Achieving carbon-neutral cement production by 2050 through the adoption of decarbonization technologies

by

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Abstract

Global warming caused by anthropogenic greenhouse gas (GHG) emissions is leading to measurable environmental impacts that threaten to disrupt societies globally. Food and water security, human health, and economies are expected to be adversely affected. Therefore, as the world strives to reduce anthropogenic GHG emissions, hard-to-abate sectors should not be ignored. Cement, the binding agent in concrete, is extensively used in the built environment. Cement production is responsible for 8% of global GHG emissions and is the second-largest industrial emitter. Between 2015 and 2021, GHG emissions from cement production rose 15%, despite calls to mitigate climate impacts by reducing emissions. Fortunately, there are many levers by which to decarbonize cement production. Categorized, they are fuel-switching, energy-efficient technologies, alternative raw materials, alternative binders and cement chemistries, and carbon capture and sequestration (CCS). Carbonation, which is the natural uptake of carbon dioxide from the air into concrete products, is also being more widely recognized as a potential offset for GHG emissions from cement production. However, studies that explore decarbonization methods in cement production typically focus on the application of a single technology, or a small subset of technologies, missing the opportunity to compare a broad range of available technologies. Furthermore, few studies combine the impacts of all categories, thereby omitting inter-category impacts and failing to quantify the role of each category in decarbonization. This research aims to address those gaps by identifying and assessing multiple technologies within several of the decarbonization categories. Additionally, technologies from each category are combined to create carbon-neutral scenarios that explore the contribution of each category in decarbonizing the sector.

With Canada as a case study, energy demand and GHG emissions were modelled and validated against historical data from 1990-2019 at national and subnational levels. Technology and carbon-

neutral scenarios were then evaluated from 2020-2050 and included capital costs, non-energy operating costs, energy costs, and carbon costs. For fuel-switching, transitioning to municipal solid waste or biomass in the precalciner can be done with negative GHG emission abatement costs under Canada's current carbon price schedule. At full deployment, municipal solid waste and biomass reduce combustion GHG emissions by 39-62% annually. Hydrogen fuel and electrification of thermal energy, both transformative technologies, are not available until 2040 but reduce combustion GHG emissions from 89-98% annually when fully deployed. These results emphasize the competing demands of immediate GHG reductions and the long-term pursuit of carbon-neutral cement production. Establishing reliable, low-cost, low-carbon fuel supply chains is necessary to support fuel-switching in cement production, specifically for alternative fuels such as biomass and municipal solid waste in the short term and hydrogen in the long term.

An evaluation of several CCS technologies demonstrated that energy can account for as much as 81% of the total costs, eroding the benefits of capturing emissions and increasing sensitivity to energy price fluctuations. However, carbon pricing is the factor that most influences the economic benefit of carbon capture and storage technologies. Under the current carbon pricing schedule, marginal abatement costs range from -22 to 1 CAD/t CO_2e, with the lowest energy demand technologies having the best economic return. A carbon price analysis shows that a minimum price of 90 CAD/t CO_2e by 2030 is necessary to ensure there is at least one CCS technology with a negative abatement cost in each region.

Finally, energy-efficient technologies, alternative raw materials, alternative binders and chemistries and the impacts of carbonation were evaluated alongside fuel-switching and CCS technologies to establish carbon-neutral scenarios. The scenarios covered a range of possible technology mixes driven by overarching goals such as highest emissions reductions and lowest

cost. The results show that carbon-neutral cement production can be achieved before 2050 with cumulative GHG reductions ranging from 199-242 Mt CO_2e and marginal abatement costs ranging from -17 to -34 CAD/t CO_2e at a carbon price of 170 CAD/t CO_2e by 2030. Canada continues to have a higher clinker/cement ratio and lower alternative fuel consumption than other jurisdictions, meaning CCS is expected to play a larger role in reducing GHG emissions. Furthermore, carbon neutrality cannot be achieved without carbonation or a similar offset. Therefore, it is important that all cement-producing regions begin formalizing a framework to guide the calculation of carbonation impacts.

Preface

This thesis contains content from three studies. **Chapters 3**, **4**, and **5** provide the background, study-specific data and methods, results, discussion, limitations, policy implications, and conclusion for each study. These sections are presented as they appear in the individual studies, with minor edits to ensure accurate references to figures, tables, equations, and appendices. **Chapter 2** outlines the model, model assumptions, and analysis techniques that are common across each study. The thesis is organized in this manner to improve readability.

The content of **Chapter 3,** combined with the supporting model, model assumptions, and analysis methods described in **Chapter 2**, will be submitted for publication as "Assessment of fuel-switching as a decarbonization strategy in the cement sector" by Garrett Clark, Matthew Davis, Shibani, and Amit Kumar.

The content of **Chapter 4**, combined with the supporting model, model assumptions, and analysis methods described in **Chapter 2**, will be submitted for publication as "Carbon capture and storage technologies as a means of decarbonizing cement production" by Garrett Clark, Matthew Davis, and Amit Kumar.

The content of **Chapter 5**, combined with the supporting model, model assumptions, and analysis methods described in **Chapter 2**, will be submitted for publication as "Multi-measure pathways for achieving carbon-neutral cement production" by Garrett Clark, Matthew Davis, and Amit Kumar.

In each study, I was responsible for model design, model application, literature review, data collection, data processing, analysis, interpretation of the results, and writing. Matthew Davis provided input into the model framework, design, and application, provided the original upstream electricity generation and hydrogen production modules, assisted with model troubleshooting, and provided feedback on the written content and visuals including the studies and this thesis. Dr. Amit Kumar provided overall supervision and conceptualization, feedback on the written content and visuals included in the three studies and this thesis, and managed funding for this work. Shibani created and applied a framework to quantify hydrogen retail prices for each region in Canada. The results of Shibani's research were used in the creation of hydrogen fuel-switching scenarios for the content of **Chapter 3**.

Acknowledgements

I am appreciative of Dr. Amit Kumar for granting me this opportunity to explore the world of academic research and pursue a deeper understanding of energy management and decarbonization. I am also grateful to Matthew Davis for his guidance over the course of my research. The outputs would not have been the same without it.

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Finally, a big thank you to my family for putting up with my career shift, late night classes, and near-constant stress of graduate school. I will be forever grateful.

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Abbreviations

ABC	Alternative binders and chemistries
ARM	Alternative raw materials
ATR-CCS	Autothermal reforming with carbon capture
CAD	Canadian dollar
CAR	Carbonation
CCS	Carbon capture and sequestration
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COP	Conference of the Parties
CP0	Carbon price policy of 0 CAD/t
CP50	Carbon price policy of 30 CAD/t in 2020, 40 CAD/t in 2021, 50 CAD/t from 2022 onwards. Nominal prices.
CP170	Carbon price policy of 30 CAD/t in 2020, 40 CAD/t in 2021, 50 CAD/t in 2022, and rising linearly to 170 CAD/t by 2030. Nominal prices.
CP350	Carbon price policy of 30 CAD/t in 2020, 40 CAD/t in 2021, 50 CAD/t in 2022, and rising linearly to 350 CAD/t by 2030. Nominal prices.
ECCC	Environment and Climate Change Canada
EE	Energy efficiency
FS	Fuel-switching
GHG	Greenhouse gas
IPCC	Intergovernmental Panel on Climate Change
LEAP	Low Emissions Analysis Platform
MSW	Municipal solid waste
NPV	Net present value
SI	Supplementary information

Model variables, parameters and sets

Variables

CAR	GHG emissions offset by carbonation
CC	Carbon cost
CurrPen	Current penetration (as of 2019)
E	Energy consumption
EC	Energy cost
GHG	GHG emissions
LCC	Life cycle cost
MAC	GHG emission marginal abatement cost
MS	Market share
NPV	Net present value
OC	Non-energy operating cost
PE	Process GHG emissions
PECC	Carbon cost of process GHG emissions
PF	Penetration factor

Parameters

Adopt	Adoption factor
ACC	Annualized capital cost
CAP	Capital cost
CP	Carbon price
d	NPV discount rate
LS	Lifespan of technology
P1	S-curve constant 1
P2	S-curve constant 2
i	Interest rate
SY	First year of commercial availability
v	Market share cost sensitivity parameter
TSM	Transportation, sequestration, and monitoring costs of carbon dioxide

Sets

e	Type of energy
n	Year
REF	Reference (baseline) scenario
s	Technology or carbon-neutral scenario
t	Technology

Chapter 1. Introduction

1.1. Climate change and carbon neutrality

From 2011 to 2020 average global surface temperatures were 1.1 degrees Celsius above those of the period from 1850-1900, resulting in widespread weather and climate extremes impacting essential resources, human health, and economies [1]. Food and water security are expected to become increasing concerns in many parts of the world as precipitation patterns change, and adverse impacts to human health are anticipated from the rise in infectious disease, increase in wildfire occurrence, and displacement of populations by flooding, fire, and conflict. Also, climate-exposed sectors of the economy such as agriculture, forestry, and energy are expected to face disruption, impacting people's livelihoods. While some regions may experience positive impacts because of a changing climate, those impacts are generally thought to be limited and not as significant as the negative impacts. Furthermore, the most recent assessment from the Intergovernmental Panel on Climate Change (IPCC) predicts climate change impacts will be larger in extent and severity than estimated in previous assessments. Global warming is projected to increase in the near term, meaning deep greenhouse gas (GHG) emissions reductions towards net-zero carbon dioxide (CO_2) emissions are necessary to limit warming to 2 degrees Celsius by the end of the century. However, from 2015 to 2021, global cement production emissions rose 15%, to 2.5 Gt CO_2e, making cement the second-largest source of industrial GHG emissions and responsible for 8% of global GHG emissions [2].

At a global level, the terms carbon neutrality and net-zero CO_2 emissions are interchangeable. At a sub-global level, the terms have distinct differences [1]. As they apply to cement production, net-zero CO_2 emissions refer to emissions and removals under the direct control of the cement plant, while carbon neutrality refers to CO_2 emissions and removals under and beyond the direct control of the cement plant. Emissions under the direct control of the cement plant comprise on-site combustion and process emissions but do not include indirect emissions from the consumption of grid electricity. In this research, the emissions from grid electricity are considered and the term carbon neutral is applied specifically to the scenarios and results of **Chapter 5**.

1.2. How is cement produced?

Cement production is a multi-step process (**Figure 1**), consisting of three overarching processes and several subprocesses. During the first overarching process (raw material and fuel preparation), raw materials such as limestone, clay, sand, iron ore, and bauxite are mixed and finely ground to produce a homogenous mixture known as raw meal [3]. Limestone provides calcium carbonate ($CaCO_3$), the key ingredient of cement, clay and sand provide silicates that contribute to the strength of cements, and iron ore and bauxite are fluxes that reduce the sintering temperature. Other materials may be used to meet product and process requirements. The raw meal then enters the preheaters, a series of vertical cyclones, where hot gases from the precalciner and kiln transfer heat to the raw meal as it moves in the opposite direction. The preheaters heat the raw meal to nearly 900°C.

In the next overarching process, clinker production, the raw meal enters a combustion chamber at the bottom of the preheaters. This chamber, called the precalciner, is where most of the calcination process occurs. During calcination, the intense heat causes the limestone in the raw meal to decompose into calcium oxide (CaO) and CO_2. The CO_2 emissions resulting from calcination are referred to as process emissions and represent 60-70% [3] of all GHG emissions created during cement production. The calcined meal then enters a cylindrical, rotating kiln where it reaches temperatures exceeding 1400°C. As the kiln rotates, the material falls through increasingly hotter zones and eventually onto the cooler. In the heat of the kiln, any remaining limestone undergoes calcination and the calcined meal sinters to form clinker, the primary ingredient in cement. Once in the cooler, the clinker is cooled as incoming combustion air passes over and through it.

Finally, in the third overarching process, finish grinding, the clinker is ground, blended with other cementitious materials, and packaged as the final cement product. Other cementitious materials include gypsum, crushed limestone, coal fly ash, and ferrous slags such as blast furnace slag [3].

Fuel is also prepared for use, typically through drying or grinding, and transported to the precalciner and kiln. Complete combustion of all fuels is desired to maximize fuel efficiency and maintain product integrity, therefore a combination of fuel fineness and feed points is considered. Coarse solids are more suitable for the precalciner while fine solids are suitable for the kiln [4].

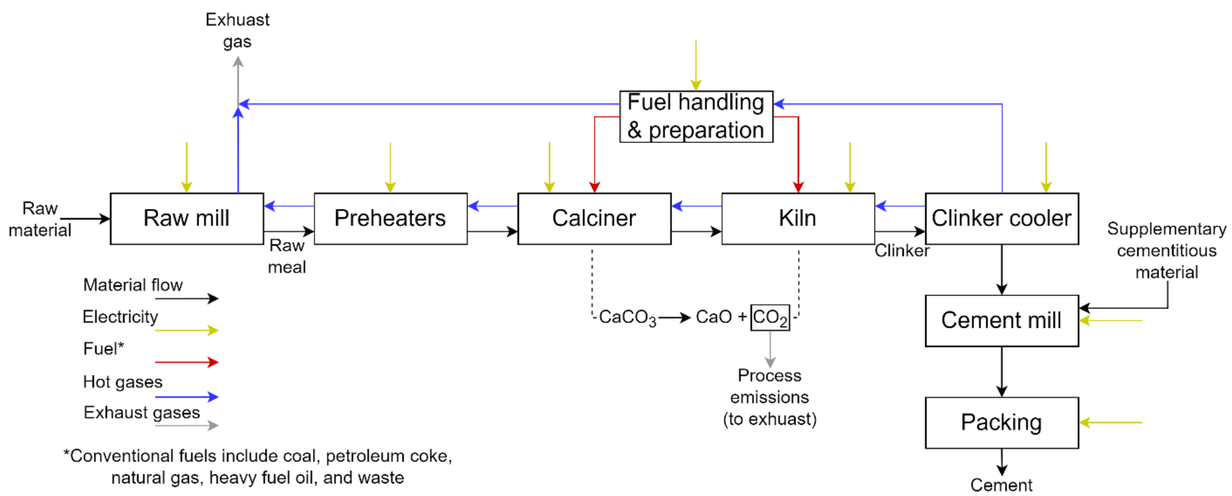

Figure 1. Cement production process

1.3. Decarbonization levers for cement production

This work explores and evaluates each of the generally accepted decarbonization categories for cement production and one emerging category. The generally accepted decarbonization categories are energy efficiency, fuel-switching, decarbonized raw materials, alternative cement binders and chemistries, and carbon capture and sequestration (CCS).

The emerging category, carbonation, is not officially recognized in the IPCC's Guidelines for National Greenhouse Gas Inventories [5] for inclusion in official cement production sector emissions calculations but has been recognized by the editorial board of the IPCC's Emissions Factor Database [6], and technical information on carbonation is available in the database [7]. Furthermore, several national cement associations have included carbonation in their carbon-neutral roadmaps, as discussed further **Chapter 5**.

Energy efficiency reduces combustion emissions and indirect emissions related to electricity consumption. Switching to low-carbon fuels reduces combustion emissions. Employing alternative, decarbonized raw materials decreases process emissions. Replacing traditional cement binders with alternative binders, or developing alternative cement chemistries, also has the potential to decrease process emissions. Carbon capture and sequestration (CCS) removes combustion and process emissions from the flue of cement plants so it can be compressed, transported, sequestered, used for another purpose, or any combination of these. Finally, carbonation is the process by which cement mixed in concrete naturally absorbs carbon dioxide (CO_2) from the air. A more detailed explanation and analysis of the fuel-switching category are available in **Chapter 3**, a more detailed explanation and analysis of the carbon capture and sequestration category are available in **Chapter 4**, and a more detailed explanation and analysis of the energy efficiency, decarbonized raw materials, alternative cement binders and chemistries, and carbonation categories are available in **Chapter 5**.

1.4. Knowledge gaps

The review of the decarbonization technologies highlighted several knowledge gaps this work aims to address. First, in the fuel-switching category, existing studies primarily consider only alternative fuels as a means of GHG emissions reduction, ignoring the many other fuel-switching technologies available to the industry. This leaves industry and policy decision-makers ill-equipped to consider the potential impacts of diverse fuel options. Second, only exploring one fuel-switching option leaves little opportunity to perform a market share analysis of fuel-switching technologies. A market share analysis can help determine which technologies are more likely to be adopted in certain jurisdictions. The third gap is that the available bottom-up technology studies do not compare fuel-switching technologies in different regions. The GHG impact and economic viability of fuels can vary among regions depending on energy prices and regional baseline energy mixes.

In the CCS decarbonization category, CCS is typically limited to or generalized as a single technology, thereby ignoring the wide range of capture rates, costs, energy impacts, readiness levels, and complexity across CCS technologies. This constrains the resultant CCS decarbonization measure to a single outcome, simplifying costs and benefits, and limiting policymakers' understanding of the different CCS technologies available. Another key gap is that previous bottom-up technology-explicit studies ignore transportation and storage costs. Without these costs, policymakers do not have complete information. Finally, the energy impacts and resultant direct and indirect GHG emissions of each CCS technology are not explicitly explored. Paired with regional energy pricing and fuel mixes, the energy and GHG emission costs and benefits of each CCS technology influence the overall economic viability of the technology.

Finally, after reviewing a variety of selected decarbonization case studies, it was found that many are limited to the economic potential of energy savings and GHG reductions. This aligns with the predominant industrial culture that all investments should offer a return, and typically a financial return. However, the need for urgent GHG reductions to limit global warming necessitates understanding the full technical potential available to the industry. From there, policies can be created to incentivize technologies that offer significant GHG reductions but may not yet be economical. Of the studies that are not limited to economic potential, most do not consider two or more decarbonization categories and only one considers all decarbonization categories. To best understand the extent that each pathway may influence the drive to carbon neutrality, all categories should be considered simultaneously. Furthermore, additional research considering all categories increases the pool of studies from which industry and future research can draw.

Summarized, the knowledge gaps are:

Gap 1: Existing studies typically limit analysis to a single or generalized technology. Consequently, they do not directly compare the wide range of technologies with various GHG emission impacts, capture rates, costs, energy impacts, readiness levels, and complexity available to the sector, and they limit the potential for market share analysis.

Gap 2: Available bottom-up technology studies do not compare technologies across different regions, making it difficult to discern the impact of regional differences.

Gap 3: Previous bottom-up technology-explicit studies ignore the transportation and sequestration costs, and energy and GHG emission penalties associated with CCS technologies.

Gap 4: There are limited studies that explore the full technical potential for GHG reductions.

Gap 5: There are limited studies that combine all decarbonization categories simultaneously, thereby ignoring inter-category impacts and making it difficult to discern how each decarbonization category may contribute to carbon neutrality.

1.5. Objectives

To address the knowledge gaps discussed in **Section 1.4**, we explore technologies for each decarbonization category, with the overarching goals of understanding how technologies compare to each other within a specific category and understanding each category's role in achieving carbon neutrality. These goals are achieved through the following sub-objectives:

1. To develop and validate a bottom-up technology- and process-explicit model of the cement sector
2. To model several technology-explicit energy efficiency, fuel-switching, decarbonized raw materials, alternative cement binders and chemistry, and CCS decarbonization scenarios using Canadian cement production as a case study
3. To develop carbon-neutrality scenarios using Canadian cement production as a case study
4. To analyze the GHG emission impacts, costs, and benefits of each scenario by region
5. To assess the economic and technical potential of energy savings and GHG reductions for each carbon-neutrality scenario by region
6. To understand the impacts of energy and carbon prices on the adoption of decarbonization technologies

1.6. Canada as a case study and international relevance

This study focuses on decarbonization of the Canadian cement sector; however, the results apply to much of global cement production. The decarbonization categories explored in this research are also of interest to cement associations in Europe [8], the United States [9], Australia [10], and the United Kingdom [11] as a means of achieving carbon neutrality. Therefore, the results of this study provide insight that can be used by these jurisdictions and any other jurisdiction that wants to employ similar decarbonization methods.

Canadian cement production has many similarities to international production. In Canada, all cement is produced in dry-process kilns [12], as is much of the world's cement. Given that dry-kiln technology is significantly more efficient than older, wet-kiln technology [13], countries will likely continue to transition to dry-process kiln technology. Additionally, fuel combustion accounted for an average of 40% of Canadian cement's direct emissions from 1990 to 2020, in line with global averages. China and India's cement sectors, which are responsible for a combined 62-64% of global cement production, primarily use coal for thermal energy [14, 15], and the International Energy Agency also estimates that more than 92% of thermal energy for cement came from the combustion of fossil fuels in 2020 [16]. Similarly, the Canadian cement sector has used carbon-intensive fuels [17], with coal and petroleum coke supplying an average of 69% of thermal energy from 2010 to 2019.

CCS is also projected to play a significant role in decarbonizing cement in all countries, and with five diverse cement-producing regions, Canada can provide the international community with insight into how CCS costs and benefits can differ between regions. Furthermore, Canada is poised to be a leader in the application of CCS technology. The Pathways Alliance, a consortium of Canada's largest oilsands producers, is working on a large-scale CCS project that could see over 20 emitters equipped with CCS technologies and over 400 kilometres of transport pipeline to move the carbon dioxide to secondary use locations or long-term storage [18]. Furthermore, the already operational Alberta Carbon Trunk Line can transport 14.6 Mt of carbon dioxide per year for secondary use or long-term storage [19]. Additionally, at least three Canadian cement CCS initiatives are underway: there is a demonstration project in its third year that has a 90% carbon dioxide recovery rate [20] and there are two feasibility studies for other facilities with a combined capture potential of nearly 2 Mt per year.

In 2018, Canada produced over 13.5 Mt of cement [21], or approximately 0.3% of the world's cement production [22], and emitted 11.4 Mt of direct GHG emissions [23]. Through the Canadian Net-Zero Emissions Accountability Act [24], Canada has legislated its commitment to achieving net-zero GHG emissions by 2050. The act also establishes a goal of 40-45% GHG reductions below 2005 levels by 2030, meaning every sector must reduce GHG emissions.

1.7. Organization of thesis

This thesis has been written in a paper-based format and is a combination of three research papers. **Chapters 3, 4,** and **5** are supposed to be read independently and some background information may be repeated in each of the chapters.

Chapter 2 describes the base model, underlying assumptions, and calculation methods, which are consistent in all three papers. This model forms the basis to which all decarbonization technology scenarios were applied, allowing technology within and across decarbonization categories to be compared with each another. Therefore, **Chapter 2** compliments **Chapters 3, 4,** and **5.**

Chapter 3 describes the assessment of the fuel-switching decarbonization category, consisting of the background and the results and discussion of the first research paper. The type of fuel used influences the impact of every other decarbonization category. In this research, scenarios that consider the transition to natural gas, biomass, municipal solid waste (MSW), hydrogen, a natural gas and hydrogen blend called hythane, and electrification of thermal energy requirements are analyzed. The distinction between hydrogen from autothermal reforming with carbon capture and sequestration and electrolytic hydrogen is also explored.

Chapter 4 describes the assessment of the CCS decarbonization category, consisting of the background and the results and discussion of the second research paper. The GHG emissions abatement costs, energy penalties, and emissions penalties are explored for six different CCS technologies. This research facilitates the direct comparison of CCS technologies across Canada and within each cement-producing region.

Chapter 5 describes the assessment of the energy efficiency, alternative raw materials, alternative binders and chemistries, and carbonation decarbonization categories, as well as the creation and assessment of carbon-neutral scenarios. The chapter consists of the background and the results and discussion of the third research paper. The results of the first two papers are reflected in the creation of the carbon-neutral scenarios.

Chapter 2. Base model development, assumptions, and analysis methods

This chapter describes the bottom-up, technology explicit energy and GHG emissions model that is used as the foundation for the research described in **Chapters 3, 4** and **5**. The framework and basic structure of the model are outlined, followed by a discussion of the validation results. Key economic inputs and assumptions are then discussed. Finally, the chapter concludes with an overview of how marginal abatement cost and market share analyses are performed.

2.1. Energy and GHG emissions model

2.1.1. Framework for development

This study incorporated several stages for the development of carbon-neutral scenarios in cement production (**Figure 2**). In stage one, the available literature was reviewed to identify cement production processes and technologies. Stage two centered around the development of the sector energy model, starting with the energy demand tree as described in **Section 2.1.2**. Historical and forecasted cement production and process-specific energy demands were also used to create and validate the sector's energy demand. Similarly, GHG emissions were calculated using built-in Intergovernmental Panel on Climate Change (IPCC) emissions factors for combustion-related emissions and a national process emissions factor [23] for process emissions. Indirect electricity-related GHG emissions were calculated in the model, the specifics of which are discussed in **Section 2.1.4**. In stage three, we identified decarbonization categories and their associated technologies, developed model scenarios, and created a database of decarbonization technologies. Scenarios were created to assess and compare technologies in each category, and the categories were then combined into carbon-neutral scenarios based on sets of criteria discussed further in **Section 5.3**. Where technologies compete with each other, a market share analysis was used to inform technology adoption under varying market cost sensitivities. Where technologies were mutually exclusive, current penetration levels and applicability informed adoption profiles. In stage four, the modelled GHG emissions, benefits, and costs were normalized through net present value (NPV) analysis and used to develop marginal GHG emission abatement costs for the decarbonization and carbon-neutral scenarios compared to the baseline scenario. The results of the carbon-neutral scenarios ultimately informed several potential carbon-neutral roadmaps, which were then compared to roadmaps from other countries in **Section 5.8.**

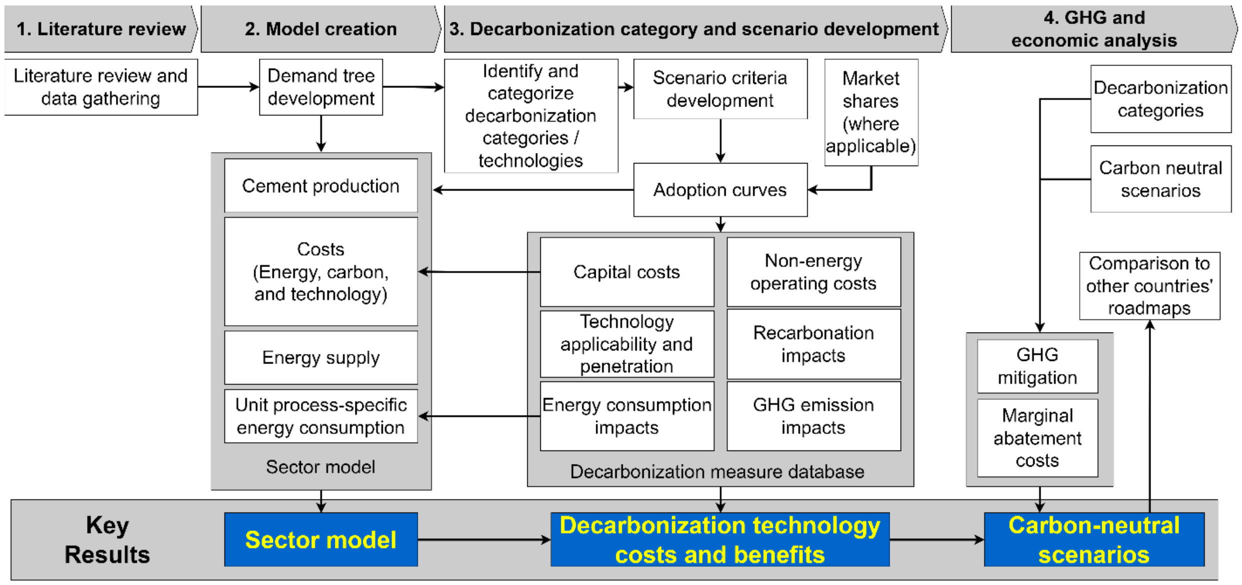

Figure 2. Framework for the study of decarbonization technologies and carbon-neutral scenarios for cement production

2.1.2. Demand tree development

An energy demand tree (**Figure 3**) was created based on a simplified cement production process. In the demand tree, every subprocess involves mechanized equipment that consumes electricity. However, clinker production is the only process that consumes fuel. Thermal energy recovered from kiln exhaust gases and the clinker cooling stage is used in other processes, such as drying and heating solid fuels and raw materials, but since that energy originates with fuel consumed in the precalciner and kiln, it is attributed to that process alone. The introduction of decarbonization technologies does not impact the structure of the demand tree, but does impact the energy intensity, fuel requirements, electricity requirements, and GHG emissions of the various subprocesses. Specific impacts are detailed in **Chapter 3, Chapter 4,** and **Chapter 5**. Finally, the designed demand tree includes a sectoral boundary that excludes upstream fuel and material extraction and processing-related costs and emissions. However, indirect emissions related to grid electricity use are included.

The five cement-producing regions all adhere to the same demand tree structure but differ in energy mix, energy intensity, and energy costs. Energy demand data from Natural Resources

Canada [25] and cement production estimates described here and in **Section 2.1.3** were combined to create regional energy intensities, which range from 3.46 to 6.22 GJ/t cement in 2019, with a Canada-wide average of 4.21 GJ/t cement. This corresponds to thermal energy intensity of 3.82 GJ/t cement or 4.40 GJ/t clinker. The United States and Switzerland have a similar thermal energy intensities of 4.05 GJ/t clinker [9] and 4.1 GJ/t clinker [26]. Australia has a lower thermal energy demand of 3.45 GJ/t clinker, primarily due to over 97% of its production using high-efficiency precalciner kilns [10]. The global average thermal energy intensity is approximately 3.6 GJ/t clinker [27].

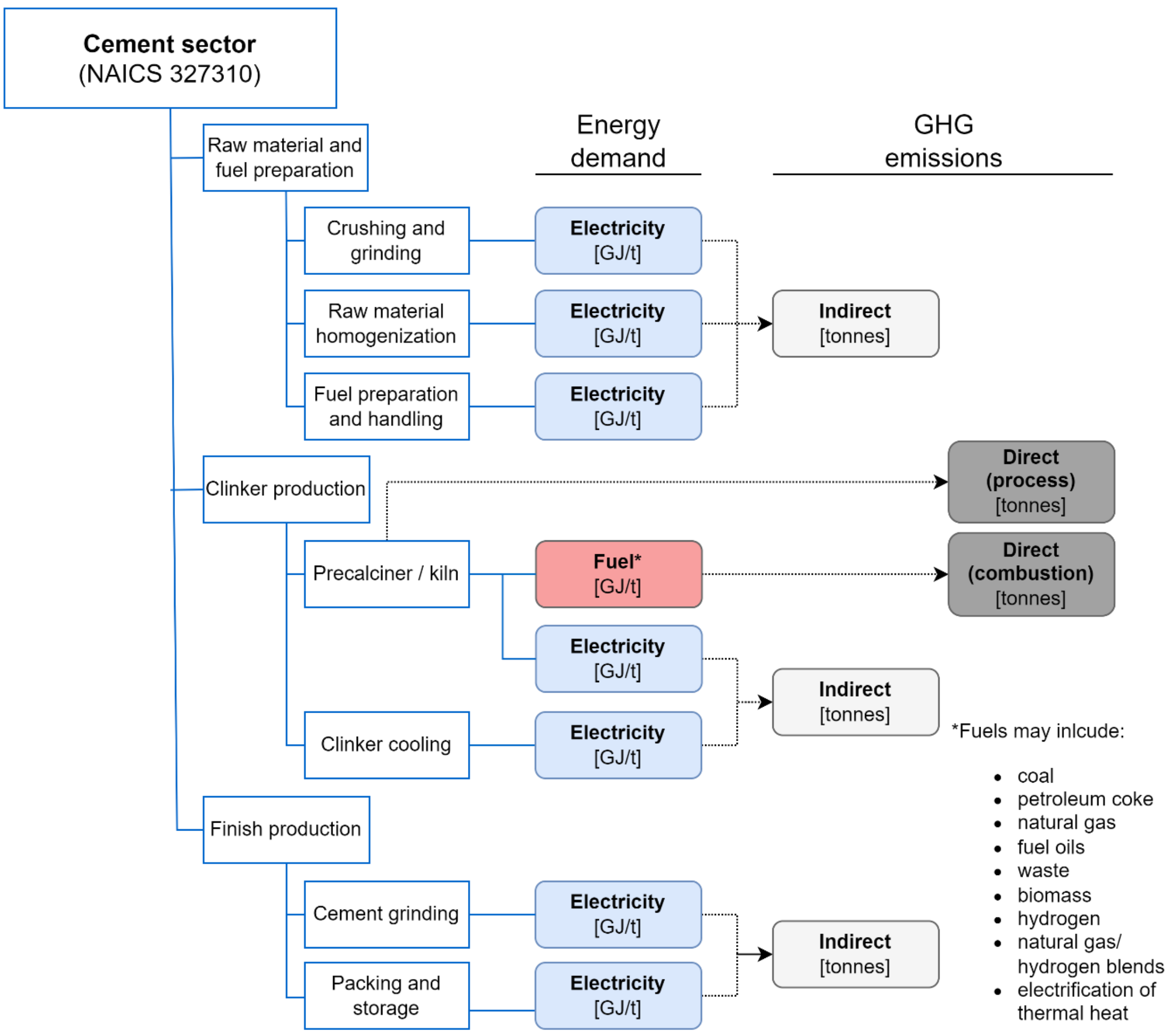

Figure 3. Cement production energy demand tree and associated types of GHG emissions

Regional energy mix data was also gathered from Natural Resources Canada [25]. To maintain confidentiality, only partial data is available on a regional level, but complete data is available on a national level. Therefore, missing data for each region was estimated and the totals of all regions were checked against the national total. Finally, electricity consumption was subdivided by process based on breakdowns provided by Worrell et al. [28, 29], Natural Resources Canada's Industry Benchmarking Report [17], and the European Cement Research Academy [30]. Considering multiple sources published years apart allowed us to more accurately reflect the changing consumption by subprocess over time.

Finally, using Low Emissions Analysis Platform Canada model (LEAP-Canada) [31], a disaggregated, bottom-up, technology-specific energy model was built for the Canadian cement sector to reflect the demand tree and collected data. LEAP-Canada enabled us to model specific unit processes and the impact of different technologies on each unit process while also realizing the sector-wide energy, GHG reductions, and cost impacts over the long term. The are several key inputs, including electricity generation, fuel emission factors, unit process-specific energy consumption, and baseline sector-specific metrics such as cement production volumes, the clinker/cement ratio, and regional energy mixes. LEAP-Canada uses built-in IPCC emission factors to calculate GHG emissions for each fuel based on demand. For this work, emissions are shown as carbon dioxide equivalents (CO_2e). Key model energy demand and emission factor inputs are shown in **Table 1**.

Table 1. Key model energy and emissions factor inputs

Energy demand	
Raw material and fuel preparation	
Crushing and grinding (GJ/t cement)	0.11
Raw material homogenization (GJ/t cement)	0.02
Fuel preparation and handling (GJ/t cement)	0.02
Clinker production	
Precalciner/kiln (GJ/t cement)	0.11
Clinker cooling (GJ/t cement)	0.02
Finish production	
Cement grinding (GJ/t cement)	0.21
Packing and storage (GJ/t cement)	0.02
GHG emission factors	
Indirect (kg CO_2e/GJ)	0.417-203
Direct combustion (t CO_2e/GJ)	0-0.093
Direct process (t CO_2e/t cement)	0.457

2.1.3. Cement production activity

Cement demand is driven by the construction industry [16]. In Canada, construction investment is expected to remain flat until at least 2027 [32]. However, forecasts for the United States West [33], Southeast [34], Central [35], New England [36], and East, North-Central and Mid-Atlantic [37] regions predict increasing construction investments resulting in cement demand growing by 3% on average through 2026. From 2010-2018, Canada exported an average of 25% of the clinker it produced to the United States [38], [21]. It is assumed that this relationship will continue, meaning the growth in United States cement production will increase the demand for Canadian clinker by an average of 0.75% per year through 2026. In the absence of long-term forecasts, it is also assumed that the demand for Canadian clinker will continue to increase at this rate for the time period considered in this study.

Using clinker production as the basis for estimating cement production aligns with the IPCC Guidelines for GHG inventories' Tier 2 method for estimating cement production [5]. Therefore, cement demand was estimated by multiplying clinker production volumes [21] with Canadian clinker/cement ratios [39]. Since regional clinker production volumes were unavailable, the national total was divided among the cement-producing regions based on their contribution to the overall gross domestic product related to cement and concrete manufacturing [40]. Cement production forecasts for each region are available in **Appendix A – Model input parameters**.

2.1.4. Electricity supply

An electricity generation module created by Gupta et al. [41] and further refined by Owttrim et al. [42] was included to meet the electricity requirements of the demand tree. The five cement-producing regions differ in their electrical grid emissions intensity and share of renewable energy as demonstrated in **Table 2**. However, from the first scenario year, renewable energy generation capacity is expected to increase, reducing the emissions intensity of the grid. Wind energy generation is responsible for the majority of the renewable capacity increases, but solar, biomass, and hydroelectric generation also contribute. Hydrogen production and transmission modules developed in LEAP-Canada by Davis et al. [43] were also used in this model.

Table 2. Model electrical grid emissions intensity and share of renewable energy generation, by capacity, for select years

	Electrical grid emissions intensity ($g\ CO_{2e}/kWh$)					Share of renewable energy (% of total generation capacity)				
Year	**BC**	**AB**	**ON**	**QC**	**NS**	**BC**	**AB**	**ON**	**QC**	**NS**
2020	10	350	118	13	447	97	30	80	98	41
2030	8	154	99	12	125	97	52	79	98	59
2040	7	117	85	11	82	97	64	77	98	69
2050	5	63	27	11	44	98	70	82	98	81

2.1.5. Energy model validation

For the years 1990-2019, modelled energy demand and GHG emissions outputs were validated against multiple sources of government data [23, 25, 44] on national and regional levels. **Figure 4** displays the validation results on a national level, and regional validation results are available in **Appendix B – Subnational model validation**. The modelled national energy demand had an absolute average difference of 1.8% compared to available data, while the total of combustion, process, and indirect emissions had an absolute average difference of 1.7% compared to available data. National combustion and process GHG emissions accounted for 95-97% of modelled GHG emissions and had absolute average differences of 5.8% and 0.6%, respectively. Indirect emissions accounted for the remainder of modelled national GHG emissions and had an absolute average difference of 5.6%.

