carbon and renewable energy technologies in the Canadian oil sands from 2019 to 2050. Hydrogen production through wind-powered electrolysis, nuclear thermochemical process, and biomass gasification were considered to replace conventional SMR plants in a market penetration modelling. Low-carbon hydrogen could reduce up to 0.1% of annual oil sands emissions. Our colleagues Davis et al. [18] assessed the GHG abatement potential and cost-effectiveness of blending and supplying low-carbon hydrogen with natural gas, specifically hythane, through 576 long-term scenarios from 2026 and 2050. The authors found that hythane blends for end-use energy applications reduce 1 to 2% of GHG emissions economy-wide and lead to economic benefits at carbon prices over $300/tonne. Our research group colleagues Okunlola et al. [126] assessed the techno-economic feasibility of the intercontinental export of low-carbon hydrogen, focusing on the Pacific and Atlantic oceans. The authors found that exporting hythane in existing natural gas pipelines reduced the delivered cost by 17%. Leptizki and Axsen [127] explored the potential of a low-carbon fuel standard applied to the personal and freight vehicle sector in British Columbia, Canada, in achieving long-term GHG abatement targets. Low-carbon natural gas- and electrolysis-based hydrogen were considered as fuel sources in the modelling framework.

Studies from different jurisdictions world-wide also assessed the energy and economic impacts of low-carbon hydrogen. Navas-Anguita et al. [19] studied the long-term potential of hydrogen production technologies with and without CCS to meet the hydrogen demand by fuel cell electric vehicles in Spain from 2020 to 2050. The authors concluded that SMR could satisfy this hydrogen demand until 2030, be replaced by water electrolysis after this year, and ultimately reduce carbon emissions. Ren et al. [128] reviewed the GHG emissions reduction technologies and low-carbon development in the iron and steel industry in China. CCS strategies and hydrogen-based technologies are projected to reduce costs by 12 to 35 billion USD by 2050. In an older study, McCollum et al. [129] introduced the CA-TIMES, a bottom-up integrated environmental-economic systems model, to explore low-carbon scenarios in achieving California's goal of 80% reduction in GHG emissions below the 1990 level by 2050. The authors included the adoption of hydrogen as a low-carbon fuel in GHG mitigation scenarios, evaluating carbon emissions abatement potential and associated costs impacts.

Other studies modelled the long-term development and deployment of low-carbon hydrogen production technologies. McPherson et al. [130] included long-term hydrogen scenarios in an integrated assessment model, MESSAGE, to evaluate low-carbon energy transitions and associated costs. Hanley et al. [131] reviewed different integrated energy system models and evaluated the drivers and policy scenarios that lead to the development of hydrogen from other low-carbon technologies. A wide range of marginal abatement costs and GHG emissions reductions in 2050 were found for different scenarios that considered the deployment of low-carbon hydrogen. Quarton et al. [132] recommended several modelling tools, scenario design approaches, and data assumptions to adequately model global energy scenarios with the deployment of low-carbon hydrogen. The study also summarizes the effect of GHG emissions abatement on hydrogen prevalence in different energy scenarios. Quarton and Samsatli [133] analyzed the effectiveness of carbon budgets and taxation in achieving net-zero emissions over the long term and how emerging hydrogen technologies contribute to the decarbonization of the energy sector in current policy scenarios.

While long-term projections on GHG emissions, cumulative mitigation potential, and associated costs were carefully assessed in previous studies on the transition to a low-carbon hydrogen economy, assessments of associated water-use implications are limited. Yea et al. [134] evaluated the water footprints of a hydrogen fuel cell electric vehicle and a compressed natural gas vehicle. The authors concluded that hydrogen production through SMR and wind-powered electrolysis can save water resources in the fuel cell electric vehicle industry. Mehmeti et al. [26] studied the life cycle environmental performance of natural gas- and electrolysis-based hydrogen and included water consumption footprints. The study did not include long-term water consumption projections from the deployment of low-carbon hydrogen technologies. Woods et al. [27] quantified the different types of water in Australia, including waste, surface, ground, and desalinated water in different states across the country and evaluated their potential to meet local hydrogen demand through water electrolysis. The authors concluded that the alternative types of water in Australia, this is, water that is not sourced from freshwater bodies, have the potential to enable the green hydrogen economy in the country. However, no long-term projections on water consumption were provided.

A few studies focused on quantifying total water consumption over the long term with the large-scale deployment of electrolysis-based hydrogen. Webber [31] analyzed the total water consumption of the transitional hydrogen economy by quantifying direct and indirect water requirements to produce 60 million tonnes of hydrogen per year through thermoelectrically powered electrolysis. The author found that hydrogen production using this technology is significantly more water-intensive than gasoline production. The water requirements of different kinds of renewable electrolysis were not considered. Beswick et al. [135] projected the total water consumption of electrolysis-based hydrogen and discussed whether the technology is an issue for the world's saline and freshwater resources. Even though the authors did not consider different water electrolysis technologies in their analysis, they concluded that water supply will not limit the operation of electrolyzers and that the focus should be on improving the energy efficiency of these technologies. Shi et al. [28] quantified water consumption and scarcity footprints of hydrogen production from electrolysis-based options, namely AEC, through the geographical distribution of the water footprints along the hydrogen supply chain. Grid and renewable-powered electrolysis were considered.

A study considering the water-use implications, GHG emissions reduction, and cost impacts of low-carbon hydrogen production in a long-term analysis period is missing. More specifically, there is a knowledge gap in the hydrogen literature in that a range of low-carbon technologies has not been assessed within a single study framework that considers an integrated assessment of water consumption, GHG emissions, and cost impacts. The value of such a framework is effective technology scenario comparisons in terms of water consumption, GHG emissions, and marginal abatement costs. This information will aid in low-carbon hydrogen policy development by answering the question of whether current policies are sufficient to fully decarbonize hydrogen production and simultaneously lead to water savings (or consumption). Therefore, to fill this knowledge gap, the following novel contributions of this research are provided to support policy- and decision-makers transitioning to a low-carbon hydrogen economy:

- Detailed bottom-up market penetration modelling of different low-carbon hydrogen is limited for different carbon pricing environments. This study considers 20 different market penetration scenarios of low-carbon natural gas- and electrolysis-based hydrogen over a long-term horizon. Different technology costs, energy requirements, and energy prices are considered in the market share modelling through a bottom-up modelling approach.
- While many strategies to mitigate GHG emissions from the hydrogen-production industry have been proposed, associated water-use impacts assessment is missing. This research contributes the novelty of assessing the water-GHG nexus with the large-scale deployment of hydrogen through a set of demand scenarios that consider the supply of hydrogen in its pure form or blended with natural gas, i.e. hythane, for the oil sands, residential and commercial, transportation, and economy-wide sectors over a long-term horizon. Combining the hydrogen production and demand scenarios gave us 120 scenarios.
- This study also adds the novelty of providing the associated costs (or benefits) of saving (or consuming) water and abating GHG emissions for different large-scale technology deployment scenarios and carbon pricing environments with respect to a baseline case.

The overall purpose is to determine the impacts on hydrogen production water use, GHG emissions, and costs associated with the large-scale deployment of low-carbon technologies over the long term. The specific objectives are to:

- Project the market shares of natural gas- and electrolysis-based hydrogen from 2026 to 2050 for several carbon pricing and technology-mix scenarios.
- Project the large-scale deployment of low-carbon hydrogen through six demand scenarios and consider the projected market shares from the hydrogen-producing scenarios.
- Project and compare total water consumption and GHG emissions for different carbon pricing environments considering indirect and direct water consumption and GHG emissions.

- Determine the net cost (or benefit) of saved water and abated GHG for different carbon pricing environments.
- Evaluate how projected cumulative water savings and GHG abatement are affected by variations in techno-economic parameters through a Morris sensitivity analysis and how much these projections vary through a Monte Carlo simulation.

The western Canadian province of Alberta was selected as the jurisdiction of analysis because it is a highly emission-intensive region [63] and is responsible for most of Canada's current hydrogen production [113]. Investment attraction programs and emerging hydrogen partnerships have been announced in the province, such as the Edmonton Region Hydrogen Hub [136] and the Southeast Alberta Hydrogen Task Force [137]. The partnerships will leverage hydrogen deployment in Alberta and support the development of a strong regional hydrogen economy. The province already has more than 100 kilometres of pipeline infrastructure to transport pure hydrogen to industrial users [118]. According to the Alberta Hydrogen Roadmap report [118], incremental and transformative scenarios projections for hydrogen production are expected to be 0.85 and 3.03 MtH_2 in 2030 and 1.00 and 12.2 MtH_2 in 2050, respectively, with the largest portions for industrial use under the incremental scenario and for exports under the transformative scenario. Alberta can play a significant role in the international market by exporting clean hydrogen to North America, Asia Pacific, and Europe. The Government of Canada estimates the demand for clean hydrogen in international exports to be more than 40 million tonnes per year by 2050 [11], and Alberta's capacity, by the same year, for low-carbon hydrogen production is projected to be approximately 45 million tonnes per year [118]. This shows that the province can supply clean hydrogen for local use and for international markets. Alberta hosts two large carbon capture and storage projects: the Alberta Carbon Trunk Line [138] and Shell's Quest project [139]. 17 CCS projects have been proposed for the province [140]. Air Products announced a multi-billion-dollar project to build a net-zero hydrogen facility in Edmonton, Alberta [121]. Hydrogen will be produced through ATR with a 95% carbon capture. The province has also the potential to implement renewable electrolysis-based hydrogen. Despite the cost difference between natural gas-based and water electrolysis hydrogen production technologies, Alberta is increasing its renewable energy capacity to 19% of the province's 2020 electricity capacity and 27% of the projected capacity in 2023 [141].

For the aforementioned reasons, the province of Alberta represents a suitable jurisdiction of analysis for this study.

3.2. Method

3.2.1. Study framework

This study develops a novel framework to assess water consumption, GHG emissions, and marginal costs associated with the adoption of low-carbon hydrogen production technologies. Figure 2-1 shows the modelling framework and calculation procedures. The first stage involves data gathering, filtering, and analysis. Data is obtained as part of the literature review from technical reports, public databases, and relevant studies. The second and third stages involve scenario development. We considered six hydrogen demand scenarios and five hydrogen production scenarios. The hydrogen production scenarios were modelled for four different carbon pricing environments and include distinct natural gas- and electrolysis-based hydrogen technologies. A description of each hydrogen technology and scenario is presented in Table 3-1, Table 3-2, and Table 3-3.

Hydrogen demand drives hydrogen production for each carbon pricing environment. 120 scenarios were evaluated. Data was used to develop the market penetration model in a fourth stage. The model was used to project the market shares of natural gas- and electrolysis-based hydrogen technologies through the different scenarios between 2026 and 2050. Low-carbon hydrogen technologies start competing for additional hydrogen production capacity in 2026 and 2030, depending on the technology readiness level. Based on our research group's modelling on hydrogen production and demand, we considered that only conventional natural gas-based technologies assume hydrogen production from 2020 to 2025. The fifth and sixth stages involve the projections of GHG emissions and water consumption of the different scenarios with LEAP- and WEAP-Canada models, respectively. The LEAP-Canada model is built in the Low Emissions Analysis Platform (LEAP) [58] software, a tool based on scenario modelling that design and project energy consumption, production, and resource extraction, accounting for both energy and non-energy sector GHG emissions sources and sinks. The WEAP-Canada model is developed through the Water Evaluation and Planning (WEAP) [59] software, which takes an integrated approach to water resources planning, providing an intuitive GIS-based graphical interface to model the supply and demand of water from different resources. The seventh stage is a cost-benefit analysis, in which the water and GHG mitigation projections obtained through the WEAP- and LEAP-Canada models are used to determine the marginal water savings and GHG abatement costs of each decarbonization pathway compared to the reference scenario. The robustness of the results is improved through a sensitivity and uncertainty analysis in the eighth stage. The Regression, Uncertainty, and Sensitivity Tool (RUST) [60] developed by our research group is used to perform a Morris global sensitivity analysis and calculate the Morris mean and standard deviation for the input variables analyzed. For the uncertainty analysis, RUST runs the Monte Carlo simulation with Latin Hypercube Sampling. The RUST model is built in RStudio and Excel VBA and is inserted into Excel-based models to run sensitivity, uncertainty, and contribution to variance analysis. The LEAP- and WEAP-Canada models were developed, validated, and used by members of our research group as part of GHG mitigation and water savings studies on Canada's energy use [61, 62], water use [53], GHG emissions [63], power generation [64-66], residential and commercial [67, 68], oil sands [14-17], petroleum refining [69], chemical [70], mineral mining [71, 72], iron and steel [73], cement [74], and agricultural [75] sectors. The RUST model was also used as part of several studies by this same research group to carry out global sensitivity and uncertainty analysis [76-84].

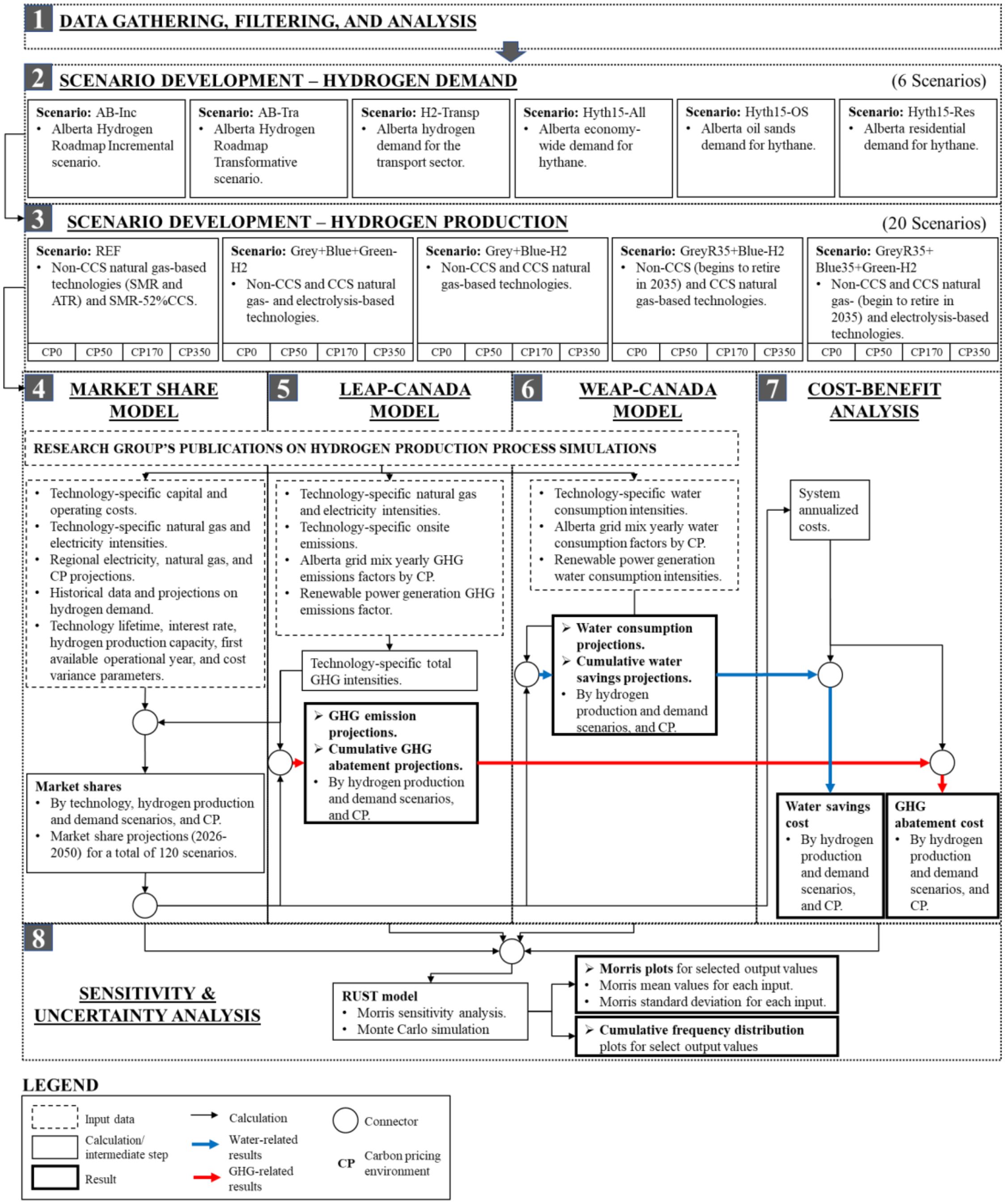


Figure 3-1: Integrated assessment framework for conventional and low-carbon hydrogen technologies

3.2.2. Scenario development

The premise of scenario development was to distinguish the types and combinations of natural gas- and electrolysis-based hydrogen production technologies, compare the water and GHG footprints, and compare the abatement cost impacts of different decarbonization pathways. The non-CCS and CCS natural gas-based and electrolysis-based hydrogen technologies considered are listed in Table 3-1. The long-term low-carbon hydrogen production scenarios, presented in Table 3-3, are based on four different carbon policy environments: CP0: \$0/tCO_2e; CP50: \$40/tCO_2e in 2021 and \$50/tCO_2e from 2022 onward; CP170: \$40/tCO_2e in 2021, \$50/tCO_2e in 2022, and rising linearly to \$170/tCO_2e by 2030; and CP350: \$40/tCO_2e in 2021, \$50/tCO_2e in 2022, and rising linearly to \$350/tCO_2e by 2030. These carbon policy environments provide a considerable range of results that remain applicable regardless of policy change. The higher the carbon price, the higher the economic stimulus to transition to a low-carbon hydrogen industry. The different carbon pricing environments considered are from the Canadian carbon pollution pricing benchmark [90]. The large-scale deployment of hydrogen is modelled through six different hydrogen demand scenarios, presented in Table 3-2. For each demand scenario, five hydrogen production scenarios are considered for four carbon pricing environments. The combined hydrogen production and demand scenarios, along with carbon pricing policy environments, total 120 scenarios.

Table 3-1: Hydrogen production technologies

Hydrogen source	Technology name	Acronym
Natural gas	Steam methane reforming	SMR
	Steam methane reforming with 52% carbon capture and sequestration. Onsite emissions are reduced by 39.8% over conventional SMR.	SMR-52%CCS
	Steam methane reforming with 85% carbon capture and sequestration. Onsite emissions are reduced by 78.4% over conventional SMR.	SMR-85%CCS
	Autothermal reforming	ATR

Hydrogen source	Technology name	Acronym
	Autothermal reforming with 91% carbon capture and sequestration. Onsite emissions are reduced by 91% over conventional ATR.	ATR-91%CCS
	Natural gas decomposition	NGD
	Natural gas decomposition with 61% carbon capture and sequestration. Onsite emissions are reduced by 51% compared to conventional NGD.	NGD-61%CCS
Water (electrolysis)	Centralized alkaline electrolysis cell powered by Alberta's grid mix.	AEC-Grid
	Centralized proton exchange membrane powered by Alberta's grid mix.	PEM-Grid
	Decentralized alkaline electrolysis cell powered by a dedicated wind power plant.	AEC-Wind
	Decentralized proton exchange membrane powered by a dedicated wind power plant.	PEM-Wind
	Decentralized alkaline electrolysis cell powered by a dedicated hydroelectric plant.	AEC-Hydro
	Decentralized proton exchange membrane powered by a dedicated hydroelectric power plant.	PEM-Hydro
	Decentralized alkaline electrolysis cell powered by a dedicated photovoltaic solar power plant.	AEC-Solar

Hydrogen source	Technology name	Acronym
	Decentralized proton exchange membrane powered by a dedicated photovoltaic solar power plant.	PEM-Solar

For the hydrogen production technologies, the carbon capture rate percentage specified with the acronym of the production technology indicates the amount of facility emissions to which CCS is applied. This percentage does not mean the amount of emissions that are reduced with the implementation of the CCS unit, but the volume of emissions that are subjected to CCS. The actual amount of onsite carbon dioxide emissions reduced is given in Table 3-1.

Table 3-2: Hydrogen demand scenarios

Scenario name	Scenario description	Number of scenarios (total = 6)
AB-Inc	• The Alberta Hydrogen Roadmap incremental scenario is considered. • This scenario assumes business-as-usual hydrogen demand based on existing policies and regulations.	1
AB-Tra	• The Alberta Hydrogen Roadmap transformative scenario is considered. • This scenario assumes the integration of clean hydrogen into Alberta's economy on a large scale. We considered a more supportive policy and regulatory environment for large-scale hydrogen deployment.	1
H2-Transp	• Hydrogen demand for the road transport sector in Alberta is considered. • This scenario considers the effect of carbon prices, zero-emission vehicle mandates, and financial incentives on vehicle costs to model hydrogen demand for this sector.	1
Hyth15-All	• Economy-wide demand for hythane is considered in Alberta. • We assumed that the hythane blend consists of 15% hydrogen and the rest of natural gas. Hythane demand sectors include residential and commercial/institutional, pulp and paper,	1

Scenario name	Scenario description	Number of scenarios (total = 6)
	petroleum refining, chemicals, iron and steel, mining, cement, resource extraction, and other manufacturing sectors.	
Hyth15-OS	• The demand for hythane by the oil sands sector is considered. • We assumed that the hythane blend consists of 15% hydrogen and the rest of natural gas.	1
Hyth15-Res	• The demand for hythane by the residential and commercial/institutional sectors is considered. • We assumed that the hythane blend consists of 15% hydrogen and the rest of natural gas.	1

Table 3-3: Hydrogen production scenarios

Scenario name	Scenario description	Technologies	Carbon price	Number of scenarios (total = 20)
REF	• Baseline or business-as-usual scenario used for the cost-benefit and cumulative water-GHG savings analysis. • Non-CCS SMR and SMR-52%CCS assume hydrogen production between 2020 and 2023 and compete alone for incremental capacities between 2024 and 2029. • ATR starts penetrating the market in 2030. • Conventional non-CCS SMR facilities start to retire in 2026 and the retired hydrogen production capacity adds incremental capacity to the market penetration modelling of the other technologies considered.	SMR, ATR, and SMR-52%CCS.	CP0 CP50 CP170 CP350	4

Scenario name	Scenario description	Technologies	Carbon price	Number of scenarios (total = 20)
Grey+Blue+Green-H2	• This scenario considers all the technologies included in this study. • Non-CCS SMR and SMR-52%CCS assume and compete for hydrogen production between 2020 and 2025. SMR-85%CCS and electrolysis-based technologies start penetrating the market in 2026. • Emerging ATR and NGD technologies with and without CCS are included in the market penetration modelling in 2030. • Conventional non-CCS SMR facilities start to retire in 2026 and the retired hydrogen production capacity adds incremental capacity to the market penetration modelling of the other technologies considered.	SMR, ATR, NGD, SMR-52%CCS, SMR-85%CCS, ATR-91%CCS, NGD-61%CCS, AEC-Grid, PEM-Grid, AEC-Wind, PEM-Wind, AEC-Hydro, PEM-Hydro, AEC-Solar, and PEM-Solar.	CP0 CP50 CP170 CP350	4

Scenario name	Scenario description	Technologies	Carbon price	Number of scenarios (total = 20)
Grey+Blue-H2	• Natural gas-based hydrogen technologies with and without CCS compete for new market shares effective 2026. • Non-CCS SMR and SMR-52%CCS assume and compete for hydrogen production between 2020 and 2025. SMR-85%CCS start penetrating the market in 2026. • Emerging ATR and NGD technologies with and without CCS are included in the market penetration modelling in 2030. • Conventional non-CCS SMR facilities start to retire in 2026 and the retired hydrogen production capacity adds incremental capacity to the market penetration modelling of the other technologies considered.	SMR, ATR, NGD, SMR-52%CCS, SMR-85%CCS, ATR-91%CCS, and NGD-61%CCS.	CP0 CP50 CP170 CP350	4

Scenario name	Scenario description	Technologies	Carbon price	Number of scenarios (total = 20)
GreyR35+Blue-H2	• This scenario assumes a non-CCS natural gas-based technology phase-out policy effective 2035. • Non-CCS SMR and SMR-52%CCS assume and compete for hydrogen production between 2020 and 2025. SMR-85%CCS start penetrating the market in 2026. • Emerging ATR and NGD technologies with and without CCS are included in the market penetration modelling in 2030. • Conventional non-CCS SMR facilities start to retire in 2026 and ATR and NGD in 2035 as a result of the new phase-out policy. The retired hydrogen production capacity adds incremental capacity to the market penetration modelling of the other technologies considered.	SMR, ATR, NGD, SMR-52%CCS, SMR-85%CCS, ATR-91%CCS, and NGD-61%CCS.	CP0 CP50 CP170 CP350	4

Scenario name	Scenario description	Technologies	Carbon price	Number of scenarios (total = 20)
GreyR35+Blue R35+Green-H2	• This scenario assumes a natural gas-based technology (with and without CCS) phase-out policy effective 2035, with incremental and retired electrolysis-based hydrogen capacities from this year onwards. • Non-CCS SMR and SMR-52%CCS assume and compete for hydrogen production between 2020 and 2025. SMR-85%CCS start penetrating the market in 2026. • Emerging ATR and NGD technologies with and without CCS are included in the market penetration modelling in 2030. • Conventional non-CCS SMR facilities start to retire in 2026 and the remaining natural gas-based technologies with and without CCS in 2035 as a result of the new phase-out policy. The retired hydrogen production capacity adds incremental capacity to the market	SMR, ATR, NGD, SMR-52%CCS, SMR-85%CCS, ATR-91%CCS, NGD-61%CCS, AEC-Grid, PEM-Grid, AEC-Wind, PEM-Wind, AEC-Hydro, PEM-Hydro, AEC-Solar, and PEM-Solar.	CP0 CP50 CP170 CP350	4

Scenario name	Scenario description	Technologies	Carbon price	Number of scenarios (total = 20)
	penetration modelling of the electrolysis-based technologies.			