National indirect emissions data from electricity used by the cement sector was not available; however, Environment and Climate Change Canada (ECCC) has published grid emissions factors [23] for many of the years in the validation period. Where emissions factors were not published for a specific year, data was estimated using linear extrapolation. Using these emissions factors and electricity consumption data [25], national and regional indirect emissions were estimated and compared with model results. A regional comparison of model grid emission factors and published factors is available in **Appendix C – Electricity grid emission factors validation**.

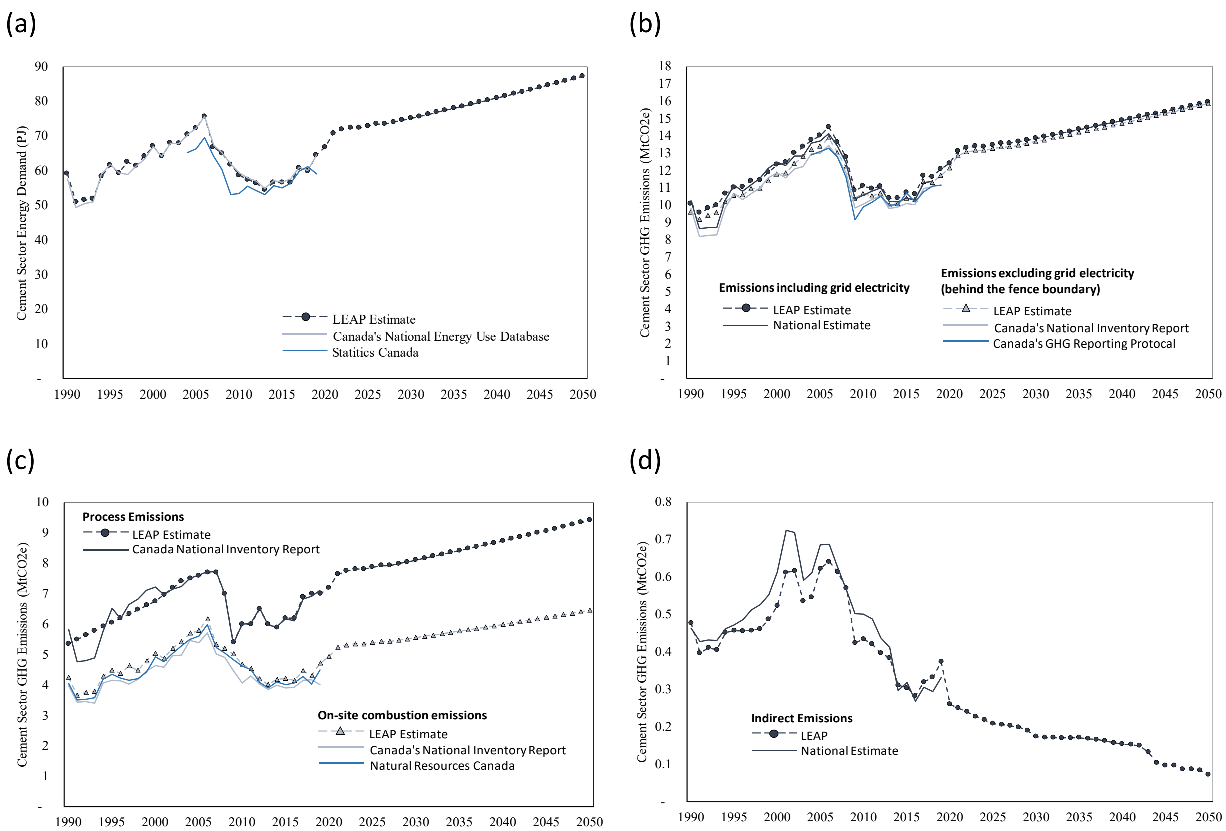

Figure 4. Canada's cement sector validation results based on the reference scenario: (a) final energy demand, (b) total GHG emissions including and excluding indirect (grid) emissions, (c) process and on-site combustion emissions, and (d) indirect (grid) emissions

2.2. Economic assumptions

2.2.1. Energy prices

Regional natural gas, fuel oil, and electricity prices to 2050 were taken from the Canada Energy Regulator [45]. Coal and petroleum coke price data were obtained from Davis et al. [46] and Owttrim et al. [42]. Shibani et al. [47] compare the delivered cost of domestically produced and imported hydrogen for each region in Canada. A description of the methods used is in **Appendix D – Hydrogen price calculation**. For electrolytic hydrogen, domestic production is most cost effective for British Columbia, Alberta, and Quebec. Ontario and Nova Scotia import electrolytic hydrogen from Quebec. For hydrogen produced using ATR-CCS, British Columbia and Alberta produce hydrogen domestically and all other regions import hydrogen from Alberta. Finally, biomass prices are based on Yun et al.'s [48] estimate for the cost of delivered wood pellets from British Columbia to other cement-producing regions. Municipal solid waste (MSW) is assumed to be provided to cement facilities at no cost because it would otherwise be landfilled or exported at a cost to local governments or waste management organizations. It is assumed MSW that is consumed in a cement plant has been sorted, dried, and otherwise assessed as suitable for co-processing. Waste mixes high in chlorine, sulfur, and heavy metals must be avoided to prevent the formation of harmful emissions such as hydrochloric acid, dioxins, and furan [49]. Energy prices for the first and last scenario years are available in **Appendix A – Model input parameters**, along with charts showing price change over time.

2.2.2. Carbon prices

Canada's Greenhouse Gas Pollution Pricing Act [50] outlines the current national carbon pricing schedule. Starting in 2020 at 30 CAD/tonne, carbon prices rose to 40 CAD/tonne in 2021, 50 CAD/tonne in 2022, and 65 CAD/tonne in 2023. The price is expected to increase by an additional 15 CAD/tonne per year until it reaches 170 CAD/tonne in 2030. This pricing schedule is assumed as the baseline for all calculations in this study. Additional carbon pricing scenarios are explored and outlined in **Chapter 3, Chapter 4,** and **Chapter 5.**

2.2.3. CO_2 storage and transportation costs

The IPCC Fifth Assessment Report [51] assumes 10 US/t CO_2 for transport, long-term storage, and long-term measurement and monitoring of captured CO_2 but notes costs are unlikely to exceed 15 USD/t CO_2, with some estimates below 5 US/t CO_2. Geographic region, geological formations, available transportation methods, transport distance, CO_2 output, and the regulation of transportation and storage infrastructure ultimately influence the cost. In a review of CO_2 transport and storage costs, Smith [52] observes onshore pipeline-based costs feasibly range from 4 to 45 US/t CO_2 in the United States, with a typical base case of 11.2 US/t CO_2 assuming 100 miles (161 kilometres) and permanent geological storage of 3.2 Mt CO_2 annually. For this study, the same rate of 11.2 US/t CO_2 (13.4 CAD/t CO_2) is assumed in all regions. To achieve the efficiencies of the 3.2 Mt CO_2 annual storage benchmark, Canada's cement plants will have to participate in a larger CCS infrastructure development with other emitters in the same geographic area.

2.2.4. Capital and non-energy operating costs

Capital and non-operating costs for technologies in each decarbonization scenario were gathered from the literature and are available in **Chapter 3, Chapter 4,** and **Chapter 5**. Annualized capital costs are calculated according to **Eq.(1)**:

$$ACC_t = CAP_t \times \frac{i}{1-(1+i)^{-LS_t}} \tag{1}$$

where CAP_t is the capital cost of technology t, r is the investment discount rate, and LS_t is the lifespan of technology t. An investment discount rate of 10% is used in this study. This rate matches the rates used in a previous study and falls within the 8-10% range found by Garcia and Berghout [53] for CCS technologies, and the 8-15% upper and lower bounds used by Dinga and Wen [54] for their carbon-neutral pathway analysis.

2.3. Abatement cost analysis

GHG emission abatement costs, also called marginal abatement costs (MACs), were calculated for each technology at a subnational level according to **Eq. (2)**,

$$MAC_s = \frac{NPV_s - NPV_{Ref}}{GHG_s - GHG_{Ref}} \tag{2}$$

where the numerator is the difference between the net present value (NPV) of the decarbonization scenario and the NPV of the reference scenario from 2020 to 2050, and the denominator is the difference in total GHG emissions between the decarbonization scenario and the reference scenario from 2020 to 2050. Discounted annualized capital costs, operating costs, energy costs, and carbon costs determine the NPV for each scenario. The resulting GHG abatement costs for each decarbonization scenario are then presented in terms of 2020 CAD per tonne of GHG emissions abated. **Eq. (3)** is used to calculate the NPV of the reference and decarbonization scenarios,

$$NPV_{Ref,s} = \sum_{n=2020}^{2050} \left(\frac{\sum_t (ACC_t + OC_t) \times PF_{t,n} + \sum_e (EC_{e,n} + CC_{e,n}) + PECC_n + TSM_n}{(1+d)^{n-2020}} \right) \qquad \textbf{(3)}$$

where ACC_t is the annualized capital cost per tonne of cement, OC_t is the operating cost per tonne of cement, PF_t is the penetration of the technology t in year n, $EC_{e,n}$ is the energy cost of energy e for the year n, $CC_{e,n}$ is the carbon cost of energy e for the year n, $PECC_n$ is the carbon cost associated with process emissions for year n, TSM_n is the cost of carbon transportation, storage and monitoring, and d is the NPV discount rate in %. All costs are in 2020 CAD, and a discount rate of 5% was used to represent the opportunity cost. The carbon cost of energy, the carbon cost of process emissions, and the carbon transportation, storage, and monitoring costs are determined by **Eq. (4)**, **Eq. (5)**, and **Eq. (6)**,

$$CC_{e,n} = CP_n \times \sum_e \left(E_{e,n} \times EF_{e,n} \right) \qquad \textbf{(4)}$$

$$PECC_n = CP_n \times (Prod_n \times PEF_n) \qquad \textbf{(5)}$$

$$TSM_n = 13.44 \times \left(GHG_{ref,n} - GHG_{s,n} \right) \qquad \textbf{(6)}$$

where CP_n is the carbon price in year n, $E_{e,n}$ is the energy consumed of type e in year n, $EF_{e,n}$ is the emissions factor for energy type e in year n, $Prod_n$ is the cement produced in year n, and PEF_n is the process emission factor in year n. The carbon is expressed in CAD per tonne of CO_2e, the energy consumed is expressed in GJ, the energy emissions factor is expressed in tonnes of CO_2e per GJ, cement production is expressed in tonnes, and the process emissions factor is expressed in tonnes of CO_2e per tonne of cement.

2.4. Market share analysis

For this study, a market share analysis was conducted for the fuel-switching and alternative binders and chemistries decarbonization categories. The technologies in these categories can be adopted simultaneously but are not mutually exclusive, meaning they compete with each other for market share. The technologies of the CCS decarbonization category are also not mutually exclusive but cannot be adopted simultaneously within a cement-producing facility, so a market share analysis was not pursued. Conversely, the technologies of the energy efficiency category are mutually exclusive, and the alternative raw materials category is simplified to one technology, so market share analysis is not applicable.

The market share analysis is conducted using the market sensitivity equation obtained from our colleagues Radpour et al. [55] and shown in **Eq. (7),**

$$MS_t = \frac{(ACC_t + OC_t + EC_t + CC_t)^{-v}}{\sum_{k=1}^{K}(ACC_t + OC_t + EC_t + CC_t)^{-v}} \tag{7}$$

where MS_t is the market share of technology t, ACC_t is the annualized capital cost, OC_t is the non-operating cost, EC_t *is* the energy cost, CC_t is the carbon cost, and K represents the number of technologies vying for market share. The cost sensitivity variable, v, dictates how sensitive the market is to costs, as described by Nyboer [56]. A low cost sensitivity variable indicates a low sensitivity to cost while a high cost variable indicates a high sensitivity to cost. This study explores a range of cost sensitivity variables (v = 2, 6, and 10) to better understand potential market share outcomes. The market shares determined by **Eq. (7)** are subject to the s-curve adoption profile and penetration factors described for each decarbonization category described in **Chapter 3, Chapter 4,** and **Chapter 5.**

Chapter 3. Assessment of fuel-switching as a decarbonization strategy in the cement sector

3.1. Background

Thermal energy production in the global cement sector is dominated by fossil fuels. The International Energy Agency estimates that more than 92% of thermal energy for cement was from the combustion of fossil fuels in 2020 [16]. China's cement sector, which is responsible for 55-56% of global cement production, received 87-89% of its thermal energy from coal between 2005 and 2009 [14]. Similarly, India, the second-largest producer of cement with 7-8% of global production, predominantly uses coal for thermal energy [15]. The remainder of global thermal energy demand for the sector is typically met by non-renewable wastes, and bio-energy and renewable wastes.

Cement production is a multi-step process. After raw materials such as limestone, clay, and sand are delivered to the cement plant, they are mixed with additional minerals and finely ground to produce a homogenous mixture, often referred to as raw meal [3]. The heated raw meal then enters the preheaters, where hot gases from the precalciner and kiln heat it to nearly 900ºC. Next, the raw meal enters the precalciner, where most of the calcination process occurs. During calcination, the intense heat causes the limestone in the raw meal to decompose into lime (calcium oxide) and carbon dioxide (CO_2). These CO_2 emissions are referred to as process emissions and, according to the International Energy Agency and World Business Council for Sustainable Development, represent 60-70% [3] of all GHG emissions during cement production. The remaining GHG emissions come from the combustion of fossil fuels on-site or GHG emissions released during the production of electricity off-site. The meal then enters the kiln, where it reaches temperatures exceeding 1400ºC. In the kiln any remaining limestone undergoes calcination and the meal is transformed into clinker, the primary ingredient in cement. The clinker is then cooled, blended with other materials, and packaged as the final cement product.

Energy efficiency has long been an area of interest in the industry. Reducing energy consumption reduces energy costs and has the side effect of reducing GHG emissions associated with energy use. This is especially important in the cement sector, where energy costs typically account for 20-40% of operating costs [29]. However, the 21st Conference of the Parties (COP) in Paris in 2015 [57] marked a fundamental shift in the perspective of global industry. GHG emissions reduction, not just energy efficiency, became a primary objective of government and industry alike. The introduction of carbon pricing or tax incentives in many regions also introduced a financial benefit for reducing GHG emissions. Today, the cement sector has identified several means of decarbonizing apart from energy-efficiency improvements. These include fuel switching (FS) to reduce on-site combustion GHG emissions, alternative cement binders and chemistries and decarbonated raw materials to reduce process GHG emissions, carbon capture and storage to nearly eliminate exhaust GHG emissions, decarbonizing electricity, and considering carbonation, whereby concrete continues to absorb CO_2 throughout its life cycle.

Fuel combusted to produce thermal energy accounts for 30-40% of the cement sector's GHG emissions [3]. Therefore, switching to lower carbon fuels presents a significant opportunity to reduce the sector's GHG emissions. Alternative fuels, such as waste fuels and biomass, have established roots within the sector, especially in Europe, where they accounted for 46% of thermal energy needs in 2017 [8]. In North America, natural gas is discussed in a Global Efficiency Intelligence report as a means of immediately reducing GHG emissions [58] because it has a much lower carbon content than other fossil fuels typically used by the sector. More recently, a Government of Canda report of a hydrogen economy [59] introduced hydrogen as a potential no-carbon fuel for many global sectors. Similarly, in jurisdictions with lower carbon electrical grids, electrification of thermal energy is being considered as a way to significantly reduce, if not eliminate, GHG emissions [60].

Alternative fuels refer to waste and by-products from other industrial or agricultural processes that replace conventional fuels in the cement kiln through coprocessing [61, 62], for example, sewage sludge and solid waste from municipalities, solvents and plastics from chemical industries, moulding, paint residues, oil residues and used tires from the automotive industry, agricultural biomass, and wood waste. Alternative fuels are not equal in their GHG emission impacts. Petroleum-based alternative fuels such as tires, oil residues, and plastics have a typical net-negative impact of -0.5 to -1.0 tonnes of CO_2 per tonne of coal replaced, while non-agricultural biomass (such as sewage sludge) and agricultural biomass have typical net-negative impacts of -2.5 tonnes of CO_2 per tonne of coal replaced [61]. Yet, regardless of the alternative fuel, the result is still net-negative emissions compared to coal, meaning co-processing of alternative fuels continues to warrant consideration as a decarbonization measure for cement. While the European Cement

Association maintains there are no technical impediments to obtaining 90-100% of thermal energy from alternative fuels [8], local availability, the presence of trace elements [63] and heavy metals, chlorine content, sulphur content, polychlorinated biphenyl (PCB) content, moisture content, physical size, and calorific value all influence the viability of using alternative fuels to replace conventional fuels [49, 61]. Nevertheless, in 2019, members of the European Cement Association derived, on average, 48% of thermal energy from alternative fuels [64], with the Netherlands exceeding 80% over a decade ago [49] and specific European plants claiming 100% alternative fuel mixes [8]. Globally, alternative fuel adoption is lower than in Europe, with North America, India, the Middle East, and Asia deriving 15%, 4%, 13%, and 11% of thermal energy from alternative fuels, respectively [64].

For jurisdictions where high carbon fuels such as coal and petroleum coke dominate the fuel mix, transitioning to natural gas can provide immediate GHG emissions reductions of up to 50%, based on US Environmental Protection Agency emissions factors [65]. Hydrogen, with no carbon dioxide emissions, also presents an opportunity to reduce the sector's GHG emissions. The hydrogen economy is an emerging market with the potential to greatly reduce or eliminate combustion GHG emissions from many sectors, including cement. Rissman et al. [66] identify hydrogen as a measure that can help the industry achieve net-zero emissions, assuming policy to support its development is put in place. Canada is just one country already promoting hydrogen as a means of achieving net-zero emission [59], suggesting the requisite policy is now being discussed. Hydrogen has also been identified by cement sector industry organizations in Europe [8] and the United States [9] and demonstrated by at least one major cement producer [67]. However, hydrogen production, supply, and storage networks are still being established, new burner and kiln designs will be necessary to accommodate high percentages of hydrogen fuel, and hydrogen is expected to be in demand in many industries, so widespread penetration of hydrogen in the cement sector is likely far off [68]. According to the International Energy Agency's net-zero roadmap, 5% of the global cement sector's thermal energy requirements will be met by hydrogen in 2030 [16] and increase to 10% by the 2040s [69]. The roadmap also recognizes that hydrogen–natural gas blends (also known as hythane) offer nearer-term GHG emission reduction. Davis et al. [43] found that hythane blends have the potential to reduce GHG emissions. Others have found that blends of up to 15% hydrogen are possible without impacts on existing appliances and delivery infrastructure [70].

The electrification of process heat is another way to transform the cement sector, assuming low- or zero-carbon electricity is available. CemZero, a feasibility study funded by the Swedish Energy Agency to explore the electrification of the cement sector, identifies plasma generators, electric flow heaters, electric resistance heating, and microwave heating as potential methods for electrifying process heat [71]. The study selected plasma generators as a promising technology for electrifying cement production because the precalciner/kiln systems used widely across the globe can be retrofitted to accommodate the generators. Other electrification technologies require complete system redesigns or rebuilds. Plasma generators use an electric arc to heat a carrier gas and transform it into plasma as it leaves the generator. The plasma exits the generator at 3000-5000ºC, well above the temperature at which clinker is produced in conventional kilns. To ensure reliable clinker production, it is necessary to use recycled process gases to control the kiln outlet temperature and maintain outlet temperatures around 1400ºC. Plasma generators also produce a nearly pure stream of carbon dioxide emissions that can be captured at the flue and recycled as carrier gas, or transported for storage. While plasma generators have matured in other applications, they have only been tested in laboratory settings for cement production and must be scaled up to meet production quantities the industry expects. Other barriers to using plasma generators in cement production include the need for an air-tight system if carbon dioxide is used as the carrier gas, a better understanding of heat transfer from plasma within rotary kilns, potential clinker chemical composition issues due to the high concentration of carbon dioxide in the kiln, and lack of chemical input from conventional and alternative fuel ash. Heidelberg Materials is studying these barriers in several ongoing research projects, with the results of these studies expected in 2025 [72]. Mineral Products Association et al. [73] and Parra et al. [74] have also explored electrifying cement production using computational fluid dynamics and process modeling software, respectively. Both agree the use of plasma generators is possible, but further testing and scaled-up demonstration is necessary to maintain operational performance and reliability.

Publications on the decarbonization of the cement sector can be classified as peer-reviewed academic studies, white papers (also known as gray literature) from industry, and industry roadmaps. Of these, roadmaps offer the least detail but provide a high-level understanding of the decarbonization pathways being pursued by the sector and are usually created or commissioned by government or an industry organization. For example, the Global Cement and Concrete Association offers a net-zero emissions roadmap from a global perspective [75] while regional cement associations, including those in Australia [10], Europe [8], the United Kingdom [11], the United States [9], and Canada [76], explore pathways specific to their respective markets. In these roadmaps, FS primarily involves the replacement of traditional fossil fuels with alternative biomass or waste-derived fuels, although Australia [10], the United Kingdom [28], and Europe [8] suggest hydrogen could be used to meet a fraction of thermal energy needs. An earlier study for the United Kingdom's cement sector used computational fluid dynamics to propose a zero-carbon fuel mix including biomass and hydrogen [73]. In jurisdictions where low-carbon electricity is available, such as Sweden, the feasibility of electrifying thermal energy has been explored [71] and potential net-zero emissions scenarios involving electrification discussed [60]. In the United States, where fossil fuels are more abundant, natural gas is identified as an immediate lower carbon alternative to coal and petroleum coke [9]. The International Energy Agency suggests that for the sector to reach net zero, natural gas will account for 40% of the sector's thermal energy demands on a global level [69]. However, only some roadmaps quantify the anticipated GHG mitigation impacts of fuel-switching. The European and United Kingdom roadmaps indicate FS will be responsible for 13% [8] and 16% [28] of GHG reductions necessary to reach net zero, while all other national-level roadmaps either present the combined impacts of multiple pathways or are ambiguous. A California (United States) roadmap also suggested 14% of current GHG emissions could be mitigated through FS in that state [58].

A search of peer-reviewed academic literature identified two types of research publications related to reducing GHG emissions in the cement sector: (1) technology reviews that discuss the applicability, application, cost, energy, and GHG impacts of individual technologies and (2) bottom-up technology models that investigate the specific cost, energy, or GHG impacts of individual technologies over a set time frame. Technology reviews can further be subcategorized into reviews that focus on technologies from two or more decarbonization pathways and those that solely focus on one or more FS technologies. The most comprehensive decarbonization pathway technology review was published by the European Cement Research Academy [30]. It is comprised of seven high-level discussion papers on state-of-the-art technologies in the cement sector, followed by fifty-two technology papers that cover nearly all the core pathways identified in industry net-zero roadmaps. Specific to FS technologies, the European Cement Research Academy suggests up to 70% of fuel needs may be met by alternative fuels (biomass and waste-derived) by 2050 in developed countries, although biomass is not expected to exceed 40% of fuel requirements by itself because of supply limitations. A transition to 65% alternative fuels (consisting of up to 40% biomass) could result in a 6% decrease in direct GHG emissions per tonne of clinker produced. However, the potential of hydrogen fuel and the electrification of thermal energy is not discussed. Other technology reviews covering multiple decarbonization pathways present similar gaps. Worrell et al. [29] present twelve categories of efficiency measures and over fifty individual technologies, but only three of those are FS technologies. Further to that, the technologies are presented in the light of energy consumption impacts and there is very little discussion about GHG emission impacts. This highlights the focus existing literature has placed on energy efficiency, which is only one decarbonization pathway. Other publications discuss FS opportunities at a high level [77] or within the broader context of sustainable industry [78], but again, there is little detailed discussion around GHG emission impacts.

However, technology reviews that focus solely on FS technologies begin to shift the focus toward GHG emissions. Murray and Price [61] discuss the per unit energy and GHG impacts of various alternative fuels (including biomass and waste-derived fuels) in detail. They also present potential substitution rates and the feasibility of each fuel based on a set of co-processing guidelines. Rahman et al. [49] also present and discuss the availability, substitution rates, emissions factors, and potential concerns with the use of a variety of alternative fuels in the cement sector. Other studies take a more targeted approach and evaluate life cycle GHG emissions from one or more select alternative fuels co-processed in the cement sector. Bourtsalas et al. [79] evaluate non-recycled plastics and paper, Georgiopoulou and Lyberatos [62] evaluate used tires, waste-derived fuel, and biological sludge, Ayer and Dias [80] evaluate bio-oil and bio-char, and Zhang and Maybee [81] evaluate wood waste, asphalt shingles, railway ties, and plastics. Each study concluded that the alternative fuels analyzed resulted in reduced GHG emissions over the life cycle of the fuel compared to conventional fossil fuels used in the cement sector. However, it becomes clear that FS technology reviews are nearly solely focused on alternative fuels, and there is a knowledge gap in directly comparing FS technologies outside of alternative fuels.

The second type of research publication, bottom-up technology models, has similar gaps when it comes to directly comparing multiple fuels. Morrow et al. [82], Talaei et al. [83], Hasanbeigi et al. [84], and Dinga and Wen [54] consider only alternative fuels as a means of energy and GHG emission reduction. This highlights a shared characteristic of these studies: they tend to simplify and generalize many decarbonization pathways to a single demonstrative technology if they are included at all. In some of these studies, the alternative fuel used is left ambiguous, or a long list of potential alternative fuels is shown, but the life cycle differences between them are ignored. Two bottom-up technology models exploring decarbonization pathways acknowledge but explicitly exclude FS technologies [26, 85]. In the studies that do include alternative fuels, all of them found that using alternative fuels reduces GHG emissions. The total reduction varies, depending on the jurisdiction, the penetration rates, and the assumed applicability of the measure. One paper presented its results in a similar manner to industry roadmaps, suggesting that 15.8% of CO_2e emissions could be avoided through the use of alternative fuels [54]. This is in line with the reductions touted by the United Kingdom [11], European [8] and Californian (United States) [58] roadmaps.

3.2. Capital and non-energy operating costs

A range of capital costs for each technology was gathered from published sources and annualized according to **Eq. (1)**. The high and low ends of the cost range were then averaged to determine the capital cost used in the model. Capital costs for switching to natural gas, biomass, and MWS were derived from the European Cement Research Academy [30]. The capital cost of switching to hythane was assumed to be the same as switching to natural gas. A feasibility study for fuel-switching in the UK [73] provided the cost of a new kiln and burner to support hydrogen. Additional infrastructure costs such as piping, instrumentation, storage, and handling were estimated based on the natural gas and similar fuel-switching options explored by the European Cement Research Academy [30]. Capital costs associated with electrification were obtained from Wilhelmsson et al. [71]. Non-energy operating costs were assumed to be 4.5% of the capital costs, covering insurance, administrative, and maintenance costs over the life of the equipment supporting each technology. **Table 3** outlines the capital costs, non-energy operating costs, and lifespan of the FS technologies chosen. The lifespan of a dry kiln is typically around 40 years [69], so this was the value used for natural gas and hythane as they do not require any significant operational changes, just potentially some infrastructure changes, such as a larger gas service. The lifespans for biomass and MSW were assumed to be thirty years because they require storage and transportation equipment to move the fuel to the precalciner/kiln. Electrification of thermal energy and hydrogen was assumed to have a lower, twenty-five-year life because the technology is not yet commercially available and the life of the technology cannot be completely known unless implemented for a long period.

Table 3. Capital costs, non-energy operating costs, and lifespan of each FS technology

FS technologies	Capital costs (CAD/tonne cement)	Non-energy operating costs (CAD/tonne cement)	Lifespan (Years)
NG - Natural gas	3.46	0.16	40
BIO – Biomass	6.91	0.31	30
MSW – Municipal solid waste	6.91	0.31	30
HYD - Hydrogen	6.91	0.31	25
ELC - Electrification	143.34	6.45	25
HYT - Hythane	3.46	0.16	40

3.3. Fuel-switching scenario creation and assumptions

Six FS technologies (natural gas, biomass, MSW, hydrogen, electrification, and hythane) were selected to be analyzed according to the scenarios outlined in **Table 4**. A reference scenario was created to establish a baseline against which all other scenarios were evaluated. The reference scenario assumes the regional energy mixes do not change past 2019, the last year energy mix information was available.

Natural gas, MSW, and biomass are assumed to be available from 2020 onwards. However, because of the heterogeneous composition of MSW and concerns around potential impacts to clinker quality [49], MSW will be phased in as a replacement to the current alternative fuel mix over the study period. Hythane is assumed to be available from 2030, allowing more than 5 years for standards, governance, infrastructure, and supply chains to be established around natural gas / hydrogen blending, similar to the approach taken by Davis et al. [43]. In line with the International Energy Agency's Net Zero by 2050 report [69], the electrification of thermal energy is assumed to be available from 2040 onwards. Currently, kiln electrification is at the feasibility assessment and prototype stage. The International Energy Agency also assumes hydrogen does not meet thermal energy needs until the 2040s, although some blending with natural gas begins earlier [69].

Redesign and the kiln burners to support hydrogen fuel may also be necessary [68], therefore this study assumes hydrogen kilns do not start penetrating the market until the 2040s.

Low, medium, and high penetration scenarios were created for each technology to understand the impact of different penetrations by 2050. Biomass and MSW have high penetration scenarios capped at 65% because that is the share of thermal energy consumed in the precalciner [30]. It is assumed that biomass and MSW will only be consumed in the precalciner because they are likely to have a lower calorific value than what is necessary to achieve the higher sintering temperatures necessary in the kiln. This presents an opportunity to pair biomass and MSW technologies with another technology to be used in the kiln. The multi-technology scenarios identified in Table 4 were informed by the results of the marginal abatement cost (MAC) and market share results. The specific energy consumption impacts of the multi-technology scenarios are derived from the energy impacts of the individual technologies.

An s-curve adoption profile was used to illustrate the adoption of each technology to its target penetration over the period specified in **Table 4**. The s-curve simulates an initially slow uptake, followed by a steady transition, and finally slow adoption by the laggards. The fuel mixes for each scenario are designed to accommodate the adoption of the FS technologies by reducing the shares of the other fuels in equal proportion to maintain the same overall energy demand. For example, the adoption of natural gas decreases the shares of coal, petroleum coke, and fuel oils, but does not change the share of electricity used by non-thermal processes in the plant. It also does not change the share of alternative fuels if they are being used, given that it has been shown that there are low-carbon alternative fuel options available that perform better than natural gas. However, for electrification and hydrogen scenarios the shares of all the other fuels, including alternative fuels, are reduced in proportion to the adoption of electricity or hydrogen because these are lower carbon technologies.

Table 4. Scenario descriptions

Scenario name	Description	Penetration by 2050 (% of thermal energy from scenario fuel) Low	Med	High	Specific energy consumption impacts Demand tree branch(es)	Energy Type	GJ/t cement
1. Individual Scenarios							
NG – Natural gas	Transition to higher shares of natural gas for thermal energy generation between 2020 and 2050. Current penetration of natural gas in cement-producing regions ranges from 0% to 93%.	40%	70%	100%	Precalciner/ kiln	Fuel	±0.000 [30]
MSW – Municipal solid waste	Transition to higher shares of municipal solid waste for thermal energy generation in the precalciner between 2020 and 2050. This alternative fuel mix is assumed to have 30% organic material. Petroleum and wood wastes currently account for 3-20% of thermal energy. MSW is assumed to have 0% penetration currently.	25%	45%	65%	Fuel prep & handling Precalciner/ kiln	Electricity Fuel	+0.009 [30, 83] +0.172 [30, 83]
BIO – Biomass	Biomass as an energy source is considered nearly carbon neutral. Transition to torrefied biomass for thermal energy generation between 2020 and 2050. Current penetration is 0%.	25%	45%	65%	Fuel prep & handling Precalciner/ kiln	Electricity Fuel	+0.009 [30] +0.258 [30]
HYD – Hydrogen	Transition to hydrogen for thermal energy generation between 2040 and 2050. This assumes the design and installation of new kiln technology as necessary.	10%	50%	100%	Precalciner/ kiln	Fuel	±0.000
ELC – Electrification	Electrification of thermal energy between 2040 and 2050. This assumes the use of a plasma kiln and direct air separation precalciner technology. Electricity is considered a fuel in this scenario.	10%	50%	100%	Precalciner/ kiln	Fuel	+0.900 [71]
HYT – Hythane	Transition to hydrogen-natural gas blend (15% hydrogen, 85% natural gas by volume) known as hythane for thermal energy generation between 2030 and 2050.	40%	70%	100%	Precalciner/ kiln	Fuel	±0.000
2. Multi-technology Scenarios							

Scenario name	Description	Penetration by 2050 (% of thermal energy from scenario fuel) Low	Med	High	Specific energy consumption impacts Demand tree branch(es)	Energy Type	GJ/t cement
HYT + ALT BIO	Transition to 65% torrefied biomass for thermal energy generation between 2020 and 2050, with the remainder being a 15% hythane blend adopted from 2030 to 2050.	-	-	100%	Fuel prep & handling	Electricity	+0.009
					Precalciner/ kiln	Fuel	+0.258
HYT + ALT MSW	Transition to 65% municipal solid waste for thermal energy generation between 2020 and 2050, with the remainder being a 15% hythane blend adopted from 2030 to 2050.	-	-	100%	Fuel prep & handling	Electricity	+0.009
					Precalciner/ kiln	Fuel	+0.172
Market share High sensitivity to cost ($v = 10$)	Transition to a combination of municipal solid waste (64-65%), natural gas (1-8%) ,and hythane blend (1-9%) by 2050, with the remainder (20-33%) as the reference fuel mix, according to market share analysis results for each region. Hythane is not available before 2030.	-	-	100%	Fuel prep & handling	Electricity	+0.009
					Precalciner/ kiln	Fuel	+0.111
Market share Moderate sensitivity to cost ($v = 6$)	Transition to a combination of biomass (2%), municipal solid waste (62-63%), natural gas (3-10%), and hythane blend (1-7%) by 2050, with the remainder (17-29%) as the reference fuel mix, according to market share analysis results for each region. Hythane is not available before 2030.	-	-	100%	Fuel prep & handling	Electricity	+0.009
					Precalciner/ kiln	Fuel	+0.115 - +0.118
Market share Low sensitivity to cost ($v = 2$)	Transition to a combination of biomass (15%), municipal solid waste (49-50%), natural gas (9-15%), and hythane blend (8-11%) by 2050 ,with the remainder (13-18%) as the reference fuel mix, according to market share analysis results for each region. Hythane is not available before 2030.	-	-	100%	Fuel prep & handling	Electricity	+0.009
					Precalciner/ kiln	Fuel	+0.129

In determining the specific energy impacts of hydrogen and hythane, it was considered that on a per volume basis those fuels have less energy content than natural gas, meaning additional compression energy may be required to enhance volumetric flows [86]. However, the estimated compression energy per tonne of cement was found to be negligible.

MSW and biomass were selected as alternative fuels for this study because of their comparatively low emission factors compared to other alternative fuels. Environment and Climate Change Canada's published emission factors for alternative fuels currently used in the cement sector [23] show a 100-year global warming potential of 0.083 TCO_2e/GJ, only slightly less than coal at 0.093 TCO_2e/GJ. This slight difference is because reported alternative fuels in the sector are typically petroleum products such as used tires, waste oils, and waste solvents. However, studies estimate MSW to have a carbon content of 0.26 [61] to 0.48 [79] tonnes of carbon per tonne of MSW. For this study a carbon content of 0.32 tonnes of carbon per tonne of MSW was chosen, which translates to a 100-year global warming potential of 0.033 TCO_2e/GJ, assuming similar methane and nitrous oxide emissions to those published by Environment and Climate Change Canada for alternative fuels. Biomass has a 100-year global warming potential of 0.002 TCO_2e/GJ using IPCC emissions factors built into the LEAP-Canada model.

In 2016, Canadians produced 34 Mt of MSW. Just over one-quarter of that was diverted to recycling and composting facilities, 60% was disposed of in landfills, 11% was exported, and 2.5% was incinerated, primarily to produce energy [87]. MSW has a calorific value of 8-14 GJ/tonne, generally less than the 13 GJ/tonne required by the precalciner and much less than the 20-22 GJ/tonne required by the kiln [30]. However, the drying and grinding of MSW can raise its calorific value, at least so it is sufficient for the precalciner. Furthermore, at a calorific value of 13 GJ/tonne, Canada's MSW disposed of in landfills or exported has the potential to supply up to 313 GJ of fuel energy, significantly more than the 57 GJ the Canadian cement sector consumed in 2019. In addition to MSW, Canada is estimated to produce approximately 88 Mt of biomass from agricultural crop residues annually [88]. Canada also produced 4.5 Mt of wood pellets in 2019, although 99% of that was exported [48]. At a calorific value of 13 GJ/tonne, agricultural crop residues have the potential to supply up to 1,144 PJ of thermal energy, far exceeding the total fuel energy used by the cement sector.

This study assumes an adequate supply of hydrogen, electricity, and natural gas to cement-producing facilities to meet the penetration parameters.