3.2.3. Market share model

The market share model simulates technology competition from the annualized lifetime costs of each technology and scenario considered, thus providing additional shares captured by individual hydrogen-producing technologies in a specific year. This modelling approach was adapted from Nyboer [86] and publications largely by our research group on oil sands [13, 16], CCS deployment [14, 87], and energy technologies [88], among others. Equation 1 is used to calculate the additional share for a specific technology in a certain year for a given production scenario.

$$AS_{j,y,ps,cp} = \frac{{LCC_{j,y,cp}}^{-v}}{\sum_{j=1}^{J}\left({LCC_{j,y,cp}}^{-v}\right)_{ps}} \tag{14}$$

$$LCC_{j,y,cp} = \left(CC_j \frac{r}{1-(1+r)^{-n}} + OC_j\right)\frac{CR_{j,y}}{HPC_j} + EC_{j,y,cp} + Ct_{j,y,cp} \tag{15}$$

$$CR_{j,y} = 1 - \frac{crf_j(y-2026)}{2050 - 2026}\text{ , for } y \geq 2026 \tag{16}$$

$AS_{j,y,ps,cp}$ is the additional share calculated for technology j, in year y, for the production scenario ps, and for the carbon policy environment cp. $LCC_{j,y,cp}$ is the annualized lifetime cost of technology j, in year y, and carbon pricing environment cp. J represents the hydrogen-producing technologies included in the production scenario under analysis (ps). CC_j and OC_j are the total capital and operating costs (in dollars), excluding energy consumption costs. Capital and operating costs include the costs associated with the hydrogen production plant, and the CO_2 capture, transportation, and sequestration units. Labor and admin costs are included in the operating cost term. HPC_j represents the annual hydrogen production capacity of technology j and is used to annualize the capital and operating cost terms. $CR_{j,y}$ represents the capital and operating cost reduction term of technology j in year y. Equation 16 provides the details on the calculation of $CR_{j,y}$. The capital and operating cost reduction term assumes a linear decrease in the projection period of 2026 and 2050 by a total percentage given by the cost reduction factor crf_j for a given technology j. The capital and operating cost reduction factors of each technology are given in Table 3-4. Details on the capital and operating cost reduction factors are provided in studies by our colleagues Davis et al. [18] and Okunlola et al. [126]. The energy consumption cost is represented by $EC_{j,y,cp}$ (in dollars per kilogram of hydrogen produced), which considers natural gas and electricity costs of technology j, in year y, and for the carbon policy environment cp. $Ct_{j,y,cp}$ represents the carbon cost (in dollars per kilogram of hydrogen produced) of technology j, in year y, and for the carbon policy environment cp. This cost is obtained through the GHG intensity of technology j and the carbon price applied in year y for one of the four carbon policy environments cp. Equations 17 and 18 present the breakdown of the energy and carbon cost terms, respectively. The interest rate used for capital amortization is represented by the variable r, while n represents the lifetime of a technology. The sensitivity to cost parameter v is a measure of the preference given to cheaper technologies in market competition modelling. A low value for sensitivity to cost means the price differential of competing technologies has less impact on technology adoption, whereas higher values for sensitivity to cost lead to market shares that more strongly favour less costly technologies. A more comprehensive analysis of the sensitivity to cost parameter is found in the work by Nyboer [86] and Rivers and Jaccard [142]. In this study, a median value of 8 was selected to run the model and obtain the technology shares for each hydrogen production and demand scenario and for each carbon pricing environment. A sensitivity to cost value between 8 and 10 reflects a situation where, with a 15% price difference between technologies, about 80% to 85% of new capacities would be allocated to the cheapest technology. A sensitivity to cost value of around eight is also in line with the values assumed in previous publications from our research group colleagues [13-16, 88]. Distinct values are assessed in the sensitivity and uncertainty analysis.

$$EC_{j,y,cp} = EP_{y,cp}EI_j + NP_{y,cp}NI_j \tag{17}$$

$$Ct_{j,y,cp} = CtP_{y,cp}GHGI_j \tag{18}$$

$EP_{y,cp}$ and $NP_{y,cp}$ represent the electricity and natural gas price in year y and for the carbon policy environment cp, whereas EI_j and NI_j represent the electricity and natural gas intensities of technology j. Only the centralized technologies that are powered by the Alberta grid mix incur the electricity cost. The energy cost of decentralized renewable electrolysis-based technologies is included in the respective total operating costs. $CtP_{y,cp}$ represents the carbon price in year y and for the carbon policy environment cp, and $GHGI_j$ represents the GHG intensity of technology j.

Depending on the hydrogen production scenario and the technologies considered to retire (phase out), the market shares are calculated differently and using Equations 19 and 20.

$$MS^R_{j,y,ps,cp,ds} = \frac{HD_{y-1,ds}MS^R_{j,y-1,ps,cp,ds} + AS_{j,y,ps,cp}\left(\Delta HD_{y,ds} + \frac{HD^R_{y-1,ds}}{n}\right) - \frac{HD^R_{y-1,ds}}{n}}{HD_{y,ds}} \quad 19$$

$$MS^{NR}_{j,y,ps,cp,ds} = \frac{HD_{y-1,ds}MS^{NR}_{j,y-1,ps,cp,ds} + AS_{j,y,ps,cp}\left(\Delta HD_{y,ds} + \frac{HD^R_{y-1,ds}}{n}\right)}{HD_{y,ds}} \quad 20$$

The $MS^R_{j,y,ps,cp,ds}$ and $MS^{NR}_{j,y,ps,cp,ds}$ represent the market shares of technology j, in year y, for the hydrogen production scenario ps, carbon pricing environment cp, and hydrogen demand scenario ds. The superscript notations R and NR indicate that the variable is specific to retiring and non-retiring hydrogen production technologies, respectively, in a given production scenario ps. $HD_{y,ds}$ represents total hydrogen demand in year y and for the demand scenario ds, while $\Delta HD_{y,ds}$ represents the additional or incremental hydrogen demand in year y and demand scenario ds, and given by the difference in hydrogen demand in year y and $y-1$, $HD_{y,ds} - HD_{y-1,ds}$. The term $HD^R_{y-1,ds}/n$ corresponds to the total retired hydrogen production capacity from the previous year $(y-1)$ and for the demand scenario ds. It is assumed that once a novel technology captures additional hydrogen production capacity in a given year, that technology will already operate at full capacity to produce the amount of hydrogen allocated to it.

The techno-economic data of each hydrogen production technology is summarized in Table 3-4. The costs and other relevant techno-economic data, such as interest rate, hydrogen production capacity, and technology lifetime required to calculate the annualized lifetime costs, are derived from studies by our research group colleagues that assessed natural gas-based hydrogen [18, 124] and electrolysis options [91, 143, 144]. In this study, all monetary values are expressed in Canadian dollars. Natural gas and electricity price projections were extracted from Davis et al. [18] and obtained from endogenous modelling that takes into account the four different carbon pricing environments. These projections are presented in Figure 3-2 together with the CER's projections for the industrial sector in Alberta [101] for validation purposes. The values comprise the projection period under analysis in this study, 2026 to 2050. For natural gas and electricity price projections, LEAP-Canada's projections vary by less than \$10/GJ from CER's projections. The values provided under the CER-EP scenario differ by a maximum of 60% from LEAP-Canada's projection under the CP350 environment in 2050 for natural gas price and in 2026 for electricity price. More details on differences between LEAP-Canada's and the CER's projections on natural gas and electricity price are provided in the study by our colleagues Davis et al. [18].

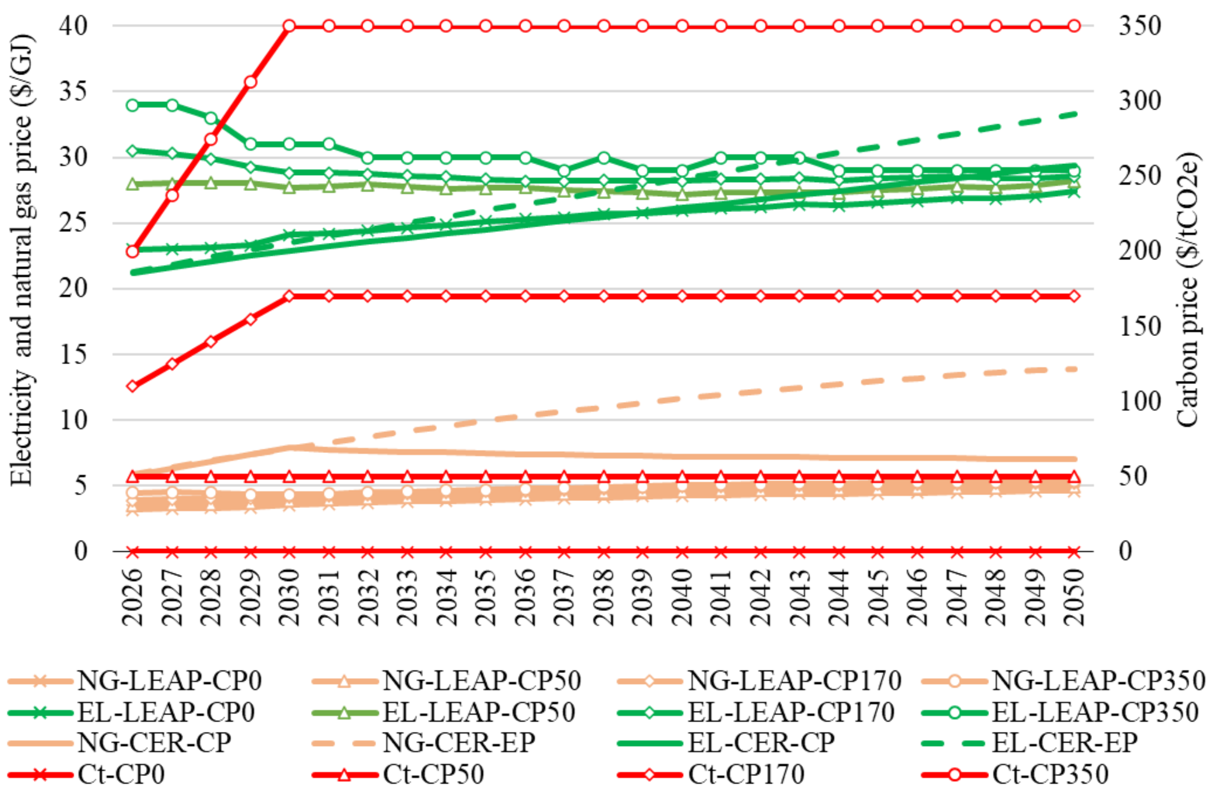


Figure 3-2: Natural gas and electricity price projections and the four different carbon policy environments: Ct-CP0, Ct-CP50, Ct-CP170, and Ct-CP350

Table 3-4: Techno-economic data of hydrogen production technologies

	Natural gas-based technologies							Electrolysis-based hydrogen							
	SMR	SMR-52% CCS	SMR-85% CCS	ATR	ATR-91% CCS	NGD	NGD-90%CCS	AEC-Grid	PEM-Grid	AEC-Wind	PEM-Wind	AEC-Hydro	PEM-Hydro	AEC-Solar	PEM-Solar
Hydrogen production plant CAPX (M$)	397	395	402	723	807	774	798	437	520	1416	1503	1948	2051	1503	1590
CO_2 capture CAPX (M$)	-	74	247	-	100	-	123	-	-	-	-	-	-	-	-
CO_2 transportation CAPX (M$)	-	113	166	-	131	-	36	-	-	-	-	-	-	-	-
CO_2 sequestration CAPX (M$)	-	113	166	-	131	-	36	-	-	-	-	-	-	-	-
Hydrogen production plant OPX (M$/yr)	= 4% of hydrogen production plant CAPX							21.9	22.3	78.2	78.2	58.1	58.1	78.2	78.2

Labor/admin OPX (M$/yr)	2.16	3.21	4.33	6.41	6.41	2.52	5.04	Included in hydrogen production plant OPX							
CO_2 capture OPX (M$/yr)	= 4% of CO_2 capture CAPX							-	-	-	-	-	-	-	-
CO_2 transportation OPX (M$/yr)	= 4% of CO_2 transportation CAPX							-	-	-	-	-	-	-	-
CO_2 sequestration OPX (M$/yr)	= 4% of CO_2 sequestration CAPX							-	-	-	-	-	-	-	-
CAPX/OPX cost reduction factor (% reduction 2026-2050)	Does not apply to natural gas-based technologies							= 12% for all electrolysis-based technologies							
Lifetime (yr)	25	25	25	25	25	25	20	20	20	20	20	40	40	20	20
Interest rate	10%	10%	10%	10%	10%	15%	15%	= 12% for all electrolysis-based technologies							
First available operational year (yr)	2026	2026	2026	2030	2030	2030	2030	= 2026 for all electrolysis-based technologies							
Hydrogen production	= 199 for all natural-based technologies							= 54 for all electrolysis-based technologies							

capacity (kt-H_2/yr)		
Source	[18, 124]	[91, 143, 144]

3.2.4. LEAP-Canada model

The natural gas- and electrolysis-based technologies and the production and demand scenarios were incorporated into the LEAP-Canada model to project the GHG emissions intensities in kilograms of CO_2 emitted per kilograms of hydrogen produced, as well as the total GHG emissions. The carbon emissions come from natural gas supply to be consumed as feedstock for the reforming process and as fuel for heating processes, electricity consumption (indirectly), and onsite emissions. Emission factors are applied from LEAP's Technology and Environmental Database (TED), which are the IPCC emission factors from the 5th Assessment Report [99]. The renewable power generation plant emission factors were extracted from the Natural Renewable Energy Laboratory (NREL) report [145], which considered approximately 3,000 published life cycle assessment studies on utility-scale electricity generation from many renewable and non-renewable resources in North America. The Alberta grid mix emission factors for different carbon policy environments were extracted from Davis et al. [65], the natural gas supply emission factors from Davis et al. [18], and the natural gas-based hydrogen technology emission factors from Oni et al. [124], all of them our research group's colleagues. The Alberta grid mix and natural gas supply emission factors for different carbon pricing environments are presented in Figure 3-3 together with the Alberta grid mix emission factor projections from Lyseng et al. [146] for validation purposes. The natural gas and electricity intensities of each hydrogen technology are summarized in Table 3-5.

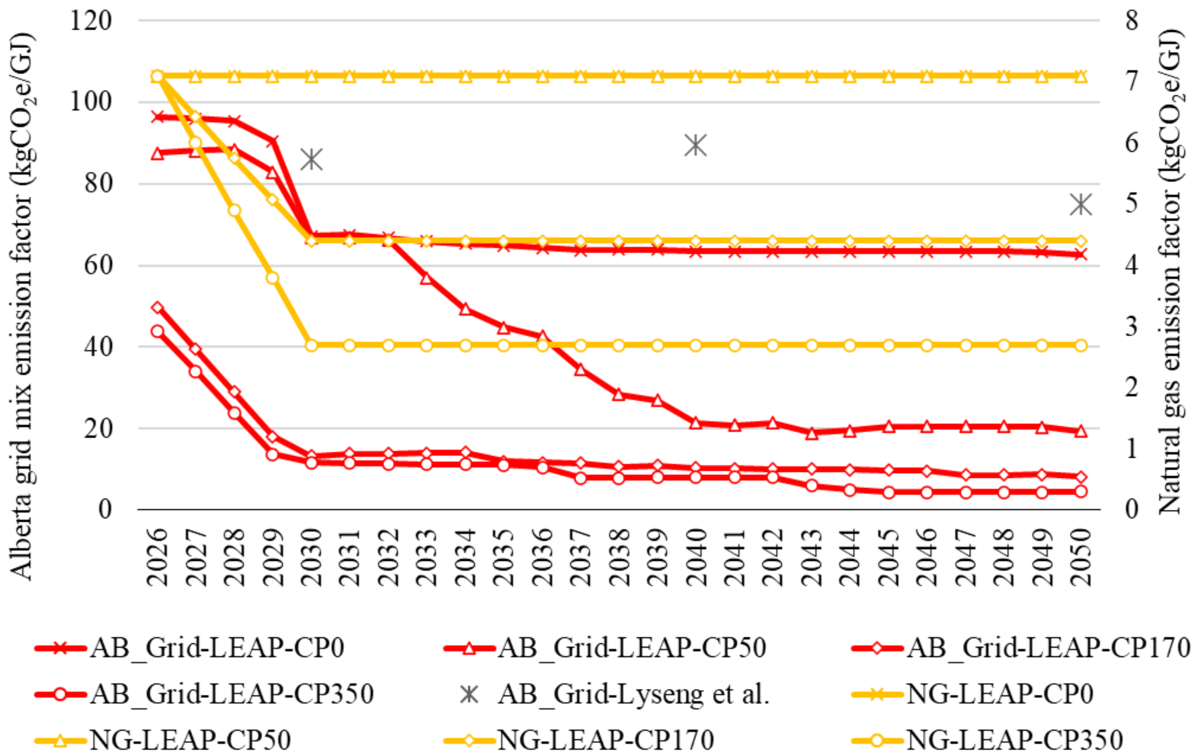


Figure 3-3: Annual Alberta grid mix and natural gas supply emission factors by carbon pricing environment

Overall, the LEAP-Canada Alberta grid emission factor projections for CP0 are 19%-41% lower than the projections made by Lyseng et al. [146]. This difference can be explained by the technologies and costs assumptions in the analysis. Unlike our colleagues Davis et al. [18, 65], Lyseng et al. [146] did not consider a wide range of technology options in their analysis. Furthermore, Lyseng et al.'s projections [146] for wind and solar costs were significantly higher than the presently realized costs and recent cost reduction trends. The study by our colleagues Davis et al. [18, 65] considered a wider range of renewable and non-renewable technologies, a high penetration cogeneration options, and policy implications when projecting Alberta grid mix emission factor for different carbon pricing scenarios.

The total GHG intensity of each technology is used as an input to run the market share model and project the long-term market penetration of natural gas- and electrolysis-based technologies. The projected market shares and GHG intensities are used as inputs in the LEAP-Canada model to project disaggregated GHG emissions and mitigation potential per hydrogen technology, production scenario, carbon pricing environment, and demand scenario according to Equations 8 and 9, respectively.

$$GHG_{j,y,ps,cp,ds} = HD_{y,ds} MS_{j,y,ps,cp,ds} GHGI_j \qquad 21$$

$$CGHG_{nps,cp,ds} = \sum_{y=2026}^{2050} \left(\sum_{j=1}^{J_{REF}} GHG_{j,y,REF,cp,ds} - \sum_{j=1}^{J_{ns}} GHG_{j,y,nps,cp,ds} \right) \qquad 22$$

$GHG_{j,y,ps,cp,ds}$ is the projected GHG emissions from technology j, in year y, for production scenario ps, carbon pricing environment cp, and hydrogen demand scenario ds. $CGHG_{nps,cp,ds}$ represents the cumulative GHG mitigation potential of novel production scenario nps, and segregated by carbon pricing environment cp, and hydrogen demand scenario ds. J_{REF} and J_{ns} represent the total number of technologies considered in the REF and novel production scenarios, respectively.

The long-term hydrogen demand scenarios were obtained from LEAP-Canada model [18] and the projections are presented in Figure 3-4. The historical hydrogen demand in Alberta between 2020 and 2022 was obtained from the Alberta Energy Regulator [113].

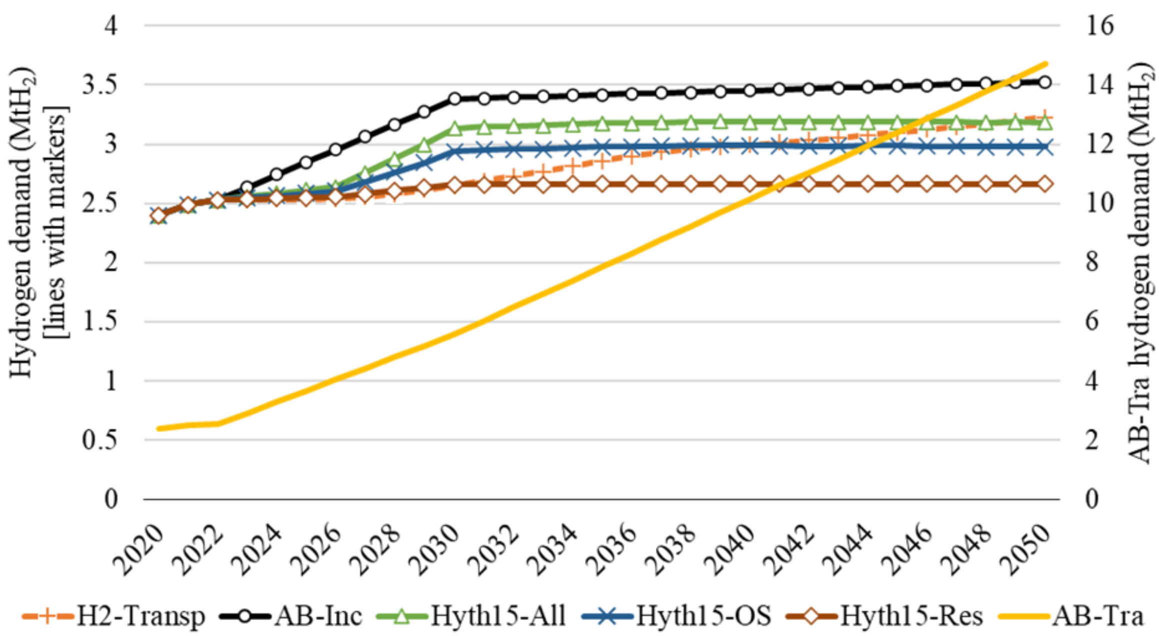


Figure 3-4: Annual hydrogen and hythane demand scenarios for Alberta, Canada

Table 3-5: Energy intensities of hydrogen production technologies and emission factors

	Natural gas-based technologies							Electrolysis-based hydrogen							
	SMR	**SMR-52% CCS**	**SMR-85% CCS**	**ATR**	**ATR-91% CCS**	**NGD**	**NGD-90%CCS**	**AEC-Grid**	**PEM-Grid**	**AEC-Wind**	**PEM-Wind**	**AEC-Hydro**	**PEM-Hydro**	**AEC-Solar**	**PEM-Solar**
Onsite emission intensity ($kgCO_2e/kgH_2$)	9.17	5.52	1.98	8.39	0.62	1.84	0.9	-	-	-	-	-	-	-	-
Natural gas intensity – feedstock (GJ/kgH_2)	0.12	0.12	0.12	0.15	0.15	0.18	0.18	-	-	-	-	-	-	-	-
Natural gas intensity – fuel (GJ/kgH_2)	0.06	0.10	0.13	-	2E-05	0.03	0.04	-	-	-	-	-	-	-	-
Natural gas supply emission factor ($kgCO_2e/GJ$)	Annual natural gas emission factors presented in Figure 3-3.														
Electricity intensity (kWh/kgH_2)	0.96	1.32	4.42	2.35	3.59	2.23	3.19	53	54.6	53	54.6	53	54.6	53	54.6
Electricity emission factor ($kgCO_2e/kWh$)	Annual Alberta grid mix emission factor by carbon pricing environment presented in Figure 3-3.									13E-03	13E-03	21E-03	21E-03	43E-03	43E-03

Source	[18, 65, 124]	[18, 145]

3.2.5. WEAP-Canada model

The natural gas- and electrolysis-based technologies and the production and demand scenarios were incorporated into the WEAP-Canada model to calculate yearly water consumption. A schematic of the WEAP-Canada model is presented in Figure 2-3, highlighting the water supply-demand sites in the province of Alberta. Even though not all capabilities from WEAP are necessary to obtain the results from this work, WEAP provides a robust framework to assess multiple scenarios and technologies disaggregated by river basins.

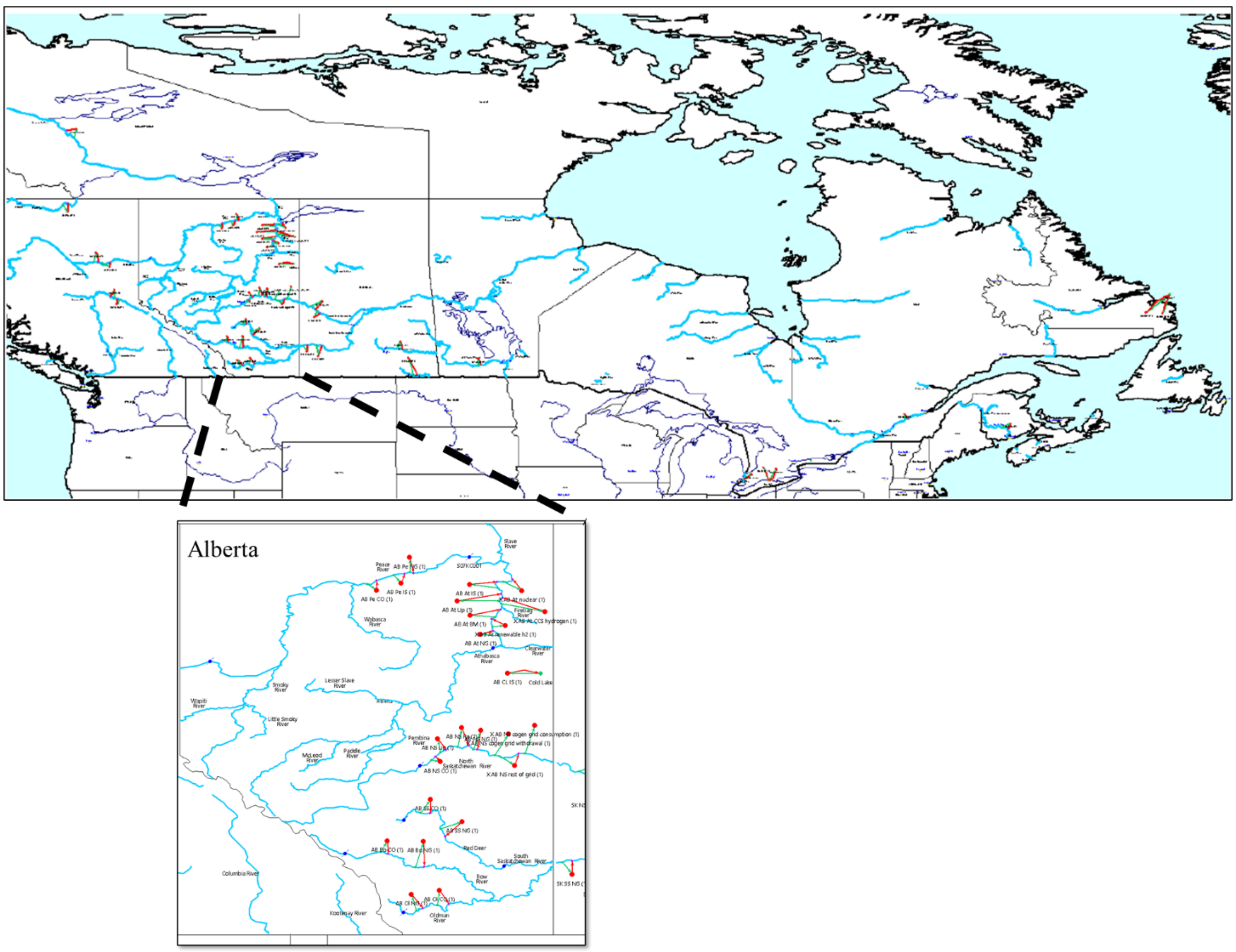


Figure 3-5: Schematic of the WEAP-Canada model highlighting the province of Alberta adapted from Gupta et al. [66]

The projected market shares and water intensities are used as inputs in the WEAP-Canada model to project disaggregated water consumption and cumulative savings potential per hydrogen technology, production scenario, carbon pricing environment, and hydrogen demand scenario according to Equations 23 and 24, respectively. Table 3-6 presents the water intensity values in litres of water consumed per kilogram of hydrogen produced for each natural gas- and electrolysis-based technology. The renewable power generation plant water factors were extracted from Ali and Kumar's study [147], the Alberta grid mix water factors for different carbon policy environments from Davis et al. [65] and Agrawal et al. [64], the natural gas-based technologies water intensities from Oni et al. [124], the AEC technology water intensities from Ghandehariun and Kumar [148] and Koj et al. [149], and the PEM technology water intensities from James et al. [150] and Barbir [151]. The Alberta grid mix water factors for different carbon pricing environments are presented in Figure 3-6 for the projection period of 2026 and 2050. To the best of the authors' knowledge, no projections on the Alberta grid water factor are available in the literature. For this reason, only WEAP-Canada's projections are presented in Figure 3-6. A data table is included in the Appendices.

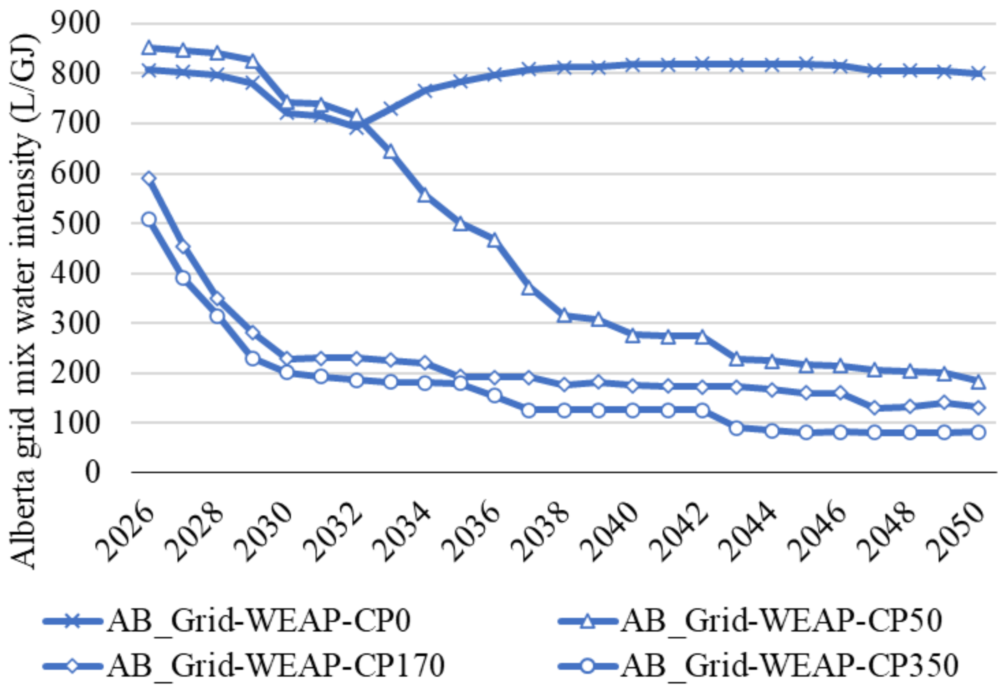


Figure 3-6: Annual Alberta grid mix water factor by carbon pricing environment

$$WC_{j,y,ps,cp,ds} = HD_{y,ds}MS_{j,y,ps,cp,ds}WCI_j \quad 23$$

$$CWS_{nps,cp,ds} = \sum_{y=2026}^{2050} \left(\sum_{j=1}^{J_{REF}} WC_{j,y,REF,cp,ds} - \sum_{j=1}^{J_{ns}} WC_{j,y,nps,cp,ds} \right) \qquad 24$$

$WC_{j,y,ps,cp,ds}$ is the projected water consumption from technology j, in year y, for production scenario ps, carbon pricing environment cp, and hydrogen demand scenario ds. $CWS_{nps,cp,ds}$ represents the cumulative water savings potential of novel production scenario nps, segregated by carbon pricing environment cp and hydrogen demand scenario ds.

Table 3-6: Water consumption intensities of hydrogen production technologies and water consumption factors

	Natural gas-based technologies							Electrolysis-based hydrogen							
	SMR	**SMR-52% CCS**	**SMR-85% CCS**	**ATR**	**ATR-91% CCS**	**NGD**	**NGD-90%CCS**	**AEC-Grid**	**PEM-Grid**	**AEC-Wind**	**PEM-Wind**	**AEC-Hydro**	**PEM-Hydro**	**AEC-Solar**	**PEM-Solar**
Water consumption intensity – feedstock (L/kgH_2)	1.45	1.45	1.45	3.29	3.29	1.76	1.73	10	11.3	10	11.3	10	11.3	10	11.3
Water consumption intensity – cooling & pre-CO_2 capture (L/kgH_2)	2.44	2.44	2.44	3.35	3.35	-	-	= 4.54 for all electrolysis-based technologies							
Water consumption intensity – post-CO_2 capture (L/kgH_2)	-	-	2.59	-	0	-	0.31	-	-	-	-	-	-	-	-

Water consumption intensity – CO_2 transport (L/kgH_2)	-	0.86	1.59	-	1.15	-	0.08	-	-	-	-	-	-	-	-
Water consumption intensity – CO_2 sequestration (L/kgH_2)	-	0.24	0.44	-	0.58	-	0.02	-	-	-	-	-	-	-	-
Electricity water factor (L/kWh)	Annual Alberta grid mix water factor by carbon pricing environment presented in Figure 3-6.									5.28E-03	5.28E-03	18.2	18.2	0.33	0.33
Source	[64, 65, 124]							[147-151]							

3.2.6. Cost-benefit analysis

A cost-benefit analysis is performed to understand the cost-effectiveness of the decarbonization scenarios in terms of marginal GHG abatement and water savings costs. The marginal GHG abatement and water savings costs for each scenario are obtained with Equations 25 and 26, respectively.

$$MAC_{nps,cp,ds} = \frac{\sum_{y=2026}^{2050} HD_{y,ds}\left[\left(\sum_{j=1}^{J_{nps}} MS_{j,y,nps,cp,ds}LCC_{j,y,cp}\right) - \left(\sum_{j=1}^{J_{REF}} MS_{j,y,REF,cp,ds}LCC_{j,y,cp}\right)\right]}{CGHG_{nps,cp,ds}} \quad 25$$

$$MSC_{nps,cp,ds} = \frac{\sum_{y=2026}^{2050} HD_{y,ds}\left[\left(\sum_{j=1}^{J_{nps}} MS_{j,y,nps,cp,ds}LCC_{j,y,cp}\right) - \left(\sum_{j=1}^{J_{REF}} MS_{j,y,REF,cp,ds}LCC_{j,y,cp}\right)\right]}{CWS_{nps,cp,ds}} \quad 26$$

$MAC_{nps,cp,ds}$ represents the marginal cost of each tonne of CO_2 abated through the novel production scenario nps, for carbon pricing environment cp, and hydrogen demand scenario ds. $MSC_{nps,cp,ds}$ is the marginal cost of each cubic meter of water saved in the novel production scenario nps, for carbon pricing environment cp, and hydrogen demand scenario ds. The total annualized costs of each technology considered are brought to present value at an interest rate specified in Table 3-4. The numerator of Equations 25 and 26 represents the total system cost difference between the novel production scenario and the reference scenario, while the denominator represents the cumulative GHG abated and water savings. The units of the marginal abatement and savings costs are in 2023 Canadian dollars per tonne of CO_2 abated and per cubic meter of water saved, respectively. The marginal costs are broken down into marginal capital, operating, energy, and carbon costs.

3.2.7. Sensitivity and uncertainty analysis

Sensitivity analysis is performed to investigate the output parameter sensitivity to variation of individual input parameters. The uncertainty analysis has the objective to quantify the output variation due to changes on the input parameters. In this work, the Morris sensitivity analysis and Monte Carlo simulation were performed with the help of RUST to assess the sensitivity and variability of the cumulative water savings and GHG abatement, and marginal GHG abatement and water savings cost to variations in different input values. For the sensitivity analysis, the Morris sensitivity method does not use a one-at-a-time approach to conduct the analysis; instead it considers the interactions between the input parameters by examining the sensitivity of the output variables across the entire parameter domain. This is done by calculating several partial derivatives for each selected input in different locations of the parameter space. The mean and standard deviation of the absolute values of the partial derivatives are obtained and used to obtain the Morris plot for each output analyzed. In the Morris plot, the sensitive inputs are located at the top right of the chart, whereas insensitive variables appear in the bottom left part. Now, for the uncertainty analysis, the Monte Carlo simulation is performed through Latin Hypercube Sampling and the results are displayed in a cumulative frequency distribution plot [104]. 500 samples were run in the Monte Carlos simulation.

Table 3-7 gives the input parameters used in the sensitivity and uncertainty analysis, the baseline values, the variations from the baseline, and the justification of each variation assumed. Over 80 input variables were considered in the sensitivity analysis. To run RUST, the modelling structure developed in this study and incorporated into LEAP- and WEAP-Canada was built in Excel to perform the Morris sensitivity analysis and Monte Carlo simulation.

Table 3-7: Sensitivity and uncertainty analysis input parameters

Input variable	Baseline value	Variation	Comment
Technology-specific capital and operating costs	See Table 3-4	*(1±0.25)	An arbitrary 25% variation is assumed from the baseline values as capital and operating costs data are limited in the literature. Every technology was considered.
Technology-specific electricity, natural	See Table 3-4	*(1±0.25)	An arbitrary 25% variation is assumed from the baseline values. The variation rate is equal to the value used for the technology-specific capital and operating costs since the

Input variable	Baseline value	Variation	Comment
gas, and carbon intensities			technology-specific energy intensities and costs are used with the same weight in the market share model to obtain the market shares of the novel production scenarios. Every technology was considered.
Water (feedstock) intensity – electrolysis technologies	See Table 3-4	Min = 9.0 Max (AEC) = 10.98 Max (PEM) = 13.36	Minimum value from stoichiometry. Maximum value, from Lampert et al. [152] and James et al. [150].
Water (process requirement) intensity – electrolysis technologies & total water intensity – natural gas-based technologies	See Table 3-4	*(1±0.25)	An arbitrary 25% variation is assumed from the baseline values due to variations in process cooling water and pre-CO_2 capture cooling water.
Interest rate	See Table 3-4	± 2.5%	Based on different values used in previous studies by our research group on long-term GHG emissions and water consumption projections [13, 64, 91, 92].

Input variable	Baseline value	Variation	Comment
Sensitivity to cost	8.0	1.0 – 10.0	Based on different values obtained from empirical data in a consumer discrete technology choice survey carried out by Rivers and Jaccard [142].

3.3. Results and discussion

The years 2035 and 2050 were chosen to present the results obtained, since in 2035 new technologies such as ATR and NGD will have penetrated the market and no phase-out policy will have affected the modeling. The year 2050 is then used to assess the effects of a phase-out policy and evaluate the market penetration of low-carbon technologies when only costs affect decisions, i.e., no phase-out policy is in place. We compare the 2050 results with the 2035 results and analyze the effectiveness of carbon pricing environments and phase-out policies in deploying low-carbon hydrogen production options, mitigating GHG emissions, and saving (or consuming) water.

3.3.1. Market share results

The market share projections of each technology, production scenario, and carbon pricing environment are presented in Figure 3-7 for the years 2035 and 2050. The results are presented for the AB-Inc hydrogen demand scenario. The market shares for the other demand scenarios are in the Appendices; they are not included here as the interpretation of the market penetration of different technologies for different carbon pricing environments is similar or the same for distinct hydrogen demand scenarios.

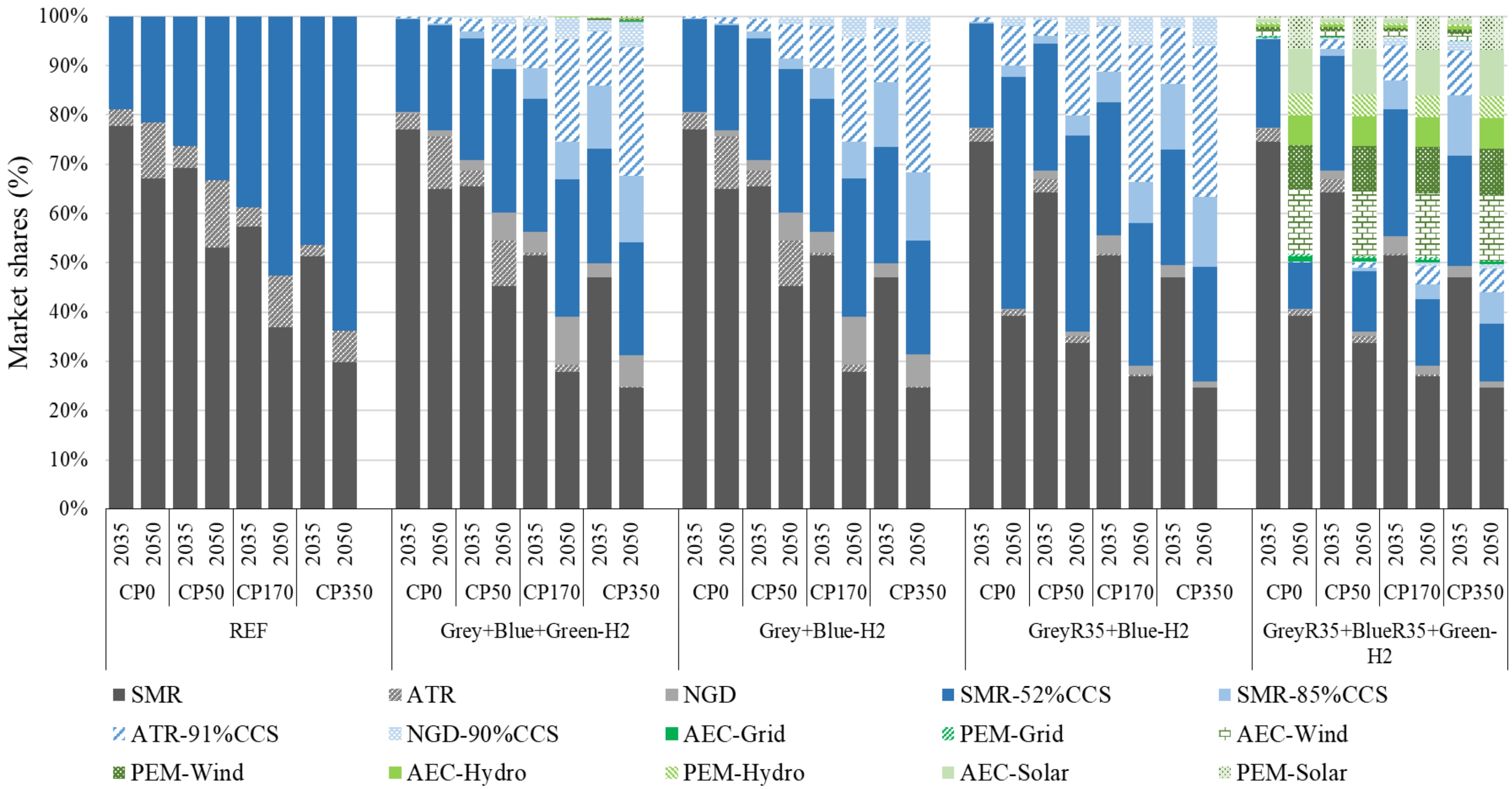


Figure 3-7: Market share projections for each hydrogen production scenario and carbon pricing environment for the AB-Inc hydrogen demand scenario.

In general, the market share model favours the penetration of less expensive options. The low-carbon technologies, especially CCS natural gas-based options, penetrate the market more aggressively as carbon price grows from \$0/tCO_2e to \$350/tCO_2e in 2050. Except for the GreyR35+BlueR35+Green-H2 production scenario, the market penetration of electrolysis-based technologies is minor because of the high capital and operating costs of these options compared to natural gas-based technologies with and without CCS. Figure 3-8 presents the total unit costs of all technologies considered in this study for the year 2035 and carbon pricing environment CP170. From Figure 3-8, the total unit costs of the electrolysis-based technologies are approximately two to three times higher than the total unit costs of the natural gas-based options. For grid-powered electrolysis, even though capital and operating costs are not as high as for renewable electrolysis, energy costs due to electricity consumption are significant. The effect of the higher costs of electrolysis-based technologies is observed in the Grey+Blue+Green-H2 scenario, in which all technologies included in this study compete for market shares and the electrolysis-based options assume less than 5% of all hydrogen production in 2050 at CP350.

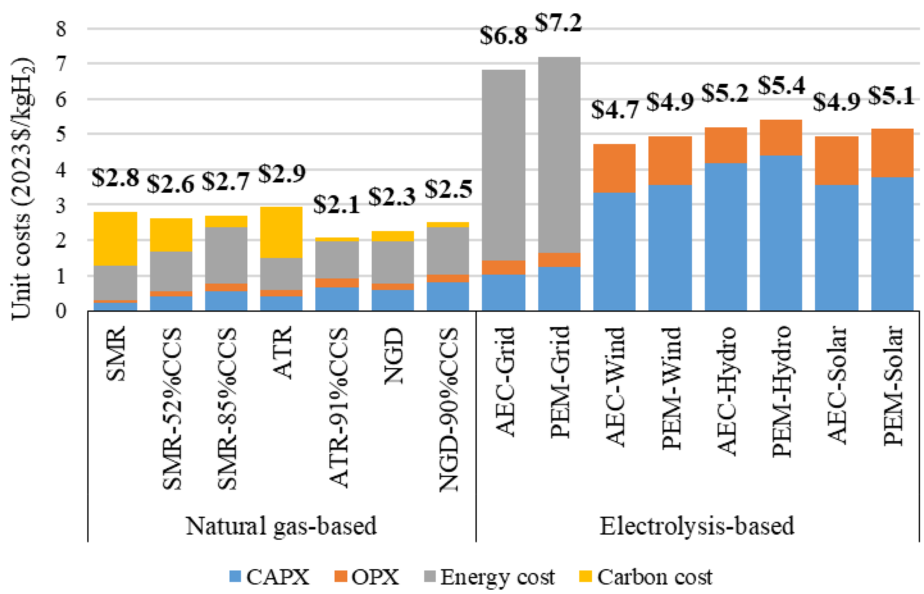


Figure 3-8: Total unit costs of hydrogen technologies for the year 2035 for carbon pricing environment CP170 and discounted for the year 2023.

If a jurisdiction chooses to produce low-carbon hydrogen from water electrolysis rather than natural gas reforming tied to CCS, the market share modelling results show how crucial it is to have a policy in place that facilitates the large-scale deployment of the electrolysis-based options. Having such a policy is considered in GreyR35+BlueR35+Green-H2. In this scenario, natural gas-based technologies start to retire in 2035 and electrolysis-based technologies assume more than 50% of the hydrogen production shares in 2050. Wind-powered electrolysis assumes the largest share, followed by solar-, hydro-, and grid-powered electrolysis. The renewable-powered electrolysis technologies do not change their market penetration considerably as carbon price increases, once capital and operating costs are major components of total unit costs.

The market share projections from the Grey+Blue+Green-H2 and Grey+Blue-H2 scenarios result in similar market penetrations of natural gas-based technologies tied to CCS, even though the former scenario considers electrolysis options in the market competition. CCS technologies assume more than 60% of hydrogen production in 2050 at CP350. ATR-91%CCS takes over 26% of the market shares, followed by SMR-52%CCS with over 23%, SMR-85%CCS with 14%, and NGD-90%CCS with 7%. ATR technology's participation in the market decreases as the price of carbon increases, because of its high emission intensity. ATR-91%CCS and NGD-90%CCS present similar and lower market shares than SMR with CCS, respectively, since the former technologies start competing for hydrogen capacities only in 2030 because of their lower technology readiness levels. Conventional SMR and SMR-52%CCS still represent over 20% of CP350 market shares in 2050, since these technologies assume 100% of the total hydrogen production capacity until 2025 and compete for incremental hydrogen production capacities with novel technologies only after 2026. The participation of NGD is considerable relative to ATR when the carbon price rises. Even though the capital cost of NGD is higher than ATR, the cost savings due to lower carbon emissions by NGD offset its higher CAPX and lead to greater market penetration of NGD over ATR. The percentage of market share that is reduced from NGD from CP170 (10%) to CP350 (6.5%) is absorbed by NGD-90%CCS with the additional cost savings seen for this technology at higher carbon pricing environments.

GreyR35+Blue-H2 shows how significant it is to have a CCS policy incentive in place to replace non-CCS technologies with low-carbon natural gas-based technologies tied to CO_2 capture, transportation, and sequestration units, especially in low-carbon pricing environments. For example, for the Grey+Blue-H2 scenario, CCS technologies assume approximately 25% and 67% of all hydrogen production capacities in 2050 at CP0 and CP350, respectively, whereas the same technologies take over 60% and 75% in 2050 at CP0 and CP350, respectively, in GreyR35+Blue-H2. The increase in carbon price is significant in stimulating the market penetration of low-carbon options; however, the implementation of phase-out policies on carbon-intense technologies are imperative for the deep decarbonization of the hydrogen production industry, and especially in low carbon pricing environments. These results are valuable for policy formation as they show how effective it can be in boosting the market penetration of CCS technologies and leading to deep decarbonization of the hydrogen industry.

3.3.2. GHG emissions results

The 2035 and 2050 projections for total GHG emissions, in million tonnes of CO_2-equivalent, for each production scenario and carbon pricing environment are presented in Figure 3-9**.** The results are presented for the AB-Inc demand scenario and broken down into GHG emissions coming from onsite emissions, natural gas supply to be consumed as feedstock and as fuel, and indirectly through electricity consumption. The GHG emissions for other hydrogen demand scenarios are given in the Appendices. The cumulative GHG abatement between 2026 and 2035, and 2026 and 2050, are also presented in Figure 3-9 to properly compare novel production scenarios in decarbonizing the hydrogen industry.

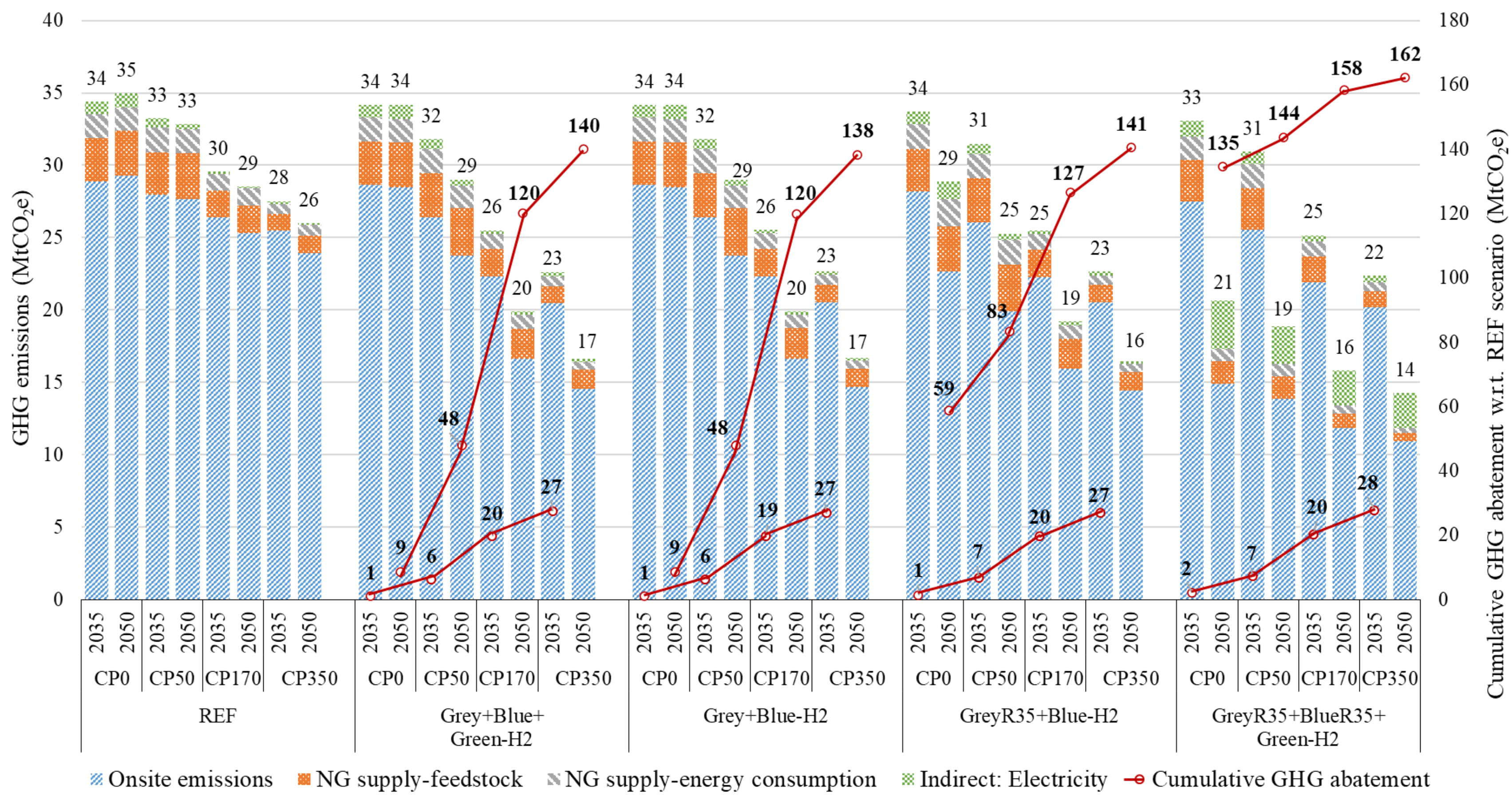


Figure 3-9: GHG emissions projections for each hydrogen production scenario and carbon pricing environment for the AB-Inc hydrogen demand scenario

For the scenarios where no phase-out policy applies, under CP0, no reduction in carbon emissions is captured between 2035 and 2050 because of the lower market penetration of novel low-carbon hydrogen production options. As the carbon price rises, the total emissions for 2050 decrease by 9%-39% from 2035 levels. With the exception of the GreyR35+BlueR35+Green-H2 production scenario, indirect electricity emissions decrease as carbon price increases once Alberta's grid mix emission factor falls following the penetration of renewable energy generation in the grid. Onsite emissions represent approximately 84% of total GHG emissions, with the supply of natural gas to be consumed as feedstock and as fuel contributing 8% and 5%, respectively, and the remaining 3% from electricity consumption. The total GHG emissions in the year of 2035 are similar for every scenario, since only in this year do grey and blue hydrogen phase-out policies start interfering in the market share modelling of the GreyR35+Blue-H2 and GreyR35+BlueR35+Green-H2 scenarios, respectively.

For GreyR35+BlueR35+Green-H2, indirect emissions from electricity consumption are higher than other production scenarios considered in this study, ranging from 14% to 17% of total GHG emissions in 2050 because of the high electricity intensity of electrolysis-based technologies. Solar-powered AEC and PEM technologies account for most emissions among the electrolysis options, representing 57% of their total emissions, followed by wind-powered AEC and PEM at 24% because of higher market penetration, hydro-powered electrolysis at 18%, and grid-powered electrolysis the remaining 1%.

From the cumulative GHG abatement potential results, all novel low-carbon hydrogen production scenarios at all carbon pricing environments lead to CO_2 abatement compared to the REF scenario. GreyR35+BlueR35+Green-H2 abate more GHG emissions than the other novel low-carbon hydrogen production scenarios, from 135 to 162 million tonnes of cumulative CO_2e abated between 2026 and 2050. Figure 3-9 shows that as the price of carbon increases, the cumulative GHG mitigation does not increase linearly, thus demonstrating how carbon pricing, in a non-linear way, affects the environmental performance of the scenarios by changing energy and carbon prices, as well as electricity and natural gas supply emission factors. The price of carbon is a key player in shaping policies to strengthen the large-scale deployment of low-carbon hydrogen, and the effects of changing it must be carefully analyzed. However, as discussed in the Market share results section, implementing a phase-out policy has a significant impact on the large-scale deployment of novel and more expensive low-carbon options and further GHG abatement. For example, the GreyR35+BlueR35+Green-H2 scenario leads to an additional 22 to 126 million tonnes of GHG abated compared to the Grey+Blue+Green-H2 scenario with the phase-out of natural gas-based technologies with and without CCS.

Regarding the other hydrogen demand scenarios, the cumulative GHG abatement potential for the residential and oil sands sectors in Alberta with the large-scale deployment of hythane ranges from 6 to 110 $MtCO_2e$ and 7 to 135 $MtCO_2e$, respectively. For the transportation sector in Alberta, the cumulative GHG abatement potential ranges from 8 to 152 $MtCO_2e$. For the Alberta Hydrogen Roadmap transformative scenario (AB-Tra), in which a more supportive policy environment for large-scale hydrogen deployment is considered, the cumulative emissions reductions range from 50 to 865 $MtCO_2e$. Although great GHG emissions abatement potential is projected with the implementation of low-carbon hydrogen technologies, 2050's carbon emissions will still not be equal to zero. The total GHG emissions in 2050 range from 12 to 33 $MtCO_2e$ among the production scenarios and carbon pricing environment that most favour emissions reduction. This highlights for policy- and decision-makers that more efforts are needed to achieve the target of net-zero emissions by 2050.