3.4. Scenario results

3.4.1. Individual scenarios

The high penetration biomass scenario offers an 18% reduction (60 Mt) in cumulative indirect and combustion GHG emissions from 2020 to 2050 compared to the reference scenario, followed by hydrogen, MSW, electrification, natural gas, and hythane at 10% (35 Mt), 9% (32 Mt), 9% (31 Mt), 8% (29 Mt), and 7% (22 Mt). However, in the year 2050 the high penetration hydrogen scenario offers the largest reduction in direct combustion and indirect GHG emissions at 98% less than the reference scenario (**Figure 5**) because hydrogen is a zero-carbon fuel within the boundaries of this study, and the electrical grid carbon intensity is expected to decrease from 2020 to 2050 in every jurisdiction. The remaining emissions in 2050 are indirect emissions from grid electricity. Electrification, biomass, MSW, hythane, and natural gas high penetration scenarios offer 88%, 62%, 39%, 30%, and 30% GHG emission reductions in 2050, respectively. The discrepancy between the cumulative and year 2050 results is due to the differing penetration profiles of the technologies in the sector. Because hythane is not available until 2030, and electrification and hydrogen until 2040, these technologies have a shorter period during which GHG abatement occurs. These results highlight the competing demands faced by the cement sector: immediate GHG reductions and achieving net zero in the long term. The high GHG reduction potential of transformational fuel-switching, such as hydrogen and electrification, gets the industry closer to net-zero emissions from on-site fuel combustion than the other scenarios but does not offer immediate GHG reductions.

In terms of total emissions (direct combustion emissions, indirect emissions, and process emissions), the high penetration scenarios range from reductions of 12% (natural gas) to 40% (hydrogen) in the year 2050, with an average value of 24%. This is higher than the findings presented by Dinga and Wen (16%) [54], Cembureau (13%) [8], and the Global Cement and Concrete Association (<9%) [75], although Dinga and Wen only analyze alternative fuels and this study assumes higher penetration ceilings for hydrogen and electrification than Cembureau and the Global Cement and Concrete Association. If the low penetration scenarios are assumed for hydrogen and electrification, and high penetration scenarios for the other scenarios, the total emissions are reduced by an average of 12%, in line with other roadmaps.

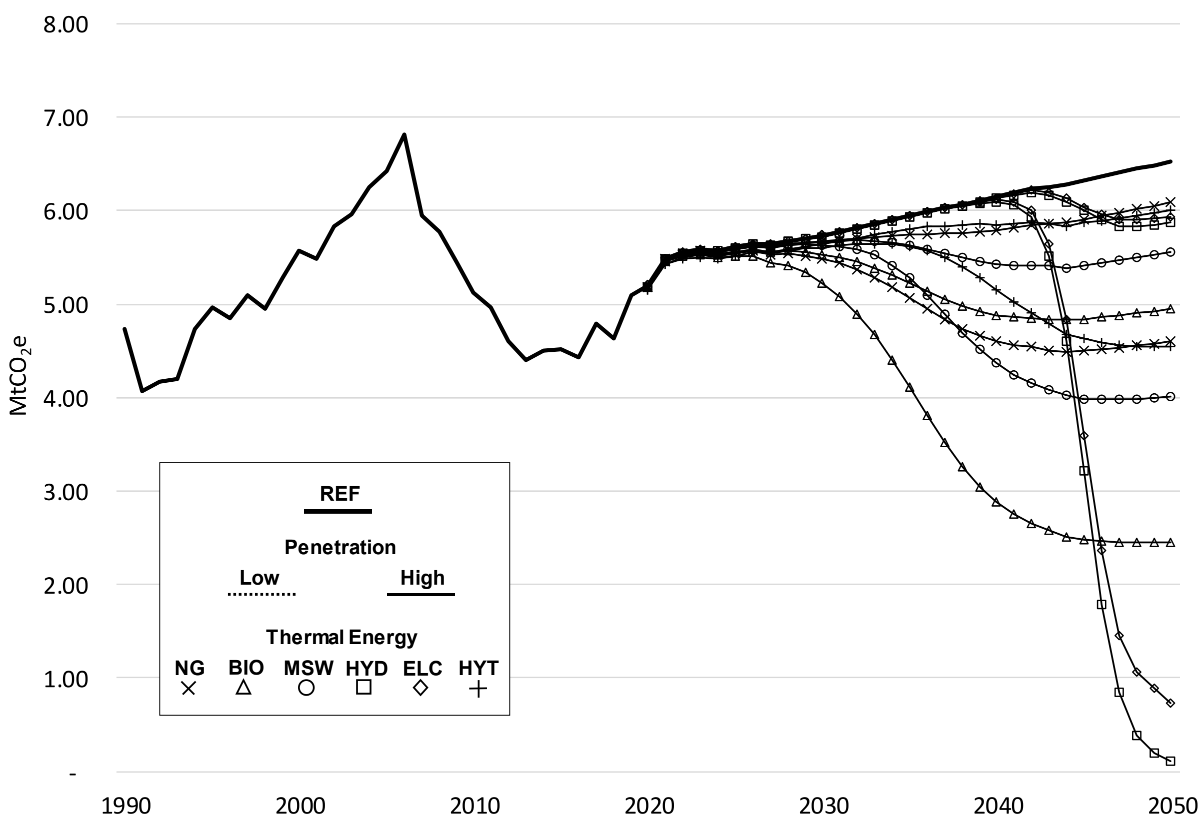

Figure 5. Scenario direct and indirect (electricity) GHG emission results for individual FS technology scenarios. Only high and low penetration scenarios are shown.

Since each cement-producing province is subject to different energy prices, different baseline fuel mixes, and different electrical grid carbon intensities over time, the MAC for each scenario differs by province. The Canada-wide MAC for each FS technology is shown in **Figure 6**, and provincial MAC figures are in **Appendix D – Hydrogen price calculation.**

All provinces exhibit a similar MAC curve in that the MSW and biomass scenarios have a negative MAC, while most other FS technologies generally result in a positive MAC. A negative MAC indicates money will be saved (per tonne of GHG emissions abated while using the technology), whereas a positive MAC indicates it will cost money (per tonne of GHG emissions abated). Furthermore, the penetration (low, medium, or high) of the technology has little impact for low-cost fuel scenarios such as MSW and biomass and an increasing impact with higher cost fuels. Across all the provinces, electrification and hydrogen result in the highest MACs of all the scenarios primarily because of their higher energy costs compared to other technologies. However, relatively high capital costs and indirect emissions also contribute to this. Furthermore, electrolytic hydrogen has a higher MAC than ATR-CCS-produced hydrogen across all provinces. This is a result of the price of electrolytic hydrogen exceeding ATR-CCS produced hydrogen. Even Quebec, with the lowest cost electrolytic hydrogen in Canada, is still expected to benefit from cheaper hydrogen produced by ATR-CCS in Alberta.

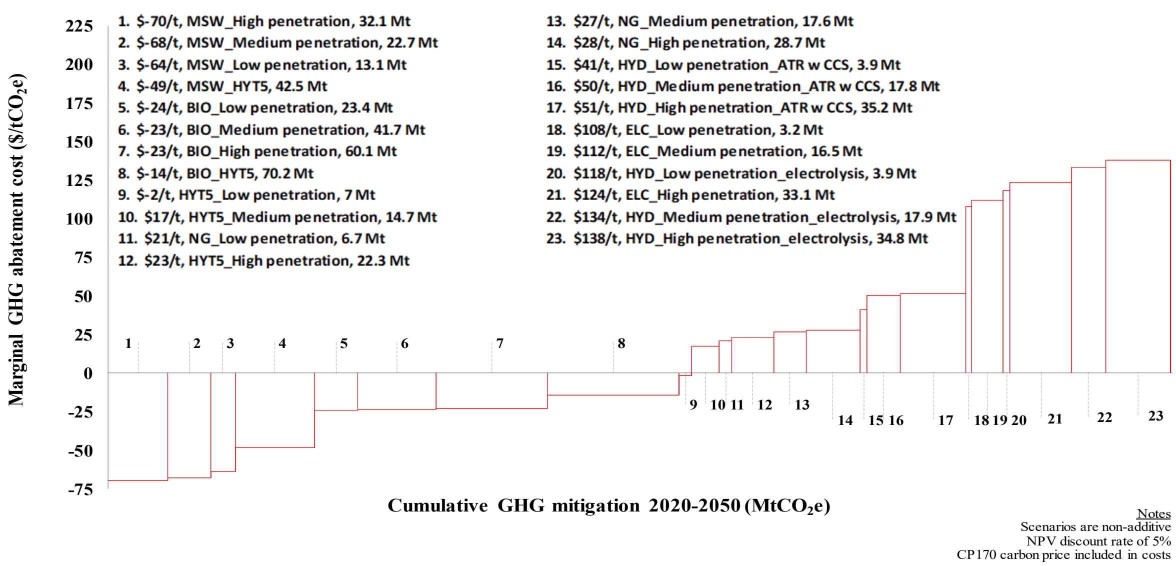

Figure 6. MACs for each FS technology in Canada

3.4.2. Multi-technology scenarios

Biomass and MSW are the two FS technologies with the lowest MACs. However, these technologies are generally limited to use in the precalciner because of their lower calorific values [30]. Therefore, it is important to consider how the thermal energy requirements of the kiln can be met with lower carbon fuels when using biomass and MSW in the precalciner. In this study, combined biomass-hythane and MSW-hythane scenarios were evaluated, in which biomass and MSW are used in the precalciner and hythane in the kiln. Hythane was chosen because of its similar MAC to natural gas, its lower combustion-related emissions compared to natural gas, its lower carbon content compared to other traditional fuels that meet the calorific requirements of the kiln, and its generally high readiness level assuming an adequate supply of hydrogen. The hydrogen used to create the blended hythane is assumed to come from the lowest cost source in Canada. In this study, British Columbia and Alberta produce hydrogen with ATR-CCS, while the remaining regions import hydrogen from Alberta.

The biomass-hythane scenario offers a 76% reduction in direct combustion and indirect GHG emissions in the year 2050, an increase of 14% over the biomass-only scenario (Figure 7). Similarly, the MSW-hythane scenario offers at least a 13% increase in GHG emission reduction over the MSW only scenario. Therefore, it is clear that transitioning to hythane in the kiln from 2030 onwards will result in a 13% decrease in GHG reductions regardless of what fuel is used in the precalciner. When considering cumulative emissions from 2020 to 2050, the biomass-hythane scenario results in a 21% (70 Mt) decrease from the reference scenario, the highest of any scenario. MSW-hythane results in a 13% (43 Mt) decrease in GHG emissions from the reference scenario, the third highest of any scenario, behind the biomass-hythane and biomass high penetration scenarios.

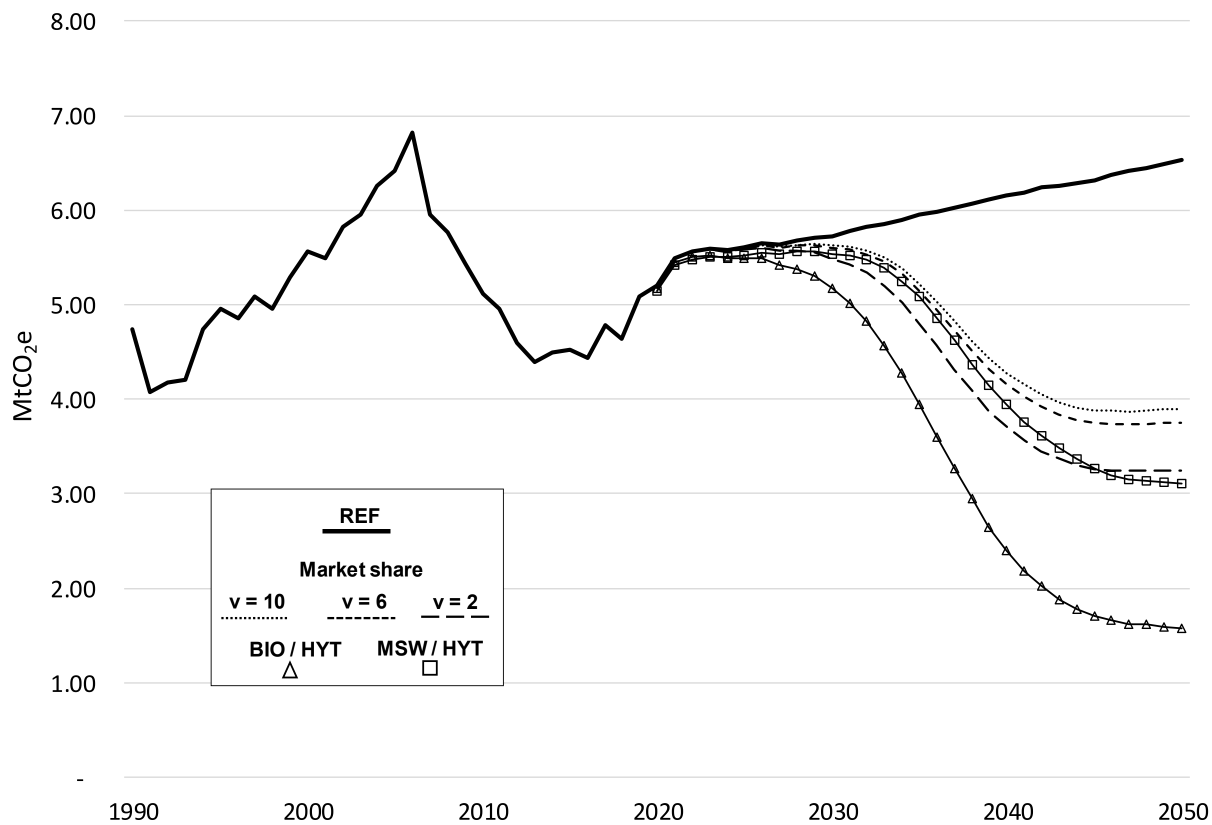

Figure 7. GHG emission results for hybrid FS technologies for low (v = 2), moderate (v = 6), and high (v = 10) market share cost sensitivity scenarios compared to the Reference scenario. High technology penetration scenarios only.

Applying **Eq. (7)** to the competing FS technologies and reference fuel mix reinforced that MSW is preferred by the market under every sensitivity scenario. Biomass claimed the second-largest share of the market, followed by natural gas hythane and the reference fuel mix with comparable but much lower shares and only in the low cost sensitivity ($v = 2$) scenario. After 2040, hydrogen and electrification claimed at most 5% and 1% of the market in the low cost sensitivity scenario and none of the market in the other scenarios. Considering these results, a second iteration of the market share scenarios was created without the electrification and hydrogen technologies. Furthermore, MSW and biomass were limited to 65% of thermal energy, the same as the individual and other combined scenarios. The resulting market shares are described in **Table 4** and Appendix

H – Additional scenario results, and the impact on GHG emissions in **Figure 7**. The market share scenarios are generally comparable to the MSW-hythane scenario because of the market preference to MSW. The low cost sensitivity scenario offers the largest cumulative and 2050 GHG emissions reductions because of the higher share of biomass adopted by that scenario. However, some of those gains are lost because of the reference fuel mix holding onto a larger share of the market than the lower cost sensitivity scenarios.

3.5. Sensitivity analysis

It is impossible to predict future energy prices. Geopolitical conflict, consumer demand, disruptive technology, and policy are among the factors that can influence energy prices. Therefore, as with all techno-economic modelling, the results of this research are tied to the specific future energy price predictions used and are subject to change. Similarly, government turnover at the federal (national) level and the influence of Canadians' willingness to pay may impact future carbon prices. For example, in the 2021 federal election, the four major political parties all proposed different carbon pricing schemes, and Benjamin et al. [89] found that political affiliation was statistically significant when estimating Canadians' willingness to pay. Therefore, this study performed an energy and carbon price sensitivity analysis to provide context on their impact on MAC and market share results.

Energy prices were modified by ±25% and ±50% from the baseline one at a time, with the exception of fuel oils because of their low use and MSW because of its assumed delivered cost of 0 CAD. Then MACs were recalculated for each high penetration scenario. Charts displaying the results for each energy price sensitivity case are in Appendix I – Fuel-switching sensitivity analysis results, and the Canada average results are discussed here.

Changes to coal and petroleum coke fuel prices impacted MACs in all scenarios because coal and petroleum coke are widely used across Canada, although the impacts were limited, with a high of -11/+10% for coal and -23/+21% for petroleum coke. This is largely because in each scenario these fuels are phased out over the study period. Conversely, price modification to fuels that are being phased in have much larger impacts on MACs. The Canada average MAC changed up to ±87% for biomass, ±63% for electricity, ±95% for hydrogen, and -170/+168% for natural gas price modifications. However, for each price modification, the biomass scenario still had a negative Canada-wide MAC and the hydrogen and electricity scenarios had a positive Canada-wide MAC.

At a price reduction of -25%, the MAC for the natural gas scenario becomes negative in all provinces except Ontario and Quebec, with a Canada-wide average of 4 CAD/tonne of GHG compared to 28 CAD/tonne of GHG in the reference scenario. These results demonstrate that the MACs of fuel-switching are sensitive to fuel costs. Therefore, price uncertainty is likely to deter the adoption of lower carbon fuels. Furthermore, the low capital and non-energy operating costs associated with switching to natural gas mean the MAC is more sensitive to fuel cost changes than other types of fuel-switching. While a decrease in natural gas prices can lead to superior payback, an increase will lead to comparable costs. This risk can only be mitigated through stable natural gas markets.

The impact of carbon cost on MACs was also evaluated (**Figure 8**). In the first sensitivity case (CP0), the carbon cost is completely removed, resulting in higher marginal abatement costs in all scenarios and only the MSW scenario having a negative MAC. At 50 CAD/tonne from 2022 onwards (CP50), the MSW scenario is still the only scenario with a negative MAC. In the third sensitivity case (CP350), the carbon costs increase to 350 CAD/tonne by 2030. Because of their relatively high capital and fuel costs, the Canada average for the electrolytic hydrogen, hydrogen from ATR-CCS and electrification scenarios are still positive with MACs of 58 CAD/tonne, 14 CAD/tonne and 51 CAD/tonne but are much closer to achieving cost savings. Furthermore, CP350 makes the natural gas and hythane scenarios cost effective. Low capital and non-energy operating costs mean the natural gas scenario MAC is more sensitive to carbon cost changes than the other scenarios.

(a) (b)

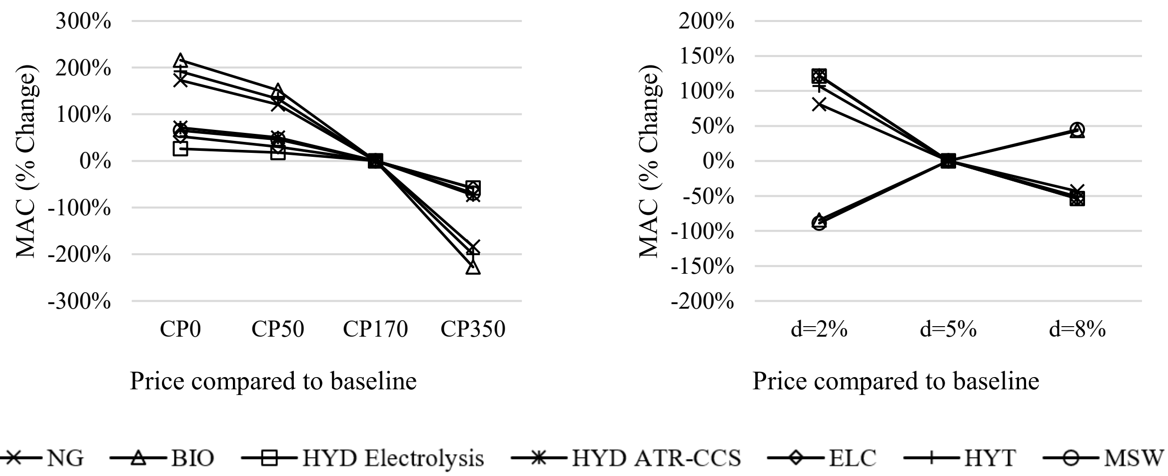

Figure 8. The impact of Canada's carbon price (a) and net present value discount rate (b) on fuel-switching marginal abatement costs

Finally, the discount rate used to calculate NPVs and the subsequent MACs was varied by ±3% and the impact on MACs evaluated. **Eq. (3)** shows that the NPV and the discount rate have an inverse relationship. Thus, for a discount rate of 2%, the absolute value of the MACs increases from the baseline because the value of future costs and benefits is greater. Conversely, for a discount rate of 8%, the absolute value of the MACs decreases from the baseline. From this we can draw the conclusion that higher discount rates erode MACs, making technologies more comparable, whereas lower discount rates inflate MACs, highlighting differences in net costs and benefits.

3.6. Limitations and future work

The use of biomass fuels provided the largest cumulative GHG emissions reduction in each cement-producing province over the study period. However, biomass supply chains to large industrial users and operations that prepare the biomass so that it meets calorific requirements for the precalciner are not yet widely established. For cement producers to switch to biomass as a primary fuel would require stable, established supply chains that deliver a consistent product. Likewise, for cement producers to switch to hydrogen as a primary fuel, established, stable supply chains are required.

Additionally, the impact of each fuel on cement properties must be well understood and managed before any transformative fuel-switching can take place. The introduction, removal, increase, or decrease of minerals due to fuel-switching cannot impact the quality of the cement. Nor can fuel-switching lead to an unacceptable amount of heavy metals, PCBs, chlorine, dioxins, or furans that may pose immediate or long-term environmental hazards due to leaching. Therefore, further work on the impact of specific fuel mix changes is necessary at the plant level to determine which fuels are fine to use in what amounts during the production of specific cement products. This is especially true for MSW, whose content is likely to vary by region.

Finally, knowledge of specific plant raw material inputs, fuel mixes, production volumes, and decision-making would improve the model. For instance, the amount of carbonates in the raw material influences process emissions. In this study, a Canada-wide value provided by Environment and Climate Change Canada was used, but in reality, this value varies by plant. Similarly, provincial fuel mixes and production were estimated based on the available data, but those also differ by plant and their combination impacts direct combustion and indirect electricity emissions. Lastly, the actions of cement manufacturers are driven by more than GHG reductions and MAC curves. Many factors are difficult to include in a technology-explicit model, such as the influence of public perception, social impacts, and even the will of a single individual in the decision-making process. The potential impacts of these, and other possible decision drivers, could be better understood by surveying the manufacturers on these topics.

3.7. Policy implications

The results of this study emphasize the role that biomass and MSW can play in reducing cumulative GHG emissions from 2020 to 2050. However, stable supply chains have yet to be established in Canada for both of these in this use as fuels. Short-term policy decisions should establish the necessary regulations and empower suppliers and industry to establish these supply chains. Doing so would maximize cumulative GHG reductions and ensure the best available MACs for the fuels and necessary capital expenditures to support those fuels.

In the long term, both hydrogen and electrification offer the largest annual GHG emissions reductions when fully deployed. The continued development of the hydrogen sector and the continued pursuit of net-zero electricity [59, 90] in Canada can be buoyed by forward-thinking, long-term policy decisions geared at ensuring adequate supply and reducing prices.

Finally, carbon costs have the ability to eliminate or enhance fuel-switching profitability. Policymakers should consider the implications of carbon cost changes on technology adoption within the cement sector. Maintaining 50 CAD/tonne from 2022 onwards eliminates the cost savings of most fuel-switching technologies.

3.8. Conclusion

The objective of this study was to analyze the costs and benefits of alternative fuels and fuel-switching in the context of the Canadian cement sector. This was done by identifying alternative and low-carbon fuels, establishing baseline fuel mixes by region, modelling the energy demand and subsequent GHG emission impacts of fuel-switching, and analyzing the costs of fuel-switching at a regional level. Market shares and the impacts of energy and carbon prices on the results were also assessed. When all the potential low-carbon fuels were considered individually, biomass as an alternative fuel in the precalciner was found to provide the largest cumulative GHG emissions reduction at 18% less than reference from 2020 to 2050 with profitable MACs, ranging from -20 CAD/tonne of CO_2 to -34 CAD/tonne of CO_2 depending on the region in Canada. When combined with the burning of hythane fuel in the kiln, the biomass-hythane fuel mix results in a 21% reduction of GHG emissions over the study period, an increase over using biomass with MACs ranging from -9 CAD/tonne of CO_2 to -37 CAD/tonne of CO_2. MSW as an alternative fuel in the precalciner was also found to provide significant cumulative GHG emissions reductions from 2020 to 2050, both individually (9%) and when used in combination with hythane fuel (13%). MSW also resulted in the lowest (most profitable) MACs in most regions, ranging from -54 CAD/tonne of CO_2 to -170 CAD/tonne of CO_2, with a Canada-wide average of -64 CAD/tonne of CO_2 to -70 CAD/tonne of CO_2, depending on the level of penetration. Finally, a market share analysis was performed through life cycle costing. This analysis determined that MSW was preferred by the market, followed by biomass. However, since the study limited MSW and biomass to the precalciner, natural gas and hythane met the remaining market demand. Because of their high energy prices, and to a lesser extent their high capital costs, hydrogen and electrification were largely shut out of the market, even in the low cost-sensitive scenario.

Hydrogen and electrification, two low-carbon fuel options that require new kiln technologies and have high energy price and capital costs, provide cumulative combustion GHG reductions of 10% and 9%, respectively, over the study period. However, this is primarily due to their late deployment, as these technologies were assumed to be commercially unavailable until 2040. At full deployment, they offer the largest annual energy-related GHG emissions reductions of 98% and 89%, respectively, compared to a 76% reduction using the biomass-hythane fuel mix and 52% using the MSW-hythane fuel mix. This highlights the competing demands of immediate GHG reductions versus achieving net zero in the long term. However, the MACs of hydrogen and electrification are not as attractive as those of biomass and MSW. The MACs of electrolytic hydrogen range from +119 CAD/tonne of CO_2 to +242 CAD/tonne of CO_2, the MACs of ATR-CCS hydrogen range from +25 CAD/tonne of CO_2 to +89 CAD/tonne of CO_2, and the MACs of electrification range from +49 CAD/tonne of CO_2 to +212 CAD/tonne of CO_2 for high penetration scenarios, depending on the region and level of penetration.

This study compared six individual low-carbon fuels for the Canadian cement sector by jurisdiction. There are several viable decarbonization pathways involving alternative fuels and fuel-switching, decreasing the likelihood that regional limitations are a barrier to adopting meaningful solutions. Under high penetration scenarios, from 12% to 40% of total sector GHG emissions in the year 2050 can be eliminated, suggesting that with policies that promote zero- and low-carbon fuel, the sector can take significant steps towards net-zero emissions. Policymakers should strive to empower the sector and fuel suppliers to establish low-carbon fuel supply chains, for biomass and MSW in the short term and for hydrogen in the long term. Furthermore, reducing the cost of hydrogen and electricity would significantly improve their MACs, making them more competitive with the other FS technologies.

Chapter 4. Comparing carbon capture and storage technologies as a means of decarbonizing cement production

4.1. Background

Cement production is considered a hard-to-abate sector because of the large share of process emissions associated with calcination. While energy-efficiency improvements have the potential to decrease combustion and indirect GHG emissions, as demonstrated in an earlier study by Talaei et al. [83], they have no impact on process emissions. A previous study [91] also showed that fuel-switching has the potential to significantly reduce combustion GHG emissions. However, process GHG emissions remain unchanged except in limited circumstances where partially decarbonated raw materials with an integral fuel component are used, such as partially decarbonated calcareous oil shale [92]. Thus, the cement sector has identified other pathways to reduce process GHG emissions: alternative binders and cements, alternative raw materials, and carbon capture and storage (CCS). The alternative binders and cements and the alternative raw materials pathways generally refer to either decreasing the share of clinker in cement through increased use of binders instead of clinker or reducing the limestone content of the material feedstock by increasing the decarbonated raw materials. In both cases, the process GHG emissions associated with each unit of cement produced are decreased proportionally to the clinker or limestone displaced. However, there are limitations to reducing process GHG emissions as the properties of the concrete made with alternative cements must meet established regulatory requirements for their intended end use. Some cements have been proven with up to a 50% clinker reduction but only in certain applications [93]. Furthermore, there is currently no cost-effective alternative to traditional Portland cement clinker [93]. Given these limitations, post-combustion CCS will play a key role in lowering the GHG emissions from cement production to net zero.

At a fundamental level, CCS is the removal of carbon dioxide from exhaust gases before it enters the atmosphere [77]. The carbon dioxide is then typically compressed, transported, stored, used for another process, or a combination of these. Chemical absorption, physical adsorption, calcium looping (also called carbonate looping), oxyfuel, and membrane technologies are all types of CCS technologies at various levels of readiness for incorporation in cement production.

Since 2020, government and regional industry associations including those in Europe [8], the United Kingdom [11], the United States [9], Sweden [60], Australia [10], and Canada [76] have prepared or commissioned cement decarbonization roadmaps. Australia, Europe, and the United Kingdom offer quantitative projections on the impact of CCS, suggesting that 33%, 42%, and 61%, respectively, of current GHG emissions will be mitigated by CCS. Furthermore, the United Kingdom's roadmap describes CCS as the "most significant and technically disruptive investment in the roadmap" [11]. On a global level, the Global Cement and Concrete Association suggests 36% of current emissions will be mitigated by CCS by 2050 [75], while the International Energy Agency suggests a 55% GHG emissions reduction from CSS, relative to today's values, by 2050 [69]. It is important to note that many of these roadmaps combine the concrete and cement industries as they are very closely related. Doing so dilutes the impact of cement production-specific pathways, such as CCS, but only by small amounts. For example, in the European roadmap, there is a 6% difference between the cement-only (42%) and combined cement and concrete (36%) mitigation impacts of CCS.

In peer-reviewed studies, CCS is most often explored through technology reviews. Hasanbeigi et al. [92] and the European Cement Research Academy [30] reviewed a variety of CCS technologies including thermal energy impacts ranging from -0.2 to over 3 GJ/tonne of cement, direct CO_2 impacts ranging from -0.55 to -0.6 t CO_2/tonne of cement, indirect CO_2 impacts of up to 0.156 t CO_2/tonne of cement, and technology readiness ranging from research to demonstration. Hasanbeigi et al. [92] discuss both pre-combustion and post-combustion capture technologies. The European Cement Research Academy [30] concludes that post-combustion technologies are best suited for cement production because of the high share of process emissions. Hills et al. [94] provide this same information and introduce commentary on the complexity and time-until-availability of five CCS technologies. In each of these reviews, chemical absorption is noted as having the highest level of readiness, but the large energy requirements are a drawback. Similarly, physical adsorption has large energy requirements and large raw material requirements. Oxyfuel CCS is discussed as an attractive economic option, but the requirement of air-tight kilns and precalciners introduces a technical challenge. Finally, the European Cement Research Academy [30] predicts that CCS technologies will not be commercially available for cement production before 2030, based on current research, development, and demonstration.

Technology review studies are important because they advise on the unique impact each CCS technology can have on decarbonizing cement production; however, they lack the wholistic analysis that quantifies and compares the long-term impacts of the technology under a specific set of conditions. This can be addressed through bottom-up modelling of CO_2 reduction technologies. Typically, CO_2 reduction in cement production has focused on energy efficiency. For example, Ke et al. [14] and Hasanbeigi et al. [84] explore the adoption of various energy-efficiency technologies and the corresponding CO_2 mitigation potential in Chinese cement production. Talaei et al. [83] did the same for Canada. Recent work has started to include CCS. Li et al. [85] include an unspecified CCS technology in an array of energy-efficiency measures under various carbon pricing scenarios. Similarly, Dinga and Wen conclude unspecified CCS technologies will be responsible for 34.2% of CO_2 reductions in achieving net-zero emissions but at significant cost without carbon pricing incentives. In Swiss cement production, Zuberi and Patel [95] use cost-efficiency curves to demonstrate that a carbon price of 80 US/t CO_2 is necessary to make amine-based CCS economical, while Obrist et al. [26] observe that a mix of oxyfuel, amine-scrubbing, and chilled-ammonia process CCS is necessary for drastic CO_2 reduction but only becomes economical with at carbon price of 70 EUR/t CO_2 or greater.

4.2. Carbon capture scenario creation and assumptions

The six CCS technologies analyzed in this study are chemical absorption (amine scrubbing), physical adsorption (using calcium or magnesium silicates), full oxyfuel technology, partial oxyfuel technology, membrane absorption, and calcium looping. Organic-metal framework physical adsorption is not included because of the lack of energy impact and cost information in the literature. Similarly, the lack of cost data for direct separation CCS in the literature precluded it from this study.

It is assumed that no CCS technology will be commercially available before 2030, aligning with the assumptions of European [8] and global [75] roadmaps and the European Cement Research Academy [30]. Furthermore, it was considered that the technology readiness level of each CCS technology (**Table 5**) [96] and assumptions in Canada's roadmap [76] when deciding the first year of commercial availability for the scenarios in **Table 6**. Given that chemical absorption has the highest technological readiness level and is proven in the chemical and fossil fuel power industries [96], it was assumed that commercial availability in cement production in 2030. Physical absorption and oxyfuel technology were assumed to be commercially available from 2035 onwards. Calcium looping was assumed to be available from 2040 onwards, in line with Canada's roadmap, and membrane absorption was assumed to be unavailable until 2040 because of its current low technology readiness level.

Table 5. Technology readiness level and anticipated importance in achieving net-zero cement production for various CCS technologies

CCS technologies	Technology readiness level	Importance to achieving net-zero emissions
Chemical absorption	7 – Full capture	Very high
	8 – Partial capture	Moderate
Physical adsorption	6	Moderate
Oxyfuel technology	6	High
Membrane technology	4	Moderate
Calcium looping	7	Very high
Direct separation	6	Moderate

Table 6. CCS scenario descriptions and specific energy consumption impacts

		Specific energy consumption impacts			
Scenario name	**Description**	**Demand tree branch(es)**	**Energy type**	**Reported ranges (GJ/t cement)**	**Selected (GJ/t cement)**
1. Individual scenarios					
CHEM - Chemical absorption (amine scrubbing)	Retrofit existing cement plants with amine scrubbing technology starting in 2030.	Precalciner/kiln	Electricity Fuel	0.15-0.28 [30] 0.86-3.01 [30]	0.22 1.72
PHYS - Physical adsorption (mineral carbonation)	Retrofit existing cement plants with physical adsorption technology starting in 2035.	Precalciner/kiln	Electricity Fuel	0.93-2.17 [30] 2.19 [30]	1.55 1.97
MEMB - Membrane separation	Retrofit existing cement plants with membrane separation technology starting in 2040.	Precalciner/kiln	Electricity Fuel	0.00-0.93 [30] Unknown	0.93 0.00
CALC - Calcium looping	Retrofit existing cement plants with calcium looping technology starting in 2040.	Precalciner/kiln	Electricity Fuel	0.07 [94] 0.6-1.2 [30] 1.6 [94]	0.07 0.88
POXY - Partial oxyfuel technology	Retrofit existing cement plants with oxyfuel technology in the precalciner only starting in 2035.	Precalciner/kiln	Electricity	0.36-0.56 [30][1] 0.78 [97] 0.14 [94]	0.46
			Fuel	(0.17)[2]- 0.22 [30][1] 0.27 [97]	0.25
FOXY – Full oxyfuel technology	Retrofit existing cement plants with oxyfuel technology in the precalciner and kiln starting in 2035.	Precalciner/kiln	Electricity	0.36-0.56 [30][1] 0.87 [97] 0.19 [94] 0.33-0.35 [92]	0.53
			Fuel	(0.17)[2]-0.22 [30][1] 0.00 [97] (0.12)[2]- (0.11)[2] [92]	(0.09)[2]

[1]The range provided by the European Cement Research Academy [30] covers both FOXY and POXY

[2]Parentheses indicate negative values

The CCS technologies chosen for this study have different energy consumption impacts, GHG capture rates, and capital and operating expenses. After reviewing the literature, a range of specific energy consumption impacts for thermal energy and electrical energy for each technology were compiled. The average of the highest and lowest points of the range was selected for the model, as shown in **Table 6**, with the exception of partial and full oxyfuel CCS fuel impacts. Since the range provided by the European Cement Research Academy [30] covers both partial and full oxyfuel, the high end of the range was applied to full oxyfuel CCS and the low end to partial oxyfuel CSS because partial oxyfuel CCS does not achieve the thermal efficiencies of full oxyfuel CCS. The selected specific energy consumption impacts for chemical absorption, physical adsorption, and calcium looping technologies include a waste heat offset of 0.22 GJ/t cement, based on waste heat recovery scenarios described by the European Cement Research Academy [30]. Since these technologies have high thermal demands, it is in the interest of the facilities to reduce heating demands by recovering any available waste heat. Where necessary, relative values from the literature were converted into intensity values based on the overall energy intensity of cement production in Canada.

For chemical absorption, the increased thermal demand is primarily for the regeneration of solvent and is met by a combination of waste heat recovery and a natural gas boiler installed as part of the capture plant. A natural gas boiler was selected because of the simplicity of installation. For physical adsorption, additional heat requirements are also assumed to be met with a natural gas boiler. Calcium looping follows the same principles as chemical absorption but uses lime (calcium oxide) as the sorbent instead of a solvent. Apart from capturing carbon dioxide emissions, this technology has the benefit of incorporating spent sorbent into the cement production process. After being used as a sorbent for several cycles, the lime loses its ability to absorb carbon dioxide and must be replaced [92]. Instead of being disposed of, the spent sorbent can be used as a decarbonated raw material in the cement production process, thereby reducing process GHG emissions by as much as 50%, according to Hasanbeigi et al. [92] and Dean et al. [98]. In this study, it was assumed that a 50% process GHG emissions reduction at full deployment. Much like chemical absorption, high temperatures are necessary to support the reactions. For calcium looping, a configuration that replaces the precalciner with dual fluidized beds is assumed so energy and waste efficiencies can be maximized in the looping process [94], meaning additional heat requirements are met by the regional fuel mix.

Oxyfuel technology can be applied under partial and whole system configurations. In the partial system configuration, the oxygen environment is only created in the precalciner because this is where the majority of the combined fuel and process emissions (60-75%) are created [97]. In the whole system configuration, both the precalciner and kiln are operated in an oxygen environment. This results in the ability to capture more than 90% of GHG emissions along with potentially improved thermal efficiency, but at a higher capital cost than the partial application.

Many factors influence the implementation and operational effectiveness of CCS technologies, making it difficult to predict when a technology can be adopted and when it will achieve full operability. For example, an early adopter may require years of learning and system refinement before a system is considered fully operational. Therefore, to approximate the varying degrees of operational effectiveness that are possible over the study period, an s-curve adoption profile defined by **Eq. (8)** was used from the first year of commercial availability to the final year of the study (**Figure 9**). In **Eq. (8)**, $Adopt_{t,n}$ is the adoption factor of technology t in year n and SY_t is the first year a technology, t, is commercially available. The s-curve adheres to slow initial adoption/partial operability, then increasingly rapid adoption/operability by the majority of the market, and finally adoption/full operability by the laggards. The adoption profile is applied to low (25%), medium (50%), and high (100%) penetration scenarios, according to **Eq. (9)**, where the adoption factor is then multiplied by the scenario penetration factor, $ScenPen_t$, for technology t to find the penetration factor $PF_{t,n}$. Current penetration for all CCS technologies is assumed to be 0% given the generally low maturity of the technologies in the sector and for simplicity. While a demonstration project exists [20] that covers approximately 7% of Canada's cement production, it does not operate continuously.

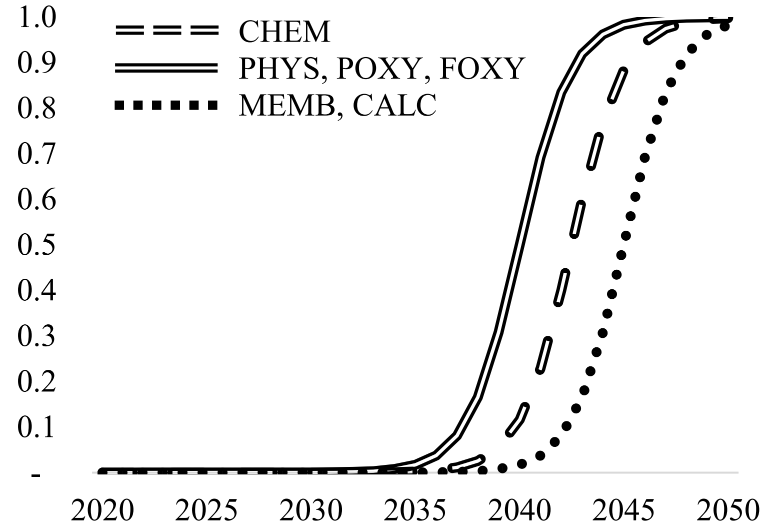

Figure 9. S-curve adoption profile for CCS technologies

$$Adopt_{t,n} = \left(1 + e^{\left(-0.9\times\left(n-\left(\frac{2050-SY_t}{2}+SY_t\right)\right)\right)^{0.9}}\right)^{-1} \qquad \textbf{(8)}$$

$$PF_{t,n} = \left(Adop_{t,n}\right) \times ScenPen_{\ t} \qquad \textbf{(9)}$$

Similarly, a range of GHG capture rates and capital costs was obtained from published sources for each technology applied to the model (**Table 7**). When reviewing these sources for capital costs, costs related to the retrofit of an existing plant were used when available because it is more likely that existing plants will be retrofitted than new cement plants built. Capital costs were converted to 2020 CAD then annualized according to **Eq. (1)**, assuming a technology life of 25 years and a real investment discount rate of 10%.

The high investment discount rate reflects the sector's expectation of high internal rates of return. Compared with CCS technology cost reviews for the cement sector, Garcia and Berghout [53] found investment discount rates of 8-10%. Like the European Cement Research Academy [30], the capital costs were decreased by 1% per year from the first year of commercial availability to reflect reduced costs associated with ongoing technological improvement and increased industry familiarity. Finally, capital costs are expressed per unit of cement produced based on an estimated average plant production of 1.2 million tonnes of cement over the study period. This production level was established based on the forecasted cement demand used in this study split among the 15 operating cement plants. Operating costs were assumed to be 4.5% of the annualized capital costs, in line with those reported by Hughes and Zoelle [99]. Operating costs include taxes and insurance fees, operating, maintenance and administrative costs, consumables (solvent, minerals, water, etc.), and waste disposal, but excluding fuel cost impacts.

Table 7. GHG capture rates, capital costs, and non-energy operating costs of CCS technologies in 2020 CAD

CCS technologies	GHG capture rate: Reported ranges (%)	GHG capture rate: Selected (%)	Capital cost: Reported ranges (million CAD)	Capital cost: Selected (million CAD)	Capital cost: Annualized per unit of cement (CAD/tonne cement)	Non-energy operating costs (CAD/tonne cement)
CHEM – Chemical absorption	up to 95% [30] 80-95% [97] >90% [94]	95%	123-369 [30] 295-485 [94] 405-424 [99]	304	58.95	11.40
PHYS – Physical adsorption	up to 90% [30]	90%	126 [30]	126	22.91	4.73
F.OXY – Full oxyfuel technology	90-99% [30] 90-99% [97] >90% [94]	95%	129-160[1] [30] 144 [94]	152	26.95	5.70
P.OXY – Partial oxyfuel technology	55-75% [30] 60-75% [97] 65% [94]	65%	129-160[1] [30] 118 [94]	123	21.73	4.61
MEMB – Membrane absorption	>80% [30]	80%	71-104 [30]	88	14.82	3.30
CALC – Calcium looping	90-95% [30] >90% [94]	95%	298-331 [30] 278 [94]	305	53.06	11.44

[1] The range provided by the European Cement Research Academy [30] covers both FOXY and POXY

4.3. Scenario results

Each CCS technology included in this study has an impact on energy consumption. Understanding these impacts is important because it allows policymakers to make informed decisions when weighing the advantages and disadvantages of different technologies. The high penetration scenario is the baseline of this study, meaning all results discussed assume 100% penetration of CCS technologies, unless otherwise stated.

The energy demand of cement production in Canada increases from 8% to 83% by 2050 (**Figure 10**), depending on the CCS technology deployed. Physical adsorption is the most energy intensive and full oxyfuel combustion the least. The thermal efficiency gained by employing oxyfuel technology in the kiln as well as the precalciner leads to lower energy consumption than when partial oxyfuel is applied. Breaking energy demand down further, **Figure 11** highlights cumulative additional thermal and electrical energy demand for each CCS technology over the study period as well as the associated direct and indirect GHG emissions. The additional energy necessary to operate CCS technology and the corresponding emissions are commonly called energy and GHG emissions penalties. It is important to note that while the relative thermal and electrical energy demands are constants in each region, the GHG emissions are not. The direct GHG emissions are a reflection of the fuel mix intensity for the region, while the indirect GHG emissions are reflection of the electrical grid carbon intensity for the region. For example, physical adsorption CCS technology in Alberta emits 42% fewer direct GHG emissions than in British Columbia over the life of the study period even though Alberta produces 13% more cement. This is because Alberta uses primarily natural gas as a thermal fuel while British Columbia uses primarily coal and petroleum coke. Conversely, Alberta emits over 21 times more indirect GHG emissions than British Columbia when deploying physical adsorption technology because Alberta has a more carbon-intensive electricity grid. It is also important to note that indirect GHG emissions cannot be mitigated by the CCS technology deployed at a cement plant, as the GHG emissions are produced off- site at a generation station. For the CCS technologies explored, cumulative indirect GHG emissions range from 0.001 to 1.0 Mt, depending on the region. Assuming the greenhouse gas capture rates in **Table 7**, the total unmitigated GHG emissions, or the GHG emissions penalty, resulting from the energy requirements of each CCS technology range from -0.3 to 1.8 Mt. However, even the highest GHG emissions penalty of 1.8 Mt is less than 0.2% of the GHG emissions expected if no CCS technology is deployed. Furthermore, if the region switches to coal as the primary means of electricity generation with an electrical grid carbon intensity of 1 kg CO_2e/kWh, the maximum regional GHG emissions penalty is 2.5 Mt and still only equals less than 1% of the GHG emissions expected if no CCS technology is deployed.

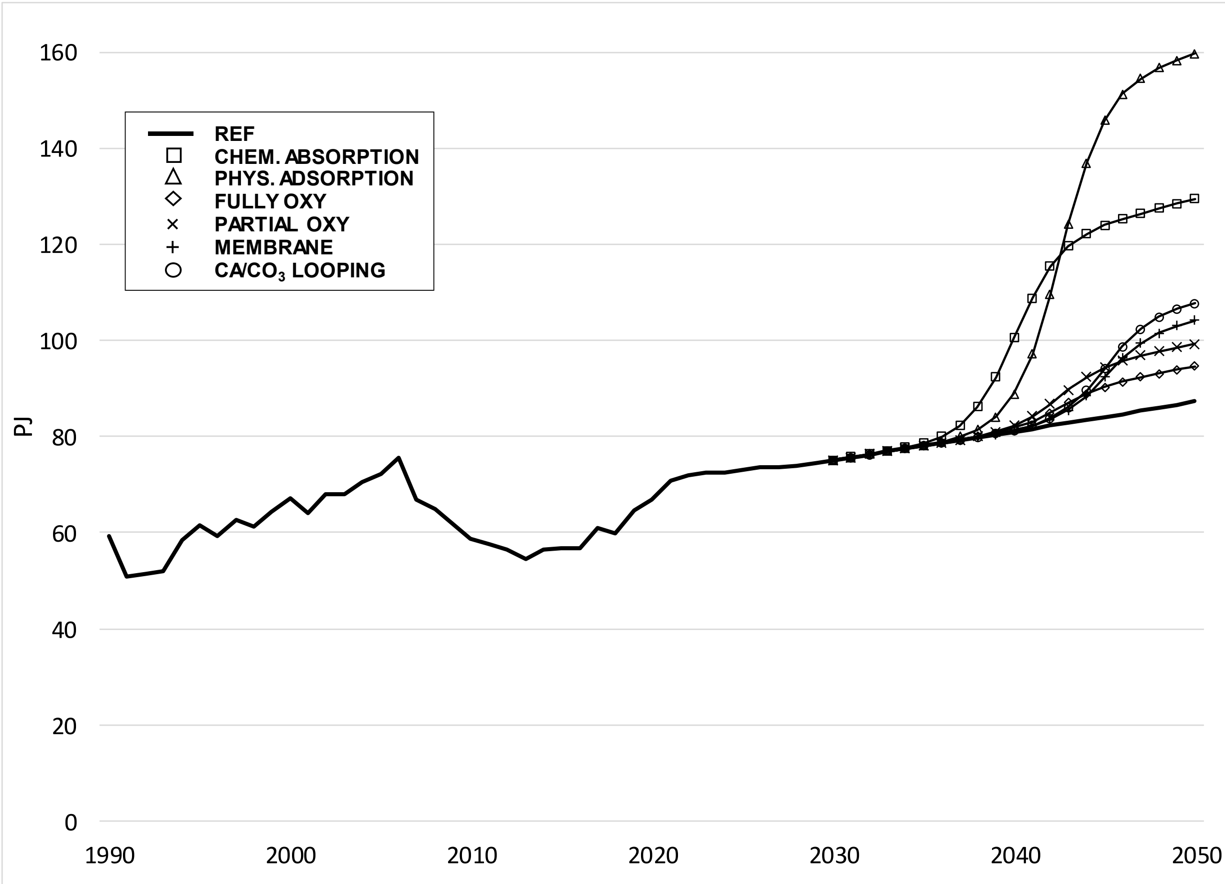

Figure 10. The final energy demand of Canada's cement sector for each CCS technology

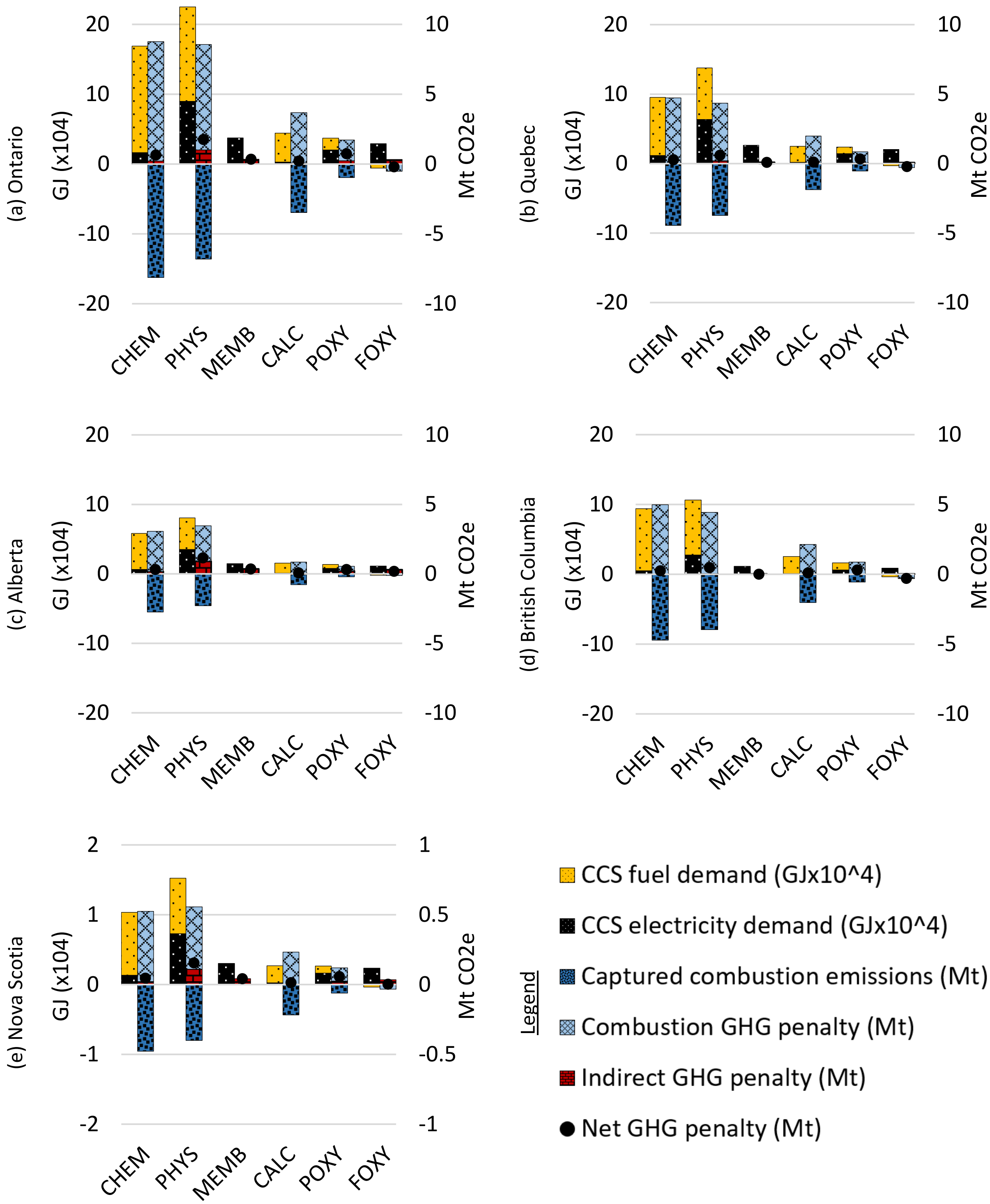

Figure 11. CCS cumulative energy demand and emissions versus the reference scenario by region, 2020 to 2050

4.4. Abatement cost analysis results

NPV analysis shows Canada-wide MACs of -22 to 1 CAD/t CO_2e abated (**Figure 12**) under the high penetration scenarios. Physical adsorption is the only technology without a negative GHG abatement cost, meaning the carbon cost savings realized do not match the sum of capital costs, non-energy operating costs, transportation, storage and monitoring costs, and additional energy costs over the study period. In all regions, capital costs per unit of cement, non-energy operating costs per unit of cement, transportation, storage and monitoring costs per unit of CO_2, and carbon costs per unit of CO_2e are consistent. However, energy costs, fuel mixes, electrical grid carbon intensity and the resultant CO_2e differ by region and therefore influence each technology's MAC differently. **Figure 13** illustrates the proportion of costs and benefits realized over the life of each technology in each region by cost category. Energy costs range from 9 to 81% of all costs, with calcium looping generally having the lowest energy costs and physical adsorption the highest. In large part this is due to electricity consumption and cost. Electricity typically costs more per GJ than other sources of energy, meaning an increase in electricity consumption increases energy costs disproportionately. Furthermore, electricity use does not result in direct GHG emissions that can be captured on-site, meaning there are no carbon cost savings to offset the additional energy cost. Ontario and Nova Scotia demonstrate these impacts: in 2020, electricity was 13 and 8 times more expensive per GJ than natural gas in Ontario and Nova Scotia, respectively, and projected to be 6 and 5 times more expensive in 2050. Therefore, we see higher energy costs for most CCS technologies compared to other regions. However, energy costs are generally muted by the carbon cost savings realized through capture and storage. Regional MAC curves are in **Appendix G – CCS marginal abatement cost curves**.

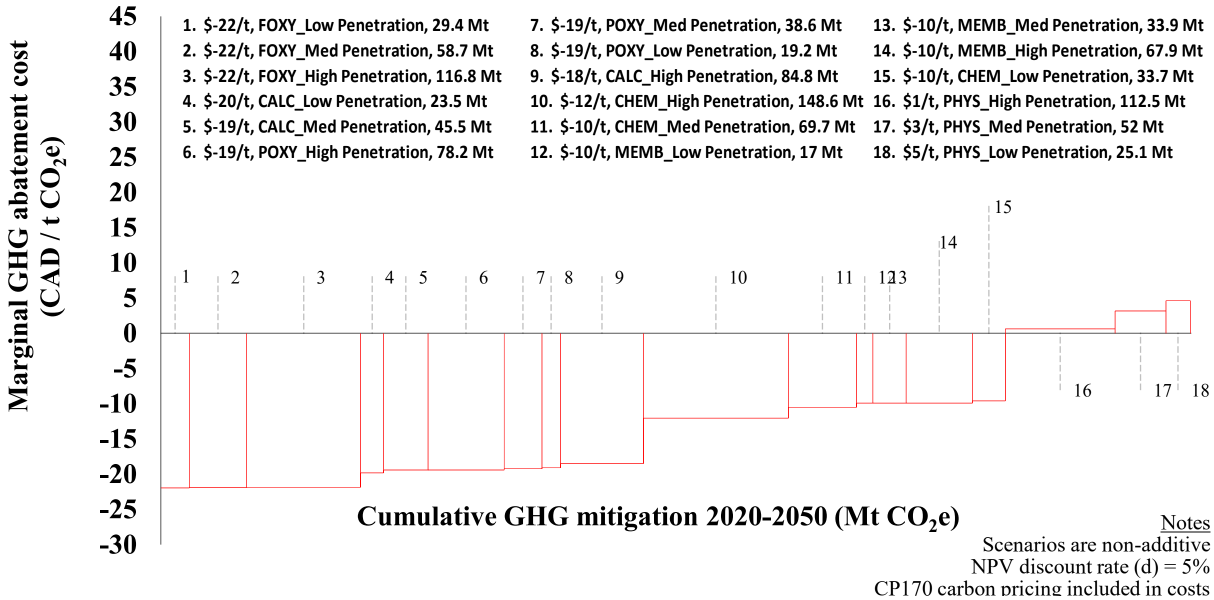

Figure 12. Canada-wide marginal abatement costs for each CCS scenario

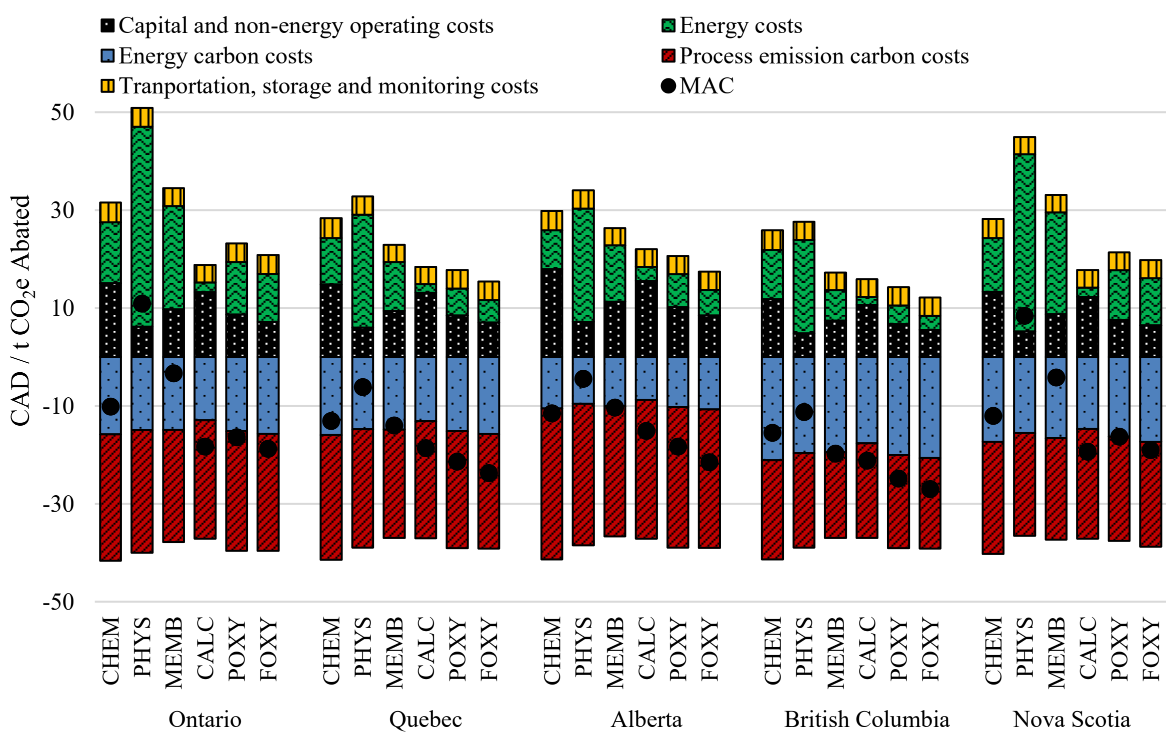

Figure 13. Costs and benefits of each CCS technology for the high penetration scenario in each region

4.5. Sensitivity analysis

Carbon and energy prices impact the economics of CCS technologies. Under Canada's current carbon price schedule (CP170), the price of carbon is expected to rise to a nominal 170 CAD/t CO_2e by 2030 [50]. However, the most recent federal election highlighted that not all the major political parties agree on the current approach to carbon pricing [89]. Any change to the current carbon price schedule will impact the MAC of each technology. Similarly, energy prices impact the implementation cost of each CCS technology. While forecasted energy prices were obtained from reputable sources, it is impossible to predict future prices with complete accuracy.

To mitigate the uncertainty around carbon prices, several additional carbon price scenarios were explored. In the first, CP0, there is no price on carbon. In the second scenario, CP50, the carbon price reaches a nominal 50 CAD/t CO_2e in 2022 but does not increase further and remains stagnant for the rest of the study period. In scenarios CP60-CP350, the carbon price rises to a nominal 60-350 CAD/t CO_2e by 2030, increasing linearly between 2022 and 2030. In the CP0 and CP50 scenarios, the Canada-wide MACs for each CCS technology are positive, demonstrating that both scenarios eliminate any financial incentive for installing CCS technologies (**Figure 14**). The same is true when considering each region individually. In the CP350 scenario, the financial case for installing CCS technologies is greater than the baseline scenario because of the increased benefits of capturing GHG emissions, and every technology has a negative MAC. The breakeven carbon price, or the price at which each technology becomes financially beneficial, was calculated within 10 CAD intervals. Canada-wide, full oxyfuel technology has the lowest breakeven carbon price interval at 70-80 CAD/t CO_2e by 2030, although this interval ranges from 50-60 CAD/t CO_2e to 80-90 CAD/t CO_2e depending on the region. Physical adsorption has the highest Canada-wide breakeven carbon price at 170-180 CAD/t CO_2e by 2030, with regional breakeven intervals ranging from 100-110 CAD/t CO_2e to 210-220 CAD/t CO_2e. Partial oxyfuel technology and calcium looping have a Canada-wide breakeven carbon price of 80-90 CAD/t CO_2e by 2030, and chemical absorption and membrane technology have a Canada-wide breakeven carbon price of 120-130 CAD/tCO_2e by 2030. A complete set of regional results is in **Appendix J – CCS sensitivity analysis** and **Appendix L – Breakeven carbon prices**.

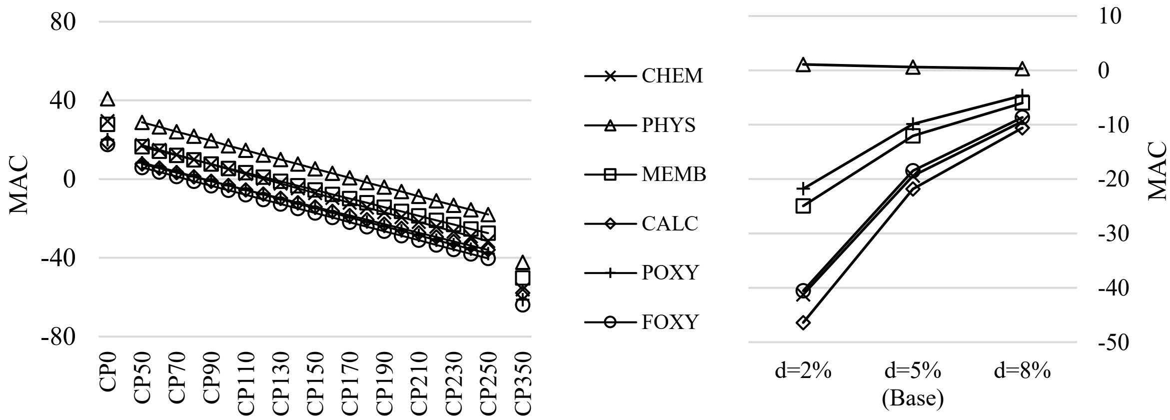

Figure 14. Marginal abatement costs for several carbon price and discount rate scenarios

Given that the NPV of each CCS technology is dependent on the discount rate, the discount rate was varied by ±3% (**Figure 14**). At the lower discount rate, the MACs for each CCS technology move away from zero because the net benefit or cost of the technology in future years is greater than at the base discount rate. Conversely, the net benefit or cost in future years is eroded by the higher discount rate. Physical adsorption is an example of a technology with a net cost under baseline parameters, while all other CCS technologies have a net benefit. Furthermore, the impact is lower for each percentage point increase compared to each percentage point decrease from the baseline discount rate because of the exponential nature of discounting.

Natural gas and electricity account for all energy cost impacts in the chemical absorption, physical adsorption, and membrane absorption scenarios. In the calcium looping, partial oxyfuel, and full oxyfuel scenarios, all other types of energy combined account for only 23%, 3%, and 1% of energy cost impacts across Canada, respectively. Therefore, natural gas and electricity prices were varied by ±25% and ±50% to explore the impacts of price changes on MACs (**Figure 15**). In addition to the reasons stated above, the impact of electricity price is more pronounced than natural gas price because electricity costs more than natural gas. Therefore, the multiplier will have a larger impact on the overall cost. In the case of physical adsorption, the CCS technology with the largest electricity consumption increase, the MAC becomes negative when electricity prices decrease. This sensitivity analysis also highlights that the technologies with the largest energy consumption increases are the most impacted by energy price fluctuations. Choosing a technology with a lower energy impact, such as calcium looping or the oxyfuel technologies, will mitigate the risk of energy prices eroding potential abatement cost benefits. Regional results are in **Appendix J – CCS sensitivity analysis**.

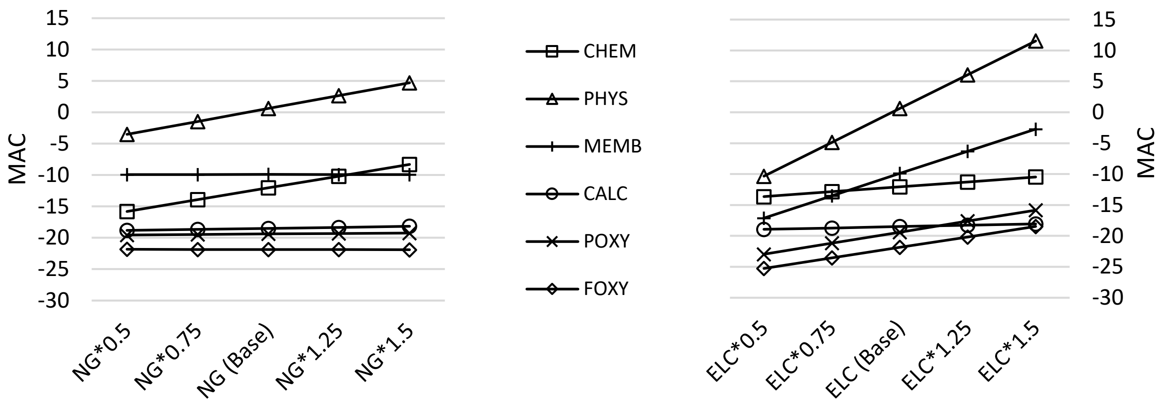

Figure 15. Marginal abatement costs after applying various multipliers applied to electricity and natural gas prices

4.6. Limitations and future work

CCS technologies are not yet established in the cement sector. While there is a growing body of literature and knowledge around potential technologies, it is difficult to predict which technologies will be embraced by the industry. As the results of future demonstration projects or partial applications become available, cost, energy and GHG capture rate data can be refined to better understand the true economic impacts of each technology in regional circumstances. Furthermore, potential markets for captured carbon may emerge, allowing the industry to recoup costs. If those markets do emerge, the corresponding benefits should be included in future cost analyses. Finally, technological advancements may significantly change the impacts of CCS technology. For example, this study explores physical adsorption using calcium or magnesium silicates, but physical adsorption using metal-organic frameworks is an emerging technology that potentially requires less energy.

4.7. Policy implications

The results of this study emphasize three key considerations for policymakers about CCS technologies in cement production. First, while the energy requirements of CCS technologies result in additional unmitigated GHG emissions, those GHG emissions are less than 1% of the expected GHG emissions if CCS technologies were not adopted. Even in the case where a carbon-intensive electricity grid is assumed, the unmitigated GHG emissions are less than 4% of the expected GHG emissions if CCS technologies were not adopted. Therefore, the GHG emissions penalty of CCS technologies is insignificant compared to the GHG emissions reduction they enable. However, in the long term they represent a barrier to complete decarbonization that can only be solved through the decarbonization of the electricity sector. The second key consideration is that high energy impact technologies are sensitive to energy price fluctuations. The sensitivity analysis results show that electricity prices can significantly improve or erode the financial case for high electricity impact technologies such as physical adsorption and membrane technologies. Similarly, natural gas price fluctuations improve or erode the financial case for high thermal energy impact technologies, especially physical adsorption and chemical absorption as they use natural gas boilers in their capture plants. Finally, under the current policy scenario, CP170, all CCS technologies except for physical adsorption in some regions have negative MACs. This remains true even if the carbon price is relaxed to 160 CAD/t CO_2e by 2030, but the financial incentive is eroded for every technology. Below 160 CAD/t CO_2e, additional technologies in some regions begin to have positive MACs. Any carbon price policy that does not meet at least 60 CAD/t CO_2e by 2030 eliminates all financial incentives for every CCS technology in each region, although 90 CAD/t CO_2e is necessary to ensure there is at least one financially attractive CCS technology in every cement-producing region.

4.8. Key results

In this study, a bottom-up technology-explicit model of the cement sector was created, and the energy, GHG emissions, and economic impacts of implementing six distinct CCS technologies were evaluated. Not only did this address the common issue of generalizing CCS technologies when exploring decarbonization, but the Canadian case study facilitated the comparison of technologies in different regions with varying energy prices and energy mixes. Under full penetration, energy demand in Canadian cement production increases from 8% to 83% by 2050, depending on the CCS technology implemented. In combination with a high carbon thermal fuel mix, high thermal demand CCS technologies such as chemical absorption and physical adsorption result in larger amounts of unmitigated direct GHG emissions, also known as a GHG emissions penalty. Similarly, carbon-intensive electricity grids paired with high electricity-consuming CCS technologies, such as physical adsorption and membrane technologies, result in larger amounts of indirect GHG emissions. However, direct and indirect GHG emissions penalties were found to be minor compared to the overall GHG emissions anticipated if no CCS technologies were deployed.

Canada-wide MACs range from -22 to 1 CAD/t CO_2e and, under the baseline of CP170, all technologies except physical adsorption result in negative abatement costs. Physical adsorption is the most energy-intensive technology, meaning energy costs outpace carbon cost savings on a national level. However, in regions with lower energy prices, physical adsorption does have a negative abatement cost. This is especially true for regions with low electricity prices. A sensitivity analysis showed the largest MAC fluctuations in Ontario and Nova Scotia when electricity prices were varied; this is due to their high baseline electricity prices. A similar trend was noted for natural gas prices, although the impacts were less significant because natural gas costs less on a unit basis. An analysis of different carbon prices also made clear the MAC breakeven prices for CCS technologies range from 70-80 CAD/t CO_2e to 170-180 CAD/t CO_2e by 2030 on a national level.

In exploring regions with different fuel mixes, electrical grid carbon intensities, and energy prices, it was demonstrated how each of these parameters impacts the financial case of each CCS technology. These results are reflections of regional differences that also exist in the international community, therefore making them applicable to a range of international communities that may have similar parameters to one or more of the regions explored. The sensitivities of certain parameters were also shown, thereby enabling communities to compare their situation to the ranges covered in the analysis. Finally, this study demonstrates the importance of carbon pricing, or a comparable financial incentive, in offsetting energy, capital, operating, and transportation, storage and monitoring costs, regardless of the region being considered.

Chapter 5. Multi-measure pathways for achieving carbon-neutral cement production

5.1. Background

From 2011 to 2020, average global surface temperatures were 1.1 degrees Celsius above those of the period from 1850-1900, resulting in widespread weather and climate extremes impacting essential resources, human health, and economies [1]. Furthermore, climate change impacts are now estimated to be larger in extent and severity than previous assessments. Global warming is projected to increase in the near term, meaning deep greenhouse gas (GHG) emissions reductions across all sectors are necessary to limit warming to 2 degrees Celsius by the end of the century. However, from 2015 to 2021, global cement production emissions rose 15%, to 2.5 Gt CO_2e [2].

Because cement production is the second largest source of industrial GHG emissions, researchers, industry associations, and governments have made an effort to identify and research decarbonization levers for it. Energy efficiency reduces combustion GHG emissions and indirect GHG emissions related to electricity consumption. Switching to low-carbon fuels reduces combustion GHG emissions. Employing alternative, decarbonized raw materials decreases process GHG emissions. Replacing traditional cement binders with alternative binders or developing alternative cement chemistries also has the potential to decrease process GHG emissions. Carbon capture and sequestration (CCS) removes combustion and process GHG emissions from the flue of cement plants so they can be compressed, transported, sequestered, used for another purpose, or any combination of these. Finally, carbonation, or the process by which cement mixed in concrete naturally absorbs carbon dioxide (CO_2) from the air, was recently acknowledged for consideration in greenhouse gas reporting guidelines [6].

Industry associations and governments have been developing carbon reduction roadmaps for at least a decade (**Table 8**). Earlier, the objective was to identify measures to limit the growth of CO_2 emissions. In contrast, by 2020 all national carbon reduction roadmaps state clear goals of decarbonizing, achieving net zero emissions, or achieving climate neutrality in the cement or combined cement and concrete sectors by 2050. The European roadmap [8] clearly outlines decarbonization categories and quantifies their projected carbon intensity impacts on cement production, including energy efficiency, low-carbon fuels, alternative raw materials, alternative binders and chemistries, CCS, and carbonation. The United Kingdom [11] and Australian [10] roadmaps are similar, although neither roadmap explicitly breaks out the impact of alternative raw materials or energy efficiency improvements. However, not all roadmaps separate cement from concrete or make explicit their assumptions or calculation methods, making it challenging to translate the categories to other jurisdictions.

Table 8. An assortment of decarbonization roadmaps

Region	Scope	Year
India [15]	Cement	2013
United Kingdom [100]	Cement	2015
California, United States [58]	Cement and concrete	2019
United Kingdom [11]	Cement and concrete	2020
Europe [8]	Cement and concrete	2020
Sweden [60]	Cement	2020
Global [75]	Cement and concrete	2021
United States [9]	Cement and concrete	2021
Australia [10]	Cement and concrete	2021
Canada [76]	Cement and concrete	2022

In peer-reviewed literature, several case studies explore decarbonization levers for cement production (**Table 9**). Zhang and Mabee [81], Ayer and Dias [80] and Georgiopoulou & Lyberatos [62] investigate using various alternative fuels as a means to reduce combustion GHG emissions. While each study confirms that alternative fuels are an effective way to reduce combustion GHG emissions, process emissions are not addressed. Li et al. [85] and Ren et al. [101] integrate cement demand modelling with GHG emissions and the potential impact of energy efficiency, fuel switching, and CCS by 2050. GHG reductions are tied to the economic potential of each technology, with increasing carbon prices resulting in larger GHG reductions. Zuberi and Patel [95] also explore the economic potential for energy savings and GHG reduction of Swiss cement production using a bottom-up technology model and energy efficiency cost curves, highlighting that low energy and carbon prices can hinder efforts to reduce energy demand and GHG emissions. Their work is complemented by Obrist et al. [26] through the evaluation of different energy and carbon price scenarios on the economic potential of similar decarbonization levers, including a carbon price scenario that realizes enough deployment of decarbonization technologies to achieve net-zero direct GHG emissions. Hasanbeigi et al. [84] and Morrow et al. [82] also go beyond evaluating the economic potential of technologies by considering the maximum technical potential for energy savings and GHG reductions should every technology be employed. Hills et al. [102] incorporate anticipated plant renovation windows into CCS adoption scenarios and compare the decarbonization potential of several CCS technologies when paired with thermal efficiency, clinker/cement ratio reduction, and fuel switching, but do not include indirect GHG emissions or a financial analysis. Cormos [103] calculates the GHG emission abatement cost and the cost of cement production for various CCS technologies. However, to the author's knowledge, only one study includes all decarbonization categories. Dinga and Wen [54] developed a bottom-up roadmap to achieve carbon neutrality in Chinese cement production by 2060, using both deterministic and uncertainty-driven scenarios, although the impact of alternative raw materials and alternative cement chemistries is blended into a single pathway.