3.3.3. Water use results

The 2035 and 2050 projections for total water consumption, in millions of cubic meters of water, for each production scenario and carbon pricing environment are presented in Figure 3-10**.** The results are presented for the AB-Inc demand scenario and broken down into water consumed as feedstock for the natural gas reforming or electrolysis processes, as process requirement in the pre-carbon capture unit and cooling systems, but also consumed in the CO_2 capture, transportation, and sequestration units, and indirectly for electricity generation. The water consumption for other hydrogen demand scenarios is given in the Appendices. The cumulative water savings from 2026 to 2035 and 2026 to 2050 are also presented in Figure 3-10.

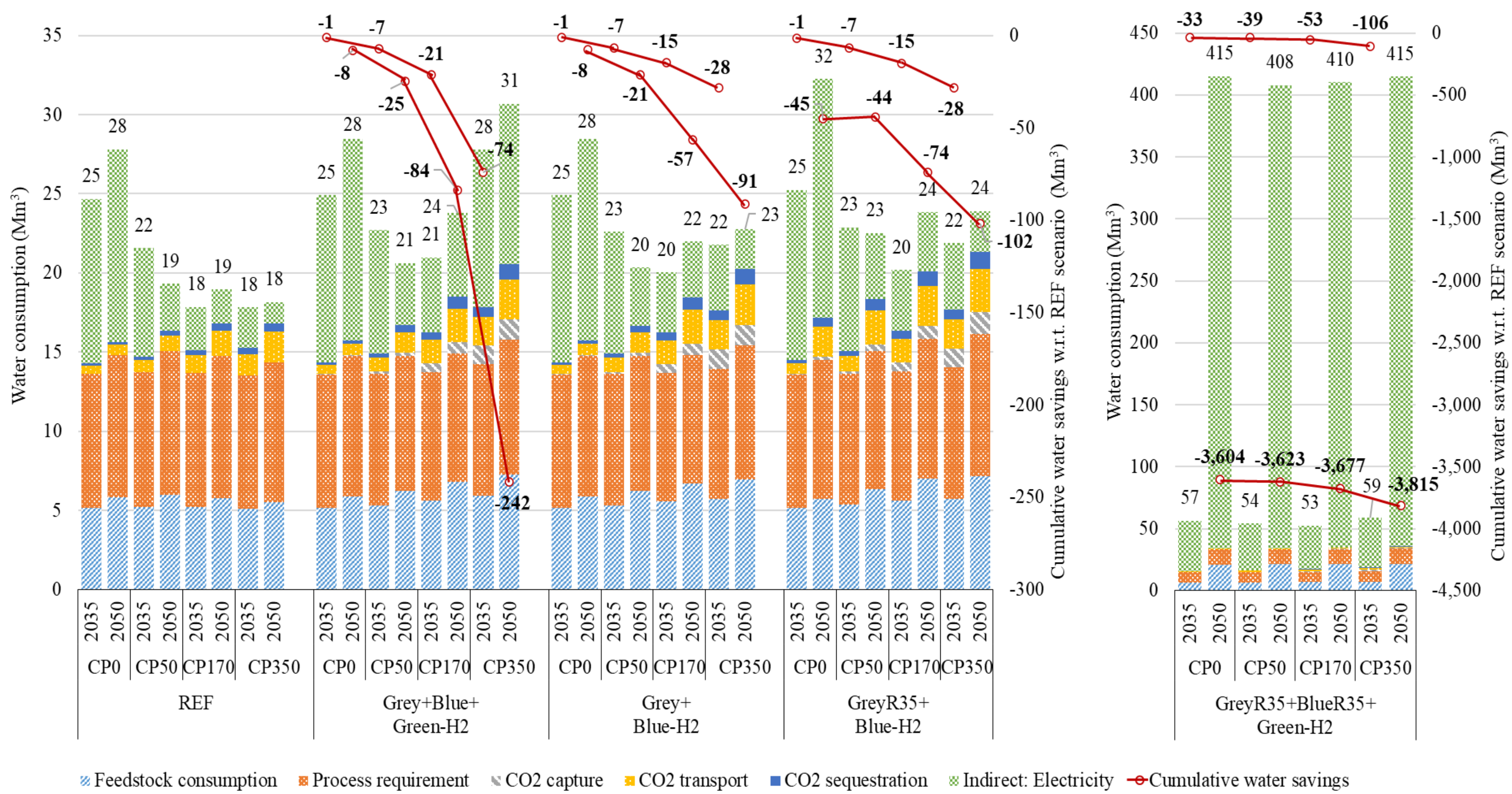


Figure 3-10: Water consumption projections for each hydrogen production scenario and carbon pricing environment for the AB-Inc hydrogen demand scenario

For GreyR35+BlueR35+Green-H2, water consumption in 2050 is 7 to 8 times higher than in 2035. Even though the market penetration is not as considerable as wind-powered electrolysis, hydro-powered electrolysis represents approximately 90% of the total production scenario water consumption due to the high water intensity of hydropower generation. For the other hydrogen production scenarios at CP0, like the GHG emissions projections, the 2050 water consumption increases from 2035 levels at different rates depending on the hydrogen technology. Taking Grey+Blue+Green-H2 as an example, at CP0, the water used because of electricity consumption accounts for 45% of total water consumption in 2050. This shows how important it is to consider indirect water use due to electricity consumption when assessing the long-term water consumption of low-carbon hydrogen deployment and how the price of carbon influences the grid mix water factor, therefore the water consumption of grid-powered hydrogen technologies.

For the hydrogen production scenarios that consider CCS technologies to penetrate the market, even though CCS units introduce a parasitic load to the system, their total water use in the long-term projections compared to the other sources of water consumption is not significant. For GreyR35+Blue-H2, which considers that non-CCS natural gas-based technologies start to phase out in 2035 and are replaced by CCS technologies, the total CO_2 capture, transportation, and sequestration water consumption accounts for 21% of total water demand at CP350 in 2050. Water consumed as process requirement represents 37% of total water consumption; feedstock water makes up 30% and the remaining 12% is indirect water for electricity generation. This shows the potential to reduce the water consumption of these scenarios, as the overall hydrogen production process and electrical efficiency can be improved to reduce water demand for cooling purposes and reduce the electricity intensity of low-carbon hydrogen technologies, respectively.

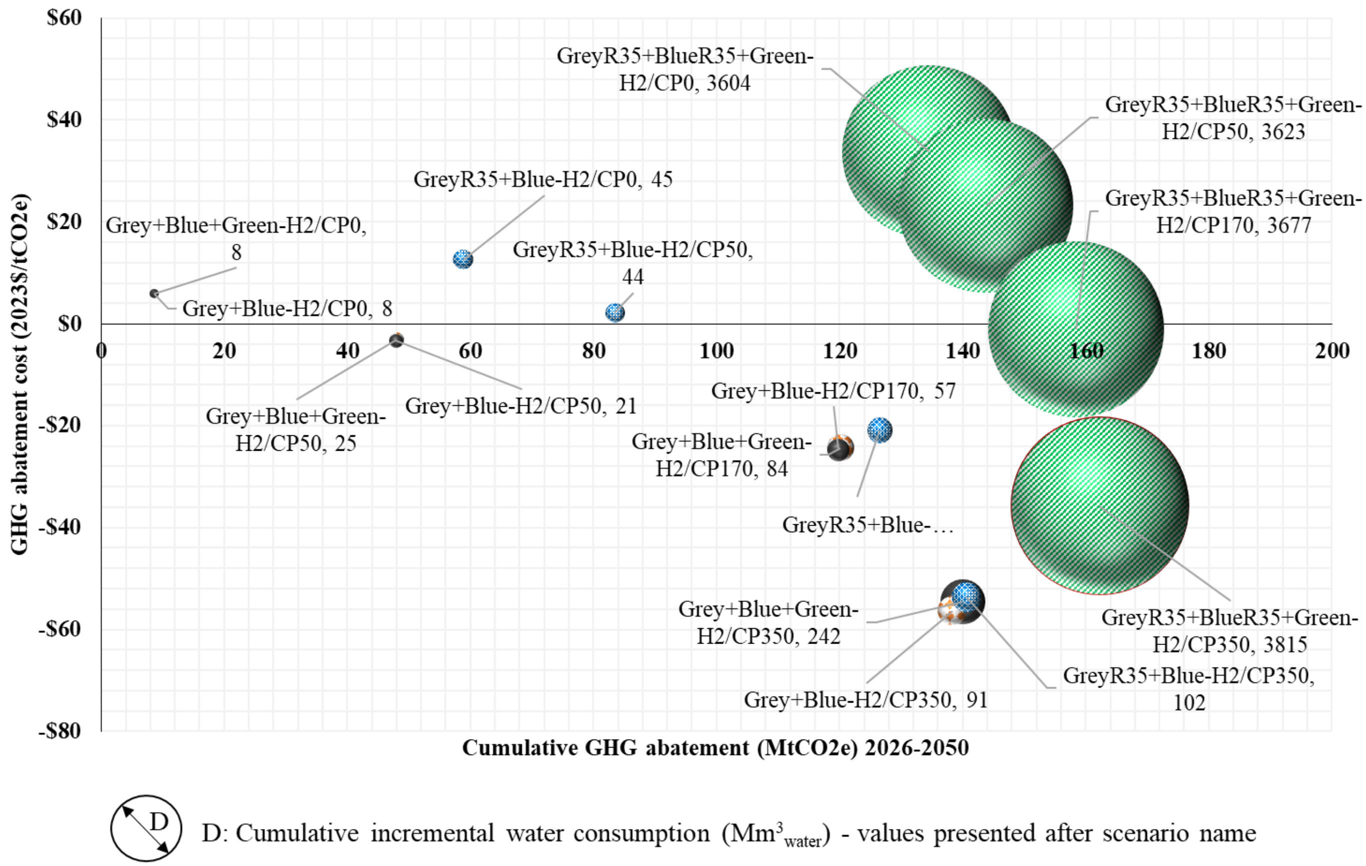
The negative cumulative water savings results in Figure 3-10 show that all low-carbon hydrogen production scenarios lead to higher cumulative water consumption compared to the reference scenario. The negative cumulative water savings results are key to interpreting the marginal water savings cost. As the price of carbon increases, low-carbon technologies, such as CCS and electrolysis-based technologies, penetrate the market more aggressively and lead to higher water consumption. This can be seen by the increase in the modulus of the cumulative water savings results from CP0 to CP350. As phase-out policies are implemented and CCS- and electrolysis-based technologies penetrate the market more significantly, water consumption increases. For example, the cumulative incremental water consumption between 2026 and 2050 for GreyR35+Blue-H2 increases by 11 and 37 million cubic metres compared to Grey+Blue-H2 and increases by more than 3,500 million cubic metres for GreyR35+BlueR35+Green-H2 compared to Grey+Blue+Green-H2.

The increase in absolute values of cumulative water savings of Grey+Blue+Green-H2 with the rise in carbon prices is directly related to the increased market penetration of electrolysis-based options. Although their market penetration is minor and results in less than 5% of hydrogen production capacity in 2050 under CP350, the electrolysis-based technologies are considerably more water-intense than natural gas-based options. Now, as stated previously for GreyR35+BlueR35+Green-H2, the large negative cumulative water savings are due to the high water consumption of hydro-powered electrolysis-based technologies. The negative cumulative water savings results will be key to interpreting the marginal water savings cost and its trends as the price of carbon changes.

In order to assess the impacts of the increase in water consumption with the large-scale deployment of low-carbon hydrogen on a water body, the Athabasca River in Alberta is used as an example of a source of freshwater to produce hydrogen. According to the weekly flow estimates for the Athabasca River in the year 2022 [110], the annual average flow rate was of 531 m^3/s, or 16,746 Mm^3/year. Under the AB-Inc hydrogen demand scenario, the total amount of water consumed in 2050 in the GreyR35+BlueR35+Green-H2 production scenario at CP350 (the scenario with the highest water footprint) is approximately 2.5% of the Athabasca River flow. For the same hydrogen production scenario and carbon pricing environment, the total amount of water consumed in 2050 under AB-Tra is 15%. For the GreyR35-Blue-H2 scenario, in which all natural gas-based technologies start to implement CCS units by 2035, at CP350 the AB-Inc and AB-Tra scenarios represent only 0.1% of the total river flowrate in 2050. Therefore, although total water consumption increases as CCS is implemented and hydrogen is produced through water electrolysis, the amount of water allocated from only one river basin to produce hydrogen from low-carbon options is small. Nevertheless, alternative types of water should be explored to offset the amount of freshwater intake and consumption by hydrogen-producing facilities. Still, limiting freshwater withdrawal and consumption of future electrolysis-based hydrogen technologies, as regulated in the oil sands industry by Directive 081 from the Alberta Energy Regulator [7], should be considered to ensure these low-carbon technologies remain within water-use rate boundaries and reduce the hydrogen production process water footprint. The results obtained in this study are in agreement with those of Beswick et al. [135], who found that, although a greater amount of water is consumed with the large-scale deployment of low-carbon hydrogen, the supply of water for natural gas- and electrolysis-based hydrogen production facilities does not pose a considerable problem for jurisdictions and, instead, efforts should be placed on improving the energy efficiency of these low-carbon technologies and making them more cost-competitive.

3.3.4. Integrated cost-benefit assessment

To better understand how each novel production scenario performs in terms of water consumption and GHG emissions abatement compared to the reference case, the cost to abate one tonne of CO_2 is shown in the bubble chart in Figure 3-11. The novel hydrogen production scenarios' acronyms are followed by the respective carbon pricing environment. The breakdown of the marginal GHG abatement costs of each novel production scenario and carbon pricing environment into capital, operating, energy, and carbon costs are provided in the Appendices. The marginal costs are discounted at a rate specified in Table 3-4 for each hydrogen technology to give the net present value in the year of 2023. The results are presented for the AB-Inc demand scenario. For water-related costs, since water is not saved (because low-carbon hydrogen is considered in the scenarios considered in this study), we left out the marginal water savings cost from the integrated cost-benefit assessment.



Values w.r.t. the REF scenario. This scenario considers that SMR and SMR-52%CCS assume hydrogen production between 1990 and 2023 and compete alone for incremental capacities between 2024 and 2029. ATR starts penetrating the market in 2030.

Figure 3-11: Bubble chart showing cumulative incremental water consumption and cumulative GHG abatement between 2026 and 2050, and marginal GHG abatement costs for each novel hydrogen production scenario and carbon pricing environment. The coordinates in the center of each bubble represent the marginal GHG abatement cost and cumulative GHG abatement of each scenario. The cumulative incremental water consumption is indicated by the bubble's size. The bubble's label gives the

hydrogen production scenario, followed by the carbon pricing environment and the cumulative incremental water consumption. The results are from the AB-Inc hydrogen demand scenario.

The marginal GHG abatement costs are negative or turn into benefits (savings) under high carbon pricing environments. As the price of carbon increases, the economic benefits increase because of the large savings from carbon emissions costs. For all novel scenarios except for GreyR35+BlueR35+Green-H2, the capital, operating, and energy costs are significant in that they do not lead to economic benefits at CP0. CAPX and energy costs become even more relevant than the operating cost as the price of carbon increases because of the higher market penetration of CCS- and electrolysis-based options. For Grey+Blue+Green-H2, Grey+Blue-H2, and GreyR35+Blue-H2, marginal GHG abatement costs at CP350 range from -\$54/tCO_2e to -\$56/tCO_2e; nevertheless, a slight difference is observed for CAPX cost due to the penetration of electrolysis-based technologies in the first scenario (more expensive in terms of capital cost than natural gas-based options) and the large-scale deployment of only CCS-based options after 2035 in GreyR35+Blue-H2.

For the GreyR35+BlueR35+Green-H2 scenario, the higher CAPX cost of electrolysis-based technologies compared to natural gas-based options with and without CCS is key in determining the higher marginal abatement cost at CP0 and CP50. The operating costs are also large for this scenario when electricity production and consumption costs from the dedicated renewable power plants are included. This confirms that more efforts are needed to make electrolysis-based technologies more cost-effective compared to natural gas-based options and equally compete for new market shares of incremental hydrogen production capacities.

These results indicate that high carbon pricing environments are extremely important in transforming novel scenarios into attractive and viable economic options for the large-scale deployment of low-carbon hydrogen, as the large cost savings are directly associated with carbon emission costs. The abatement costs provide insight into how much incentive is still needed to enable the transition to low-carbon hydrogen. These results also provide decision-makers with information on the environmental and economic aspects of each decarbonization pathway, shedding some light on the benefits and drawbacks of specific options.

Grey+Blue-H2 and GreyR35+Blue-H2 at CP350 show the highest economic benefits in terms of marginal GHG abatement costs and higher cumulative GHG abatement among the natural gas-based options. From these results, we conclude that a non-CCS phase-out policy is not as effective as the increase in carbon price in leading to economic benefits or reducing GHG emissions and water consumption compared to other low-carbon hydrogen production scenarios.

However, as previously stated, rising carbon prices do not have as significant an effect in forcing the large-scale deployment of certain low-carbon technologies, such as electrolysis-based options, as phase-out policies do. The four green bubbles in the right hand-side of the chart in Figure 12 show the great potential for GHG abatement with the large-scale deployment of electrolysis technologies through a natural gas-based phase-out policy. However, these novel scenarios have the disadvantage of consuming approximately 10 to 100 times more water than hydrogen production scenarios based on natural gas. And, at CP350, GreyR35+BlueR35+Green-H2 is \$20/tCO_2e more expensive than natural gas-based options. These results highlight the fact that efforts are needed to make electrolysis technologies more cost- and water-effective options compared to CCS and non-CCS natural gas-based hydrogen technologies.

3.3.5. Sensitivity and uncertainty analysis

The Morris sensitivity analysis results are presented in Figure 3-12 in terms of the percentage of variation of the Morris mean and standard deviation. The cumulative incremental water consumption and GHG abatement and the marginal GHG abatement cost are relative to the Grey+Blue+Green-H2 scenario. This scenario was chosen because it combines all the available conventional and low-carbon technologies considered in this study. The carbon pricing environment CP170 and the hydrogen demand scenario AB-Inc were chosen to present the results. The results from the Monte Carlo simulation are given in Figure 3-13 as cumulative distribution function plots.

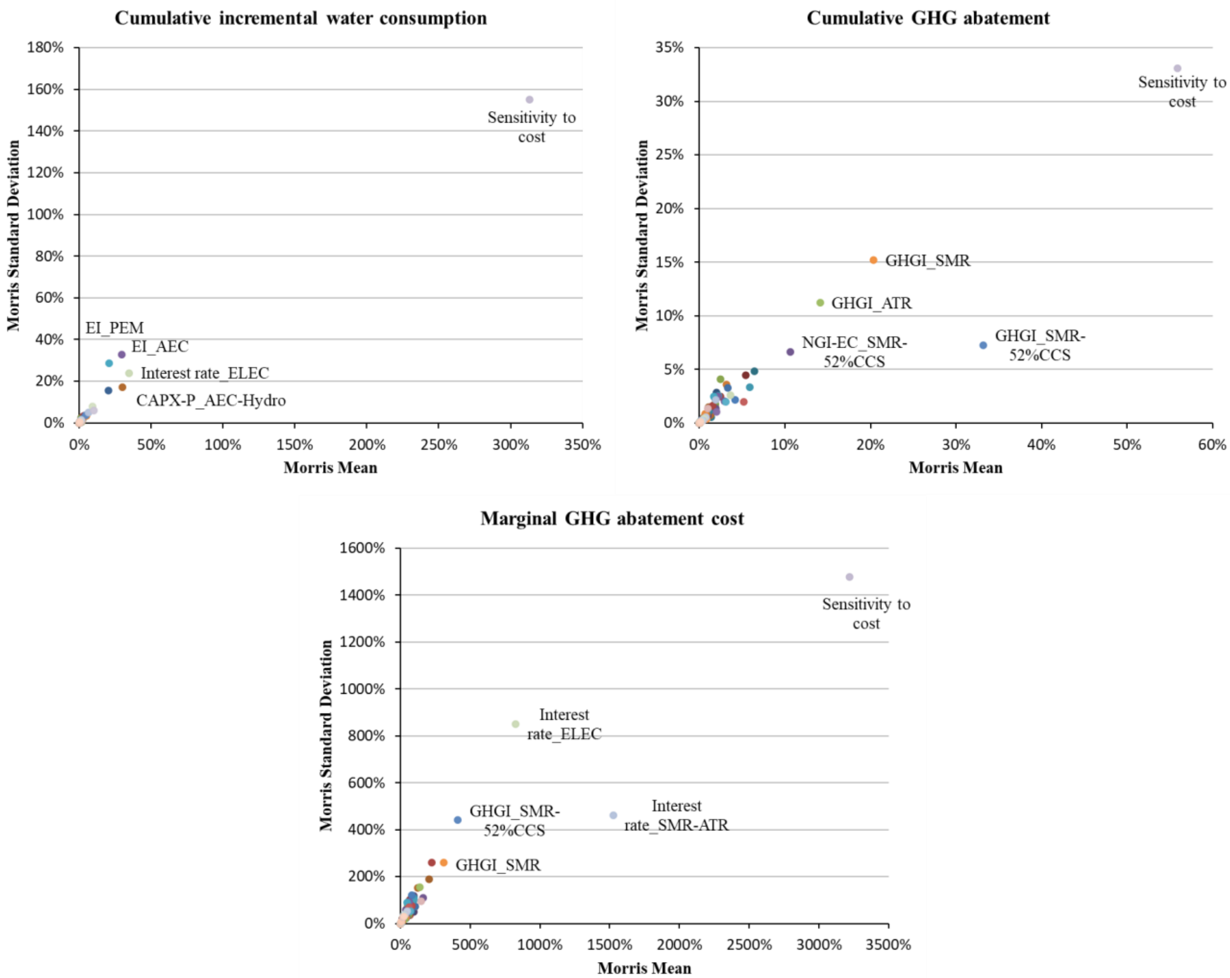


Figure 3-12: Morris sensitivity analysis results for cumulative incremental water consumption and GHG abatement between 2026 and 2050, and marginal GHG abatement costs. The results are valid for the carbon pricing environment CP170, the hydrogen demand scenario AB-Inc, and the hydrogen production scenario Grey+Blue+Green-H2.

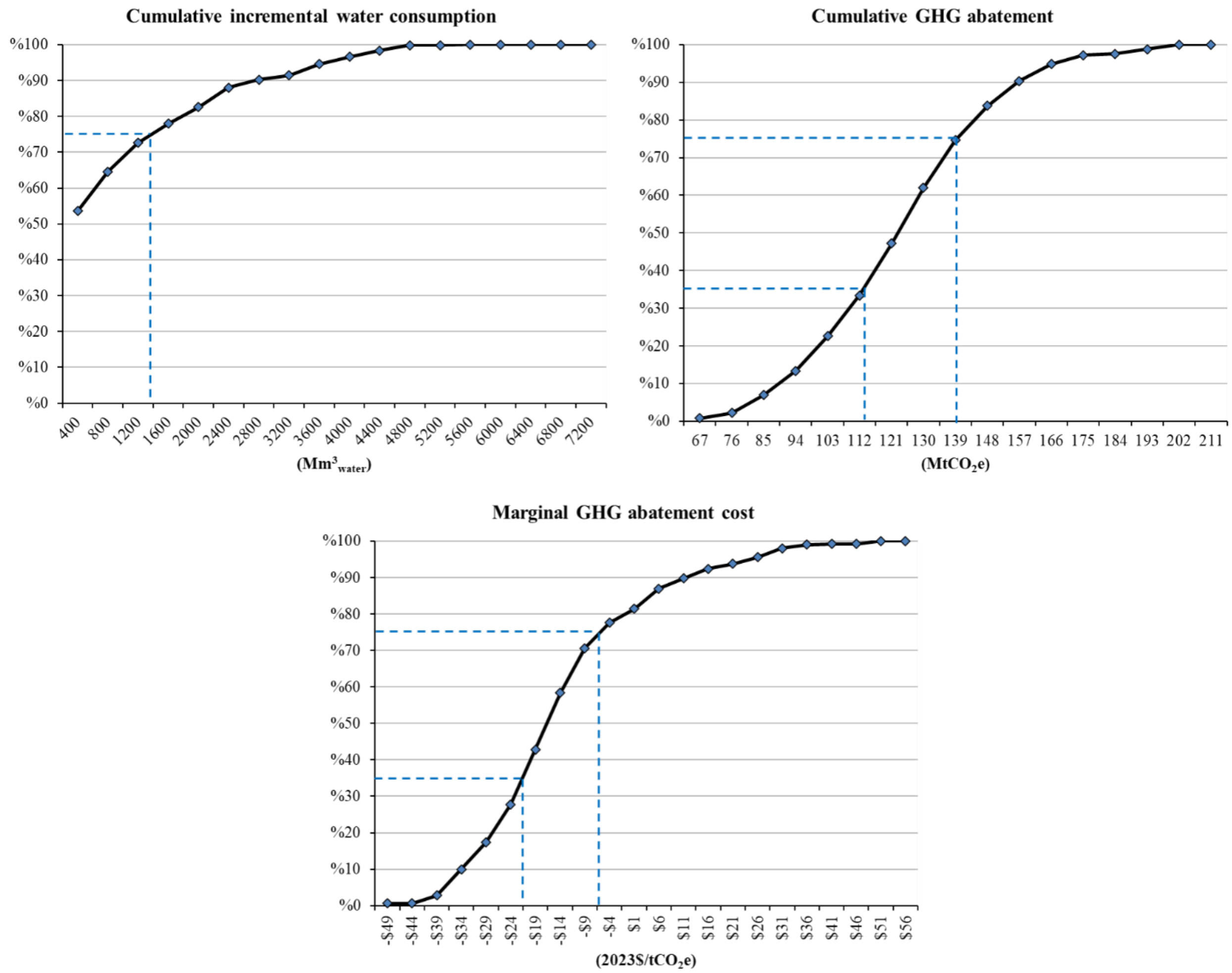


Figure 3-13: Monte Carlo simulation results for cumulative incremental water consumption and GHG abatement between 2026 and 2050, and marginal GHG abatement costs. The results are valid for the carbon pricing environment CP170, the hydrogen demand scenario AB-Inc, and the hydrogen production scenario Grey+Blue+Green-H2.

From Figure 3-12, the inputs used to perform the Morris sensitivity analysis are shown as circle markers in the charts. The input parameters change the output variables differently. The top five input parameters with the highest Morris mean (the most sensitive input parameters) are sensitivity to cost, natural gas electricity, carbon intensity, interest rate, and capital cost. "CAPX-P_," "EI_," "NGI-EC_," and "GHGI_" in Figure 3-12 are the capital cost, electricity, natural gas as fuel consumption, and onsite emissions intensities of each technology.

For all output variables, the sensitivity to cost is the input parameter to which the outputs are most sensitive. For high values of sensitivity to cost, i.e., for values around eight to ten, the preference on market penetration is given to less expensive technologies, whereas for low values, i.e., for a sensitivity to cost of one, the cost difference among technologies is not significant in determining market shares. In practical terms, if a given technology A is 15% more expensive than a given technology B, for a sensitivity to cost equal to ten, technology B will capture 85% of the market shares, while for a sensitivity to cost equal to one, technology B will capture only 55% of the market shares.

For cumulative water consumption, even though the market penetration of hydropower AEC and PEM in a high carbon pricing environment (CP350) is minor under Grey+Blue+Green-H2 (approximately 0.2% of all hydrogen production in 2050), these technologies account for 25% of the total water consumption in this scenario in 2050. With this, as the sensitivity to cost is reduced, electrolysis-based technologies penetrate the market more aggressively, including hydropower AEC and PEM. Also, as the life cycle cost of hydropower electrolysis changes with the interest rate and capital and operating costs, the market penetration of these technologies increases (or decreases), as does total water consumption. This variation is captured in the uncertainty analysis (Figure 3-13). From the Monte Carlo simulation, the cumulative incremental water consumption varies from 400 to 1,600 Mm^3_{water} for 50% to 75% of the cumulative frequencies' distribution. This variation of 300% is higher than the variation observed for the cumulative GHG abatement and marginal GHG abatement cost of 24% and 70%, respectively, even considering higher intervals of 35% to 75% of cumulative frequencies for these outputs, mostly due to the significant impact of hydropower water intensity on total water consumption.

For cumulative GHG abatement, the onsite emissions and natural gas intensities of the technologies included in the reference scenario (REF) represent the input parameters that most affect the output value. As these technologies present a higher market penetration and higher energy and onsite emission intensities, they are significant in determining the total cumulative GHG abatement between 2026 and 2050. The sensitivity to cost also plays an important role in increasing the market penetration of electrolysis-based technologies, thus increasing the potential for GHG emissions abatement as it decreases. From the uncertainty analysis, this result is likely to range from 112 to 139 $MtCO_2e$, based on the 35% to 75% cumulative frequencies interval seen from the Monte Carlo simulation.

Unlike the cumulative incremental water consumption results, hydropower electrolysis does not significantly change GHG abatement or the marginal GHG abatement cost. Instead, the sensitivity to cost and interest rates of electrolysis and natural gas-based technologies, especially SMR and ATR, have a significant effect on costs, followed by onsite GHG emissions intensities. The marginal GHG abatement cost is expected to range from -\$21.5/tCO_2e to -\$6.5/tCO_2e, based on the 35% to 75% cumulative frequencies interval seen from the Monte Carlo simulation. The lower savings of -\$6.5/tCO_2e are due to the higher penetration of more expensive electrolysis-based technologies, and the higher savings of -\$21.5/tCO_2e are due to the hydrogen production through mostly natural gas-based technologies (high values of sensitivity to cost).

The sensitivity and uncertainty analysis shows how sensitive the model is to input parameters that primarily affect the market penetration of low-carbon hydrogen technologies, especially cost. The sensitivity to cost can be obtained from empirical modelling based on discrete regressions on decisions [142] or from industry experience from many sectors across the economy [86]. However, the different values that the sensitivity to cost can assume for different industries or markets are not yet consolidated in a single source.

3.3.6. Limitations

The low-carbon hydrogen economy is facing remarkable momentum, though efforts from industry, government, and academia to integrate low-carbon hydrogen in the energy industry and to model the techno-economic performance of the large-scale deployment of natural gas- and electrolysis-based hydrogen are fairly recent. Actual water footprint data of different hydrogen production facilities is missing, and so we cannot validate the water intensities used in this study through numerical modelling, nor project water consumption from specific water bodies or different types of water (freshwater and alternative water). Nor is historical water consumption from hydrogen production available to validate the WEAP-Canada model. Nonetheless, while these limitations leave clear improvements for future work and research as data becomes available, they have not prevented the fulfillment of the objectives laid out. Other factors not considered in this work, such as changes in water and GHG intensities throughout the analysis period and in capital and operating costs of novel low-carbon hydrogen technologies, could play key roles in the projected results obtained for water consumption and GHG emissions. These factors and others are interesting topics to be examined in future work.

The scenarios examined in this study offer policy- and decision-makers useful and timely information applicable to other jurisdictions with some caveats. For instance, the natural gas and electricity price projections and the grid GHG emissions and water consumption factors used in this study are specific to the province of Alberta, Canada. Other jurisdictions will have different carbon and energy costs, which will impact the market penetration of low-carbon hydrogen technologies and result in different cumulative GHG abatement and water savings (or consumption) potential. Also, natural gas- and electrolysis-based technologies included in this work may not be applicable to certain jurisdictions, as they may not have the infrastructure to operate the hydrogen production technologies, or the technologies might not be economically viable. The exclusion or inclusion of certain technologies in the analysis can significantly affect projections on water consumption and GHG emissions. Nevertheless, the integrated bottom-up modelling approach introduced in this study allows the analyst to easily change the input parameters and verify the differences in the results obtained, thus making the modelling method applicable to any jurisdiction of analysis.

The results obtained in this study are meant to determine the GHG abatement effectiveness and water impacts associated with the large-scale deployment of low-carbon hydrogen technologies under different carbon pricing environments and phase-out policies. The scenarios were designed to give international context to the analysis and fit the different requirements that jurisdictions may have on low-carbon hydrogen deployment. The projections provided on cumulative GHG abatement and cumulative water consumption should be used to assess whether the technology mix and carbon pricing environment scenarios will meet a specific jurisdiction's requirements on long-term carbon emissions reductions and to assess the impact on specific water bodies with the increase in water consumption.

3.4. Conclusion

This study evaluated the long-term impacts on carbon emissions and water consumption with a transition to low-carbon hydrogen that must take place to mitigate climate change impacts and ensure a more sustainable supply of hydrogen world-wide as fuel, feedstock, and energy storage. The jurisdiction of interest in this study was the Canadian western province of Alberta. We developed a bottom-up model study framework to assess the water-GHG nexus with the large-scale deployment of low-carbon natural gas- and electrolysis-based hydrogen technologies in six different hydrogen demand scenarios, five distinct technology mix hydrogen production scenarios, and four carbon pricing environments. All the objectives outlined were met and corresponded to obtaining long-term projections on yearly market shares, water consumption, GHG emissions, and marginal abatement costs for each hydrogen demand and production scenario with respect to a baseline case. The robustness of the results was improved by performing a global Morris sensitivity analysis and a Monte Carlo simulation, thus assessing how cumulative incremental water consumption and GHG abatement as well as marginal costs vary when techno-economic parameters change.

In general, for the Alberta Hydrogen Roadmap Incremental scenario, we found that all low-carbon hydrogen production scenarios, in the long term, consume more water and emit fewer GHGs than the baseline case. As the price of carbon increases, although more water is consumed with the large-scale deployment of low-carbon hydrogen, the cumulative GHGs abated increase and turn the novel hydrogen decarbonization scenarios into cost-effective and -attractive options.

The projections on market penetration of low-carbon hydrogen show that phase-out policies are crucial to stimulate the deployment of expensive technologies like electrolysis and to implement CCS-based technologies when the carbon pricing environment is low. However, even though phase-out policies increase the amount of GHGs abated, a higher carbon emissions price is more effective in making the low-carbon hydrogen scenarios economically viable options as costs become negative. Still, electrolysis-based options are not as cost-effective as CCS-based hydrogen production options. Even though the latter are less carbon intense than all CCS and non-CCS natural gas-based technologies, the higher capital and operating costs cannot be ignored and are key in making the electrolysis technologies less cost-effective options.

Tied to this, CCS-based and electrolysis technologies, especially hydropower electrolysis, increase the total water consumption significantly. However, depending on the jurisdiction and the amount of water allocated from a water body, the increased water consumption may or may not be a long-term issue. For Alberta, if hydrogen were produced primarily from the electrolysis of water, the total amount of water consumed from the Athabasca River Basin would be minor, and, from CCS-based hydrogen, negligible, with the potential to be even less significant as alternative water is used. With this, we conclude that the large-scale deployment of low-carbon hydrogen technology increases water consumption; however, the real impacts of this increase should be limited to specific water bodies and jurisdictions.

The focus from industry, government, and academia should be on turning CCS- and electrolysis-based hydrogen to more energy efficient and less water-intense options in order to make the technologies cost-attractive and consume less water in the long-term. As progress is made, it is crucial to have energy, water, and cost data available to accurately model the deployment of these low-carbon technologies. The results from the Morris sensitivity analysis and Monte Carlo simulation showed how crucial it is to have reliable data on costs, energy and carbon emissions, and, mostly, sensitivity to cost, in order to obtain accurate long-term projections on GHG emissions and water consumption.

Canada and many jurisdictions around the world are beginning to work towards achieving net-zero emissions by 2050. The results obtained in this study can inform decision- and policy-makers of what low-carbon hydrogen technology mixes would be the most cost-effective option in a transition to a more environmentally friendly energy industry, hence progressing towards climate goals.

4. Conclusions

4.1. Novel contributions to knowledge and key findings

This thesis brings the novelty of developing an integrated framework that assesses the long-term GHG emissions, water consumption, and cost impacts associated with the large-scale deployment of low-carbon technologies for unconventional oil and hydrogen production. The main objective of the research is to address the knowledge gaps on the long-term impacts in terms of water demand, GHG emissions, and associated costs due to adoption of new bitumen extraction technologies and low-carbon hydrogen production technologies. The following are the key contributions of the research work.

- Development of detailed bottom-up cost-based market penetration models for different low-carbon hydrogen production and bitumen extraction technologies considering distinct carbon pricing environments and technology mix scenarios, different technology costs, energy intensities, and energy prices. The models are highly applicable to other sectors and/or jurisdictions, meaning that they can be easily adapted and replicated for other sectors under analysis.
- The novel assessment of the water-GHG nexus with the large-scale deployment of low-carbon bitumen and hydrogen through multiple feasible scenarios that consider phase-out policy changes, and different novel and conventional technology mixes.
- The development of associated costs (or benefits) of saving (or consuming) water and GHG emissions mitigation estimates for different large-scale technology deployment scenarios and carbon pricing environments with respect to a baseline case, thus providing policy- and decision-makers with useful information on environmental and economic aspects of implementing low-carbon strategies to produce hydrogen and bitumen.

The jurisdiction of interest in this study is the Canadian western province of Alberta, rich in natural resources and oil sands deposits but also a highly emission-intensive region [63] and responsible for most of Canada's current hydrogen production [113]. For the unconventional oil extraction sector, a framework by oil sands area was developed to assess the water-GHG nexus with the implementation of seven novel and three conventional in situ bitumen extraction technologies in four distinct technology mix scenarios. For the hydrogen production industry, a bottom-up model was developed to assess the water-GHG nexus with the large-scale deployment of fifteen different low-carbon natural gas- and electrolysis-based hydrogen technologies in six different hydrogen demand scenarios, five distinct hydrogen production scenarios of technology mixes, and four carbon pricing environments.

Water consumption and GHG emissions projections up to 2050 and the marginal abatement costs were obtained using the Water Evaluation and Planning (WEAP)-Canada and Low Emissions Analysis Platform (LEAP)-Canada models. Both were developed and validated earlier and have been used for GHG mitigation and water savings studies on Canada's energy use [61, 62], water use [53], GHG emissions [63], and power generation [64-66], in the residential and commercial [67, 68], oil sands [14-17], petroleum refining [69], chemical [70], mineral mining [71, 72], iron and steel [73], cement [74], and agricultural [75] sectors. The robustness of the results was improved by performing a global Morris sensitivity analysis and a Monte Carlo simulation with the help of the Regression, Uncertainty, and Sensitivity Tool (RUST) model, thus assessing how cumulative incremental water consumption (or savings), GHG abatement, and marginal costs vary as different techno-economic parameters change. The RUST model was also used in earlier studies to conduct global sensitivity and uncertainty analysis [76-84]. The key results are presented in Figure 4-1 and Figure 4-2.

In general, the market share model projections favour the penetration of less expensive options. For unconventional oil production, for the low-carbon scenario that considers all conventional and novel bitumen production technologies, the solvent-aided options penetrate the market more aggressively than solvent-based and other novel recovery options. The solvent-based options do not play an important role in bitumen production compared to solvent-aided and other novel low-carbon technologies; this is explained by the higher unit costs of the solvent-based options. For hydrogen production, the low-carbon technologies, especially natural gas-based options with carbon capture and sequestration (CCS), penetrate the market more aggressively as the carbon price grows from \$0/tCO_2e to \$350/tCO_2e in 2050. Except for the production scenario that assumes a natural gas-based technology (with and without CCS) phase-out policy effective 2035, with incremental and retired electrolysis-based hydrogen capacities from this year onwards, the market penetration of electrolysis-based technologies is minor because of the high capital and operating costs of these options compared to natural gas-based technologies with and without CCS. The increase on carbon price is significant in stimulating the market penetration of low-carbon options; however, the implementation of phase-out policies on carbon-intense technologies is imperative for the deep decarbonization of the hydrogen production industry and especially in low carbon pricing environments.

From the cumulative GHG abatement potential results, all novel low-carbon bitumen and hydrogen production scenarios at all carbon pricing environments lead to carbon emissions abatement with the reference scenario as the baseline. For bitumen production, the highest GHG abatement potential is observed for the low-carbon scenario that considers conventional and solvent-based bitumen production technologies. For this case, the GHG emissions are 47.5 $MtCO_2e$ in 2030 and 49.9 $MtCO_2e$ in 2050, 5% and 17% lower than the reference scenario in those years. For hydrogen production, the scenario that assumes a natural gas-based technology (with and without CCS) phase-out policy effective 2035, with incremental and retired capacities in electrolysis-based hydrogen from this year onwards, abates more GHG emissions than other novel low-carbon hydrogen production scenarios (135-162 million tonnes of cumulative carbon emissions between 2026 and 2050 compared to the business-as-usual scenario). The price of carbon is a key player in shaping policies that strengthen the large-scale deployment of low-carbon hydrogen, and the effects of changing it must be carefully analyzed.

Regarding water consumption, novel low-carbon options increase and/or decrease total water use depending on the technologies' water intensities. For bitumen production, the projections obtained for 2050 show that water consumption will be 44.2 Mm^3 for the S1-TechMix scenario, i.e., the scenario that considers all conventional and low-carbon bitumen extraction options to compete for new market shares, 6% less than the business-as-usual case. With respect to oil sands areas, the Athabasca- and Cold Lake-oil sands areas account for 45.6 and 45.9% of the total water consumption between 2005 and 2050, respectively, and the Peace-oil sands area the remaining 8.2%. However, the total amount of freshwater use from the Athabasca River basin is minimal. For the scenario that consumes the most water in 2050, i.e., the scenario that considers low-carbon solvent-aided and conventional bitumen production technologies, this would represent approximately 0.05% of the Athabasca River's annual flow rate, which is lower than the limit imposed by the Government of Alberta for oil sands companies of 3% [109].

For hydrogen production, water consumption increases in relation to the business-as-usual scenario as novel low-carbon technologies penetrate the market. Like the GHG emissions projections, the 2050 water consumption increases from the 2035 levels at different rates depending on the hydrogen technology. For the hydrogen production scenario that assumes a natural gas-based technology (with and without CCS) phase-out policy effective 2035, with incremental and retired electrolysis-based hydrogen capacities from this year onwards, and the AB-Inc (Alberta incremental) demand scenario, water consumption in 2050 is 7 to 8 times higher than in 2035; this is directly related to the increased market penetration of water-intense electrolysis-based options. Still, under these scenarios, if water was only withdrawn from the Athabasca River Basin, the total amount of water consumed in 2050 in the production scenario that assumes a natural gas-based technology (with and without CCS) phase-out policy effective 2035, with incremental and retired electrolysis-based hydrogen capacities from this year onwards, at CP350 would represent approximately 2.5% of the Athabasca River flow. Therefore, although total water consumption increases as CCS is implemented and hydrogen is produced through water electrolysis, the amount of water allocated from a single river basin to produce hydrogen from low-carbon options is minimal. Still, alternative types of water should be explored to offset the amount of freshwater intake and consumption by hydrogen-producing facilities. With this, it can be concluded that the large-scale deployment of low-carbon hydrogen technology increases water consumption; however, the real impacts of this increase are likely limited to specific water bodies and jurisdictions and so need to be considered by local decision- and policy-makers.

For unconventional oil, all marginal costs are positive values, indicating that novel low-carbon bitumen production technologies are more expensive in the long-term than conventional technologies, with the exemption of the scenario that assumes a larger penetration of solvent-aided options. For these, energy and carbon costs are the main drivers of cost savings and offset the high capital and operating costs of the emerging low-carbon technologies. Optimizing the energy efficiency of the novel recovery technologies is key to further savings as electricity and natural gas prices are expected to increase. For hydrogen production, the marginal GHG abatement costs become negative, or turn into benefits (savings), under high carbon pricing environments. As the price of carbon increases, the economic benefits increase because of the large savings that come from carbon emissions costs. However, more efforts are needed to make electrolysis-based technologies more cost-effective compared to natural gas-based options with carbon capture and storage and equally compete for new market shares of incremental hydrogen production capacities. These results lead to the conclusion that high carbon pricing environments are extremely important in transforming those novel scenarios into attractive and viable economic options for the large-scale deployment of low-carbon bitumen and hydrogen as the large cost savings are directly associated with carbon emission costs.

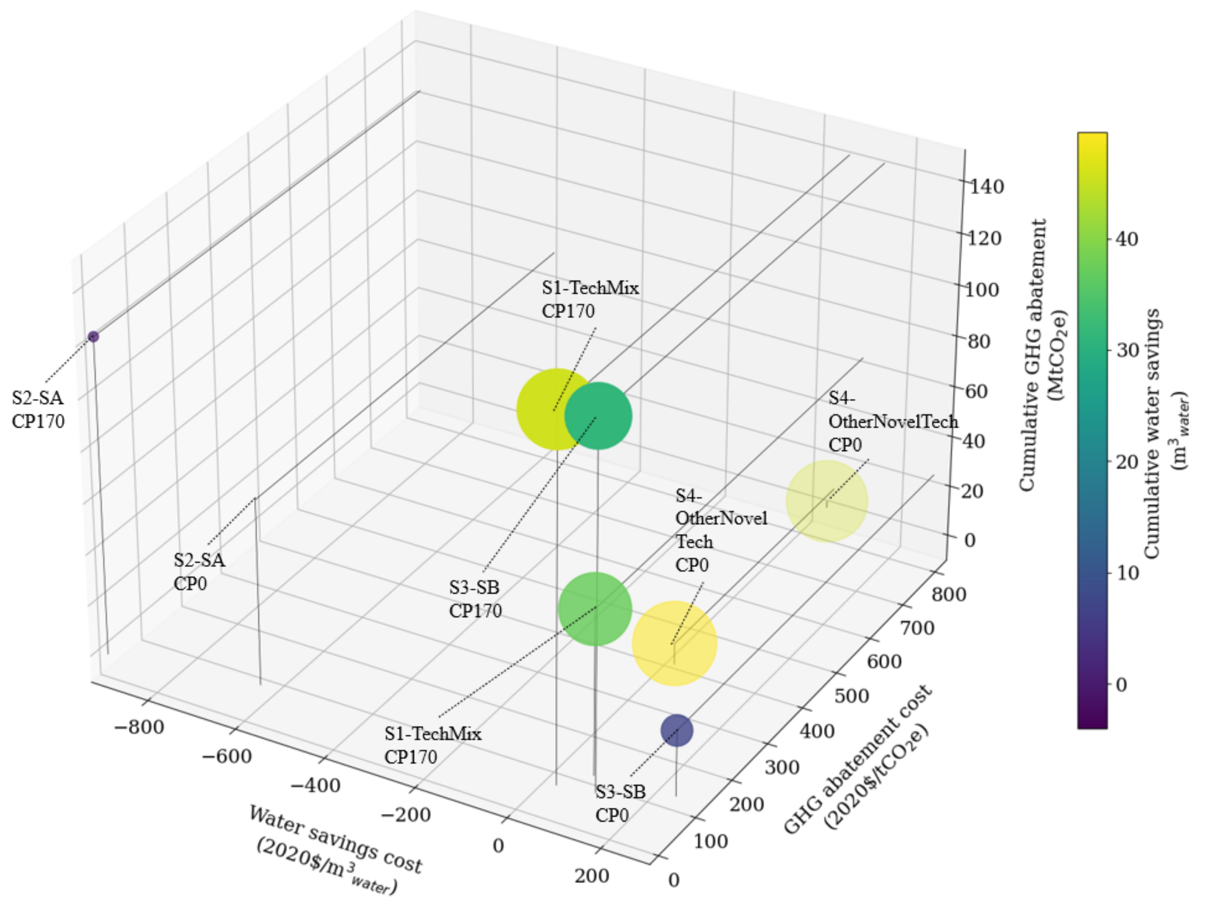
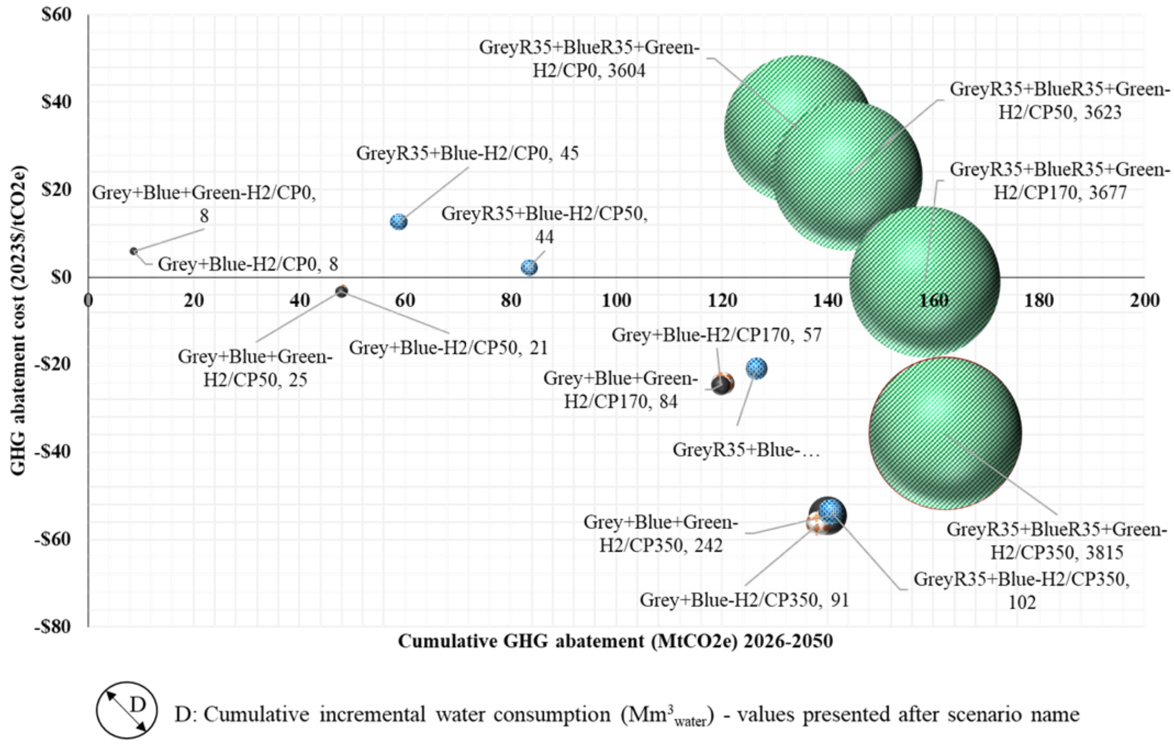


Figure 4-1: Bubble chart showing cumulative water and GHG savings between 2020 and 2050 and water savings and GHG abatement costs for each novel scenario. The coordinates of the center of each bubble represent the water savings and GHG abatement costs and the cumulative GHG abatement potential of each scenario. The cumulative water savings are indicated by the size and color of each bubble.



Values w.r.t. the REF scenario. This scenario considers that SMR and SMR-52%CCS assume hydrogen production between 1990 and 2023 and compete alone for incremental capacities between 2024 and 2029. ATR starts penetrating the market in 2030.

Figure 4-2: Bubble chart showing cumulative incremental water consumption and cumulative GHG abatement between 2026 and 2050, and marginal GHG abatement costs for each novel hydrogen production scenario and carbon pricing environment. The coordinates in the center of each bubble represent the marginal GHG abatement cost and cumulative GHG abatement of each scenario. The cumulative incremental water consumption is indicated by the bubble's size. The bubble's label gives the hydrogen production scenario, followed by the carbon pricing environment and the cumulative incremental water consumption. Thes results are from the AB-Inc hydrogen demand scenario.

In conclusion, the findings of this research highlight the fact that low-carbon technologies offer a promising solution to mitigate GHG emissions, but it is important to recognize that the large-scale deployment of these technologies may increase production costs and increase or reduce total water consumption. Therefore, a careful balance must be struck between maximizing GHG emissions abatement potential and minimizing the costs and water consumption associated with the low-carbon options. This research has shown that there is a critical need for continued research and development of low-carbon technologies, as well as the implementation of effective policies and practices that promote their adoption in the energy sector.

4.2. Recommendations for future work

The focus should be making the low-carbon technologies into more energy efficient and less water intense options, thus making them more environmentally friendly in the long term. As progress is made, it is key to have energy, water, and cost data available to accurately model the deployment of these low-carbon technologies. As novel technologies are developed and deployed, these should be integrated into the framework outlined in this research for a more comprehensive modelling and analysis of market shares, GHG emissions, water consumption, and cost impacts on bitumen and hydrogen production.

For the unconventional oil sector, other factors not considered in the modelling framework could affect this study's water consumption and GHG emissions results, i.e., potential implications to land, air, and water bodies with the addition of solvent in the bitumen extraction process; the effects of technology readiness levels on the costs of different novel low-carbon pathways in the projection of market shares; and differences in water and GHG intensities over the analysis period. These factors and others are interesting topics for future work.

Regarding hydrogen production, there is very limited water footprint data from different hydrogen production facilities, and so it is difficult to validate the water intensities used here in numerical modelling, nor project water consumption from specific water bodies or different types of water (freshwater and alternative water). Data on historical water consumption for hydrogen production to validate the WEAP-Canada model is not available in the open literature.