Table 9. Selected case studies exploring one or more decarbonization categories for cement production

Source	Case study	Year	Model construction	Energy efficiency	Alternative raw materials	Alternative binders and cements[a]	Fuel switching	CCS	Carbonation
Ke et al.[b] [14]	China	2012	Bottom-up (LEAP)	Yes	No	Yes	Alt. fuels only	No	No
Hasanbeigi et al.[b] [84]	China	2013	Bottom-up	Yes	No	Yes	Alt. fuels only	No	No
Morrow et al.[b] [82]	India	2014	Bottom-up	Yes	No	Yes	Alt. fuels only	No	No
Zhang & Mabee [81]	Plant in Bath, Canada	2016	Life cycle analysis	No	No	No	Alt. fuels only	No	No
Hills et al. [102]	United Kingdom	2016	Bottom-up	Yes	No	Yes	Yes	Yes	No
Li et al. [85]	China	2017	Bottom-up (TIMES)	Yes	No	No	Yes	Yes	No
Zuberi & Patel [95]	Switzerland	2017	Bottom-up	Yes	No	Yes	Alt. fuels only	Yes	No
Ayer & Dias [80]	Plant in Quebec, Canada	2018	Life cycle analysis	No	No	No	Alt. fuels only	No	No
Georgiopoulou & Lyberatos [62]	Unspecified	2018	Life cycle analysis	No	No	No	Alt. fuels only	No	No
Talaei et al[b]. [83]	Canada	2019	Bottom-up (LEAP)	Yes	No	Yes	Alt. fuels only	No	No

Obrist et al. [26]	Switzerland	2021	Bottom-up (TIMES)	Yes	No	Yes	Alt. fuels only	Yes	No
Dinga & Wen [54]	China	2022	Bottom-up (GAINS)	Yes	Yes	Yes	Alt. fuels only	Yes	Yes
Cormos [103]	Hypothetical plant	2022	Bottom-up (ChemCAD)	No	No	No	No	Yes	No
Ren et al. [101]	China	2023	Top-down/ bottom-up (IMED|CGE / TEC)	Yes	No	No	Yes	Yes	No

[a] Studies that consider reduced clinker/cement ratios are included here because additional binders and/or increased use of non-OPC cement are the primary methods of reducing that ratio.

[b] Only considers energy-related emissions

5.2. Decarbonization category and scenario development

Several technologies for each decarbonization pathway are modelled as described in **Table 10**, and **Sections 5.2.1** to **5.2.5**. The modelling of each technology within a decarbonization category allows for the direct comparison of technologies from energy savings, GHG mitigation, and GHG emission abatement cost perspectives. Further to that, categories are combined into carbon-neutral scenarios as described in **Section 5.3** and **Table 11**.

5.2.1. Fuel-switching

In **Chapter 3**, the GHG impact and GHG emission abatement cost of transitioning from conventional fuel mixes to natural gas, municipal solid waste (MSW), biomass, hydrogen, a hydrogen/natural gas blend (hythane), or electricity for thermal energy was analyzed. The results of that research form the fuel switching decarbonization category. Conventional fuel mixes consist of coal, petroleum coke, natural gas, fuel oils, and petroleum or construction-based wastes, although the share of each fuel type varies widely by region [25]. Fuel shares further vary based on the fuel switching scenario and are therefore not detailed in **Table 10**. Additional detail regarding scenario assumptions, energy demand tree impacts, GHG impacts and GHG emission abatement costs is provided in **Chapter 3**.

5.2.1. Energy efficiency

Energy efficiency has long been studied as a means to reduce energy intensity and associated energy costs. Worrell et al. [28] outlined over thirty energy-efficiency measures for cement making in 2004 and updated that research in 2013 to include over fifty measures [29]. The range of measures that apply to specific cement plants will vary with the age of the plant, level of maintenance, and attempts to modernize. In Canada, the energy efficiency of cement plants varies widely[17]. Without plant-specific information, it is difficult to determine technology applicability with certainty. Talaei et al. [83] performed a comprehensive review of energy-efficiency improvement options for Canada's cement plants that identified several state-of-the-art technologies and their level of applicability. All those technologies for this study were considered, although some have been recategorized.

5.2.2. Alternative raw materials

In Canada, process GHG emissions resulting from the calcination of limestone account for approximately 60% of the total GHG emissions from cement production [23]. When alternative, decarbonized raw materials are used in place of limestone, the amount of material being calcined and the associated process GHG emissions decrease. Hasanbeigi et al. [92] discuss the replacement of limestone with partially decarbonated calcareous oil shale, slag resulting from the production of ferrous metals, and non-ferrous carbide slag to reduce process emissions. Other potential decarbonated raw materials include concrete crusher sand, concrete meal, and lime residues from other industries [30]. In general, the use of alternative raw materials is limited by the need to maintain clinker quality and regional availability. In this study, it is assumed up to 8% of limestone can be replaced with decarbonized raw material, aligning with the assumptions of the European roadmap [8], which is slightly less than the 10% goal of the United States roadmap [9] but more than the 3-4% projected by the global roadmap [75].

5.2.3. Alternative binders and chemistries

Portland cement is primarily composed of ground Portland clinker, with some gypsum and up to 5% crushed limestone [104]. However, the replacement of Portland clinker with low-carbon substitutes is considered a way of delivering immediate, substantial GHG intensity reductions in cement production [93]. The Cement Association of Canada has encouraged industry to transition to the manufacture of Portland-limestone cement containing up to 15% crushed limestone [104]. Current estimates are that 60% of the cement produced in Canada is Portland-limestone cement [105]. Portland-limestone cement is found to have comparable performance to Portland cement, meaning it can fully replace Portland cement, including in blended cements. Performance metrics include compression strength, setting time, and durability, such as resistance to freeze-thaw cycles, salt deicer scaling, and the penetration of fluids. However, a finer level of grinding is required compared to traditional Portland cements. In Europe, Portland-limestone cement has been used for many decades, with the most widespread Portland-limestone cement having a limestone content of 20% [106].

Further reductions in this category are also possible through the increased use of supplementary cementitious materials, such as slag, fly ash, and pozzolanas. Some Canadian cement producers have expressed targets of 30% clinker substation by 2030 [76], while the United States [9] and European [8] roadmaps have goals of 25% and 35% clinker substitution by 2050. However, further research, testing, and development are necessary to ensure new blended cements meet necessary performance levels.

5.2.4. Carbon capture and storage

In an earlier study on CCS in cement production [107], six CCS technologies were compared: chemical absorption via amine scrubbing, physical adsorption using calcium or magnesium silicates, calcium looping, membrane absorption, partial oxyfuel technology, and full oxyfuel technology. The results of that study form the CCS decarbonization category.

It was assumed that no CCS technology was commercially available before 2030 as most projects for capturing GHG emissions from cement production are in the demonstration stage, undergoing feasibility studies, or operating at limited capacity [108]. This aligns with the assumptions of the European roadmap [8], the global roadmap [75], and the European Cement Research Academy [30]. In determining the first year of commercial availability, we also considered assumptions in Canada's roadmap [76] and the current technology readiness level of each CCS technology [96]. Chemical absorption will become commercially available in cement production in 2030 because it has the highest technology readiness level and has been used in other industries. Physical absorption and oxyfuel technology are assumed to be available from 2035 onwards, and calcium looping and membrane absorption are assumed to be available from 2040 onwards. Transportation, sequestration, and monitoring costs are included in this pathway at a rate of 13.44 CAD/t CO_2 [109].

5.2.5. Carbonation

Currently, cement carbonation is not included in the IPCC Guidelines for National Greenhouse Gas Inventories [5]. However, the IPCC emission factor database [7] includes a note on cement carbonation, recognizing that CO_2 uptake by cement-based materials does occur over their lifetimes but is not yet included in national GHG inventories because further research is necessary to better understand uncertainties surrounding carbonation. Nevertheless, the European [8] and Australian [10] roadmaps include the impacts of carbonation as they are not bound by national inventory stipulations. Canada's roadmap [76] also discusses carbonation, recognizing further research will help reduce uncertainty around carbonation impacts, and Dinga and Wen [54] consider the impacts of carbonation in their analysis of the Chinese cement sector's path to carbon neutrality. In this study a Tier 1 calculation method, described by **Eq. (10)**, is employed which estimates 20% of the process emissions, PE, in any given year n are assumed to be offset by cement carbonation during the use stage (existing structures) and 3% for the end-of-life stage (demolition, crushing and stockpiling) and secondary use [110]. **Eq. (10)** is applied to the process GHG emissions calculated in LEAP after the impacts of the other decarbonization categories have been applied, but before carbon emissions are captured. It is important to note the use stage factor changes if mortar accounts for more than 10% of applied cement-containing products. In Canada, masonry and non-Portland cement-related products accounted for less than 5% of cement-containing products produced between 2007 and 2018 [21], therefore it is assumed that mortar does not account for more than 10% of applied cement products.

$$CAR_n = (0.20 + 0.03) \times (PE_n) \qquad \textbf{(10)}$$

Table 10. Scenario descriptions, energy consumption impacts, and emission impacts

Category and scenarios	Description	Unit operations	Energy type	Energy consumption impacts (GJ/t cement)	Process emission impacts / GHG capture rate
1. Fuel switching (FS)					N/A
NG – Natural gas	Transition to 100% natural gas for thermal energy generation between 2020 and 2050.	Precalciner / kiln	Fuel	0 [30]	N/A
MSW – Municipal solid waste	Transition to 65% municipal solid waste for thermal energy generation in the calciner between 2020 and 2050. This alternative fuel mix is assumed to have 30% organic material. The remaining thermal energy requirements are satisfied using the reference fuel mix.	Fuel prep & handling Precalciner / kiln	Electricity Fuel	0.009 [30, 83] 0.172 [30, 83]	N/A
BIO – Biomass	Transition to 65% torrefied biomass for thermal energy generation in the calciner between 2020 and 2050. The remaining thermal energy requirements are satisfied using the reference fuel mix.	Fuel prep & handling Precalciner / kiln	Electricity Fuel	0.009 [30] 0.258 [30]	N/A
HYD – Hydrogen	Transition to 100% hydrogen for thermal energy generation between 2040 and 2050. This assumes the design and installation of new kiln technology as necessary.	Precalciner / kiln	Fuel	0	N/A
ELC – Electrification	Electrification of thermal energy between 2040 and 2050. This assumes the use of a plasma kiln and direct air separation calciner technology.	Precalciner / kiln	Fuel	0.900 [71]	N/A
HYT – Hythane	Transition to a hydrogen-natural gas blend (15% hydrogen, 85% natural gas by volume) known as hythane for thermal energy generation between 2030 and 2050.	Precalciner / kiln	Fuel	0	N/A
BIO/HYT	Transition to 65% torrefied biomass for thermal energy generation in the calciner between 2020 and 2050, with the remainder being a hythane blend adopted from 2030 to 2050.	Fuel prep & handling Precalciner / kiln	Electricity Fuel	0.009 [30, 83] 0.258 [30]	N/A N/A
MSW/HYT	Transition to 65% municipal solid waste for thermal energy generation in the calciner between 2020 and 2050, with the remainder being a hythane blend adopted from 2030 to 2050.	Fuel prep & handling Precalciner / kiln	Electricity Fuel	0.009 [30, 83] 0.172 [30, 83]	N/A N/A
FS market share	Using **Eq.(7)**, we calculated the market shares of biomass, MSW, natural gas, hythane, hydrogen, and electrification of thermal energy under moderate (v = 6) cost sensitivity. The combined shares of biomass and MSW cannot exceed 65% as these fuels are reserved for the calciner because of the caloric requirements of the kiln.	Fuel prep & handling Precalciner / kiln	Electricity Fuel	Calculated based on market shares Calculated based	N/A N/A

Category and scenarios	Description	Unit operations	Energy type	Energy consumption impacts (GJ/t cement)	Process emission impacts / GHG capture rate
				on market shares	
2. Energy efficiency (EE)					
PHPC – Preheater/ precalciner	Preheaters are upgraded to a 6-stage vertical cyclone system to maximize heat transfer efficiency from the calciner and kiln gases to the raw meal. All facilities are equipped with calciners. Technology is adopted from 2020 to 2050.	Precalciner / kiln	Fuel	-0.519 [30]	N/A
ADJ – Adjustable speed drive for kiln fan	Adoption of adjustable speed drives for the kiln fan from 2020 to 2050.	Precalciner / kiln	Electricity Fuel	-0.018 [83] -0.060 [83]	N/A
REFR – Improved refractories	Upgrade of refractories to reduce heat loss from kiln starting from 2020 to 2050.	Precalciner / kiln	Fuel	-0.350 [83]	N/A
COMB – Combustion system improvements	Improvements to combustion efficiency in the kiln from 2020 to 2050.	Precalciner / kiln	Fuel	-0.200 [83]	N/A
GRATE – Reciprocating grate clinker cooler	Upgrade to modern reciprocating grate clinker coolers for improved heat recovery from 2020 to 2050.	Precalciner / kiln	Fuel	-0.172 [30, 83]	N/A
		Clinker cooling	Electricity	0.004 [30, 83]	
OPTM – Optimize grate clinker cooler	Optimize modern reciprocating grate clinker cooler to maximize benefits from 2020 to 2050.	Precalciner / kiln	Fuel	-0.080 [83]	N/A
GRIND - Optimized particle size distribution	Cement constituents are ground to an optimal size to increase reactivity. This can improve the rate of compressive strength development in blended cement. Continuous improvement from 2020 to 2050.	Crushing and grinding	Electricity	0 [30]	N/A
		Precalciner / kiln	Fuel	-0.050 [30]	
AUTOC – Upgraded automation & control	Upgraded and improved automation and control throughout the production process. Continuous improvement from 2020 to 2050.	All	Electricity Fuel	-0.009 [83] -0.100 [83]	N/A
3. Alternative raw materials (ARM)	Decarbonated raw materials are used in place of limestone, reducing process emissions released during calcination. Adoption occurs from 2020 to 2050.	Crushing and grinding	Electricity	0.005 [30]	-8% [8]
		Raw material prep.	Electricity	0.005 [30]	
		Precalciner / kiln	Fuel	-0.344 [30]	
4. Alternative binders and chemistries (ABC)					
GUL – Portland-limestone cement	Transition to 100% Portland-limestone cement between 2020 and 2050. Portland-limestone cement contains up to 15% limestone (compared to 5% in ordinary Portland cement)	Precalciner / kiln	Fuel	-0.348	-10%
		Finish grinding	Electricity	0 [30]	

Category and scenarios	Description	Unit operations	Energy type	Energy consumption impacts (GJ/t cement)	Process emission impacts / GHG capture rate
GULb25 – Blended limestone cement with up to 25% clinker substitution	Transition to 100% blended limestone cement (25% limestone and other clinker substitutes). Portland-limestone cement available from 2020, with additional clinker substitutions between 2030 and 2050.	Precalciner / kiln	Fuel	-0.696	-20%
		Finish grinding	Electricity	0.010 [30]	
GULb35 – Blended limestone cement with up to 35% clinker substitution	Transition to 100% blended limestone cement (35% limestone and other clinker substitutes). Portland-limestone cement is available from 2020, with additional clinker substitutions between 2030 and 2050.	Precalciner / kiln	Fuel	-1.044	-30%
		Finish grinding	Electricity	0.025 [30]	
ABC market share	Using **Eq.(7)**, we calculated the market shares of Portland-limestone cement and the blended limestone cements under moderate (v = 6) cost sensitivity.	Precalciner / kiln	Fuel	Calculated based on market shares	Calculated based on market shares
		Finish grinding	Electricity	Calculated based on market shares	Calculated based on market shares
5. Post-combustion CO_2 capture technologies (CCS)					
CHEM – Chemical absorption	Amine-based solvent scrubbing of CO_2 from flue gases. The solvent is regenerated using steam produced on site from waste heat and a natural gas boiler	Precalciner / kiln	Electricity Fuel	0.217 [30] 1.715 [30]	95% [30, 94, 97]
PHYS – Physical adsorption	Stable carbonates are formed by reacting magnesium and calcium carbonates with CO_2 from flue gas.	Precalciner / kiln	Electricity Fuel	1.548 [30] 1.973 [30]	95% [30]
MEMB - Membrane separation	Gas-gas or gas-liquid membrane technologies that separate or absorb CO_2 directly from the flue gas	Precalciner / kiln	Electricity	0.929 [30]	80% [30]
CALC – Calcium looping	In this multi-step process, calcium oxide reacts with CO_2 in the flue gas to produce calcium carbonate. The calcium carbonate is then directed toward an oxyfuel combustion calciner that separates it back into calcium oxide and a nearly pure stream of CO_2.	Precalciner / kiln	Electricity Fuel	0.070 [94] 1.200 [30, 94]	95% [30, 94]
POXY – Partial oxyfuel technology	In the calciner, oxygen is used for combustion instead of ambient air. This results in a nearly pure stream of CO_2 gases from combustion.	Precalciner / kiln	Electricity Fuel	0.350 [30, 94, 97] 0 [30, 97]	65%[30, 94, 97]
FOXY – Full oxyfuel technology	In the calciner and kiln, oxygen is used for combustion instead of ambient air. This results in a nearly pure stream of CO_2 gases from combustion.	Precalciner / kiln	Electricity Fuel	0.500 [30, 94, 97] -0.100 [30, 92, 97]	95%[30, 94, 97]

Category and scenarios	Description	Unit operations	Energy type	Energy consumption impacts (GJ/t cement)	Process emission impacts / GHG capture rate
6. Concrete carbonation (CAR)	CO_2 is removed from the air when it reacts with hydrated cement phases in concrete-forming stable carbonates. This process occurs over the entire life of the concrete and is approximated using the Tier 1 method described by **Eq.(10).**	N/A	N/A	N/A	23%

5.3. Carbon-neutral scenario creation and assumptions

In this study, several carbon-neutral scenarios (**Table 11**) are explored. The scenarios are intended to cover a range of possible outcomes and to provide perspective on the significance of each pathway in achieving carbon neutrality. The technologies for each scenario were chosen based on the results of their assessments and the criteria for the scenario.

Table 11. Carbon-neutral scenarios

Description	FS	EE	ARM	ABC	CCS	CAR
1. Technical maximum cumulative emissions reduction						
Largest cumulative GHG emission reductions for each decarbonization category under the high penetration scenario.	BIO/HYT	All	ARM	GULb35	CHEM	23% of process emissions removed
2. Technical maximum emissions reduction in 2050						
Largest GHG emissions reductions in 2050 for each decarbonization category	HYD	All	ARM	GULb35	FOXY	23% of process emissions removed
3. Low GHG emission abatement cost scenario						
GHG emissions reductions using the lowest abatement cost technologies for each decarbonization category where technologies are mutually exclusive. Only negative abatement cost technologies are included in the EE pathway.	MSW	Negative GHG emission abatement cost technology only	ARM	GUL	FOXY	23% of process emissions removed
4. Market share scenarios (*v* = 2, 6, 10)						
GHG emissions reductions using market share results for the FS, ABC/ARM, and CCS decarbonization categories. Only negative abatement cost technologies are included in the EE pathway.	MSW%, BIO%, NG%, HYT%	Negative GHG emission abatement cost technology only	ARM	Portland Cement % GUL% GULb25% GULb35%	FOXY	23% of process emissions removed

5.4. Capital and non-energy operating costs

Capital and non-energy operating costs for technologies in the fuel switching and CCS categories are available in **Sections 3.2** and **4.2**. Capital and non-operating costs for technologies in the energy efficiency, alternative raw materials, and alternative binders and chemistries categories were gathered from the literature. A complete list of capital and non-energy operating costs, and technology lifespans is available in **Table 12**. Annualized capital costs are calculated according to **Eq. (1).** An interest rate of 10% is used in this study. This rate matches the rates used in our previous work and falls within the 8-10% range found by Garcia and Berghout [53] for CCS technologies in the cement sector and the 8-15% upper and lower bounds used by Dinga and Wen [54] for their carbon-neutral pathway analysis in the cement sector.

Table 12. Current penetration, capital costs, non-energy operating costs, and lifespan of decarbonization technologies

Category and scenario	Current penetration	Capital costs[a] (CAD/t cement)	Non-energy operating costs[b] (CAD/t cement)	Life of technology (years)
1. Fuel switching (FS) [91]				
NG – Natural gas	0-93%[c]	3.46	0.16	40
MSW – Municipal solid waste	0%	6.91	0.31	30
BIO – Biomass	0%	6.91	0.31	30
HYD – Hydrogen	0%	6.91	0.31	25
ELC – Electrification	0%	143.34	6.45	25
HYT – Hythane	0%	3.46	0.16	40
2. Energy efficiency (EE)				
PHPC – Preheater/precalciner best available technology	42% [39]	36.02 [29]	1.62	40
ADJ – Adjustable speed drive for kiln fan	50% [83]	0.23 [83]	0.01	20
REFR – Improved refractories	70% [83]	0.60 [83]	0.03	20
COMB – Combustion system improvements	80% [83]	1.00 [83]	0.05	20
GRATE – Reciprocating grate clinker cooler	40% [83]	10.0 [83]	0.45	20
OPTM – Optimize grate clinker cooler	50% [83]	0.20 [83]	0.01	20
GRIND – Optimized particle size distribution	50%	4.20 [30]	0.19	20
AUTOC – Upgraded automation & control	20% [83]	0.90 [83]	0.04	10
3. Alternative raw materials (ARM)	0% [8]	1.20 [30]	0.05	
4. Alternative binders and chemistries (ABC)				
GUL – Portland limestone cement	60% [105]	6.00 [30]	0.23	40
GULb 25 – Blended limestone cement 25	0%	7.20 [30]	0.27	40
GULb 35 – Blended limestone cement 35	0%	8.40 [30]	0.32	40
5. Post combustion CO_2 capture technologies (CCS) [107]				
CHEM – Chemical absorption	0%	253.33	11.40	25
PHYS – Physical adsorption	0%	105.00	4.73	25
MEMB - Membrane separation	0%	73.33	3.30	25
CALC – Calcium looping	0%	254.17	11.44	25
POXY – Partial oxyfuel technology	0%	102.50	4.61	25
FOXY – Full oxyfuel technology	0%	126.67	5.70	25

[a] Where sources provided overnight capital costs, the unit cost per tonne of cement was calculated assuming a 1.2 Mt cement plant (Canada average)
[b] Non-energy operating costs are calculated by multiplying capital costs by 4.5%
[c] Current natural gas use varies by region; British Columbia = 16%, Alberta = 93%, Ontario = 9%, Quebec = 19%, Nova Scotia = 0%

5.5. Decarbonization category scenario results

Over the study period, energy-efficiency technologies mitigate nearly 20 Mt CO_2e and 239 PJ of energy Canada-wide. Regional results vary from 17 kt to 3.4 Mt CO_2e and 0.2 to 38 PJ depending on the baseline energy intensity and energy mix. However, the application of each technology results in negative GHG emission MACs in all regions (**Figure 16**), except optimized particle size distribution in Alberta. The high use of natural gas in Alberta combined with low natural gas prices and a low baseline energy intensity limit the energy and carbon cost savings of the technology, resulting in a positive GHG emission abatement cost for that region. Cumulative GHG mitigation for each technology is shown in **Appendix H – Additional scenario results**.

In every region, alternative binders and chemistries scenarios have GHG emission MACs within the range of -44 to -56 CAD/t CO_2e. The GUL scenario has the lowest GHG emission abatement cost in all regions because it reduces process GHG emissions without measurably increasing electricity consumption per unit of cement produced. Additional clinker substitutes introduced in the GULb25 and GULb35 scenarios require a higher level of grinding and come with larger capital costs to create storage for the clinker substitutes. However, the MACs of the GULb25 and GULb35 scenarios only differ by as much as 1% across each region, meaning variations in energy, capital, and non-energy operating costs between the scenarios are approximately balanced with process emission carbon cost savings from additional clinker substitutes. Over the study period, the GULb35 scenario mitigates over 48 Mt CO_2e, the highest of the alternative binders and chemistries technology scenarios. The GULb25 scenario mitigates the second most at nearly 33 Mt CO_2e, and the GUL scenario mitigates the least at just 9 Mt CO_2e. Furthermore, energy demand over the study period decreases between 45 PJ for the GUL scenario and 233 PJ for the GULb35 scenario because thermal energy intensity decreases with increasing use of clinker substitutes.

A market share analysis of alternative binders and chemistries was completed under three market cost sensitivities. Regional results vary depending on energy intensity, energy cost, and energy mixes, but a Canada-wide weighted average provides a reasonable basis for discussion. By 2030, necessary policies are in place to support the use and manufacturing of blended limestone cements, GULb25 and GULb35. In the low-cost sensitivity scenario ($v = 2$), the blended limestone cements constitute approximately half the market share because of their lower energy requirements and resultant energy cost savings compared to Portland cement and Portland-limestone cement, GUL.

As cost sensitivity becomes higher (v = 6, 10), the impacts of reduced energy demands mean the blended cements achieve market shares of 72% and 82%. By 2050, Portland cement accounts for just 8% and 3% of cement produced under the low and high cost sensitivity scenarios. While GUL production remains high through the 2030s, it is replaced with blended limestone cements through the 2040s and accounts for 35% and 15% of cement produced under the low and high cost sensitivity scenarios.

The results of the market share analysis differ slightly from what the results of the GHG emission abatement cost analysis suggest. For example, the GUL scenario has the most attractive GHG emission abatement cost, yet in 2050, the blended cements GUL25 and GULb35 consistently achieve a larger market share. The reason for the difference is that the GHG emission abatement cost analysis incorporates cumulative GHG mitigation, while the market share analysis does not. Therefore, the market share analysis does not account for the amount of GHG emissions mitigated over the life of the technology or the associated benefits. Instead, it compares the technologies at single points in time and uses the costs and benefits as they are to determine market share. Yet, even with this difference, it is clear from both approaches that transitioning from Portland cement to Portland-limestone and blended limestone cements is advantageous.

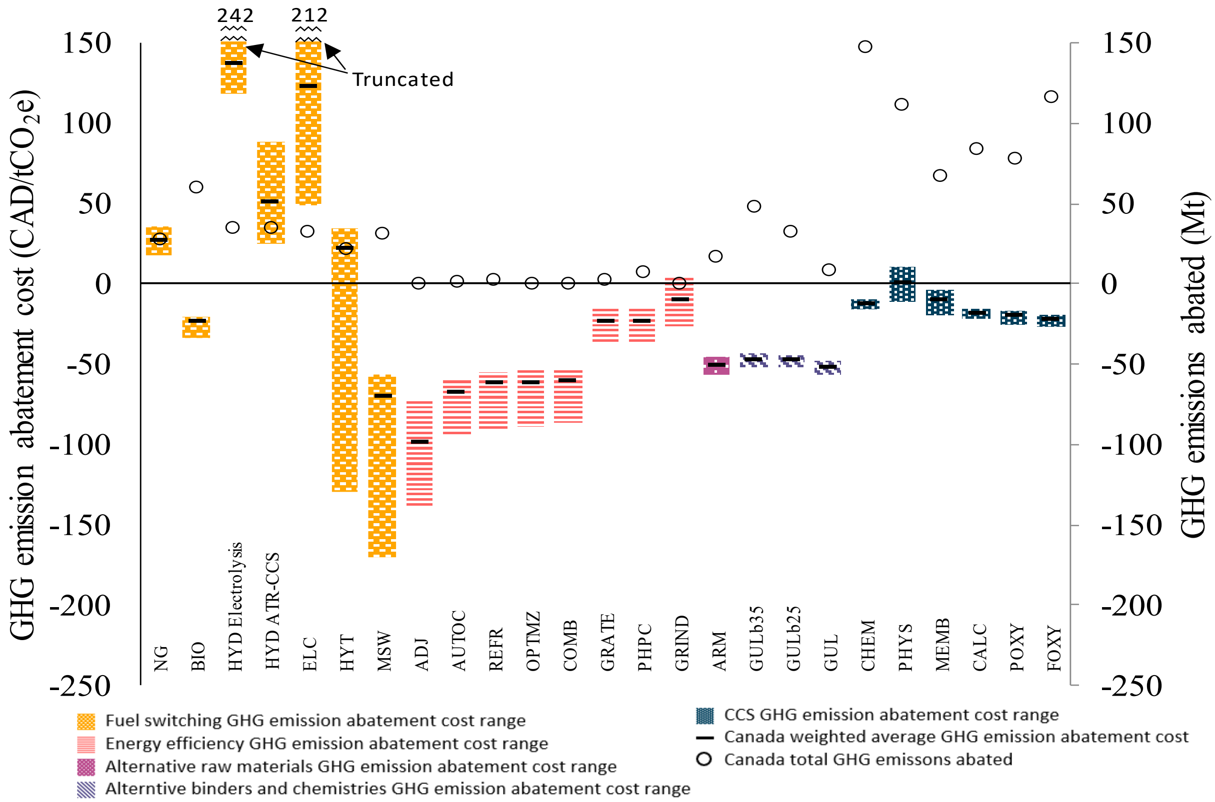

Figure 16. GHG emission marginal abatement costs and abatement for fuel switching, energy efficiency, alternative raw materials, alternative binders and chemistries, and CCS scenarios

5.6. Carbon-neutral scenario results

Several carbon-neutral scenarios are considered in this study, with the results shown in **Figure 17**. Net GHG emissions in the year 2050 range from 0.5 to 1.7 Mt CO_2e before carbonation and -0.2 to -0.9 Mt CO_2e after carbonation. On average, the CCS category accounts for the most significant GHG reductions, ranging from 35-58% of the reductions necessary to achieve carbon neutrality. Conversely, energy efficiency results in the least significant GHG reductions on average, ranging from 0-5%. This is partly because energy-efficient technologies have no impact on process GHG emissions and partly because of the energy-intensive nature of cement manufacturing. Even at a theoretical minimum, the formation of one tonne of Portland cement clinker requires approximately 1.76 GJ [13]. The impact of fuel switching is dependent on the carbon intensity of the fuel and, therefore, varies widely. Using a no-carbon fuel such as hydrogen can reduce GHG emissions by as much as 40%, as shown in the maximum emissions reduction in

2050 scenario. However, using a more economical fuel, like the MSW used in the low GHG emission abatement cost scenario, only mitigates 16% of the GHG emissions necessary to achieve carbon neutrality. The alternative raw materials and alternative binders and chemistries categories account for 5-7% and 3-20% of GHG mitigation, respectively. In each scenario, the impacts of carbonation are necessary to achieve carbon neutrality because CCS achieves at most a 95% capture rate (**Table 10**) and does not mitigate indirect GHG emissions from electricity consumption.

In its sixth assessment synthesis report, the IPCC [1] notes that maintaining global temperature increases to 1.5 or 2 degrees Celsius requires deep and immediate GHG reductions across all sectors. The maximum cumulative reductions pathway provides the largest immediate and cumulative GHG reductions (**Table 13**). Cumulative GHG reductions will be 23 Mt CO_2e by 2030, 84 Mt CO_2e by 2040, and 242 Mt CO_2e by 2050, corresponding to production intensities of 628 kgCO_2e/t cement by 2030, 183 kgCO_2e/t cement by 2040, and carbon neutrality by 2043. However, this scenario has a GHG emission abatement cost of -17 CAD/t CO_2e, the least attractive of all the scenarios, and an energy demand of 86 PJ in 2050, the highest of any carbon-neutral scenario and nearly equal to the reference scenario. Chemical absorption CCS is the primary factor in both outcomes. While it has a higher technology readiness level than other CCS technologies [96] and has been proven in other industries, it requires large amounts of energy, the cost of which erodes carbon cost savings.

Table 13. Cumulative GHG emissions reductions (Mt), 2020-2050, by decarbonization category for each carbon-neutral scenario

	Fuel switching	Energy efficiency	Alternative raw materials	Alternative binders and chemistries	CCS	Carbonation	Total GHG mitigation
Maximum cumulative emissions reductions scenario	70.2	7.4	12.0	34.6	65.9	51.5	241.6
Maximum emissions reduction in 2050 scenario	35.2	12.5	13.9	38.5	53.8	51.5	205.4
Low GHG emissions abatement cost scenario	32.1	13.7	14.7	8.1	73.2	56.8	198.6
Low cost sensitivity (v = 2) market share scenario	44.4	11.7	13.8	24.9	61.9	54	210.7
Moderate cost sensitivity (v = 6) market share scenario	35.8	13.1	14.4	30.6	60.0	53.1	207.0
High cost sensitivity (v = 10) market share scenario	33.5	13.5	14.6	34.4	58.2	52.6	206.8

Regardless of what is necessary to limit global temperature increases and their associated impacts, fiscal responsibility typically plays a central role in the industry, meaning cement producers are likely to adopt technologies that offer the best economic returns. This is explored through multiple distinct scenarios: the low GHG emission abatement cost scenario and the low, moderate, and high cost sensitivity market share scenarios. Each of these scenarios has a similar comprehensive GHG emission abatement cost, ranging from -31 to -34 CAD/t CO_2e for the low to high cost sensitivity market share scenarios and -33 CAD/t CO_2e for the low GHG emissions abatement cost scenario. Furthermore, cumulative GHG emission reductions are similar for all of these scenarios, ranging from 199 to 211 Mt CO_2e, but less than what is possible under the maximum cumulative emissions scenario. Energy demand in 2050 is also similar, at 54 to 59 PJ, over 30% less than the maximum cumulative emissions scenario and over 10% less than the reference scenario's first year in 2020. In the low GHG emission abatement cost scenario, carbon neutrality is not achieved until 2048, while carbon neutrality is achieved in all market share scenarios by 2047.

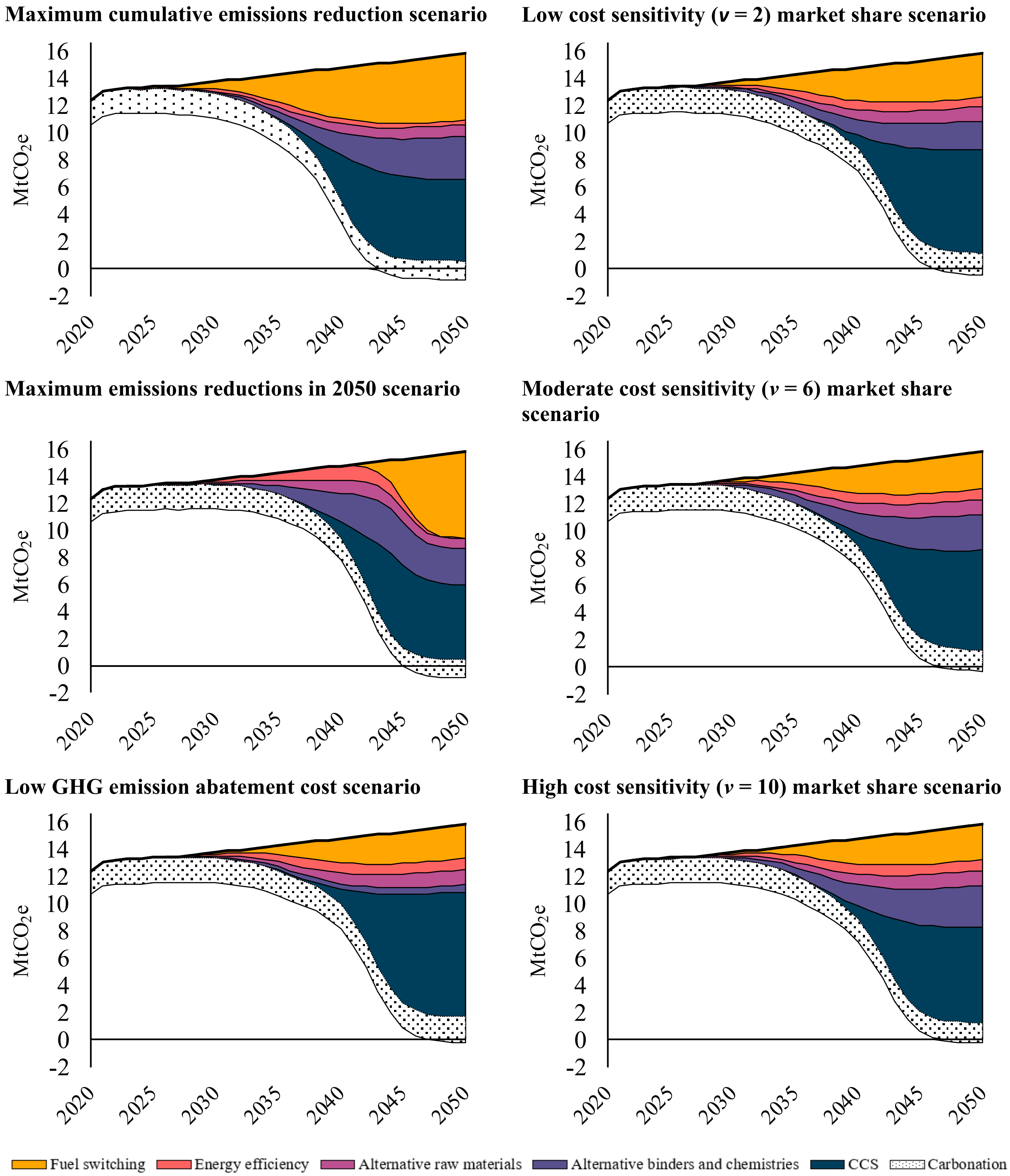

Figure 17. CO_2e emissions reductions for carbon-neutral scenarios with additive GHG emission abatement cost and cumulative emissions reductions, at a carbon price of 170 CAD/t CO_2e by 2030

5.7. Interactions between decarbonization categories

The impact of the alternative raw materials and the alternative binders and chemistries categories varies depending on the fuel being used. As the carbon content of the fuel mix decreases, the GHG impacts of energy intensity reductions lessen. The maximum cumulative emissions reduction and maximum emissions reductions in 2050 scenarios demonstrate this because they apply the same alternative raw materials and alternative binders and chemistries technologies but use different fuels, resulting in differences of 14% and 10% in cumulative emissions reductions, respectively, between the scenarios. Similarly, the impact of carbonation will vary depending on the alternative binders and chemistries technologies applied. The carbonation impact on GHG emissions is directly proportional to the volume of process emissions created. Therefore, technologies that limit process emission intensity limit carbonation impacts. With the Tier 1 carbonation method, for every 1 Mt CO_2 reduction in process emissions, carbonation will decrease by 0.23 Mt CO_2. Conversely, carbonation impacts will increase in scenarios with higher process emissions. The low GHG emission abatement cost scenario uses GUL, resulting in a higher clinker/cement ratio than the scenarios that strictly transition to GULb35. Therefore, process emissions will be higher in the low abatement scenario, meaning carbonation values are greater. CCS technologies considered in the carbon-neutral scenarios do not impact the process emissions created but only capture them after they have been created, so they do not impact carbonation results.