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Appendices

Appendix A – WEAP-Canada model input data

Table 1: Water intensity ($m^3_{water}/m^3_{bitumen}$) data of conventional in situ extraction technologies by OSA

	SAGD		CSS		Primary		
Year	Athabasca	Cold Lake	Cold Lake	Peace	Athabasca	Cold Lake	Peace
2005	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2006	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2007	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2008	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2009	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2010	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2011	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2012	0.477	1.130	0.912	4.101	0.650	0.650	0.650
2013	0.409	0.638	0.755	5.937	0.650	0.650	0.650
2014	0.339	0.865	0.671	6.333	0.650	0.650	0.650
2015	0.314	0.529	0.624	5.897	0.650	0.650	0.650
2016	0.220	0.441	0.677	5.128	0.650	0.650	0.650
2017	0.231	0.486	0.562	7.225	0.650	0.650	0.650
2018	0.216	0.296	0.752	10.619	0.650	0.650	0.650
2019	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2020	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2021	0.216	0.296	0.752	6.463	0.650	0.650	0.650

	SAGD		CSS		Primary		
Year	Athabasca	Cold Lake	Cold Lake	Peace	Athabasca	Cold Lake	Peace
2022	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2023	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2024	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2025	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2026	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2027	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2028	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2029	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2030	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2031	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2032	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2033	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2034	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2035	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2036	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2037	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2038	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2039	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2040	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2041	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2042	0.216	0.296	0.752	6.463	0.650	0.650	0.650

	SAGD		CSS		Primary		
Year	Athabasca	Cold Lake	Cold Lake	Peace	Athabasca	Cold Lake	Peace
2043	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2044	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2045	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2046	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2047	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2048	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2049	0.216	0.296	0.752	6.463	0.650	0.650	0.650
2050	0.216	0.296	0.752	6.463	0.650	0.650	0.650

Table 2: Annual Alberta grid mix water factors by carbon pricing environment in L/GJ

	AB_Grid-WEAP-CP0	**AB_Grid-WEAP-CP50**	**AB_Grid-WEAP-CP170**	**AB_Grid-WEAP-CP350**
2026	807.85	851.71	591.75	508.98
2027	802.61	846.56	454.89	389.85
2028	798.20	841.98	348.62	315.03
2029	780.65	825.98	281.94	230.77
2030	720.71	743.38	228.58	201.79
2031	715.49	738.93	230.41	193.45
2032	693.03	714.97	230.59	185.71
2033	728.96	644.06	225.47	182.58
2034	766.17	557.22	221.01	181.05

	AB_Grid-WEAP-CP0	AB_Grid-WEAP-CP50	AB_Grid-WEAP-CP170	AB_Grid-WEAP-CP350
2035	784.01	500.33	193.52	179.60
2036	797.56	468.61	192.39	154.34
2037	809.08	372.74	191.62	126.53
2038	812.67	316.58	176.57	126.38
2039	812.30	308.26	182.87	126.29
2040	817.69	277.04	174.79	126.34
2041	818.80	273.94	174.03	126.40
2042	819.09	274.41	173.00	126.32
2043	818.77	228.86	172.07	90.50
2044	818.67	224.42	166.75	85.00
2045	818.95	216.79	159.81	81.70
2046	815.62	215.22	160.44	81.81
2047	806.32	207.23	129.86	81.26
2048	805.34	204.12	133.32	81.18
2049	803.93	199.70	141.29	81.31
2050	800.62	184.19	131.01	82.35

Appendix B – LEAP-Canada model input data

Table 3: LEAP-Canada natural gas and electricity price projections, and carbon price projection for unconventional oil modelling

Year	Natural gas price (2020$/GJ)	Electricity price (2020$/GJ)	Carbon price (2020$/$tCO_2e$)
2020	2.36	24.95	30.00
2021	3.30	26.94	37.21
2022	3.47	27.93	43.27
2023	3.56	28.82	52.32
2024	3.71	29.60	59.90
2025	3.86	30.38	66.17
2026	3.91	30.50	71.28
2027	3.97	30.32	75.34
2028	4.01	29.91	78.50
2029	4.03	29.26	80.85
2030	4.17	28.85	82.48
2031	4.26	28.82	76.73
2032	4.35	28.75	71.38
2033	4.42	28.62	66.40
2034	4.49	28.52	61.76
2035	4.56	28.34	57.45
2036	4.63	28.21	53.45
2037	4.70	28.22	49.72
2038	4.77	28.26	46.25

Year	Natural gas price (2020$/GJ)	Electricity price (2020$/GJ)	Carbon price (2020$/tCO2e)
2039	4.84	28.21	43.02
2040	4.91	28.21	40.02
2041	4.95	28.33	37.23
2042	4.97	28.35	34.63
2043	5.02	28.41	32.21
2044	5.04	28.27	29.97
2045	5.08	28.40	27.88
2046	5.11	28.48	25.93
2047	5.15	28.59	24.12
2048	5.18	28.38	22.44
2049	5.22	28.38	20.87
2050	5.25	28.57	19.42

Table 4: Historical in situ bitumen production shares

	SAGD		CSS		Primary		
Year	Athabasca	Cold Lake	Cold Lake	Peace	Athabasca	Cold Lake	Peace
2005	4.17E-01	1.30E-02	3.02E-01	7.72E-03	7.76E-02	1.36E-01	4.65E-02
2006	4.17E-01	1.30E-02	3.02E-01	7.72E-03	7.76E-02	1.36E-01	4.65E-02
2007	4.17E-01	1.30E-02	3.02E-01	7.72E-03	7.76E-02	1.36E-01	4.65E-02
2008	4.17E-01	1.30E-02	3.02E-01	7.72E-03	7.76E-02	1.36E-01	4.65E-02
2009	4.17E-01	1.30E-02	3.02E-01	7.72E-03	7.76E-02	1.36E-01	4.65E-02

	SAGD		CSS		Primary		
Year	Athabasca	Cold Lake	Cold Lake	Peace	Athabasca	Cold Lake	Peace
2010	4.17E-01	1.30E-02	3.02E-01	7.72E-03	7.76E-02	1.36E-01	4.65E-02
2011	4.17E-01	1.30E-02	3.22E-01	8.21E-03	7.16E-02	1.25E-01	4.30E-02
2012	4.85E-01	1.51E-02	2.55E-01	7.78E-03	6.69E-02	1.28E-01	4.30E-02
2013	5.10E-01	1.59E-02	2.23E-01	4.55E-03	7.70E-02	1.25E-01	4.37E-02
2014	5.65E-01	1.60E-02	1.88E-01	4.27E-03	7.77E-02	1.11E-01	3.85E-02
2015	5.93E-01	2.21E-02	1.89E-01	4.26E-03	6.93E-02	9.25E-02	2.99E-02
2016	6.43E-01	3.01E-02	1.67E-01	3.98E-03	5.92E-02	7.08E-02	2.54E-02
2017	6.76E-01	2.80E-02	1.54E-01	3.00E-03	5.35E-02	5.64E-02	2.84E-02
2018	7.11E-01	3.17E-02	1.36E-01	1.80E-03	4.91E-02	5.07E-02	1.94E-02
2019	7.09E-01	3.05E-02	1.38E-01	2.27E-03	4.78E-02	4.99E-02	2.23E-02

Table 5: Historical and LEAP-Canada in situ bitumen production projections

Year	In situ bitumen production (Mm^3/year)
2005	25.4
2006	28.7
2007	31.1
2008	33.8
2009	38.5
2010	43.8
2011	49.4

Year	In situ bitumen production (Mm^3/year)
2012	57.6
2013	64.3
2014	73.4
2015	79.2
2016	80.7
2017	90.6
2018	91.4
2019	89.9
2020	86.6
2021	86.5
2022	86.1
2023	85.3
2024	86.9
2025	89.4
2026	92.2
2027	94.9
2028	97.6
2029	100.0
2030	102.3
2031	104.4
2032	106.4

Year	In situ bitumen production (Mm^3/year)
2033	108.2
2034	109.8
2035	111.3
2036	112.7
2037	113.9
2038	115.1
2039	116.1
2040	117.1
2041	117.9
2042	118.7
2043	119.4
2044	120.1
2045	120.7
2046	121.2
2047	121.7
2048	122.1
2049	122.5
2050	122.9

Appendix C – Market share results

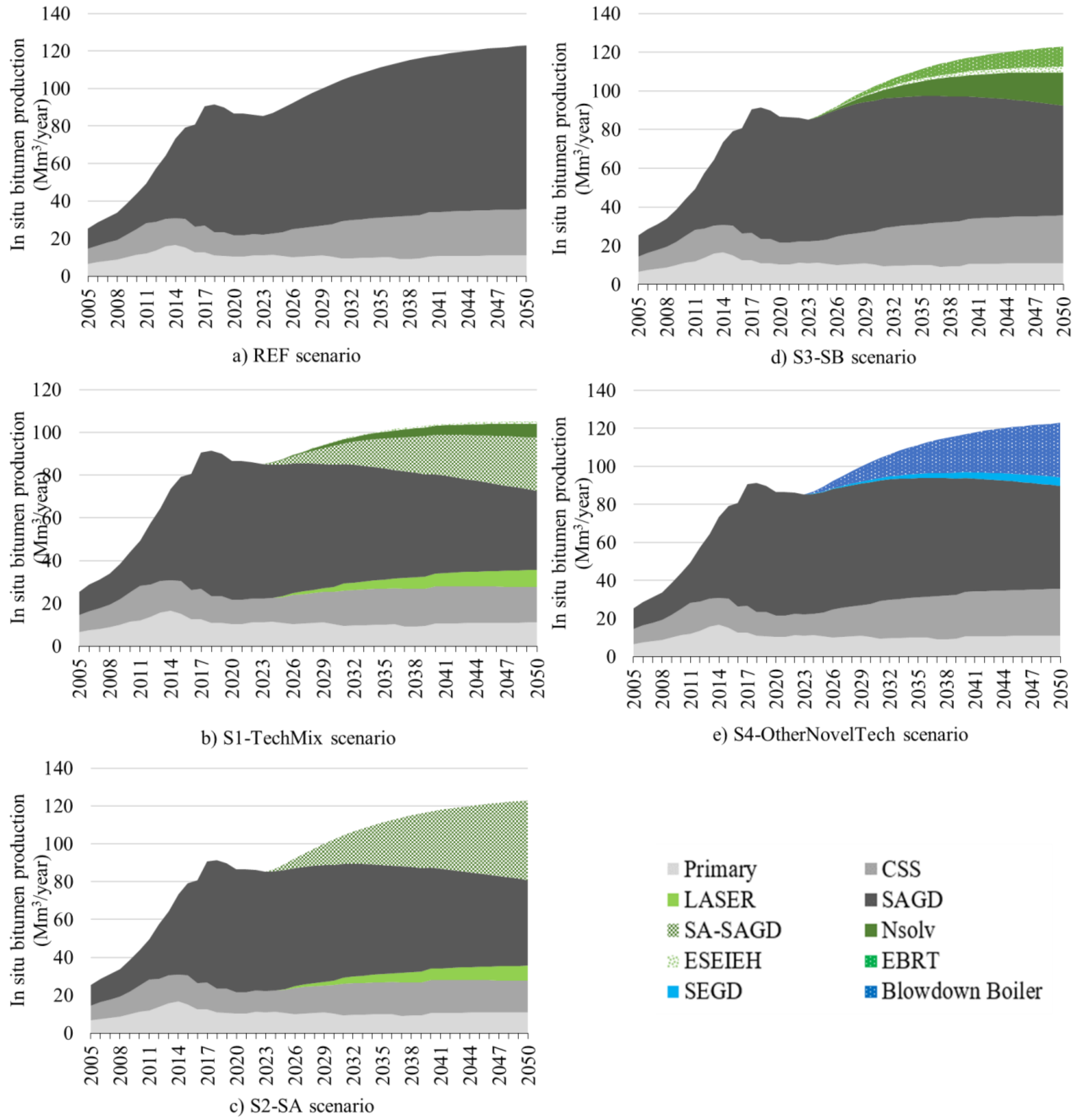

Figure 1: In situ bitumen production projection (Mm^3/year).

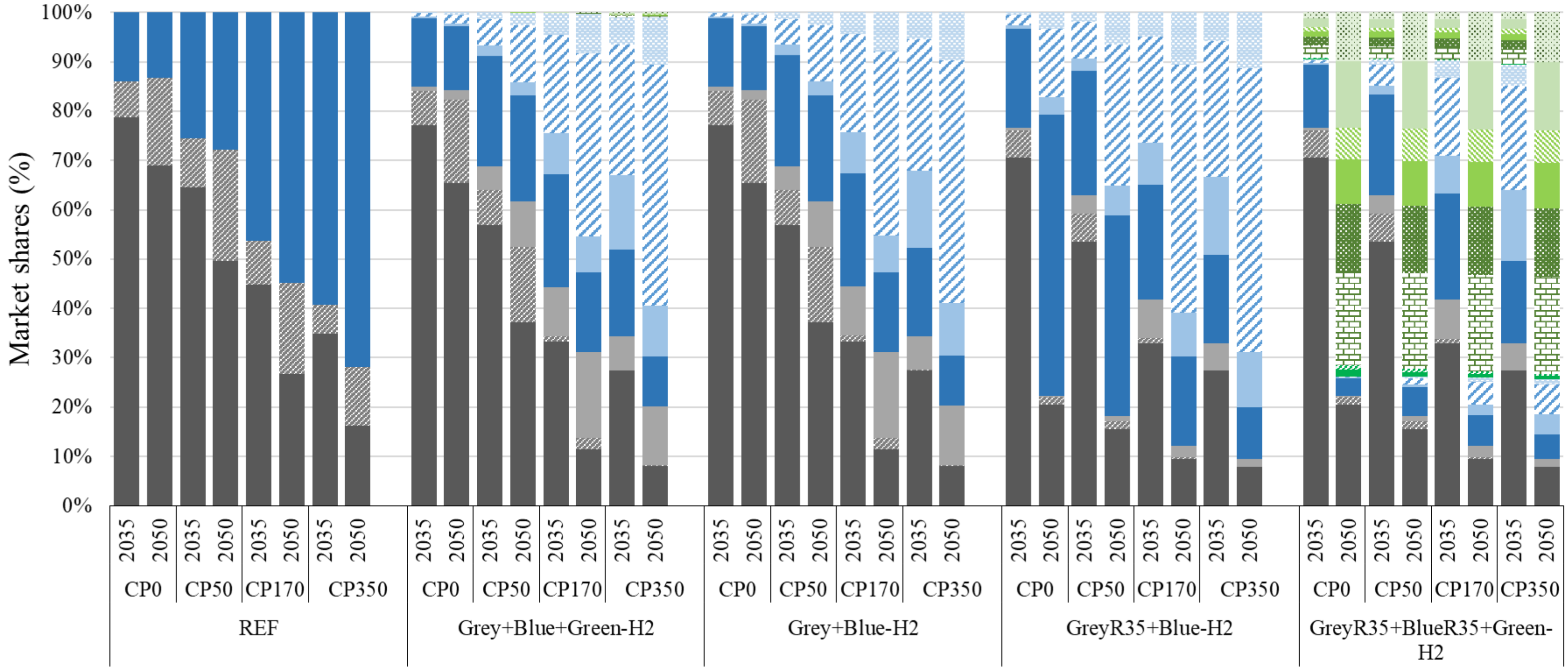

Figure 2: Market share projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the AB-Tra hydrogen demand scenario.

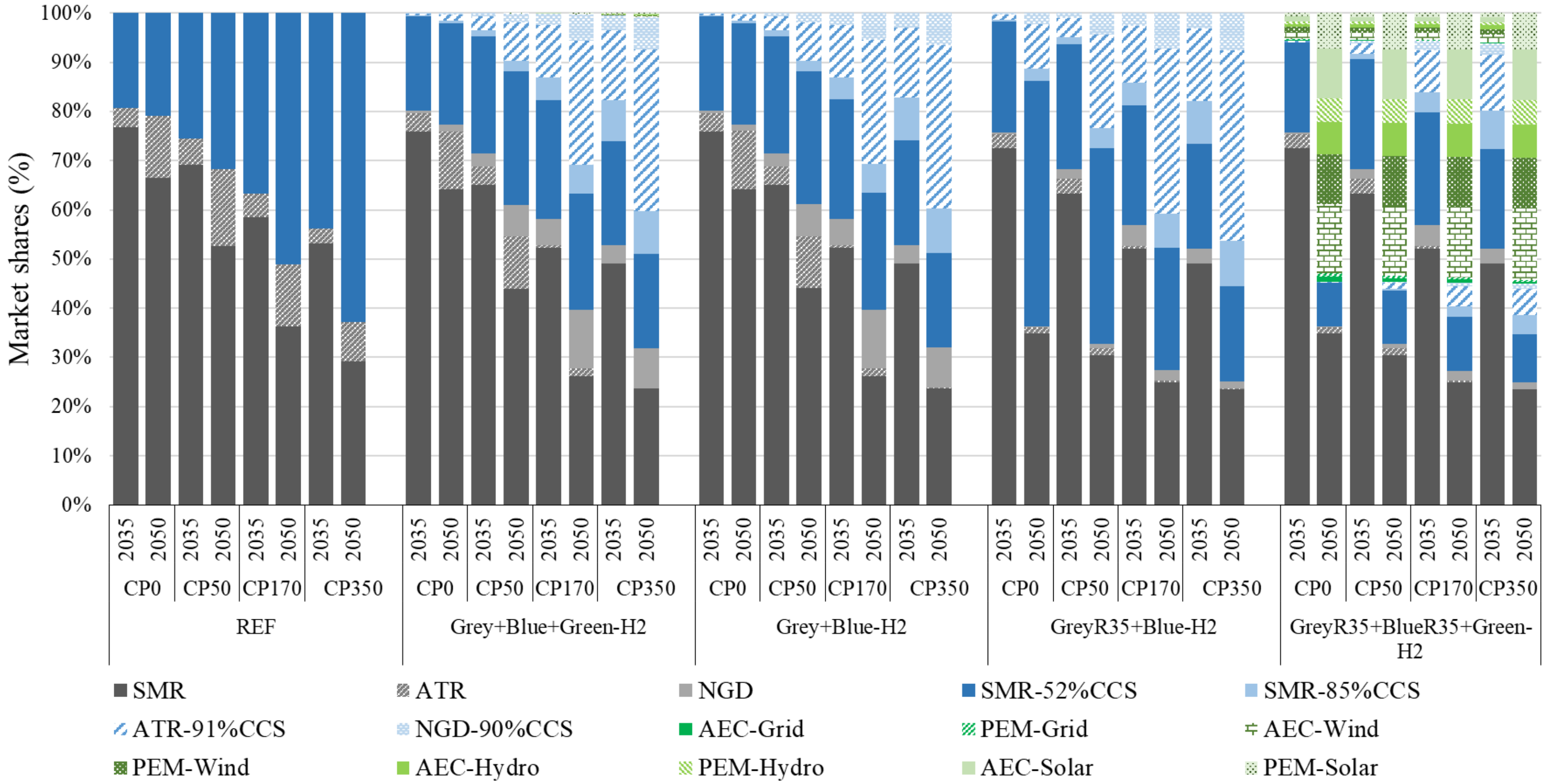

Figure 3: Market share projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the H2-Transp hydrogen demand scenario.

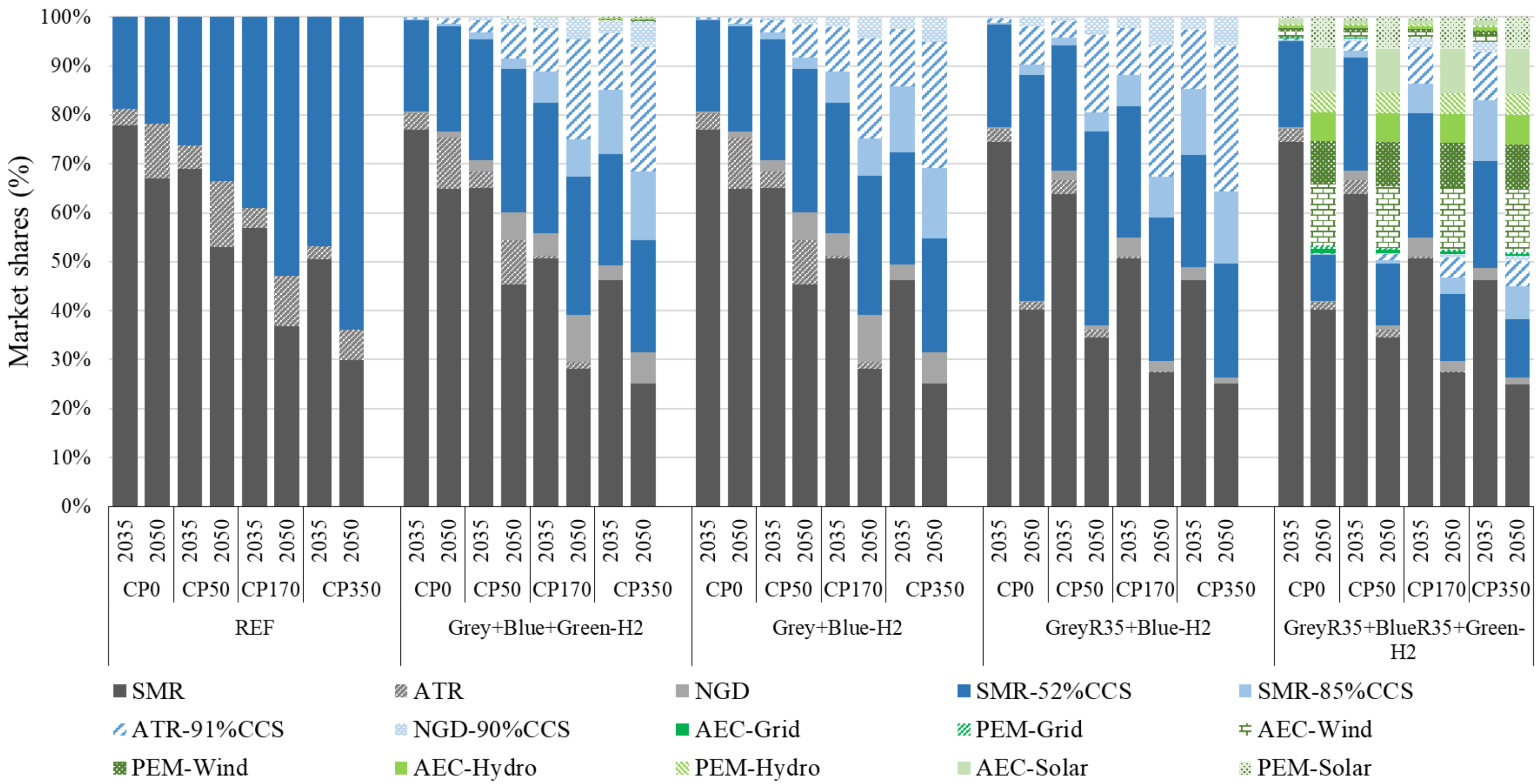

Figure 4: Market share projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-All hydrogen demand scenario.

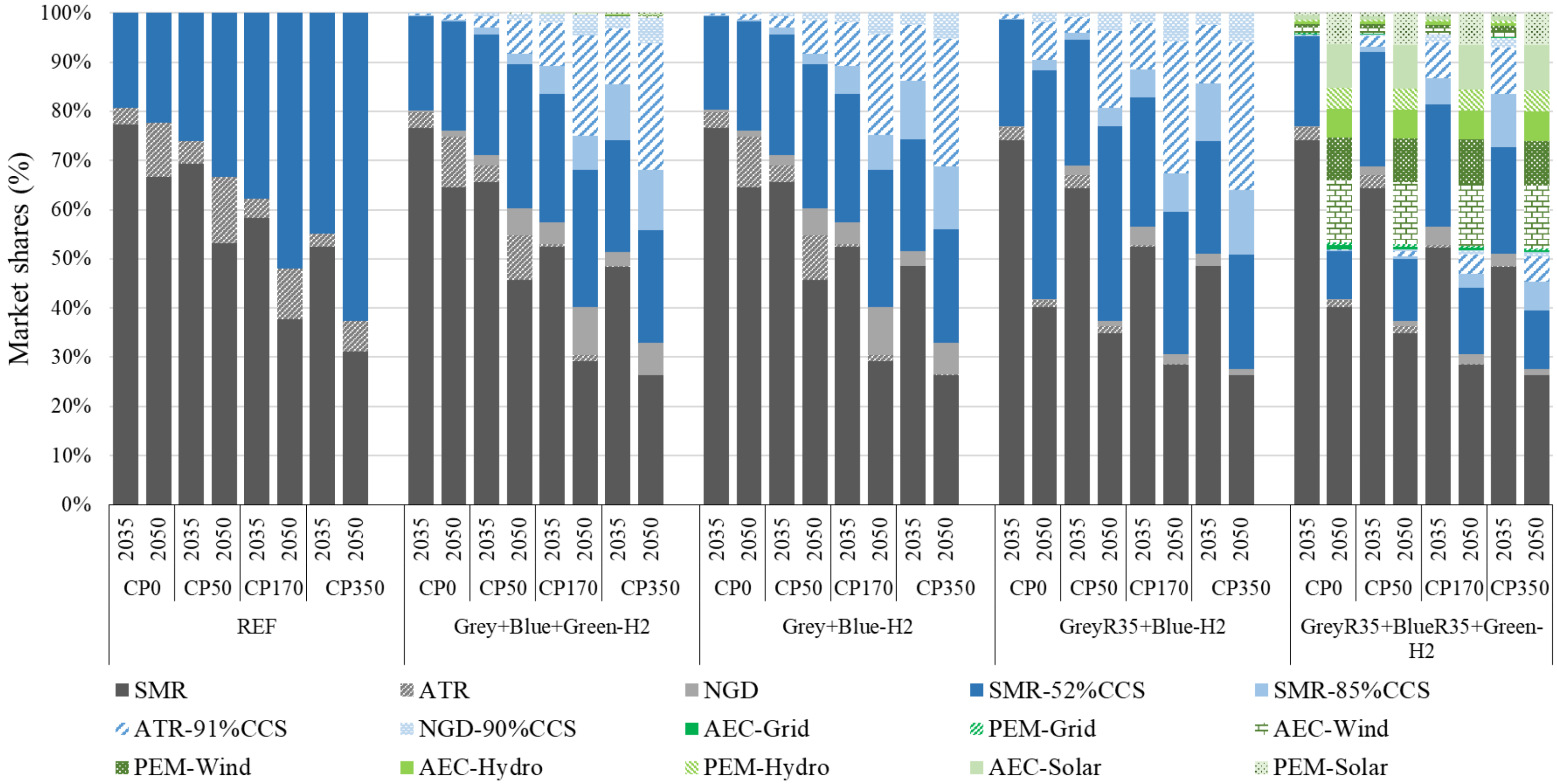

Figure 5: Market share projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-OS hydrogen demand scenario.

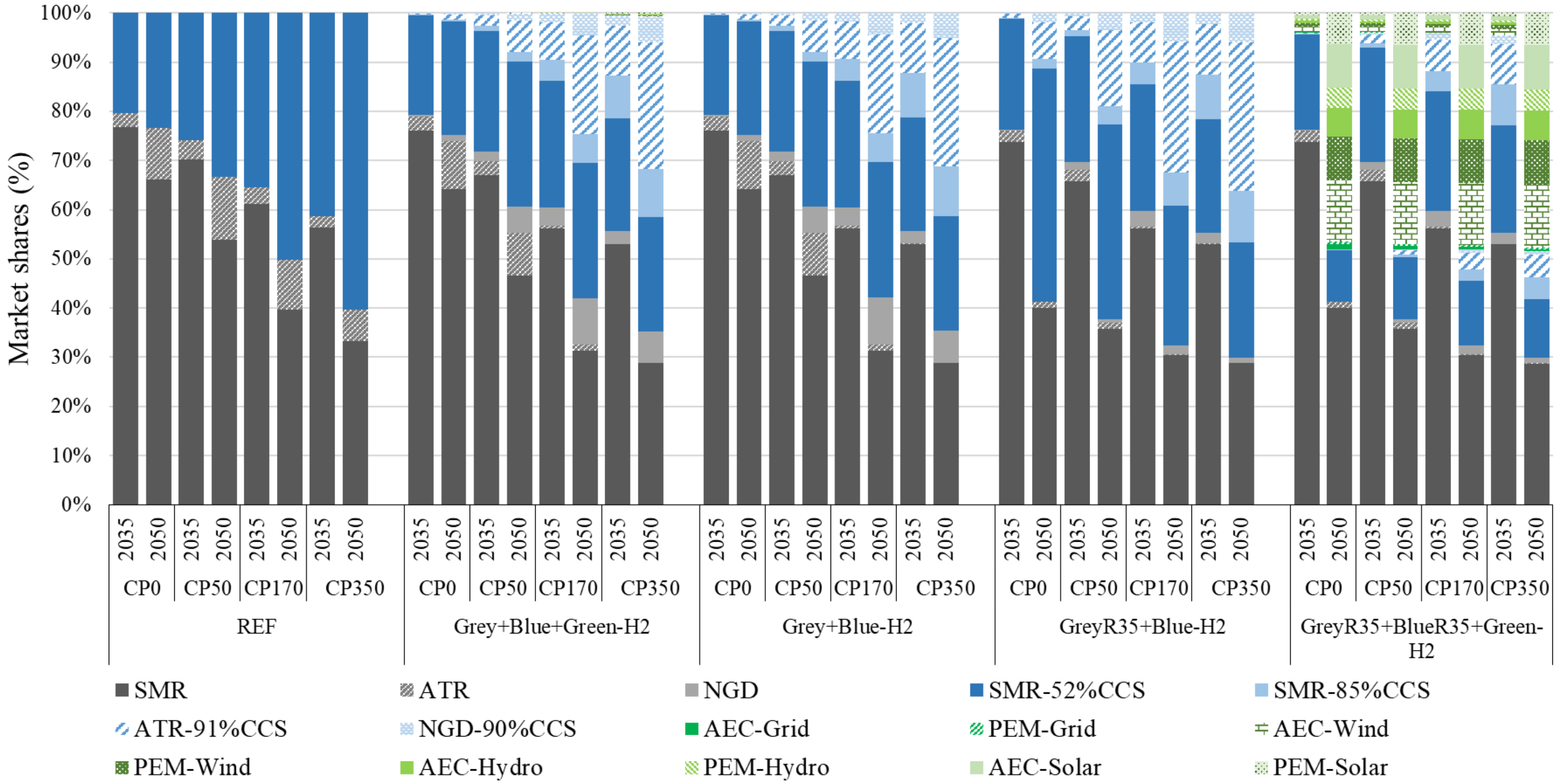

Figure 6: Market share projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-Res hydrogen demand scenario.

Appendix D – GHG emissions results

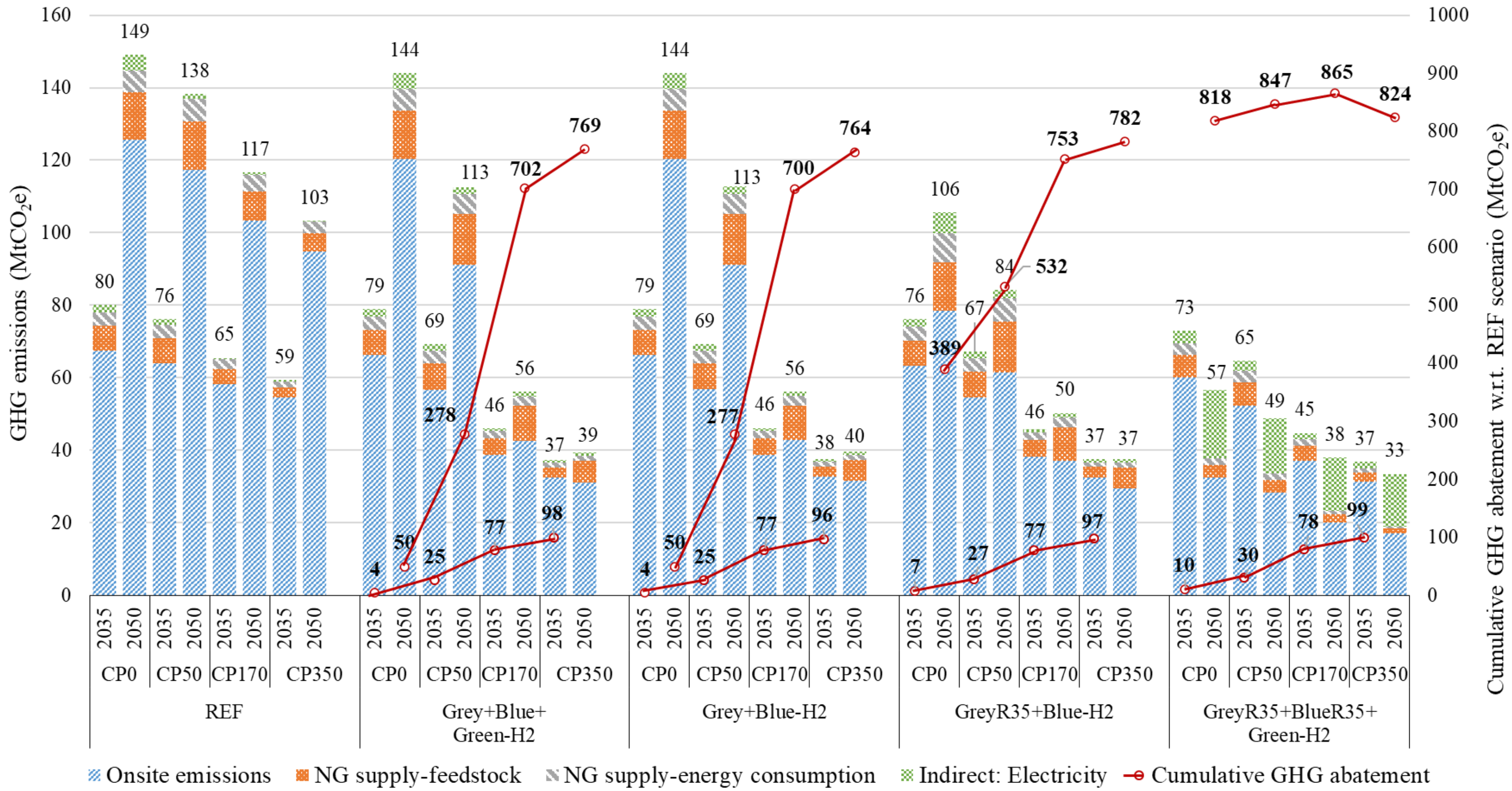

Figure 7: GHG emissions projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the AB-Tra hydrogen demand scenario.

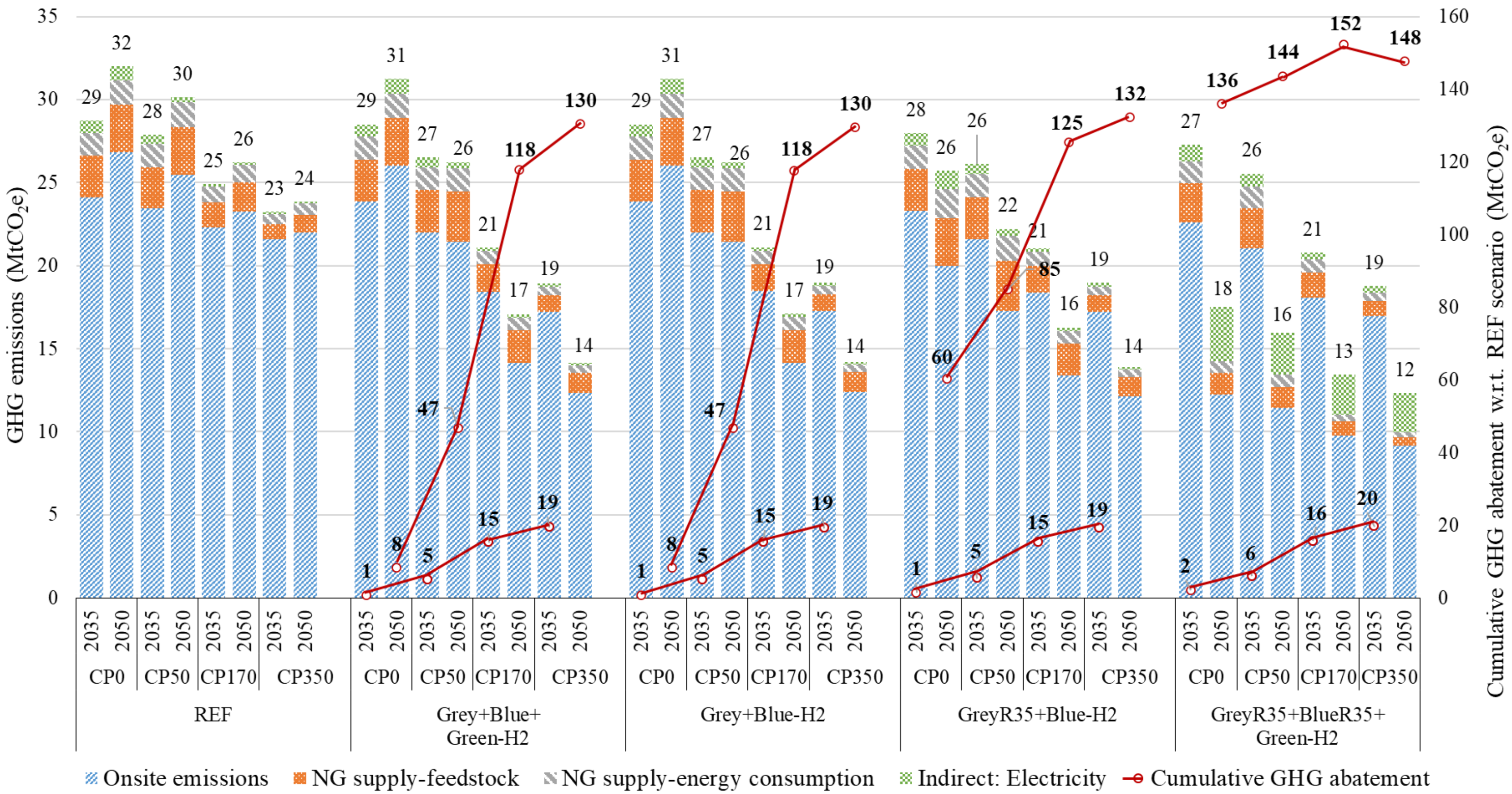

Figure 8: GHG emissions projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the H2-Transp hydrogen demand scenario.

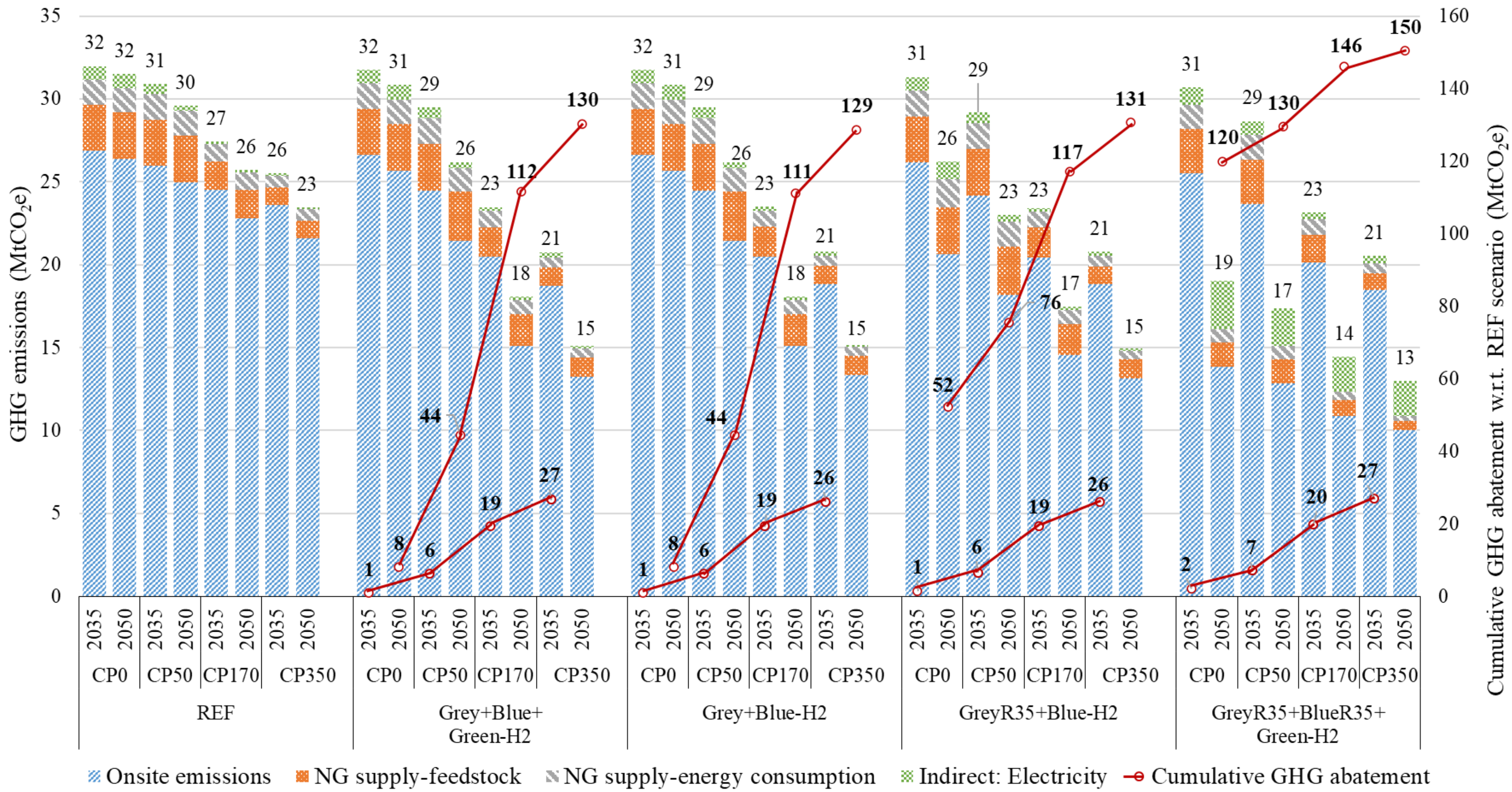

Figure 9: GHG emissions projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-All hydrogen demand scenario.

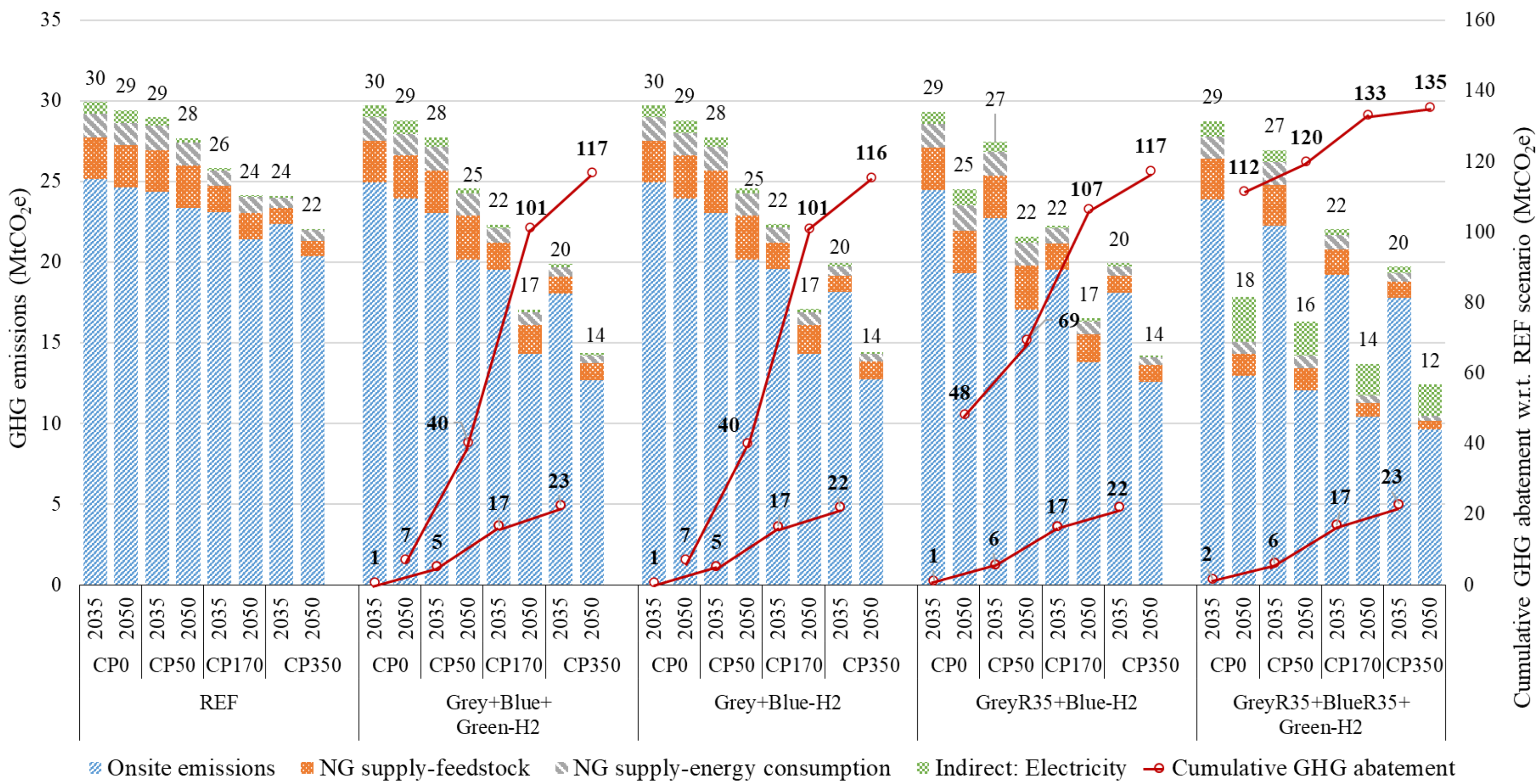

Figure 10: GHG emissions projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-OS hydrogen demand scenario.

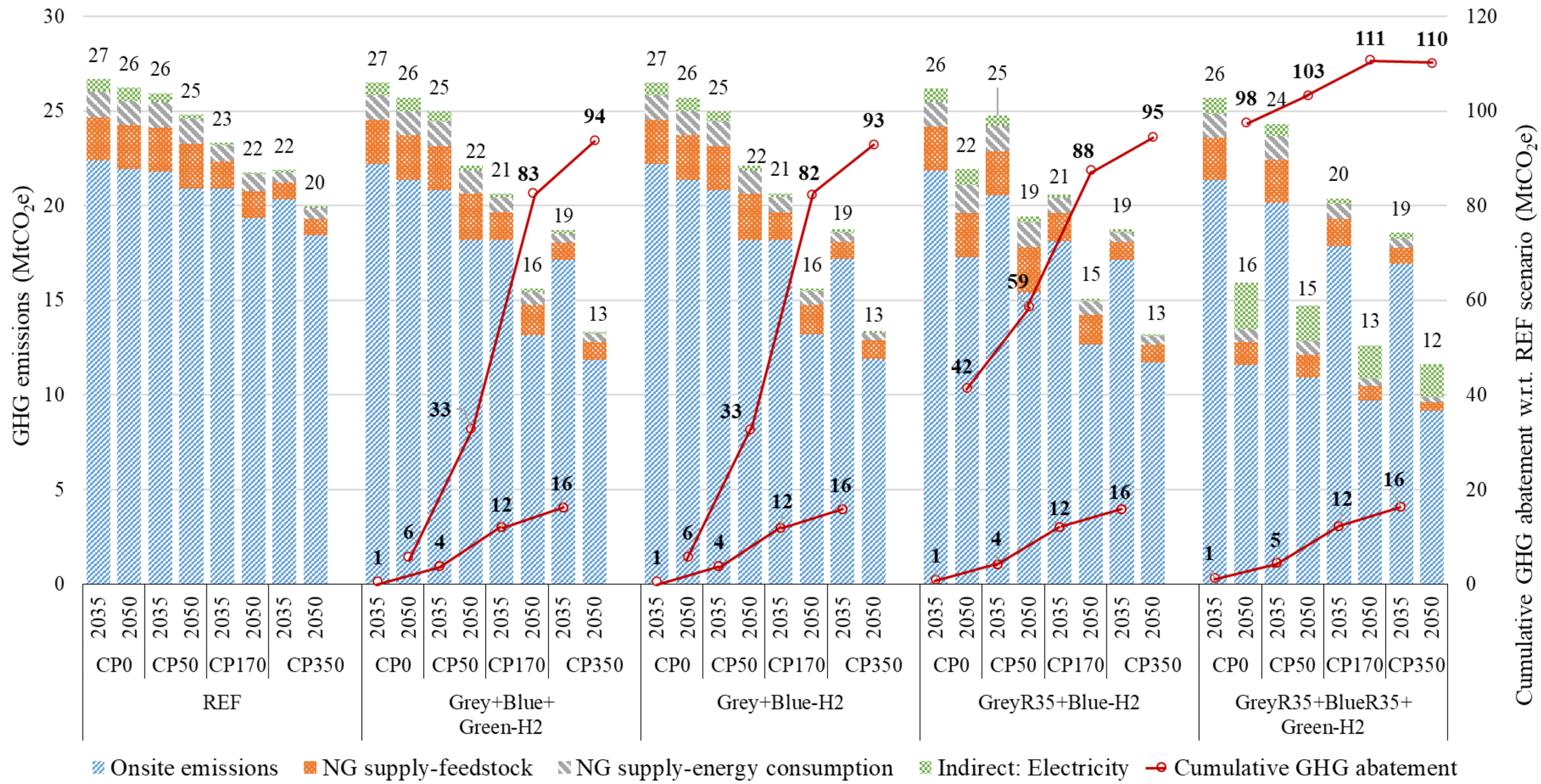

Figure 11: GHG emissions projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-Res hydrogen demand scenario.

Appendix E – Water results

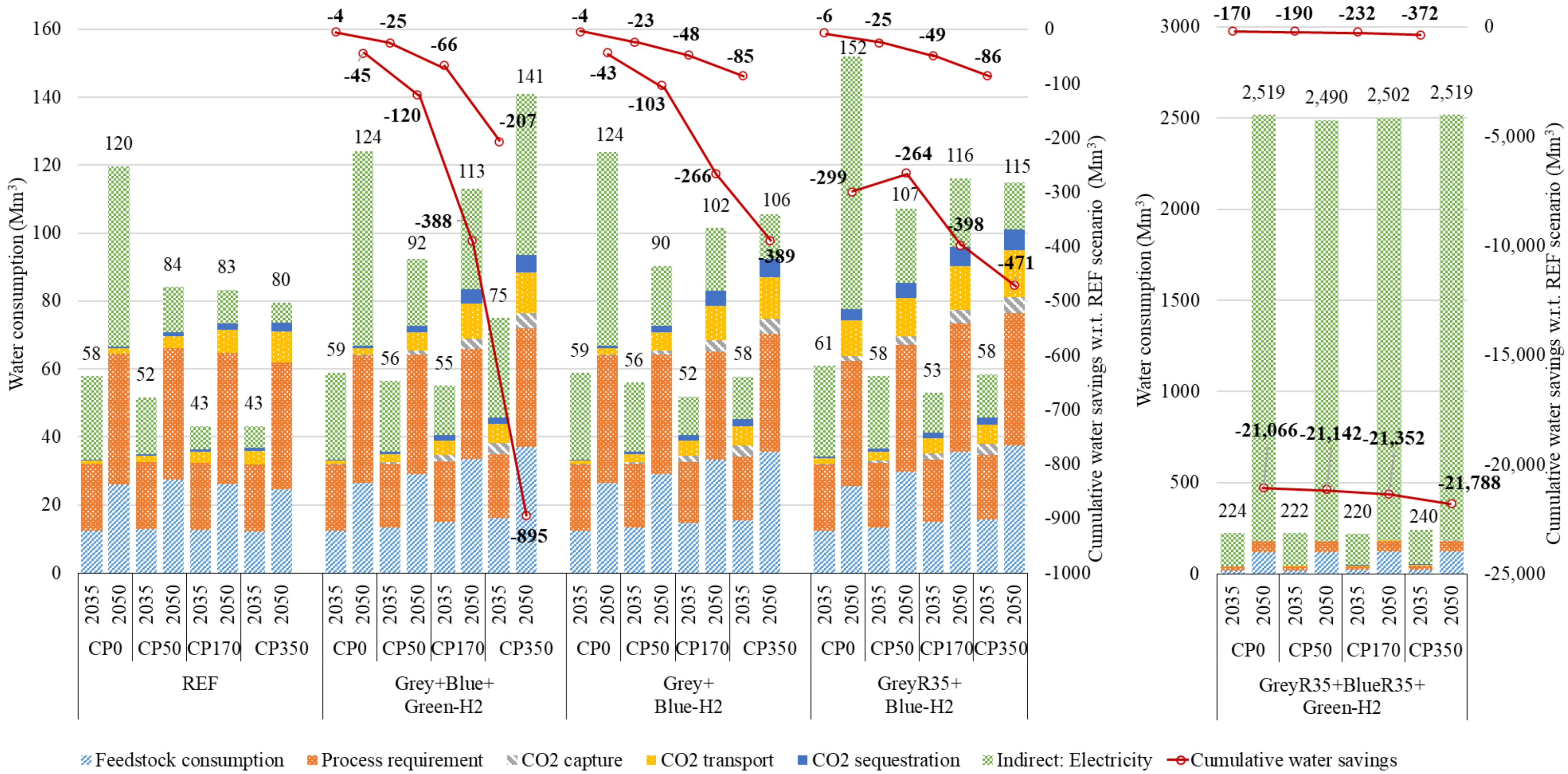

Figure 12: Water consumption projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the AB-Tra hydrogen demand scenario.

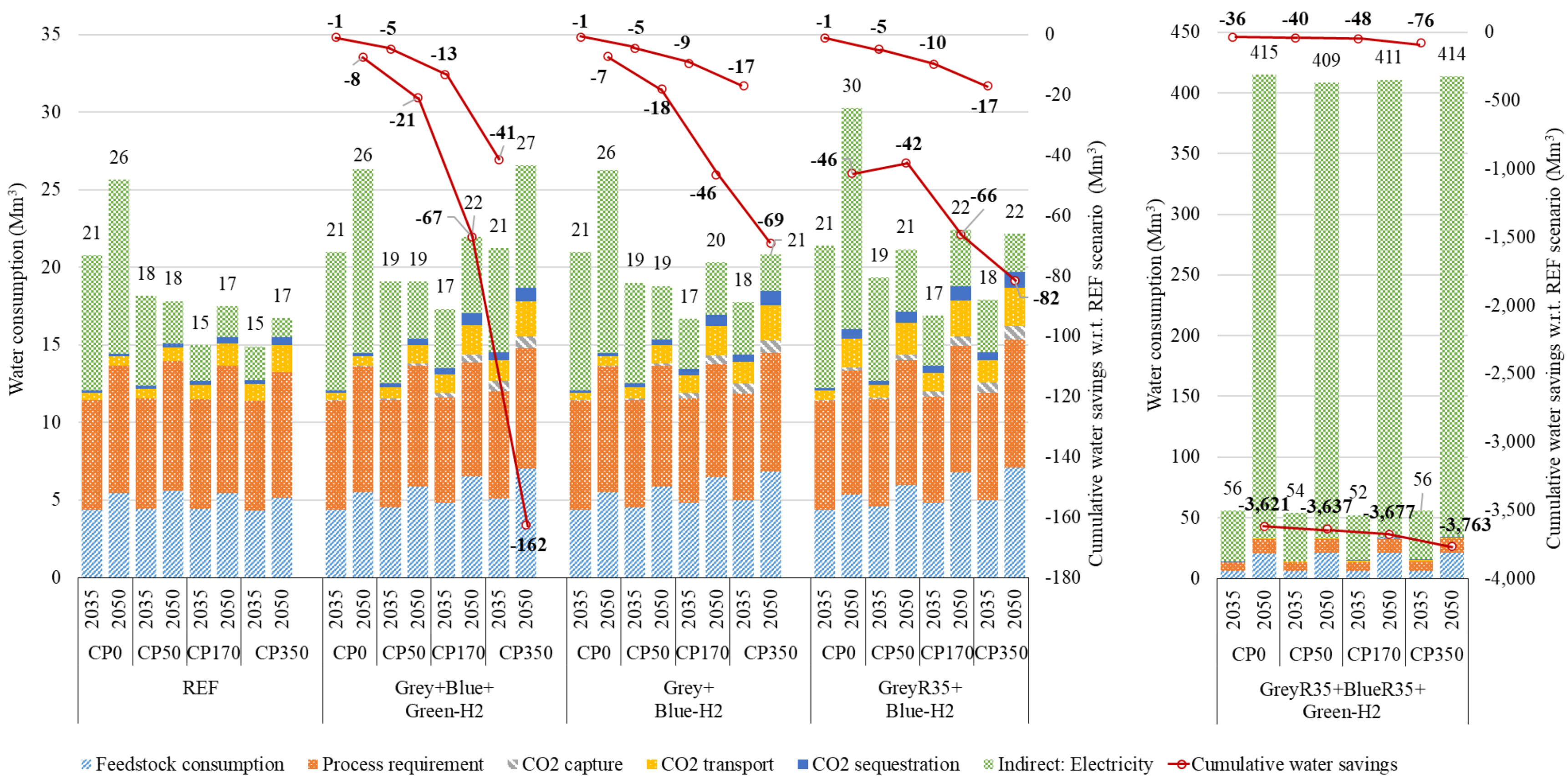

Figure 13: Water consumption projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the H2-Transp hydrogen demand scenario.