5.8. Roadmap comparison

The impacts of each decarbonization category for the maximum cumulative GHG emissions reduction, low GHG emission abatement cost, and moderate cost sensitivity market share scenarios are compared with the roadmaps for Europe [8] and China [54] in **Table 14**. Both roadmaps present the impacts of decarbonization categories in terms of carbon intensity, making them useful for comparing with the results of this study. In all three roadmaps, CCS results in the largest GHG emissions abatement. CCS abatement in the maximum cumulative emissions scenario is comparable to Europe, but, in general, CCS plays a more significant role in Canada. A contributing factor is that China and Europe anticipate clinker/cement ratios to decrease to 57% and 65% by the end of their roadmaps, while the low GHG emission abatement cost and market share (v = 6) scenarios anticipate average clinker cement ratios of approximately 85% and 74% by 2050, respectively, meaning a higher level of process GHG emissions that can only be abated through CCS. Furthermore, China and Europe already have significantly lower clinker/cement ratios than Canada, meaning even with further reductions they do not expect as much GHG abatement through this pathway as Canada. GHG emission abatement from fuel switching in the low GHG emission abatement cost and market share (v = 6) scenarios align with the Europe and China roadmaps because they all focus on the use of alternative fuels, such as waste fuels with an organic component. However, Canada's 63-65% share of alternative fuels is still expected to lag Europe's 90% and China's 80% anticipated shares. The maximum cumulative GHG emissions reduction scenario for Canada follows a transition to biomass and hythane, resulting in greater GHG emissions reductions but with less attractive financial returns. The Europe and China roadmaps also quantify the impact of decarbonizing electricity through on-site renewables. This study does not explore the impact of decarbonizing electricity in this study because, on a grid level, Canada is pursuing a clean electricity standard that would achieve net-zero electricity by 2035 [90], and any changes that occur at the grid level beyond the reference scenario are outside the scope of this study.

Table 14. A comparison of decarbonization pathway impacts, in kg/t CO_2e avoided, for the Europe and China roadmaps, and Canada carbon-neutral scenarios

	Other roadmaps[1]		**Carbon-neutral scenarios**		
Decarbonization pathway	**Europe 2018-2050**	**China 2020-2060**	**Max. cumulative emissions reduction 2020-2050**	**Low GHG emission abatement cost 2020-2050**	**Market share (v = 6) 2020-2050**
FS	-90	-95	-240	-122	-134
EE	-26	-140	-15	-39	-37
ARM	-27	-47[2]	-43	-55	-53
ABC	-89		-154	-26	-129
CCS	-280	-205	-292	-449	-357
CAR	-51	-53	-29	-83	-63

[1]Canada's published roadmap does not offer a quantitative assessment of decarbonization category impacts, so it is not included for comparison with the carbon-neutral scenarios

[2]China's roadmap combines the impacts of alternative raw materials and alternative binders and chemistries under the alternative raw materials pathway

5.9. Sensitivity analysis

A sensitivity analysis for individual fuel switching and CCS technologies was conducted as part of **Chapter 3** and **Chapter 4**. A sensitivity analysis of energy efficiency, alternative raw material, and alternative binder and chemistries technologies to energy prices, carbon prices, and interest rates was conducted as part of this sections, and the results of the analysis are included in **Appendix K – Energy-efficient technology, alternative raw materials, and alternative binders and chemistries sensitivity analysis**.

Several roadmaps based upon differing criteria are considered in this study with the intent of offering a range of possible outcomes and perspectives on the significance of each decarbonization pathway in relation to the roadmap criteria. Each roadmap is analyzed under differing carbon price scenarios, increasing in 10 CAD increments from no carbon price (CP0) to a carbon price of 350 CAD/t CO_2e by 2030 (CP350). The results of this analysis highlight the lowest carbon price for which each carbon-neutral scenario can achieve a negative GHG emission abatement cost, also called the breakeven carbon price. The maximum cumulative emissions reduction scenario has a Canada-wide breakeven carbon price of 120 CAD/tonne of CO_2e by 2030, with regional breakeven carbon prices ranging from 90-140 CAD/tonne of CO_2e. The maximum GHG emissions reduction in 2050 scenario has a Canada-wide breakeven price of 90 CAD/tonne of CO_2e by 2030, with regional breakeven carbon prices ranging from 60-120 CAD/tonne of CO_2e. The low GHG emission abatement cost and all the market share scenarios have Canada-wide breakeven prices of less than 50 CAD/tonne of CO_2e by 2030, with only Nova Scotia and Ontario having higher breakeven prices of 70-80 CAD/tonne of CO_2e. At a carbon price of 0 CAD/tonne of CO_2e, all carbon-neutral scenarios in all regions have positive MACs, meaning that some level of external economic incentive is necessary to support the transition to carbon neutrality.

5.10. Limitations

The technology MACs and roadmaps discussed in this study reflect the data that was available during this study. Technological advancements, or setbacks, may impact the prominence of decarbonization categories within the overall roadmap. Furthermore, the roadmaps assume that full market adoption can be achieved by necessary technologies in each pathway by 2050. This outcome is highly dependent on commercialization, technical maturity, availability, codes, and standards, and, in the case of fuel switching, the stable and adequate supply of the fuel to cement production facilities. Furthermore, cement plants may not adopt the same technologies or adopt technologies at the same time.

The cement chemistries explored in this study do not consider potential market shares of novel types of cement such as belite clinker cements, magnesium-based clinker cements, and carbon curing cements. These cements are typically still in the research or prototyping phase [96] and are not expected to replace Portland clinker cement for the foreseeable future [93]. Also, the impact of fuel switching on clinker quality must be fully understood as trace elements are incorporated into the clinker during sintering, or released into process equipment and the atmosphere [49]. For example, the chlorine content of fuels is monitored to limit the formation of hydrochloric gas, which forms hydrochloric acid when in contact with water vapour. Hydrochloric gas emissions are regulated, and hydrochloric acid can damage process components over time. Trace metal contents are also a concern, as described by Horsley et al. [63].

In this study, the CO_2 abatement of carbonation is calculated using the Tier 1 method. The Tier 2 and Tier 3 methods are more data-intensive and considered more accurate [111]. Furthermore, differing cement chemistries have the potential to impact the rate, depth, and volume of carbonation, but these distinctions are not captured using the Tier 1 method. No Tier 2 or Tier 3 studies exist for Canada, but these studies could be undertaken to improve the accuracy and understanding of the carbonation category as it relates to cement products in Canada.

Finally, research into carbonation is not new, and would not be complete without acknowledging the challenges introduced by carbonation. In their discussion of carbonation, Stripple et al. [111] acknowledge the breadth of research that has been undertaken on carbonation dating back decades. Historically, carbonation was considered unfavorable due to its impact on the alkalinity of cement based materials, and only in the last 15 years has there been a growing focus on the potential benefit of cement based materials as a carbon sink [112]. However, the downsides of carbonation have not gone away and must be managed to ensure the integrity of reinforced concrete structures. Carbonation decreases the alkalinity of cement based materials, including concrete, as the CO_2 migrates through the pore network and dissolves in the pore solution [113]. The lower alkaline environment makes steel in the concrete more susceptible to corrosion. The issue if further propagated when corroding steel induces cracking in the surrounding concrete due to rust expansion. The cracking then facilitates quicker penetration of CO_2 into the pore network.

5.11. Policy implications

The results of this study show that carbon neutrality can be achieved by 2050 with negative MACs. When forming future policies, policymakers can consider the following observations:

1. Among the carbon-neutral scenarios explored, CCS plays the largest role in abating GHG emissions because of the unavoidable emissions released during the calcination of limestone. In this study it is assumed that CCS technology is first commercially available in 2030, and any delay to commercial availability will impact cumulative GHG emissions reductions. A 95% capture rate is also assumed for both CCS technologies included in carbon-neutral scenarios, meaning the inability to achieve this capture rate may jeopardize the ability for cement production to achieve carbon neutrality. Therefore, it is important that the commercialization of CCS with full capture potential is supported through demonstration projects. Furthermore, capturing CO_2 is only one function of CCS technology. The planning, development, and testing of transportation and storage networks is necessary to ensure captured CO_2 can be moved off-site to create value-added products or for sequestration. In the short term, it appears that amine-based chemical absorption technologies are likely to be the first technologies commercially available for CO_2 capture. The results indicate that up to 66 Mt CO_2 can be captured under the maximum cumulative emissions scenario, but the high capital cost and energy demand will be a barrier to adoption. An earlier study [107] shows that breakeven carbon prices for amine-based chemical absorption CCS range from 110 to 130 CAD/tonne by 2030 in Canada's cement-producing regions. Oxyfuel combustion is an alternative with a lower capital cost and energy demand but is not as technically mature and still requires carbon prices ranging from 60 to 90 CAD/tonne by 2030 to break even.
2. Switching to the consumption of biomass or MSW in the precalciner offers differing incentives. MSW has the lowest MAC of all fuel scenarios considered, but as we found in our earlier study, its cumulative GHG emissions reduction of 32 Mt CO_2e in the low abatement cost scenario falls short of the 70 Mt CO_2e reduced when biomass is consumed

[91]. While existing kiln technologies support the immediate adoption of both fuels, and there is enough nation-wide supply of MSW and biomass [87, 91] to meet the energy requirements of cement production, reliable and consistent supply chains must be established to support cement producers. Additionally, regional biomass and MSW availability and suitability must be studied. Finally, research and testing will be necessary to ensure the chemical composition of MSW and biomass fuels does not negatively impact the production equipment or the cement product through the introduction of high levels of chlorine, sulfur, or dioxins.

3. Hydrogen is a fuel that can effectively eliminate combustion emissions in the long term, thereby reducing the amount of CO_2 that must be captured, transported, and sequestered. However, the high cost of hydrogen makes it less attractive than other fuel switching options [91]. Additionally, replacing conventional fossil fuels with hydrogen requires new kiln and burner designs [68], meaning research, development, and demonstration of new kilns and burners will be necessary to support the adoption of hydrogen. Reliable hydrogen supply chains will also be necessary to ensure an adequate supply of hydrogen to industry. Finally, the upstream GHG emissions of hydrogen production should also be considered. Low-carbon hydrogen can be produced using renewable-powered electrolysis or hydrogen produced from steam methane reforming or autothermal reforming with integrated carbon capture. However, hydrogen produced without carbon capture just transfers GHG emissions from the cement plant to the hydrogen plant. Even if not used to meet all thermal energy requirements, hydrogen can be paired with biomass to create a near-zero carbon fuel mix.
4. Carbon neutrality is not possible without carbonation or a different offset. The results indicate that 0.5 to 1.7 Mt CO_2e remain in 2050 after each other decarbonization category is applied, but net emissions range from -0.2 to -0.9 Mt CO_2e after carbonation. Given that carbonation is not yet included in the IPCC Guidelines for National Greenhouse Gas Inventories [5], there is no formal process for establishing carbonation offsets. Furthermore, Tier 2 and Tier 3 carbonation studies require increasingly extensive knowledge of existing building stocks, cement products, and cement production [111]. Tier 3 also requires advanced computer models that account for cement properties that impact CO_2 absorption rates and depth. To support the development of national carbonation

models, frameworks that guide the calculations and databases that include pertinent information should be developed. The frameworks should also include directions on how carbonation offsets will be split among the cement and concrete industries to avoid double counting. In this study, we have allocated all carbonation impacts to cement manufacturing.

5.12. Key results

This study complied and analyzed decarbonization technologies, arranged them by category, and created several carbon-neutral roadmaps for Canadian cement production. The roadmaps are based on differing criteria to understand the relevance of each category in relation to the roadmap criteria. In every roadmap, the comprehensive GHG emission abatement cost is negative, meaning the combined benefits of the technologies in the roadmap outweigh the costs. However, achieving more immediate and higher cumulative emissions reductions means accepting less attractive GHG emission MACs than offered by other scenarios. In the highest cumulative emissions reduction scenario, carbon neutrality is achieved by 2043, whereas the other scenarios achieve carbon neutrality in 2047 or 2048.

The Canada roadmaps outlined are generally comparable to the Europe and China roadmaps, with a few important distinctions. Canada is expected to rely more heavily on CCS to achieve carbon neutrality because of its higher clinker/cement ratios and resultant process emissions. Furthermore, alternative fuel use is less than that projected by Europe and China at the end of their roadmaps, indicating higher levels of combustion emissions in Canada that must be captured.

Continuing support of CCS research, development, and deployment is necessary to achieve carbon-neutral cement production. Further to that, lower clinker/cement ratios will reduce the energy and GHG emissions intensity of cement. Immediate progress can be made through the adoption of Portland limestone cement, and limestone cement blends offer the opportunity for continued progress in the near future. Similarly, waste fuels and biomass offer near-term combustion GHG emission reductions, while hydrogen offers the potential for further future reductions. Finally, policymakers can strive to continue to create environments that promote deep and immediate GHG reductions. The low GHG emission abatement cost and market share scenarios discussed demonstrate that meaningful reductions are possible with favourable economic returns. Continued policy development focusing on extending the list of technologies that generate favourable economic returns and making vital technologies, such as CCS, available sooner will help Canada to achieve carbon-neutral cement production.

Chapter 6. Conclusions and Recommendations for Future Research

The most recent IPCC synthesis report predicts climate impacts of greater extent and severity than previous reports and calls for immediate GHG emission reductions to limit the impacts of human-caused global warming [1]. As the second-largest global industrial emitter [2], the cement sector will face increasing pressure to decarbonize. However, cement production is generally considered hard to abate because it is energy intensive and over half of the GHG emissions are from the process of calcination. Yet, several technological levers are available to cement producers to help abate GHG emissions, typically categorized as fuel-switching, energy-efficient technologies, alternative raw materials, alternative binders and chemistries, and CCS. Furthermore, the CO_2 absorbed during the natural phenomenon of carbonation has historically been disregarded but is now being acknowledged as an important component in building an accurate carbon-neutral roadmap.

Existing studies exploring fuel-switching primarily focus on alternative fuels such as waste fuels and biomass, ignoring the many other fuel-switching technologies currently available to the industry or being developed. Similarly, studies that explore CCS often generalize the technology or limit their assessment to a single CCS technology, and transport and sequestration costs for the captured CO_2 are often not included when CSS technology costs are evaluated. In this research, several fuel-switching and CSS options are directly compared, including CO_2 transport and sequestration costs. This provides policymakers with a direct comparison of the GHG emissions abatement potential, costs, and benefits of each technology. Finally, very few studies apply all of the decarbonization categories in parallel, making it difficult to discern cross-category impacts and understand the role each category is likely to play in achieving sectoral carbon neutrality. In this research several carbon-neutral scenarios were created based on differing economic and GHG emissions abatement criteria, highlighting the extent that each decarbonization category may play in achieving carbon neutrality under those criteria. An energy and GHG emissions model for Canada was developed and formed the basis to which decarbonization technologies and carbon-neutral scenarios were applied. The base model was validated against publicly available government data from 1990-2019 and used to project energy demand and GHG emissions for the study period, 2020-2050. While the underlying model was built based on Canadian cement production, the results are applicable to much of the international community. The five cement-producing subnational regions in Canada differ in production volumes, energy prices, and baseline fuel mixes, making the regional results applicable to a wider range of cement- producing jurisdictions. Furthermore, all cement produced in Canada is manufactured using dry-process technology, similar to much of the international community.

Of the fuel-switching scenarios explored, transitioning to MSW in the precalciner offered the lowest abatement costs across each cement-producing region in Canada (**Figure 18**) and reduced cumulative combustion and indirect GHG emissions by 9% over the study period. Yet transitioning to biomass in the precalciner offered nearly twice the GHG emissions reductions, at 18% less than the reference scenario. Biomass as an energy source is considered nearly carbon neutral and has much lower emissions when compared to fossil fuels. Biomass also achieved negative abatement costs in every region; however, the additional GHG emissions reductions came with higher abatement costs compared to MSW. The more transformative fuel-switching technologies of thermal energy electrification and hydrogen reduced combustion and indirect emissions in 2050 by 89-98% but at very large GHG emission abatement costs in every region because of high capital and energy costs. Hydrogen produced from ATR-CCS had a much lower abatement cost than electrolytic hydrogen but is still not competitive with MSW and biomass. These results highlight the economic potential of MSW and biomass as fuels in the cement sector, if stable supply chains and a consistent fuel quality can be established. Other methods of greatly reducing combustion and indirect emissions are available in the long term but are not as financially attractive because of higher capital and energy costs. A market share analysis also identified MSW as the fuel with the highest shares under multiple market cost-sensitivity scenarios, with increasing levels of biomass as the cost sensitivity decreased. Electrification of thermal energy and hydrogen did not capture any share of the market because of their high costs.

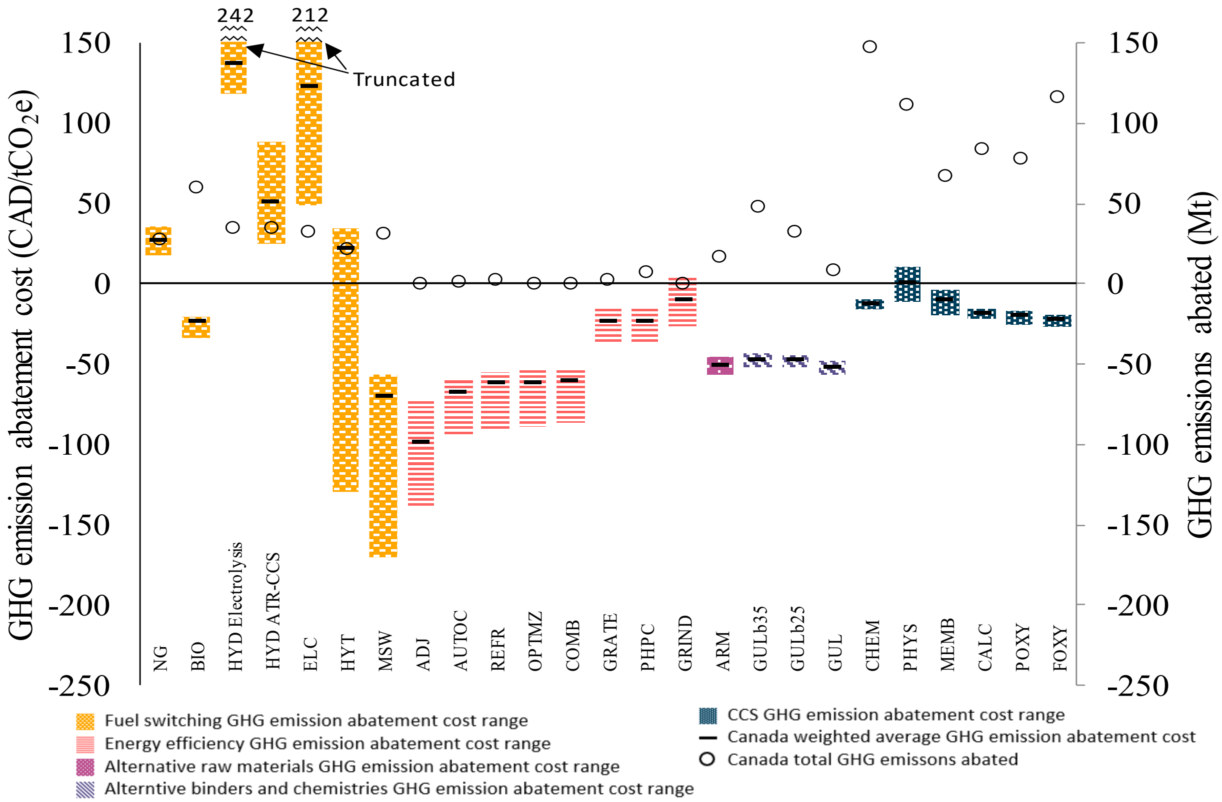

Figure 18. GHG emission marginal abatement costs and abatement for fuel-switching, energy efficiency, alternative raw materials, alternative binders and chemistries, and CCS scenarios

Of the CCS technologies explored, chemical absorption offers the largest cumulative GHG emissions reductions (**Figure 18**) because it is the most developed technology and will likely be ready for widespread deployment earlier than other CCS technologies. However, its high energy demand increases energy costs and erodes the benefits of CO_2 emissions reduction. Similarly, the high energy demand of physical adsorption increases energy costs to the point that the technology has positive abatement costs in two of the five cement-producing regions in Canada. Under the current carbon price schedule, all other CSS technologies evaluated have negative abatement costs. A cost-benefit analysis revealed that while capital cost and carbon costs are generally constant among the cement-producing regions, energy costs vary and exceed capital costs for many technologies. Therefore, energy cost increases are a real risk impacting CCS technologies. To mitigate this risk, technologies with lower energy costs such as oxyfuel combustion can be selected. The potential for the elimination or reduction of carbon pricing is also a risk impacting

CCS technologies. A sensitivity analysis determined that a carbon price of at least 90 CAD/t CO_2e is necessary to ensure there is at least one financially attractive CCS technology in each cement-producing region in Canada,

Energy-efficiency technologies, alternative raw materials, and alternative binders and chemistries were combined with fuel-switching and CCS technologies in several carbon-neutral scenarios. If cement producers were to aim for maximum emissions reductions between 2020 and 2050, 96% of GHG emissions could be abated through technological means (**Figure 19**). If cement producers were to adopt the lowest abatement cost technologies for each decarbonization category, or only negative abatement cost technologies where technologies are mutually exclusive, 89% of GHG emissions could be abated through technological means. While both scenarios highlight that deep emissions reductions are possible, they also confirm that carbon neutrality cannot be achieved through technology alone. CCS cannot capture 100% of direct GHG emissions, and no technology eliminates indirect GHG emissions associated with the use of electricity if electricity is produced using fossil fuels. Therefore, carbonation, or a similar offset, is necessary to achieve carbon neutrality. In recognition of this, it is important that nations begin to establish frameworks to account for the impact of carbonation.

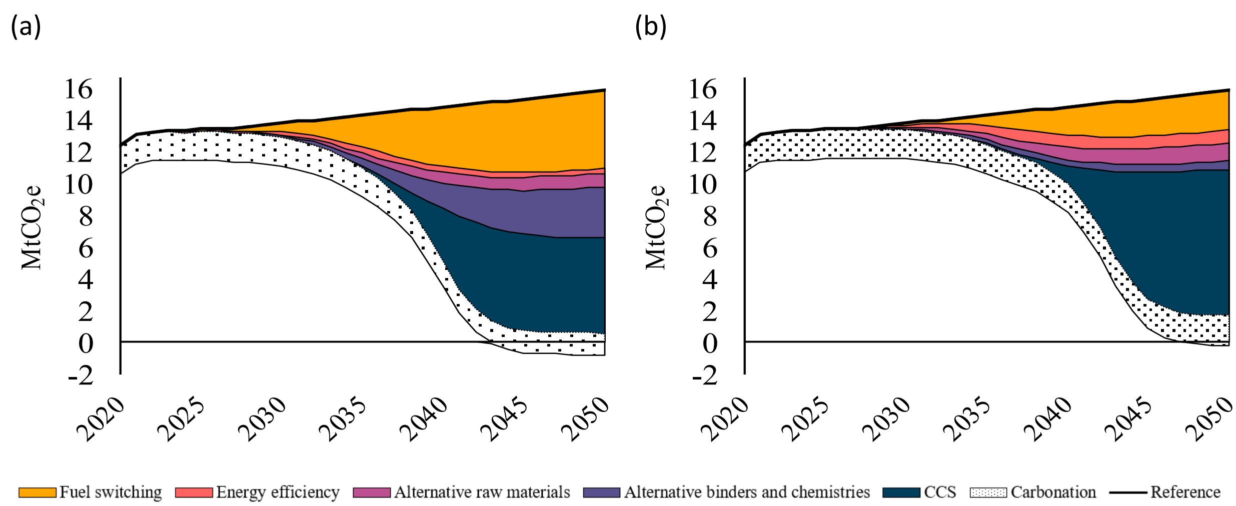

Figure 19. CO_2e emissions reductions for the maximum cumulative emissions reduction and low abatement cost scenarios

In each of the carbon-neutral scenarios evaluated, carbon neutrality can be achieved at negative abatement costs assuming the current carbon pricing schedule that increases to 170 CAD/t CO_2e by 2030. A sensitivity analysis determined a carbon price of at least 140 CAD/t CO_2e by 2030 is necessary to ensure the cost of the maximum cumulative emissions reduction scenario is non-positive in all cement-producing regions, and a carbon price of at least 70 CAD/t CO_2e is necessary to ensure the cost of the low abatement cost scenario is non-positive in all cement-producing regions (**Figure 20**). If carbon prices are abolished and not replaced by a similar incentive program, or reverted to a constant 50 CAD/t CO_2e, it will become uneconomical to achieve carbon-neutral cement production in Ontario and Nova Scotia, and no region will be able to achieve maximum cumulative emissions reduction with a negative abatement cost. Therefore, the continued increase of carbon pricing to at least 70 CAD/t CO_2e by 2030 is important for preserving the potential for maximum cumulative emissions reduction.

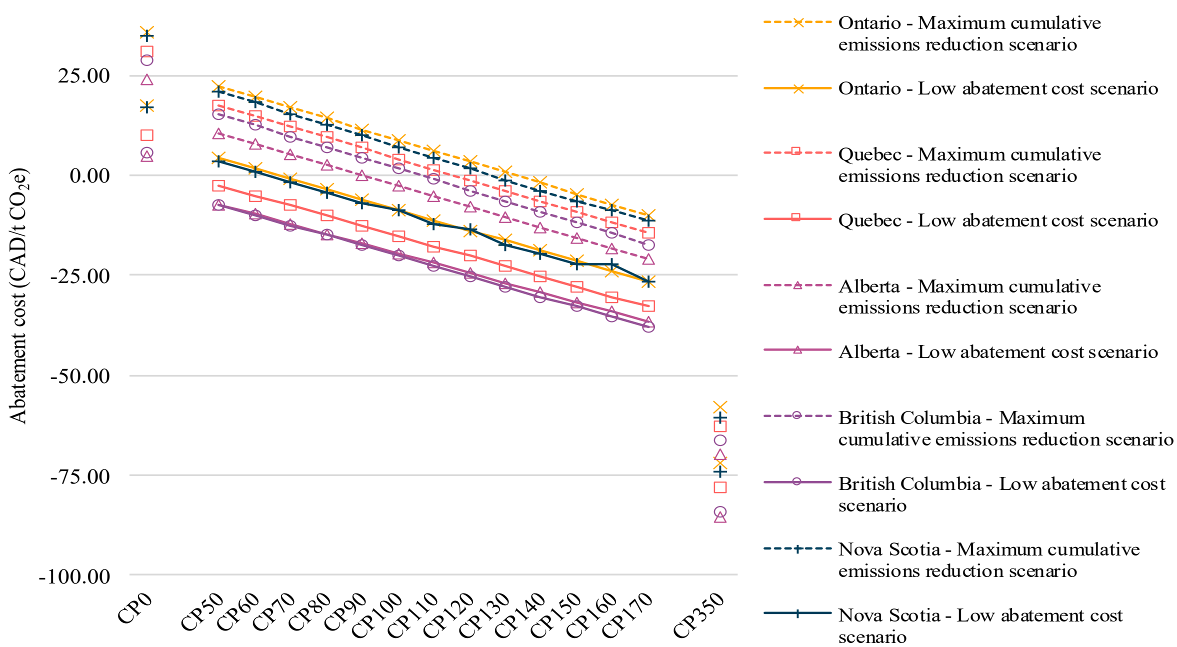

Figure 20. Carbon price sensitivity analysis for the maximum cumulative emissions reduction and low abatement cost scenarios for each region

6.1. Recommendations for future research

There are several key areas where this research can be enhanced and complemented.

1. **Updates to reflect technological advancement**: As technologies are further developed and implemented, this research can be updated to include their costs, benefits, energy demand impacts and GHG emission impacts. This is especially true for several of the CCS technologies that are in the research and demonstration phases, such as organic metal framework adsorption and direct separation technology. Canada-specific costs and challenges can be obtained from Lafarge's ongoing CO2MENT demonstration project [20] and other planned feasibility studies and demonstration projects [108]. Furthermore, the nearly two dozen international CCS projects in cement production [108] will provide valuable operational and cost information that can be applied to Canadian cement production models.
2. **Incorporate plant-specific data**: Understanding plant-specific technologies, energy intensities, fuel mixes, and cement products would enhance the accuracy of technology applicability factors and the resultant energy demand, GHG emissions reductions, and abatement costs. Furthermore, understanding raw meal mixtures would facilitate the ability to calculate plant-specific process emission factors, instead of applying a Canada-wide emissions factor, and result in more accurate regional GHG emission forecasting. Finally, this work assumes s-curve-based adoption over the study period. However, cement plants will typically replace or refurbish technologies at or near end-of-life. Knowledge of when major process technologies, such as kilns and grinding equipment, will undergo upgrades will allow for more accurate adoption profiles, resulting in more accurate energy demand and GHG emission reduction projections.
3. **Incorporating regional CO_2 sequestration options based on plant location**:
   As industry adopts and refines carbon capture technology, the demand for long-term cost effective sequestration will increase. In this research, a standard transportation and sequestration cost of 13.44 CAD/tCO_2e [52] was used. However, regional sequestration options and costs may vary by region, and plant location will impact transportation methods and distances. Western Canada has the opportunity to sequester carbon through CO_2-enhanced oil recovery at lower costs than using saline aquifers [114], although saline aquifer sequestration is expected to become more economical as carbon prices increase.

Carbon source-sink matching can provide insight into possible sequestration options for specific emitters, including cement plants, but actual sequestration options will be dictated by future projects and CO_2 transportation infrastructure. Future research that proposes specific projects to support regional carbon source-sink matching will enhance the understanding of regional sequestration costs.

4. **Perform Tier 2 and Tier 3 carbonation studies**:

   The carbonation impacts included in this research are based on a Tier 1 method in which an estimated CO_2 absorption factor is applied to process emissions. However, proposed Tier 2 and Tier 3 methods provide increasingly accurate estimates of CO_2 absorption over the life of concrete products. The Tier 2 method begins to account for specific concrete applications. Multiple applications, accounting for at least 65% of cement consumption, must be identified and specific parameters including quality, cement content, exposure types and surface area are collected [111]. The mean CO_2 absorption for each application over at least a 10-year period can then be used to assess the total annual CO_2 uptake for each application. Proposed Tier 3 methods rely on advanced, data-intensive computer models that include the use of alternative binders (such as fly ash and slags) and their specific CO_2 uptake values, concrete surface environments (such as temperature and moisture), and concrete surface treatments.

   A limited number of Tier 2 and Tier 3 carbonation studies exist internationally. Andersson et al. [115] discuss five existing Tier 2 studies and 2 existing Tier 3 studies, but no such study exists for Canada. Therefore, to more accurately assess CO_2 uptake from carbonation and the interactions between carbonation and the alternative raw materials and alternative binders and chemistry categories, advanced methods should be applied to Canadian cement production.