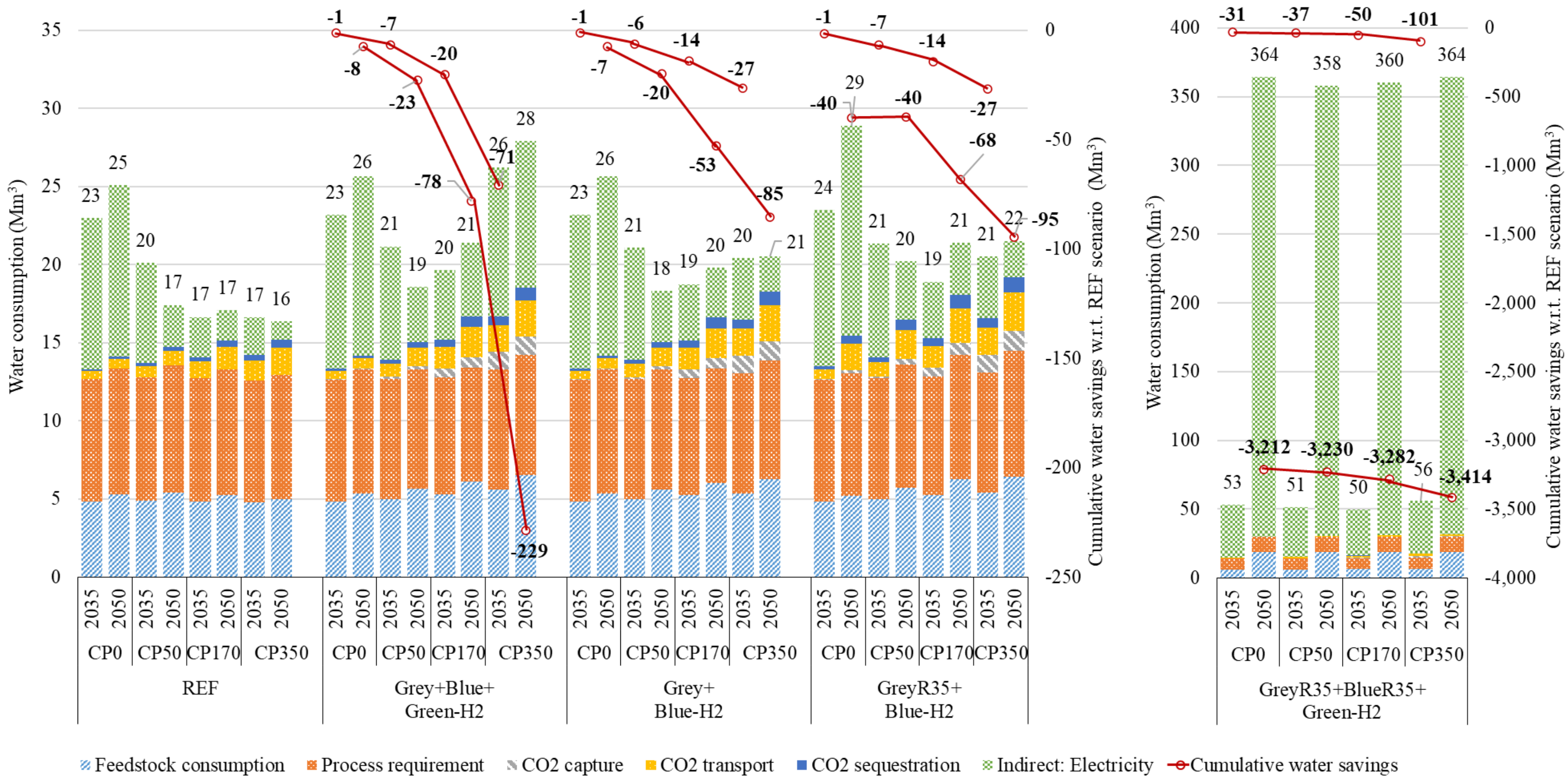

Figure 14: Water consumption projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-All hydrogen demand scenario.

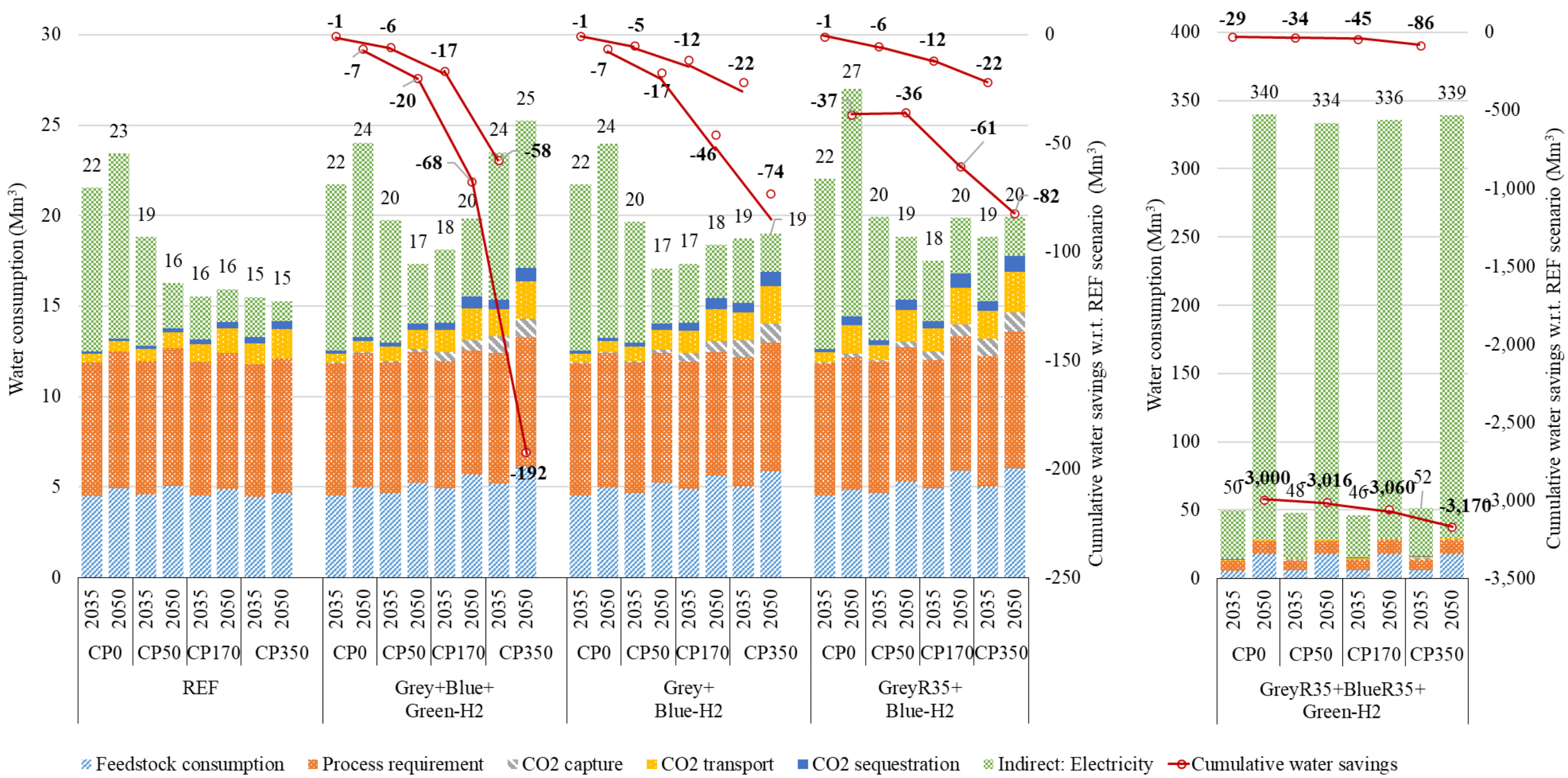

Figure 15: Water consumption projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-OS hydrogen demand scenario.

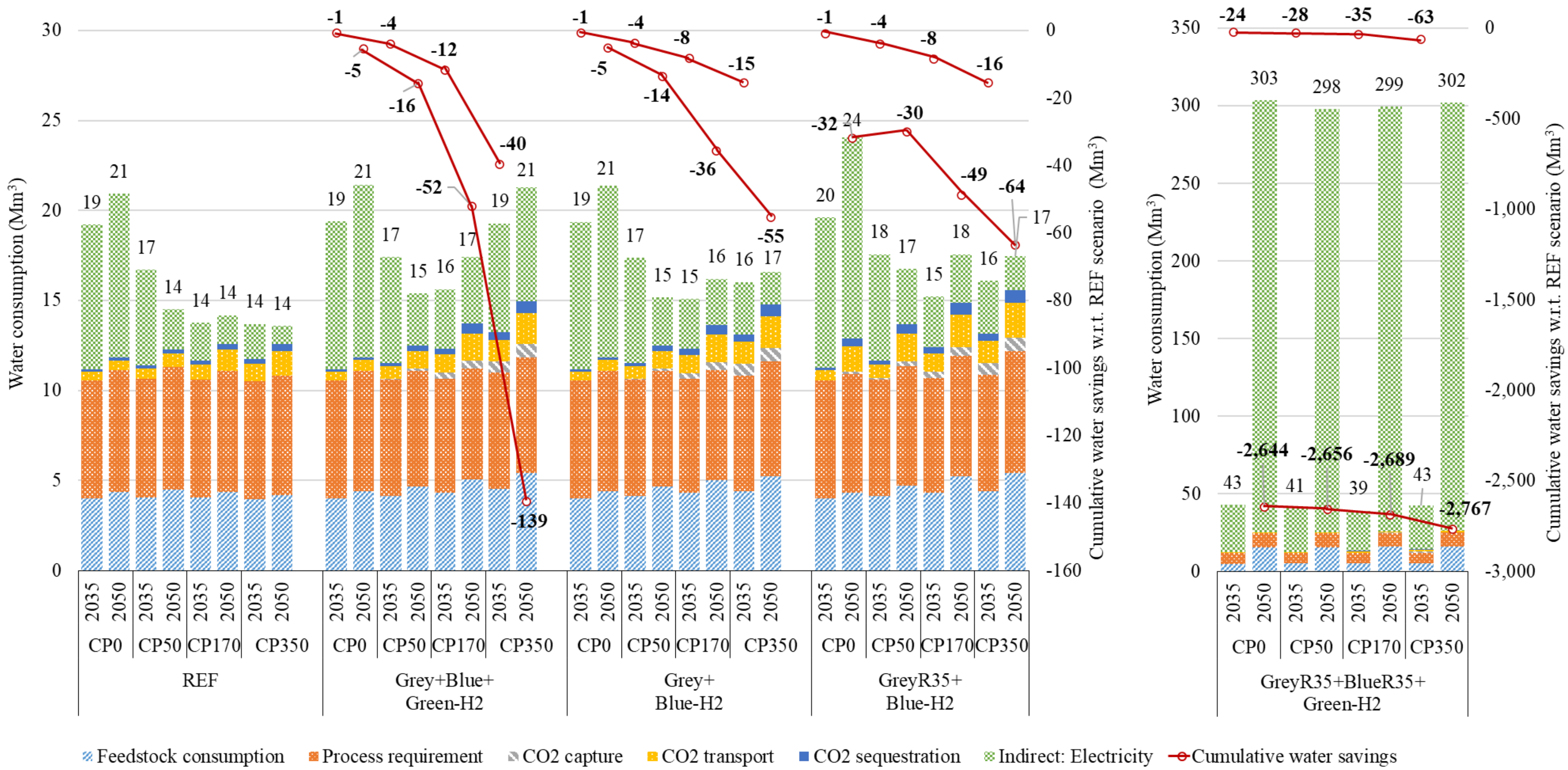

Figure 16: Water consumption projections for each hydrogen production scenario and carbon pricing environment. Results obtained from the Hyth15-Res hydrogen demand scenario.

Appendix F – Integrated cost-benefit assessment

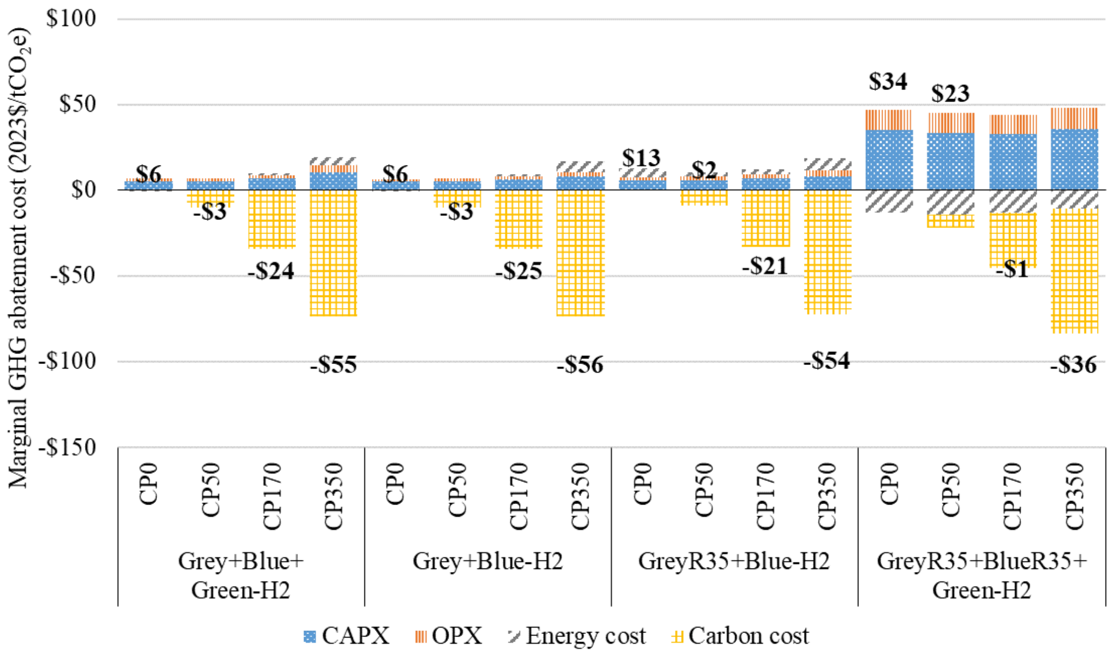

Figure 17: Marginal GHG abatement cost for each hydrogen production scenario and carbon pricing environment. The results are valid for the AB-Inc demand scenario.

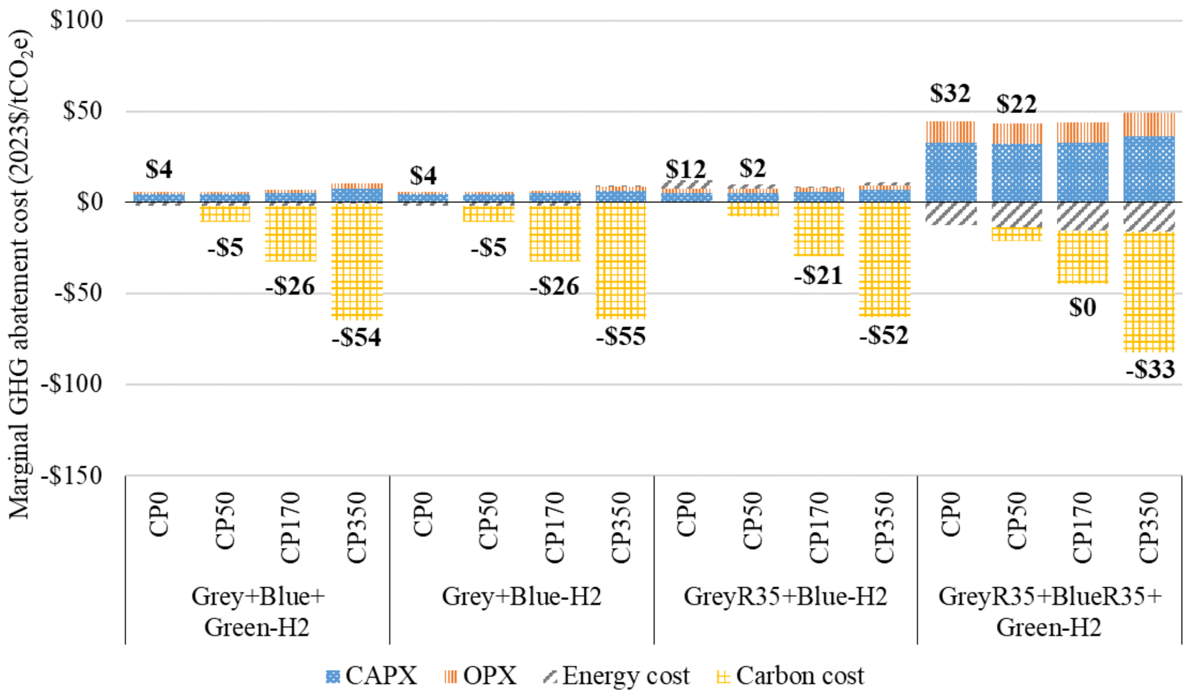

Figure 18: Marginal GHG abatement cost for each hydrogen production scenario and carbon pricing environment. The results are valid for the AB-Tra demand scenario.

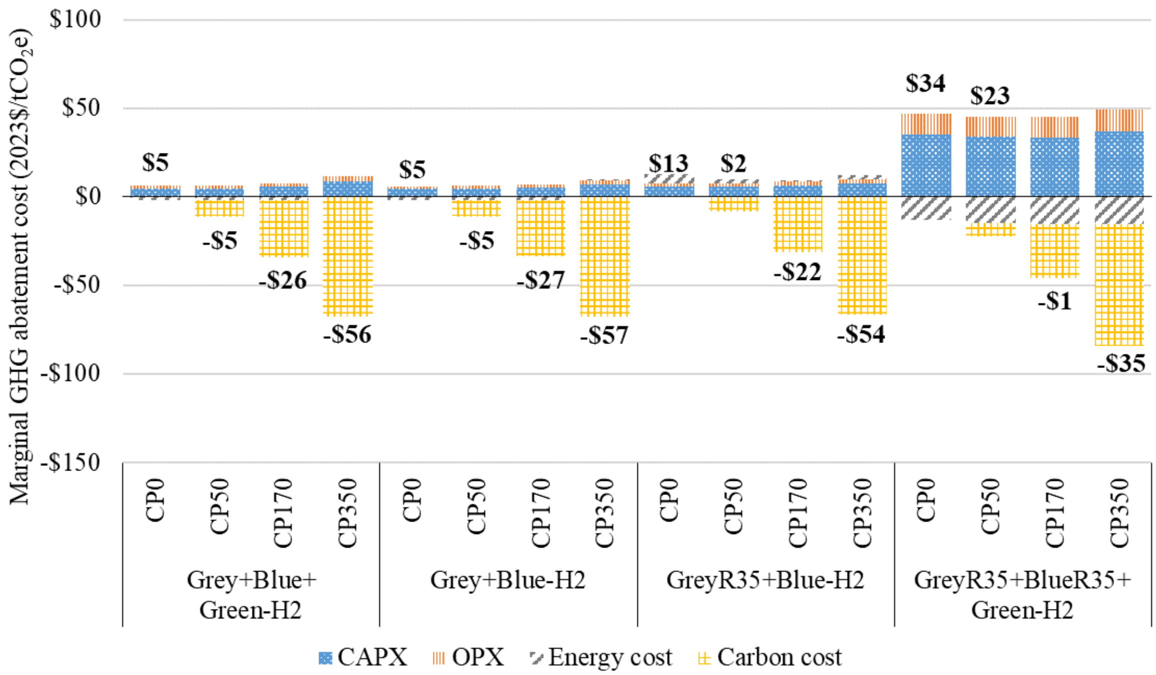

Figure 19: Marginal GHG abatement cost for each hydrogen production scenario and carbon pricing environment. The results are valid for the H2-Transp demand scenario.

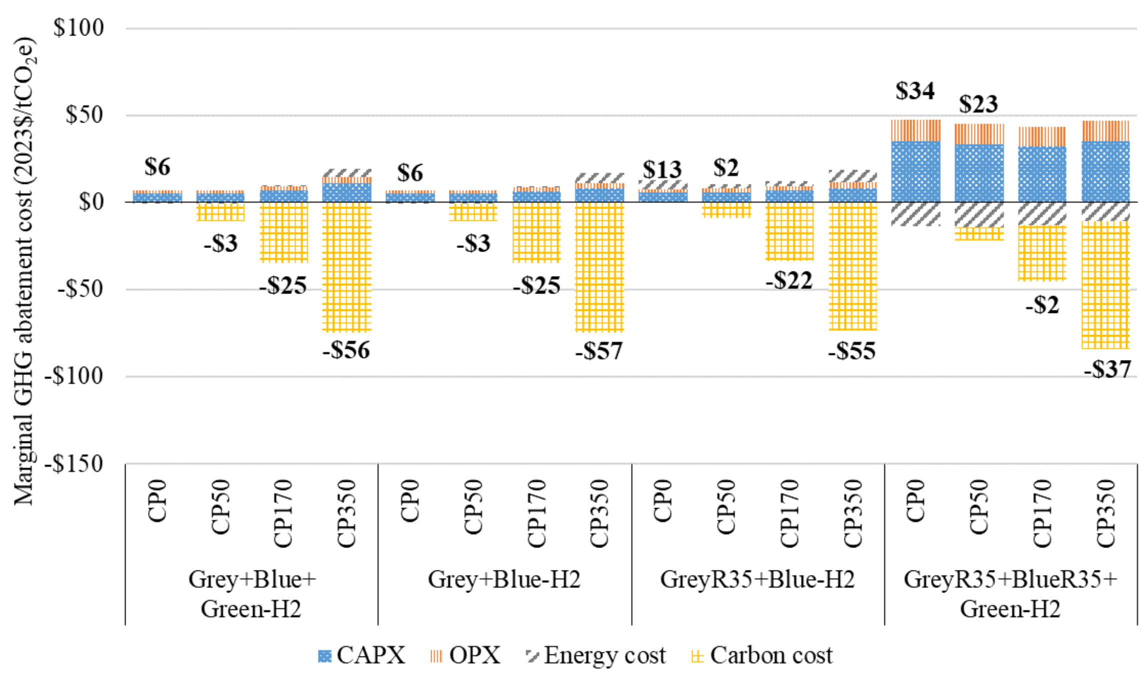

Figure 20: Marginal GHG abatement cost for each hydrogen production scenario and carbon pricing environment. The results are valid for the Hyth15-All demand scenario.

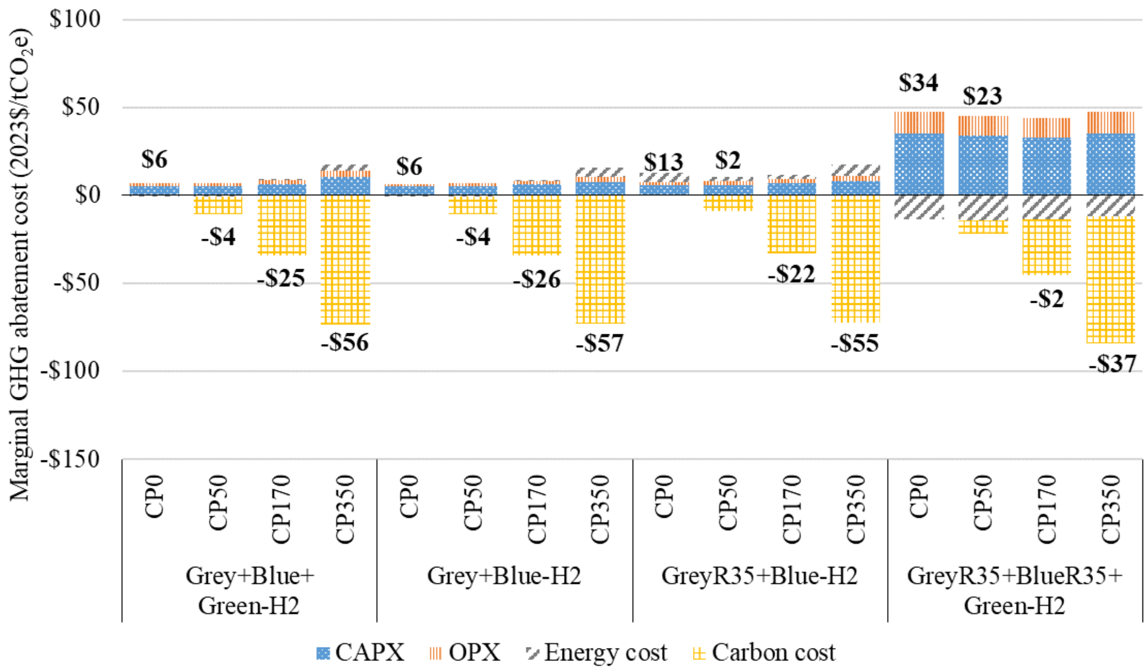

Figure 21: Marginal GHG abatement cost for each hydrogen production scenario and carbon pricing environment. The results are valid for the Hyth15-OS demand scenario.

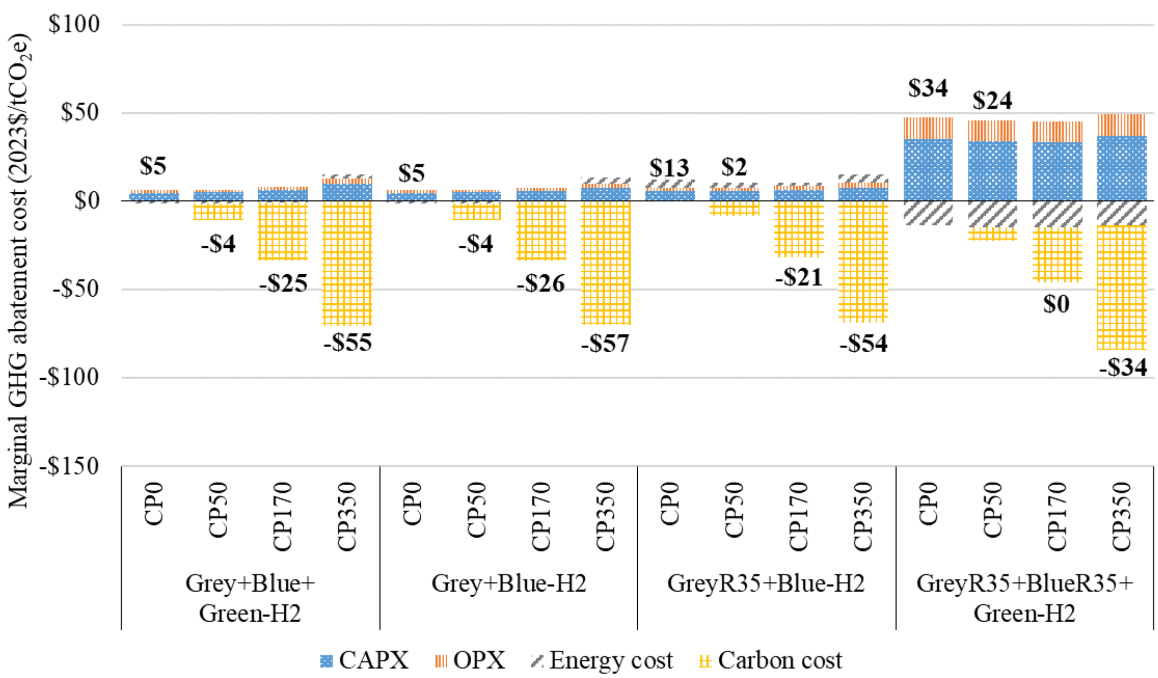

Figure 22: Marginal GHG abatement cost for each hydrogen production scenario and carbon pricing environment. The results are valid for the Hyth15-Res demand scenario.