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Appendices

Appendix A – Model input parameters

Table 15. Energy prices for the first and last scenario years

	Electricity (2020 CAD/GJ)		Natural gas (2020 CAD/GJ)		Fuel oil (2020 CAD/GJ)	
Province	**2020**	**2050**	**2020**	**2050**	**2020**	**2050**
British Columbia	25.16	26.10	4.98	8.84	29.55	35.83
Alberta	17.77	29.19	2.52	6.97	29.53	35.75
Ontario	45.97	61.63	6.27	10.73	22.14	31.44
Quebec	17.04	22.65	5.61	9.73	24.75	32.70
Nova Scotia	32.56	42.37	4.29	8.74	26.95	34.40

	Coal (2020 CAD/GJ)		Petroleum coke (2020 CAD/GJ)		Waste (2020 CAD/GJ)	
Province	**2020**	**2050**	**2020**	**2050**	**2020**	**2050**
British Columbia	1.94	1.94	1.94	1.94	0.00	0.00
Alberta	1.94	1.94	1.94	1.94	0.00	0.00
Ontario	1.94	1.94	1.94	1.94	0.00	0.00
Quebec	1.94	1.94	1.94	1.94	0.00	0.00
Nova Scotia	1.94	1.94	1.94	1.94	0.00	0.00

	Biomass (2020 CAD/GJ)		ATR-CCS hydrogen (2020 CAD/GJ)		Electrolytic hydrogen (2020 CAD/GJ)	
Province	**2050**	**2050**	**2050**	**2050**	**2020**	**2050**
British Columbia	9.00	9.00	21.40	23.60	59.54	58.37
Alberta	9.00	9.00	16.51	20.85	50.37	62.81
Ontario	9.00	9.00	30.69	35.03	57.18	61.09
Quebec	9.00	9.00	34.41	39.76	49.50	53.40
Nova Scotia	9.00	9.00	42.54	46.88	57.32	61.22

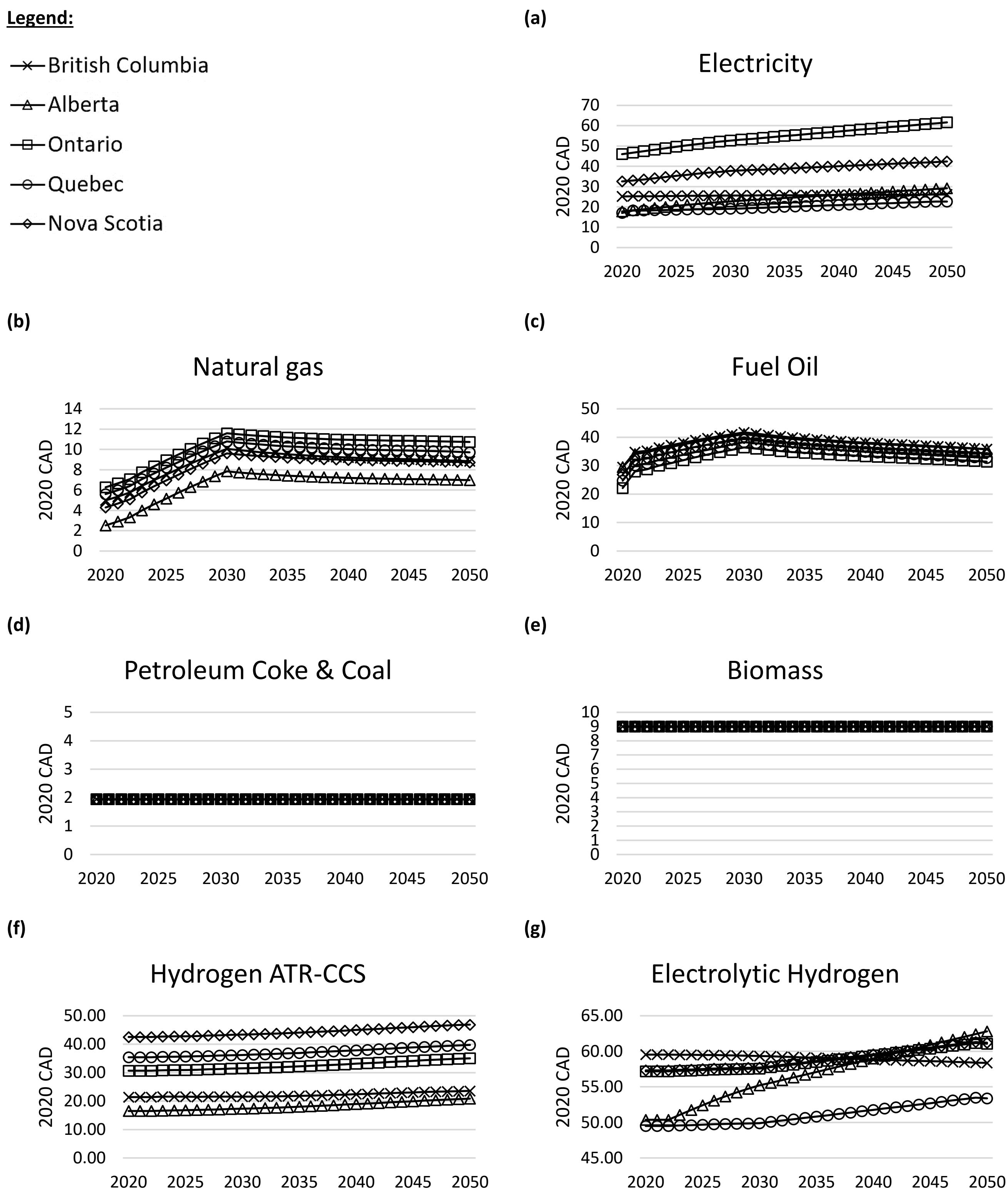

Figure 21. Delivered cost of (a) electricity, (b) natural gas, (c) fuel oil, (d) petroleum coke and coal, (e) biomass, (f) hydrogen from ATR-CCS, and (g) electrolytic hydrogen

Table 16. Forecasted cement production by subnational region

	Annual production (million tonnes)					
	Actual	Estimate		Forecast		
Geographic region	2018	2019	2020	2030	2040	2050
British Columbia	2.31	2.20	2.35	2.64	2.84	3.06
Alberta	3.09	3.07	2.64	2.97	3.21	3.45
Ontario	6.11	5.97	6.82	7.67	8.27	8.91
Quebec	3.54	3.81	3.63	4.09	4.40	4.74
Nova Scotia	0.28	0.28	0.35	0.39	0.42	0.46
Canada	**15.33**	**15.33**	**15.79**	**17.77**	**19.15**	**20.63**

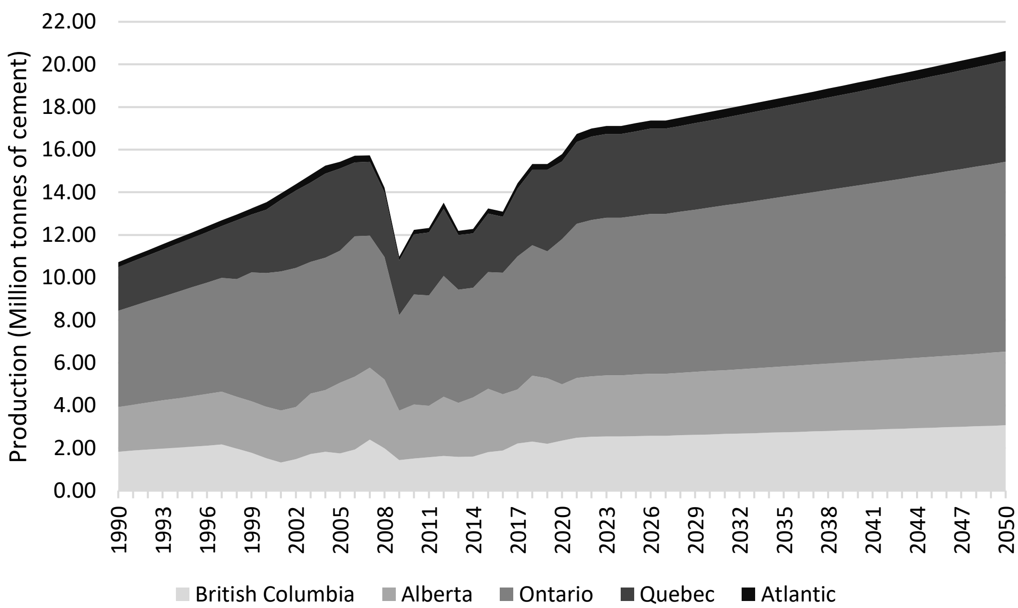

Figure 22. Cement production by subnational region, 1990-2050

Table 17. S-curve parameters for each decarbonization technology

Category and scenario	First year of commercialization, SY	P1	P2
1. Fuel-switching (FS)			
NG – Natural gas	2020	0.4	0.9
MSW – Municipal solid waste	2020	0.4	0.9
BIO – Biomass	2020	0.4	0.9
HYD – Hydrogen	2040	1.0	1.0
ELC – Electrification	2040	1.0	1.0
HYT – Hythane	2030	See NG and HYD parameters	
2. Energy efficiency (EE)			
PHPC – Preheater/precalciner best available technology	2020	0.4	0.9
ADJ – Adjustable speed drive for kiln fan	2020	0.4	0.9
REFR – Improved refractories	2020	0.4	0.9
COMB – Combustion system improvements	2020	0.4	0.9
GRATE – Reciprocating grate clinker cooler	2020	0.4	0.9
OPTM – Optimize grate clinker cooler	2020	0.4	0.9
GRIND – Optimized particle size distribution	2020	0.4	0.9
AUTOC – Upgraded automation & control	2020	0.4	0.9
3. Alternative raw materials (ARM)	2020	0.4	0.9
4. Alternative binders and chemistries (ABC)			
GUL – Portland limestone cement	2020	0.4	0.9
GULb 25 – Blended limestone cement 25	2030	0.4	0.9
GULb 35 – Blended limestone cement 35	2030	0.4	0.9
5. Post-combustion CO_2 capture technologies (CCS) [107]			
CHEM – Chemical absorption	2030	0.9	0.9
PHYS – Physical adsorption	2035	0.9	0.9
MEMB - Membrane separation	2040	0.9	0.9
CALC – Calcium looping	2040	0.9	0.9
POXY – Partial oxyfuel technology	2035	0.9	0.9
FOXY – Full oxyfuel technology	2035	0.9	0.9

Appendix B – Subnational model validation

Table 18. Final energy demand validation by subnational region

	British Columbia			Alberta			Ontario			Quebec			Nova Scotia		
Year	**LEAP**	**NRCAN**	**% Diff.**	**LEAP**	**NRCAN**	**% Diff.**	**LEAP**	**NRCAN**	**% Diff.**	**LEAP**	**NRCAN**	**% Diff.**	**LEAP**	**NRCAN**	**% Diff.**
1990	6.40	6.44	-1%	7.92	7.95	0%	29.30	27.93	5%	13.74	13.51	2%	1.80	1.77	1%
1991	6.97	7.01	0%	7.00	6.93	1%	22.89	21.64	6%	12.72	12.44	2%	1.40	1.38	1%
1992	8.57	8.59	0%	7.41	7.33	1%	24.06	23.33	3%	10.38	10.20	2%	1.10	1.07	3%
1993	8.33	8.29	0%	8.03	8.03	0%	23.28	22.57	3%	10.91	10.82	1%	1.30	1.28	1%
1994	8.91	8.89	0%	7.83	7.99	-2%	26.90	27.45	-2%	13.58	13.64	0%	1.20	1.18	2%
1995	10.50	10.49	0%	9.37	9.49	-1%	27.72	27.94	-1%	13.08	13.07	0%	0.90	0.92	-2%
1996	9.82	9.78	0%	8.34	8.52	-2%	27.93	27.85	0%	12.26	12.28	0%	1.00	1.01	-1%
1997	11.59	9.59	21%	10.39	10.30	1%	29.49	28.01	5%	10.19	10.08	1%	0.90	0.87	4%
1998	10.51	10.52	0%	10.60	10.61	0%	28.59	28.48	0%	10.68	10.65	0%	1.00	1.03	-2%
1999	9.81	9.76	1%	10.91	10.88	0%	32.18	31.36	3%	10.75	10.65	1%	0.60	0.64	-6%
2000	11.43	11.43	0%	11.18	11.18	0%	31.71	31.71	0%	11.08	11.08	0%	1.67	1.67	0%
2001	11.13	11.13	0%	10.44	10.44	0%	30.76	30.76	0%	10.81	10.81	0%	1.05	1.05	0%
2002	11.47	11.47	0%	10.63	10.63	0%	34.10	34.10	0%	10.61	10.61	0%	1.22	1.22	0%
2003	10.82	10.82	0%	7.07	7.07	0%	37.48	37.49	0%	10.73	10.73	0%	1.75	1.75	0%
2004	9.93	9.93	0%	9.29	9.29	0%	36.98	36.98	0%	12.72	12.72	0%	1.50	1.50	0%
2005	9.61	9.61	0%	10.66	10.66	0%	37.43	37.43	0%	12.90	12.90	0%	1.64	1.64	0%
2006	12.94	12.94	0%	11.13	11.13	0%	41.26	41.26	0%	8.89	8.89	0%	1.42	1.42	0%
2007	8.65	8.65	0%	10.62	10.62	0%	37.88	38.48	-2%	8.54	8.54	0%	1.13	1.13	0%
2008	8.26	8.26	0%	9.95	9.95	0%	32.24	32.46	-1%	13.02	13.02	0%	1.54	1.54	0%
2009	8.01	8.01	0%	10.01	10.01	0%	32.05	32.26	-1%	10.56	10.60	0%	1.16	1.16	0%
2010	4.89	4.89	0%	10.74	10.74	0%	30.79	31.50	-2%	11.10	11.10	0%	1.22	1.22	0%
2011	7.33	7.33	0%	11.08	11.08	0%	26.71	27.21	-2%	11.18	11.20	0%	1.18	1.18	0%
2012	5.79	5.79	0%	10.15	10.15	0%	26.66	27.16	-2%	12.45	12.44	0%	1.43	1.43	0%
2013	6.77	6.77	0%	10.47	10.47	0%	25.21	25.71	-2%	10.84	10.86	0%	1.13	1.13	0%
2014	11.06	11.06	0%	9.14	9.14	0%	24.32	24.82	-2%	10.89	10.93	0%	1.18	1.18	0%
2015	12.56	12.56	0%	9.18	9.18	0%	22.18	22.18	0%	11.49	11.49	0%	1.24	1.22	2%
2016	14.03	14.03	0%	7.93	7.93	0%	21.29	22.34	-5%	12.18	12.18	0%	1.21	1.21	0%
2017	14.26	14.26	0%	10.46	10.51	0%	21.45	21.55	0%	13.33	13.33	0%	1.34	1.34	0%
2018	16.02	16.02	0%	11.27	11.27	0%	20.40	20.52	-1%	10.93	10.93	0%	1.26	1.26	0%
2019	13.70	13.70	0%	10.62	10.60	0%	23.01	23.20	-1%	15.88	15.80	0%	1.30	1.30	0%

Table 19. Combustion GHG emissions validation by subnational region

	British Columbia			Alberta			Ontario			Quebec			Nova Scotia		
Year	LEAP	NRCAN / NIR Average	% Diff.	LEAP	NRCAN / NIR Average	% Diff.	LEAP	NRCAN / NIR Average	% Diff.	LEAP	NRCAN / NIR Average	% Diff.	LEAP	NRCAN / NIR Average	% Diff.
1990	0.32	0.34	-4%	0.40	0.35	-4%	2.35	2.08	13%	1.03	0.98	-8%	0.15	0.12	9%
1991	0.38	0.37	-3%	0.35	0.31	-5%	1.83	1.62	13%	0.98	0.97	-3%	0.12	0.09	0%
1992	0.59	0.51	-10%	0.38	0.32	-5%	1.92	1.73	11%	0.78	0.76	-8%	0.09	0.07	-8%
1993	0.59	0.52	-12%	0.41	0.35	-4%	1.86	1.66	12%	0.82	0.83	-10%	0.11	0.07	9%
1994	0.60	0.55	-15%	0.40	0.34	0%	2.13	1.97	8%	1.06	1.11	-13%	0.10	0.08	-7%
1995	0.72	0.60	-9%	0.49	0.43	14%	2.20	2.03	9%	1.02	1.02	-15%	0.07	0.08	-23%
1996	0.71	0.60	-16%	0.43	0.42	9%	2.22	2.04	9%	0.95	0.98	-15%	0.08	0.07	0%
1997	0.88	0.56	-25%	0.54	0.50	1%	2.37	2.14	11%	0.76	0.77	-11%	0.07	0.05	-2%
1998	0.75	0.63	-14%	0.56	0.52	3%	2.28	2.08	9%	0.82	0.83	-16%	0.08	0.07	2%
1999	0.77	0.61	-17%	0.58	0.54	3%	2.58	2.36	9%	0.83	0.84	-18%	0.05	0.04	-5%
2000	0.93	0.74	-16%	0.59	0.56	6%	2.53	2.36	7%	0.87	0.88	-14%	0.14	0.13	-3%
2001	0.95	0.74	-17%	0.53	0.53	8%	2.47	2.35	5%	0.84	0.87	-13%	0.09	0.08	-7%
2002	0.97	0.90	-9%	0.54	0.54	5%	2.78	2.54	10%	0.82	0.90	-17%	0.10	0.09	-6%
2003	0.86	0.86	-6%	0.52	0.47	6%	3.07	2.75	12%	0.82	0.89	-16%	0.14	0.13	-5%
2004	0.82	0.80	-9%	0.73	0.69	3%	3.05	2.78	10%	0.99	1.07	-15%	0.12	0.11	-6%
2005	0.74	0.74	-5%	0.84	0.79	2%	3.08	2.80	10%	1.01	1.03	-12%	0.14	0.11	-8%
2006	1.11	1.04	-7%	0.87	0.84	4%	3.39	3.07	11%	0.69	0.76	-14%	0.12	0.11	-5%
2007	0.69	0.68	-10%	0.82	0.80	5%	3.07	2.80	10%	0.66	0.75	-18%	0.09	0.08	-6%
2008	0.62	0.66	-8%	0.77	0.75	5%	2.61	2.34	12%	1.07	1.10	-16%	0.13	0.11	-5%
2009	0.68	0.65	-8%	0.78	0.74	5%	2.63	2.28	15%	0.84	0.88	-13%	0.10	0.09	-4%
2010	0.38	0.38	-14%	0.86	0.79	5%	2.48	2.14	16%	0.86	0.92	-11%	0.10	0.09	-4%
2011	0.58	0.59	-8%	0.88	0.84	4%	2.11	1.94	9%	0.87	0.92	-13%	0.10	0.08	-2%
2012	0.39	0.40	-15%	0.61	0.59	4%	2.11	1.94	9%	0.97	1.00	-15%	0.12	0.11	-1%
2013	0.53	0.47	-17%	0.61	0.61	4%	1.98	1.84	8%	0.80	0.86	-14%	0.09	0.08	-4%
2014	0.88	0.77	-12%	0.53	0.53	4%	1.90	1.78	7%	0.78	0.85	-11%	0.10	0.09	-2%
2015	1.01	0.91	-10%	0.57	0.54	2%	1.71	1.48	15%	0.83	0.92	-10%	0.10	0.09	-3%
2016	1.18	1.08	-8%	0.43	0.39	1%	1.61	1.51	7%	0.83	0.88	-13%	0.10	0.09	-2%
2017	1.21	1.12	-7%	0.57	0.51	-1%	1.68	1.49	13%	0.90	0.97	-8%	0.11	0.10	-2%
2018	1.29	1.17	-5%	0.62	0.55	-2%	1.58	1.40	13%	0.72	0.89	-26%	0.10	0.09	-16%
2019	1.13	0.82	13%	0.53	0.52	-7%	1.79	1.55	15%	1.17	1.24	-14%	0.10	0.08	25%

Table 20. Process emission GHG validation by subnational region

	British Columbia			Alberta			Ontario			Quebec			Nova Scotia		
Year	**LEAP**	**NIR**	**% Diff.**	**LEAP**	**NIR**	**% Diff.**	**LEAP**	**NIR**	**% Diff.**	**LEAP**	**NIR**	**% Diff.**	**LEAP**	**NIR**	**% Diff.**
1990	0.91	0.66	-28%	1.05	0.79	-24%	2.26	2.44	-7%	1.02	1.45	41%	0.11	0.18	60%
1991	0.94	0.55	-42%	1.08	0.55	-49%	2.32	2.15	8%	1.05	1.15	10%	0.12	0.16	36%
1992	0.96	0.62	-36%	1.10	0.63	-43%	2.38	2.26	5%	1.08	1.13	5%	0.12	0.11	-7%
1993	0.99	0.64	-35%	1.13	0.66	-42%	2.44	2.28	7%	1.10	1.15	4%	0.12	0.12	-4%
1994	1.01	0.74	-27%	1.16	0.76	-35%	2.49	2.68	-7%	1.13	1.38	22%	0.13	0.16	24%
1995	1.03	0.81	-21%	1.19	0.86	-28%	2.55	2.98	-14%	1.16	1.56	35%	0.13	0.25	94%
1996	1.06	0.78	-26%	1.21	0.78	-36%	2.61	2.96	-12%	1.18	1.40	18%	0.13	0.21	56%
1997	1.08	0.92	-15%	1.24	1.02	-18%	2.67	3.18	-16%	1.21	1.33	10%	0.14	0.13	-8%
1998	0.99	0.93	-6%	1.21	1.01	-17%	2.76	3.27	-16%	1.38	1.31	-5%	0.14	0.24	71%
1999	0.89	1.14	28%	1.21	1.08	-11%	3.02	3.29	-8%	1.36	1.30	-4%	0.14	0.24	74%
2000	0.76	1.13	48%	1.21	1.03	-15%	3.13	3.58	-13%	1.49	1.26	-16%	0.17	0.23	39%
2001	0.66	1.09	65%	1.22	1.00	-18%	3.27	3.51	-7%	1.67	1.24	-26%	0.16	0.14	-9%
2002	0.74	1.13	52%	1.22	1.08	-11%	3.26	3.42	-5%	1.82	1.28	-29%	0.15	0.23	53%
2003	0.86	1.14	33%	1.42	1.09	-23%	3.09	3.52	-12%	1.86	1.26	-32%	0.18	0.24	33%
2004	0.90	1.24	39%	1.42	1.07	-25%	3.05	3.65	-16%	1.94	1.31	-33%	0.18	0.24	32%
2005	0.86	1.26	47%	1.64	1.09	-34%	3.05	3.70	-18%	1.90	1.33	-30%	0.15	0.25	59%
2006	0.95	1.22	29%	1.67	1.09	-35%	3.23	3.70	-13%	1.70	1.51	-11%	0.15	0.21	36%
2007	1.17	1.25	7%	1.65	1.13	-32%	3.04	3.63	-16%	1.69	1.50	-11%	0.15	0.22	46%
2008	0.98	1.13	16%	1.59	1.06	-33%	2.82	3.25	-13%	1.50	1.33	-11%	0.11	0.22	96%
2009	0.71	0.90	27%	1.14	0.82	-28%	2.20	2.46	-10%	1.26	1.08	-14%	0.09	0.10	16%
2010	0.74	0.98	33%	1.24	0.90	-27%	2.53	2.69	-6%	1.38	1.24	-10%	0.11	0.19	78%
2011	0.76	0.98	29%	1.18	0.90	-23%	2.52	2.70	-7%	1.43	1.24	-14%	0.11	0.19	81%
2012	0.79	1.07	36%	1.33	0.98	-26%	2.73	2.93	-7%	1.51	1.34	-11%	0.14	0.21	54%
2013	0.78	0.98	26%	1.25	0.90	-28%	2.61	2.68	-3%	1.26	1.23	-2%	0.10	0.19	92%
2014	0.77	0.97	25%	1.33	0.89	-33%	2.47	2.65	-7%	1.23	1.22	-1%	0.10	0.19	89%
2015	0.84	1.01	20%	1.40	0.93	-34%	2.56	2.77	-8%	1.29	1.27	-1%	0.11	0.20	82%
2016	0.89	0.96	8%	1.26	1.10	-12%	2.70	2.64	2%	1.24	1.21	-2%	0.11	0.19	69%
2017	1.06	x	x	1.21	x	x	2.98	3.02	-1%	1.52	1.63	8%	0.13	x	x
2018	1.05	x	x	1.41	x	x	2.79	2.92	-4%	1.62	1.60	-1%	0.13	x	x
2019	1.01	x	x	1.40	x	x	2.72	2.77	-2%	1.74	2.08	19%	0.13	x	x

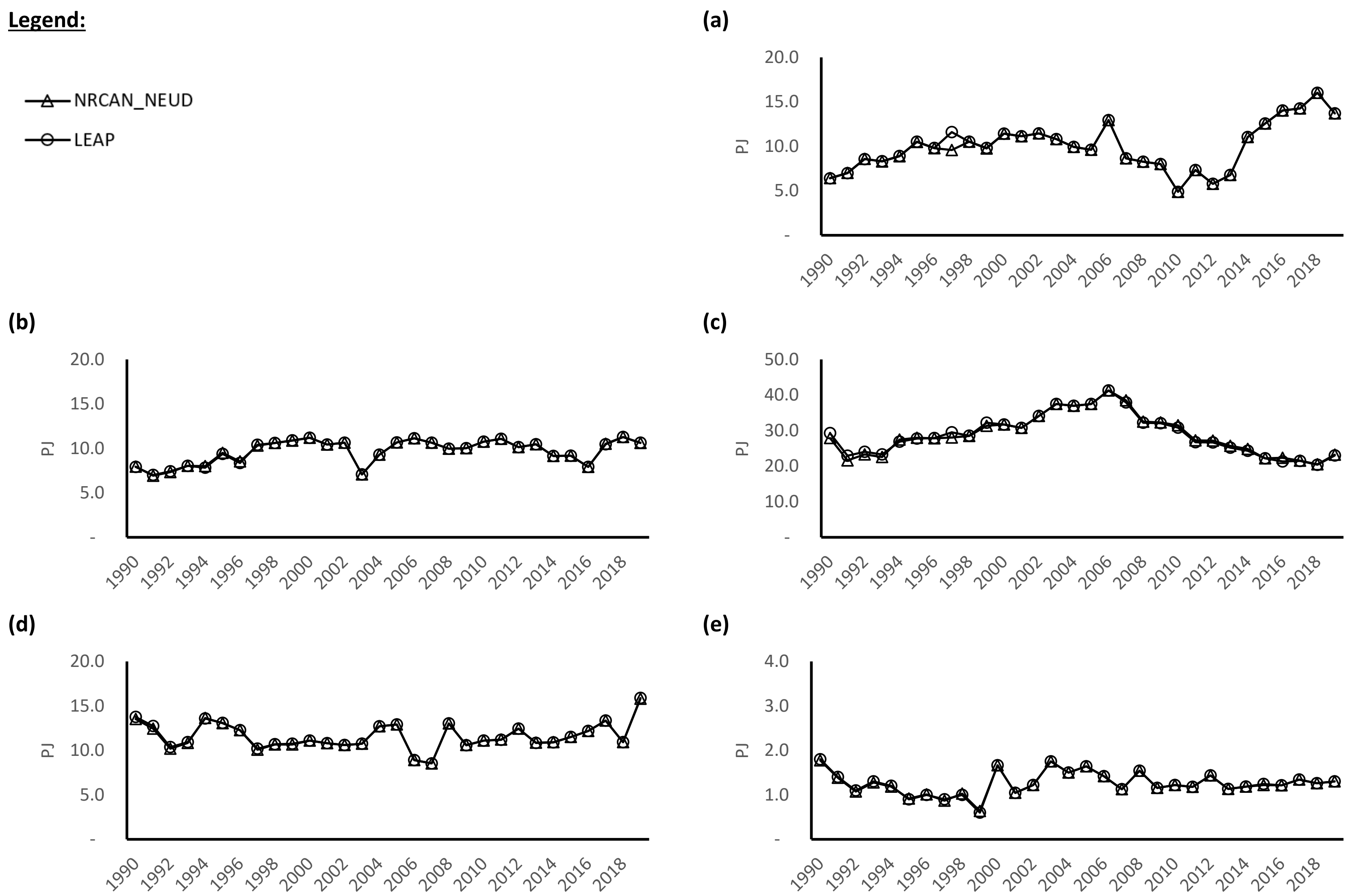

Figure 23. Final energy demand validation for (a) British Columbia, (b) Alberta, (c) Ontario, (d) Quebec, and (e) Nova Scotia from 1990 to 2019

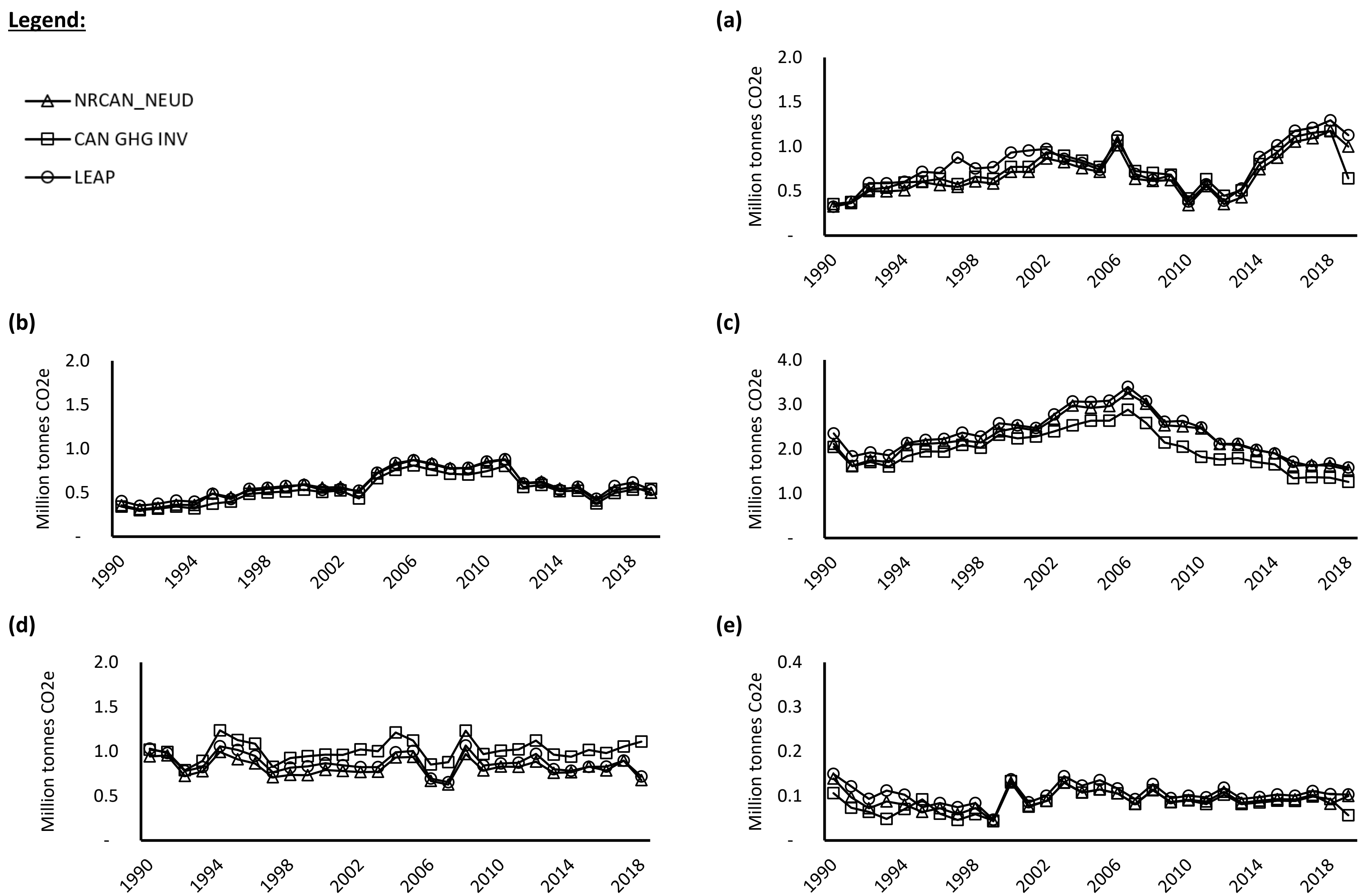

Figure 24. Combustion GHG emissions validation for (a) British Columbia, (b) Alberta, (c) Ontario, (d) Quebec, and (e) Nova Scotia from 1990 to 2019

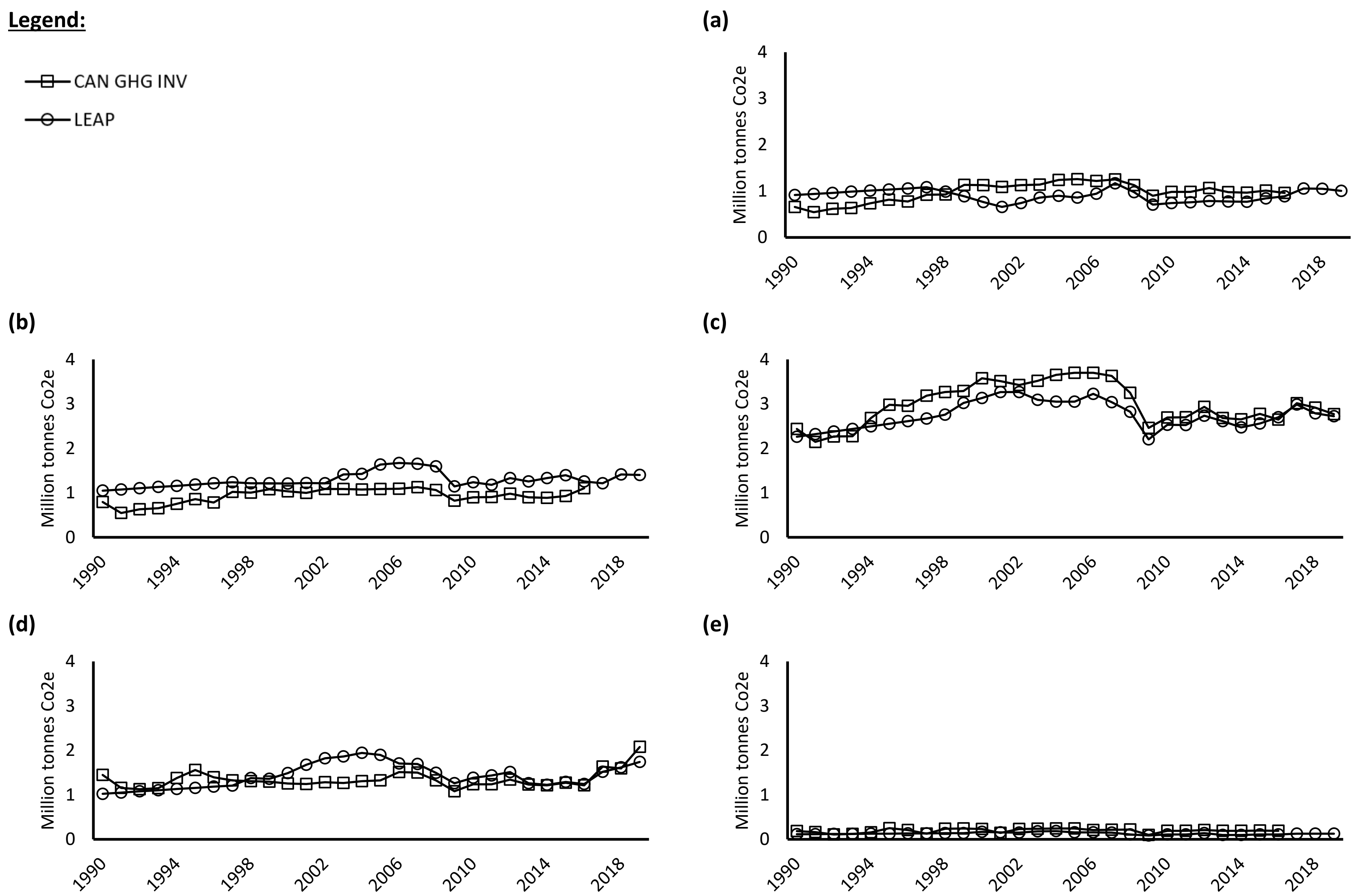

Figure 25. Process GHG emissions validation for (a) British Columbia, (b) Alberta, (c) Ontario, (d) Quebec, and (e) Nova Scotia from 1990 to 2019

Appendix C – Electricity grid emission factors validation

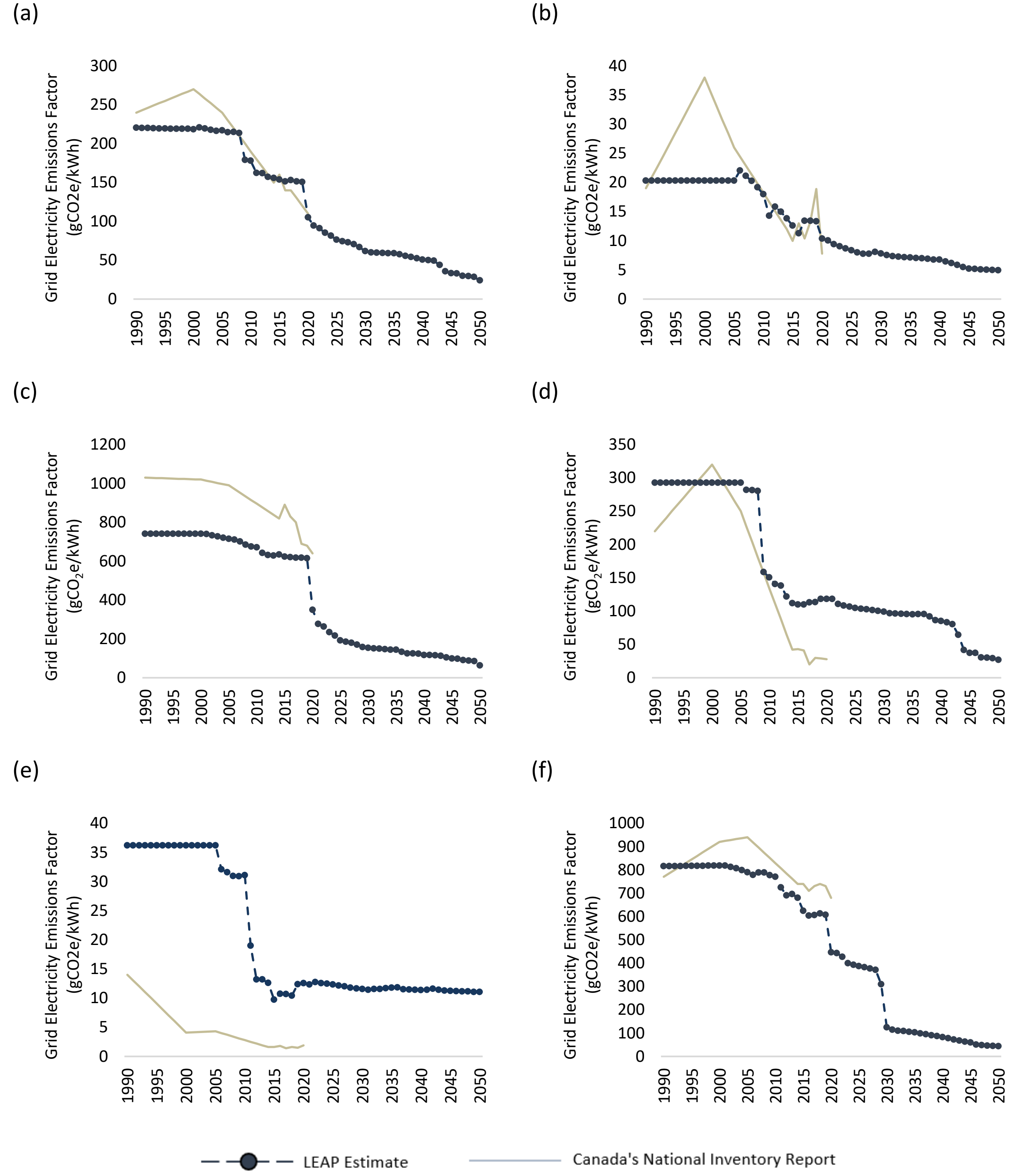

Figure 26. Electricity grid emission factors for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia, 1990-2050

Appendix D – Hydrogen price calculation

The hydrogen prices used in this study were calculated by my research colleagues Shibani et al. [47] using a method they created and verified. Production, transmission, natural gas, electricity, water, and carbon costs are considered in their methodology. Furthermore, process efficiency, facility lifespan, and various market markups for each stage of production and transportation were included.

The first output of Shibani et al.'s work [47] was retail hydrogen prices (in CAD/GJ) for domestically produced hydrogen for each province in Canada from 2022 to 2050. The second output was retail hydrogen prices for imported hydrogen in each province. Transmissions costs, including compressor stations, pipelines costs, energy cost, and distance factors, were added to domestic production costs of the exporting province to determine import costs for the destination province. A market mark-up was then applied to finalize the retail price of imported hydrogen. Finally, the lowest retail hydrogen price for each province was selected from the calculated domestic and imported prices.

Shibani et al. [47] considered multiple carbon cost scenarios. The results, corresponding to the CP170 carbon cost scenario, were used in this work, and are included in **Table 15**. For the years 2020 and 2021, the 2022 hydrogen price was used.

Appendix E – Fuel-switching subnational marginal abatement cost curves

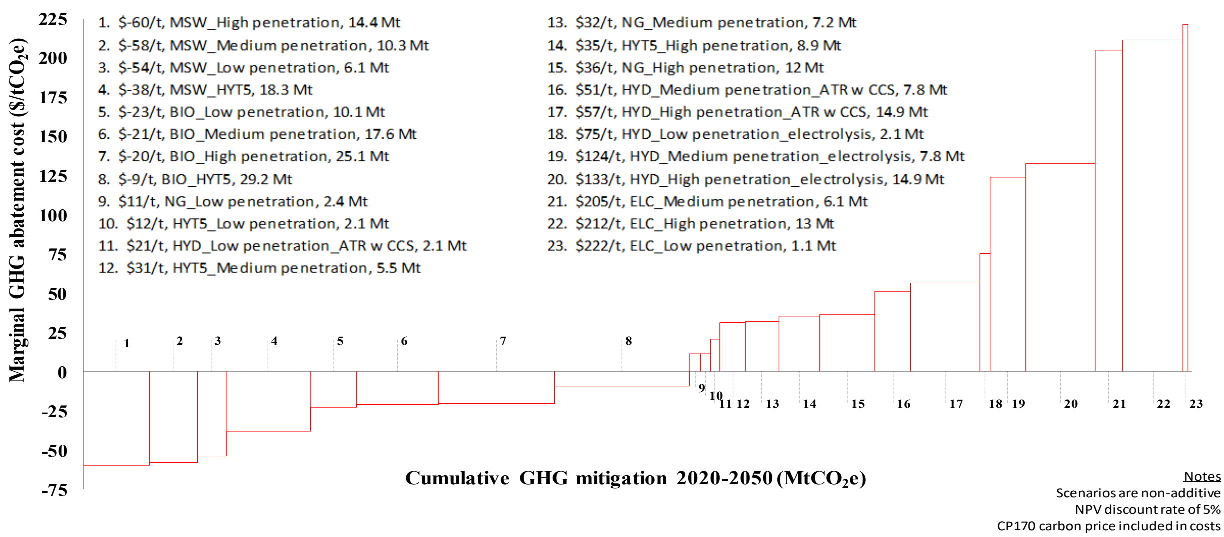

Figure 27. Fuel-switching marginal abatement cost curve for Ontario

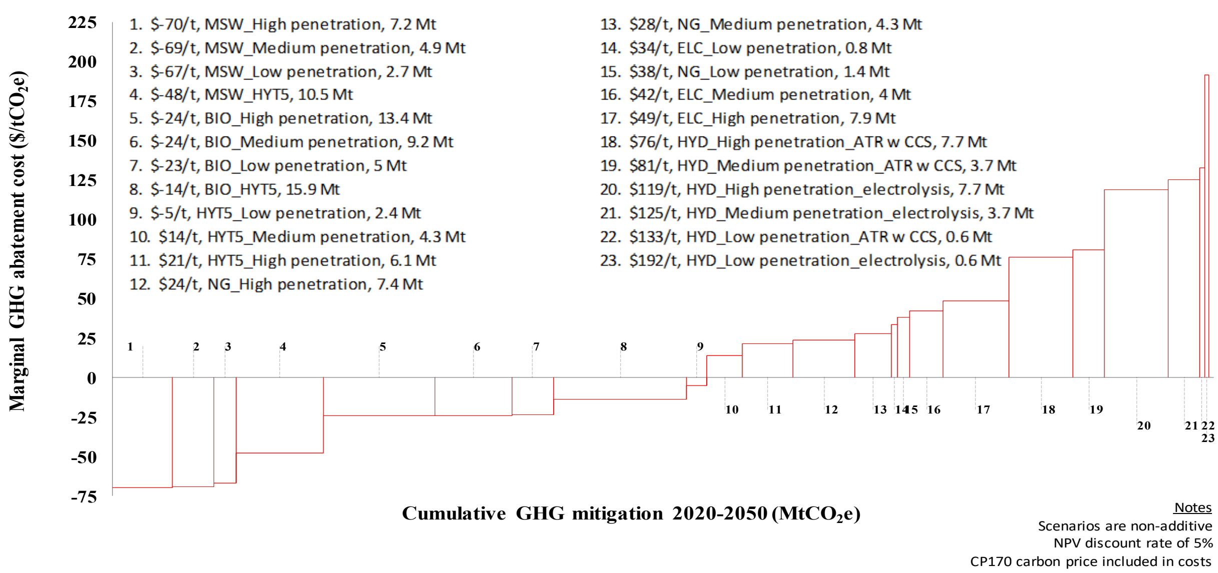

Figure 28. Fuel-switching marginal abatement cost curve for Quebec

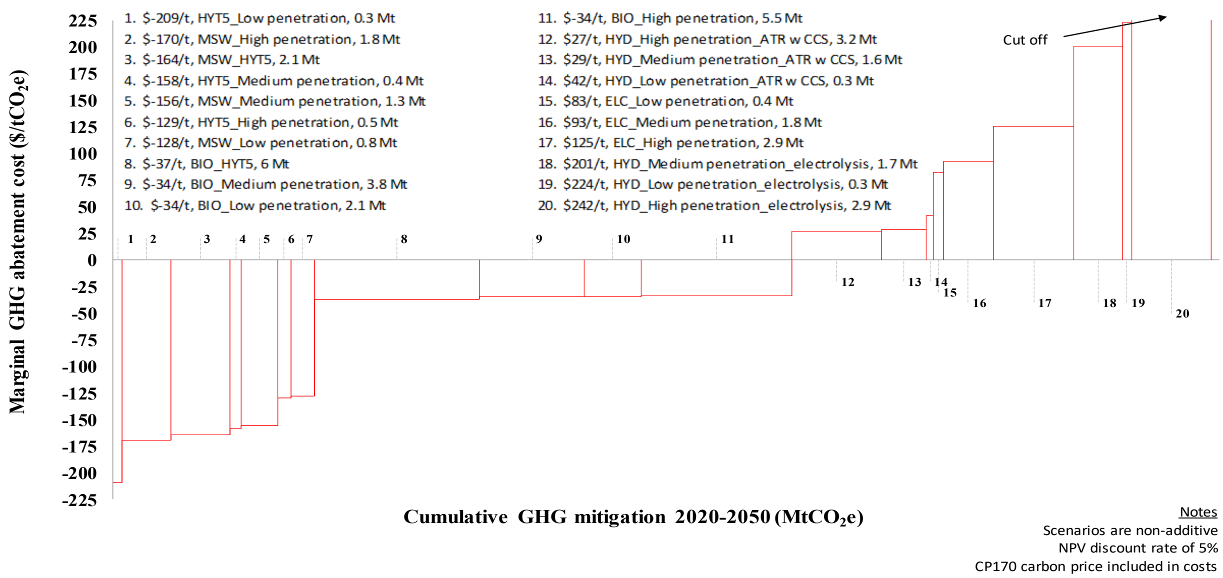

Figure 29. Fuel-switching marginal abatement cost curve for Alberta

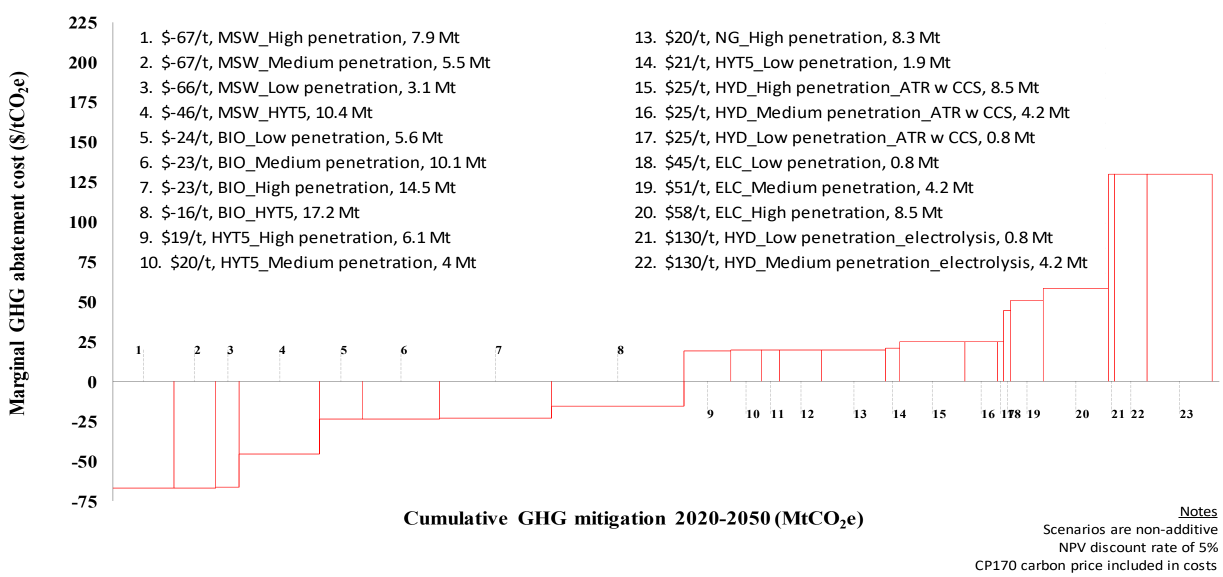

Figure 30. Fuel-switching marginal abatement cost curve for British Columbia

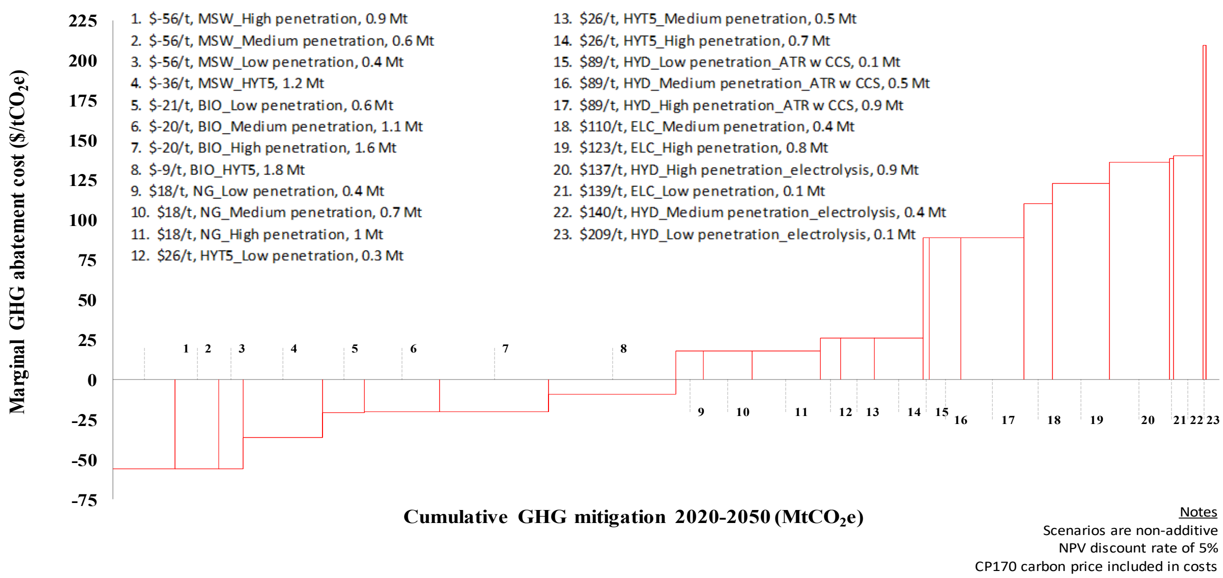

Figure 31. Fuel-switching marginal abatement cost curves for Nova Scotia

Appendix F – Energy efficiency, alternative raw material, and alternative binders and chemistries subnational marginal abatement cost curves

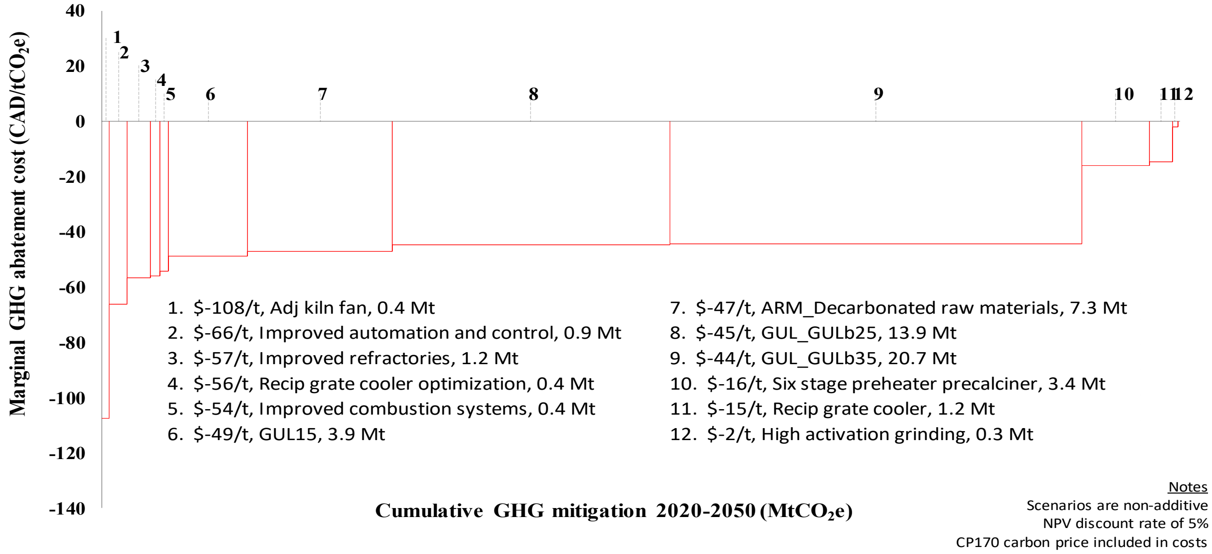

Figure 32. Energy efficiency, alternative raw materials, and alternative binders and chemistries cost curve for Ontario

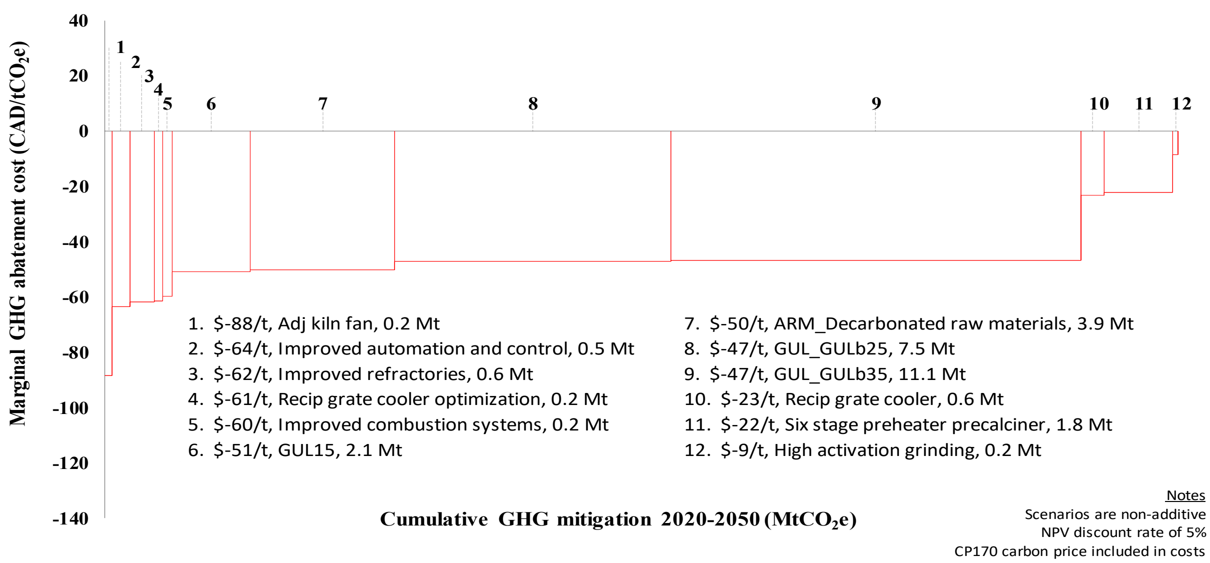

Figure 33. Energy efficiency, alternative raw materials, and alternative binders and chemistries cost curve for Quebec

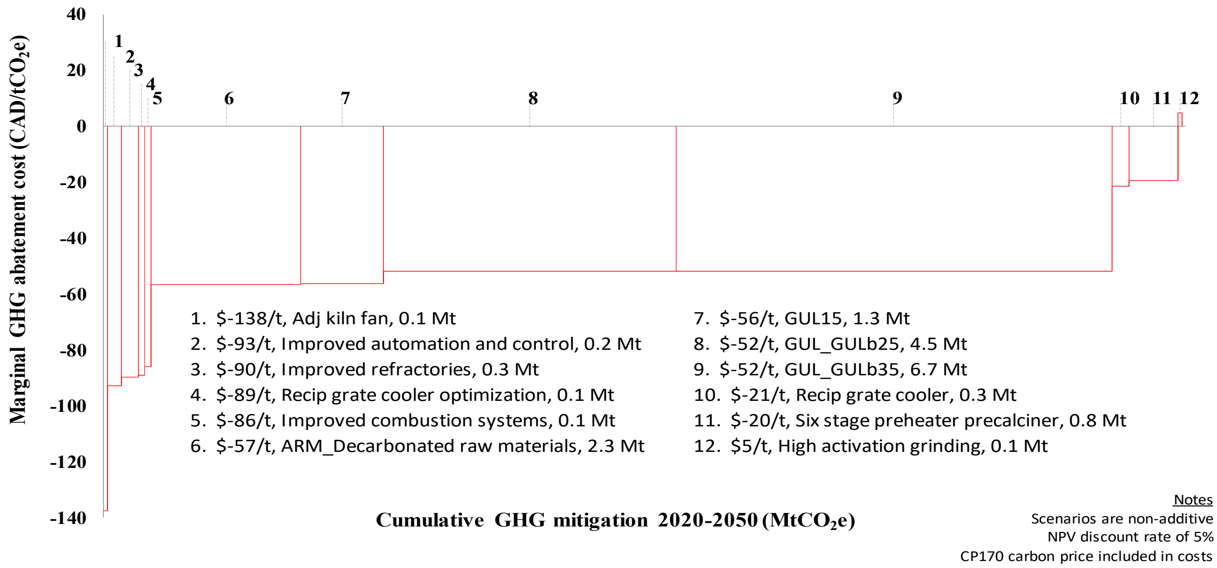

Figure 34. Energy efficiency, alternative raw materials, and alternative binders and chemistries cost curve for Alberta

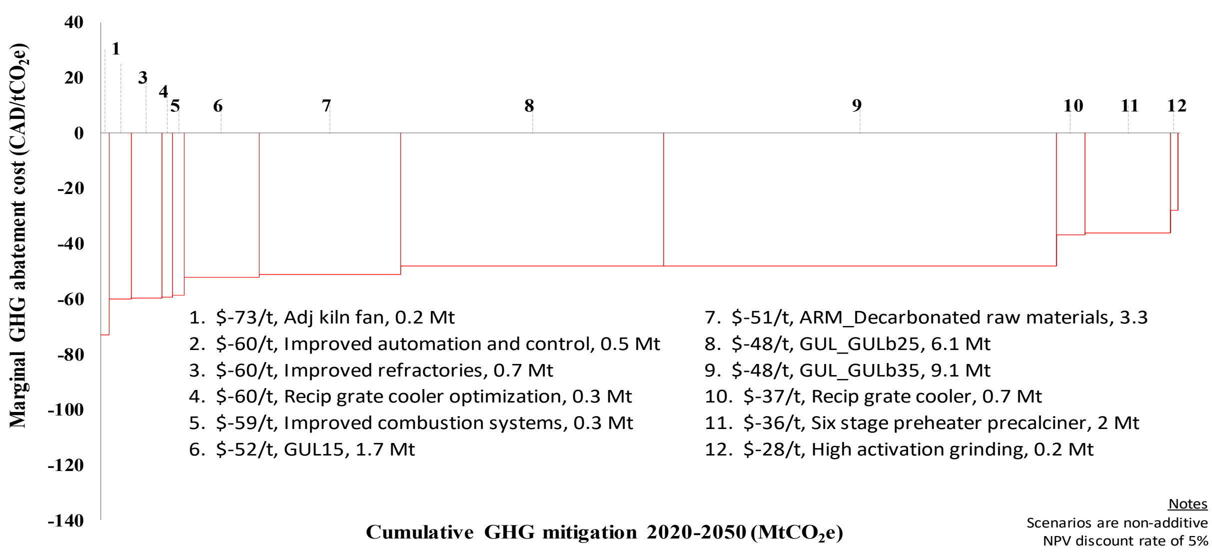

Figure 35. Energy efficiency, alternative raw materials, and alternative binders and chemistries cost curve for British Columbia

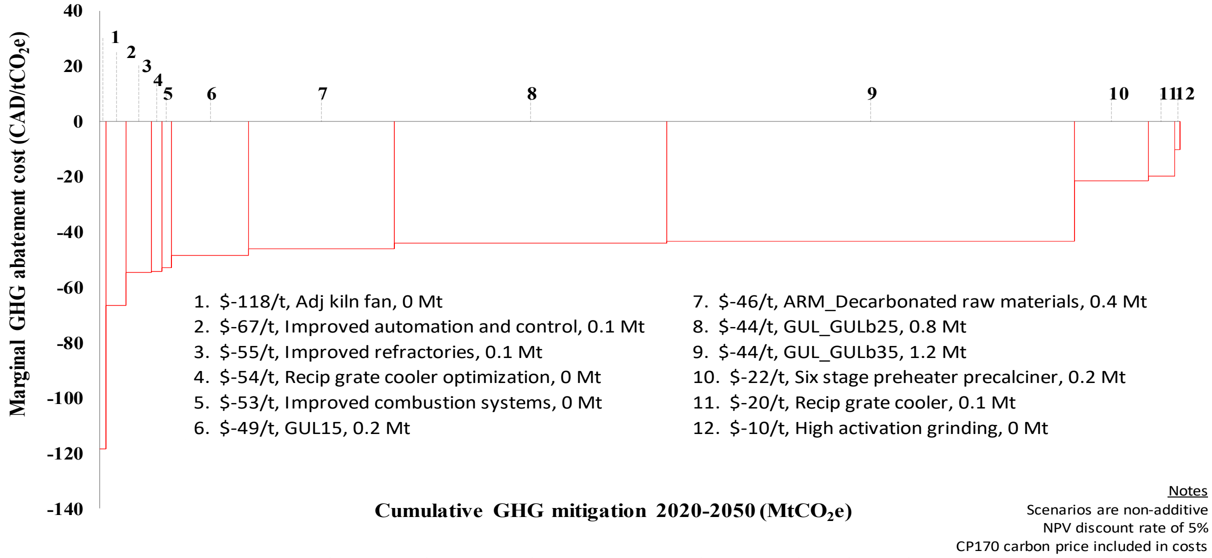

Figure 36. Energy efficiency, alternative raw materials, and alternative binders and chemistries cost curve for Nova Scotia

Appendix G – CCS marginal abatement cost curves

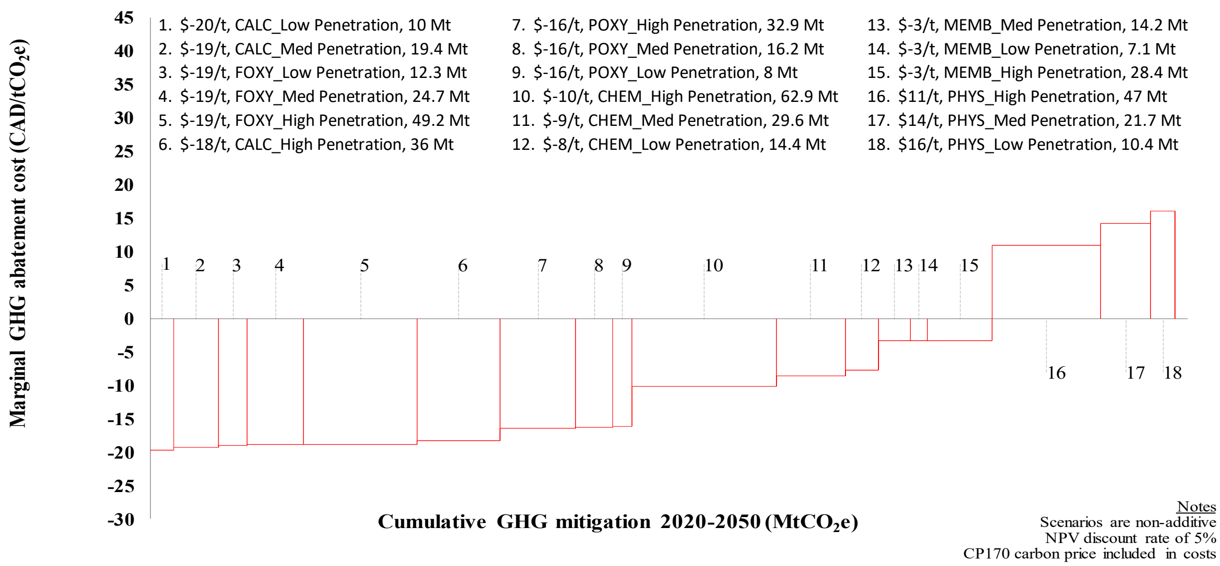

Figure 37. CCS marginal abatement cost curve for Ontario

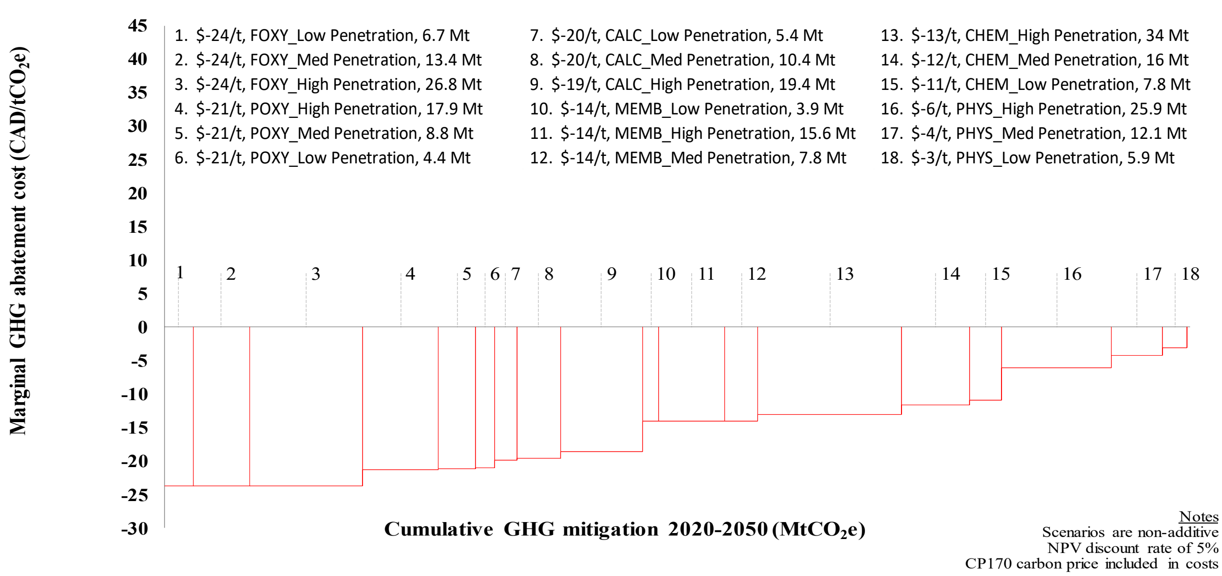

Figure 38. CCS marginal abatement cost curve for Quebec

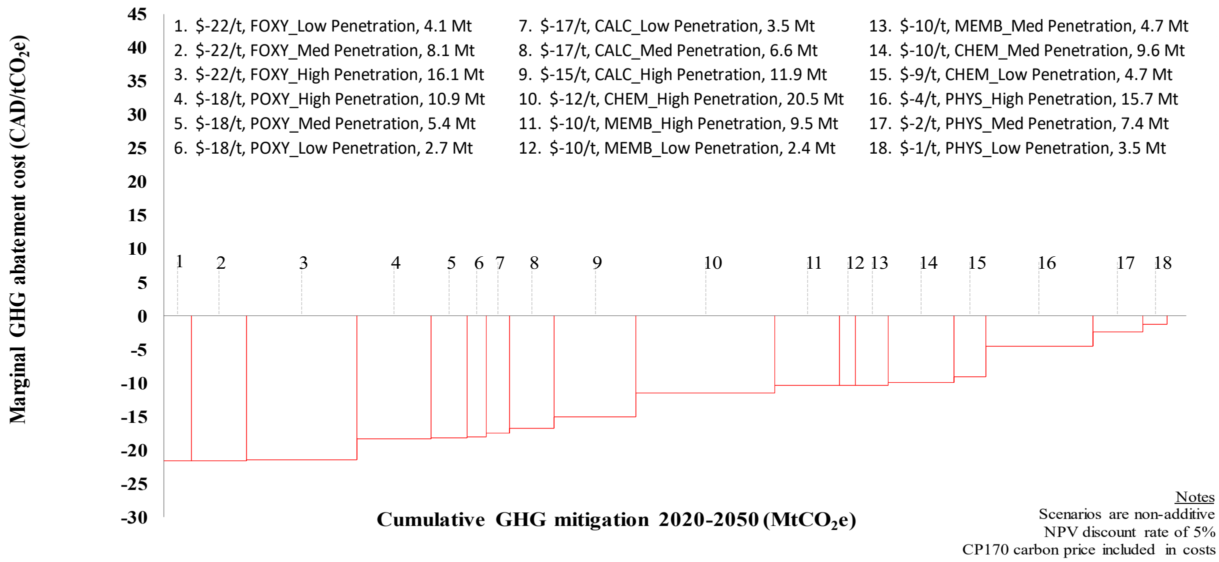

Figure 39. CCS marginal abatement cost curve for Alberta

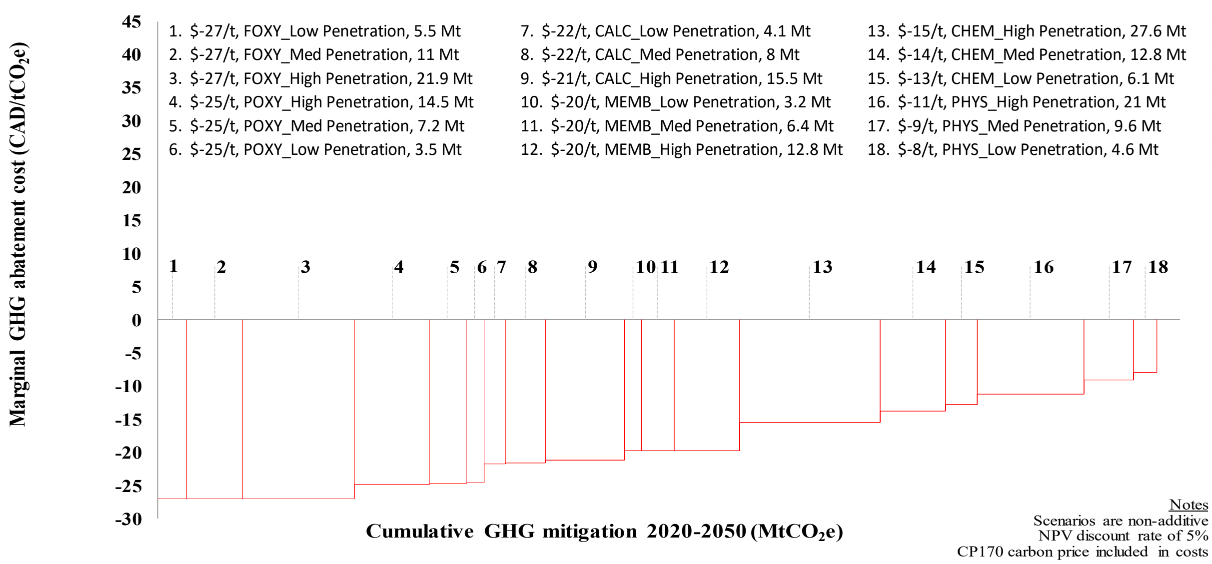

Figure 40. CCS marginal abatement cost curve for British Columbia

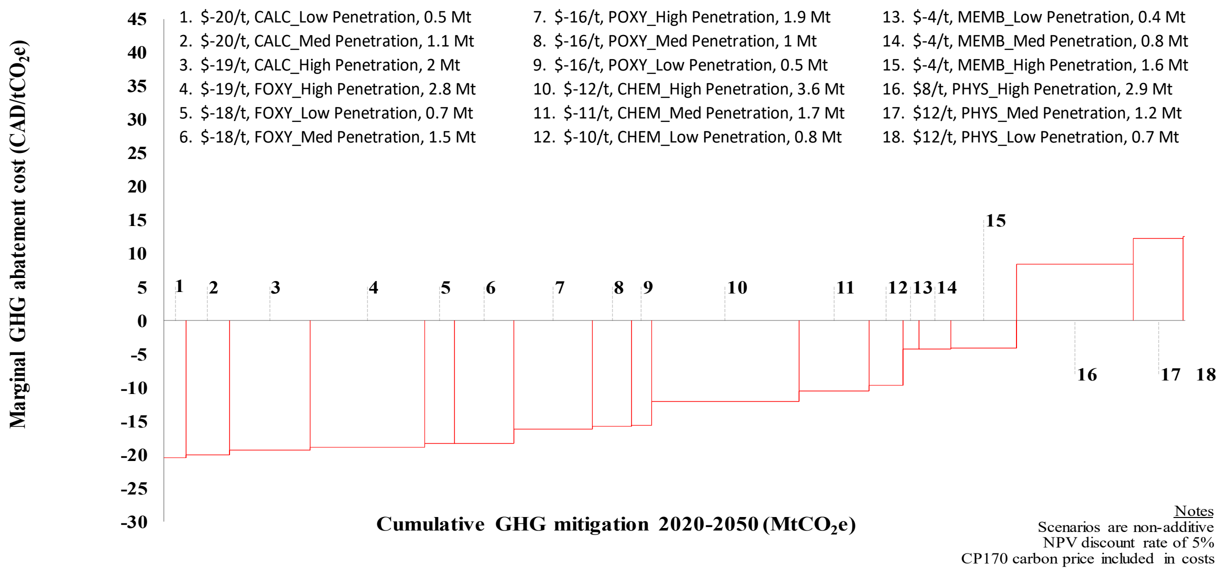

Figure 41. CCS marginal abatement cost curve for Nova Scotia

Appendix H – Additional scenario results

Table 21. Regional abatement cost and GHG mitigation results for each decarbonization technology scenario under a carbon price of 170 CAD by 2030

	British Columbia		Alberta		Ontario		Quebec		Nova Scotia		Canada	
Scenario	Abatement cost (CAD/t CO_2e)	GHG mitigation, 2020-2050 (Mt CO_2e)	Abatement cost (CAD/t CO_2e)	GHG mitigation, 2020-2050 (Mt CO_2e)	Abatement cost (CAD/t CO_2e)	GHG mitigation, 2020-2050 (Mt CO_2e)	Abatement cost (CAD/t CO_2e)	GHG mitigation, 2020-2050 (Mt CO_2e)	Abatement cost (CAD/t CO_2e)	GHG mitigation, 2020-2050 (Mt CO_2e)	Abatement cost (CAD/t CO_2e)	GHG mitigation, 2020-2050 (Mt CO_2e)
NG	19.9	8.3	N/A	N/A	36.4	12.0	23.7	7.4	18.1	1.0	27.7	28.7
BIO	-23.1	14.5	-33.9	5.5	-20.1	25.1	-24.0	13.4	-19.9	1.6	-22.9	60.1
HYD Electrolysis	129.8	8.5	242.0	2.9	133.0	14.9	119.1	7.7	136.6	0.9	138.2	34.8
HYD ATR-CCS	24.7	8.5	27.0	3.2	56.7	14.9	76.3	7.7	88.9	0.9	51.4	35.2
ELC	58.3	8.5	125.3	2.9	211.8	13.0	48.6	7.9	122.9	0.8	123.7	33.1
HYT	19.3	6.1	-129.5	0.5	35.3	8.9	21.4	6.1	26.2	0.7	23.3	22.3
MSW	-66.7	7.9	-169.7	1.8	-59.6	14.4	-69.8	7.2	-56.1	0.9	-69.5	32.1
ADJ	-73.1	0.2	-137.7	0.1	-107.5	0.4	-88.4	0.2	-118.4	0.0	-98.0	0.8
AUTOC	-60.2	0.5	-93.0	0.2	-66.1	0.9	-63.7	0.5	-66.7	0.1	-66.6	2.2
REFR	-59.9	0.7	-89.9	0.3	-56.6	1.2	-61.9	0.6	-54.6	0.1	-61.6	2.8
OPTMZ	-59.6	0.3	-89.0	0.1	-56.1	0.4	-61.4	0.2	-54.2	0.0	-61.1	1.1
COMB	-58.6	0.3	-86.1	0.1	-54.4	0.4	-59.7	0.2	-52.8	0.0	-59.5	1.1
GRATE	-36.9	0.7	-21.4	0.3	-14.6	1.2	-23.2	0.6	-20.0	0.1	-22.7	2.8
PHPC	-36.1	2.0	-19.7	0.8	-16.0	3.4	-22.3	1.8	-21.7	0.2	-22.8	8.2
GRIND	-27.9	0.2	4.6	0.1	-1.9	0.3	-8.6	0.2	-10.4	0.0	-9.4	0.7
ARM	-51.3	3.3	-56.8	2.3	-47.0	7.3	-50.4	3.9	-46.1	0.4	-49.9	17.2
GULb35	-48.1	9.1	-52.0	6.7	-44.2	20.7	-47.0	11.1	-43.5	1.2	-46.6	48.8
GULb25	-48.1	6.1	-52.1	4.5	-44.7	13.9	-47.1	7.5	-44.1	0.8	-46.9	32.7
GUL	-52.3	1.7	-56.4	1.3	-48.8	3.9	-51.0	2.1	-48.6	0.2	-51.0	9.3
CHEM	-15.5	-15.5	-11.5	-11.5	-10.1	62.9	-13.1	-13.1	-12.0	-12.0	-12.0	148.6
PHYS	-11.3	-11.3	-4.5	-4.5	10.9	47.0	-6.2	-6.2	8.4	8.4	0.6	112.5
MEMB	-19.7	-19.7	-10.3	-10.3	-3.4	28.4	-14.0	-14.0	-4.2	-4.2	-9.9	67.9
CALC	-21.2	-21.2	-15.1	-15.1	-18.3	36.0	-18.6	-18.6	-19.4	-19.4	-18.5	84.8
POXY	-24.9	-24.9	-18.3	-18.3	-16.4	32.9	-21.4	-21.4	-16.3	-16.3	-19.4	78.2
FOXY	-27.0	-27.0	-21.5	-21.5	-18.8	49.2	-23.7	-23.7	-19.0	-19.0	-21.8	116.8

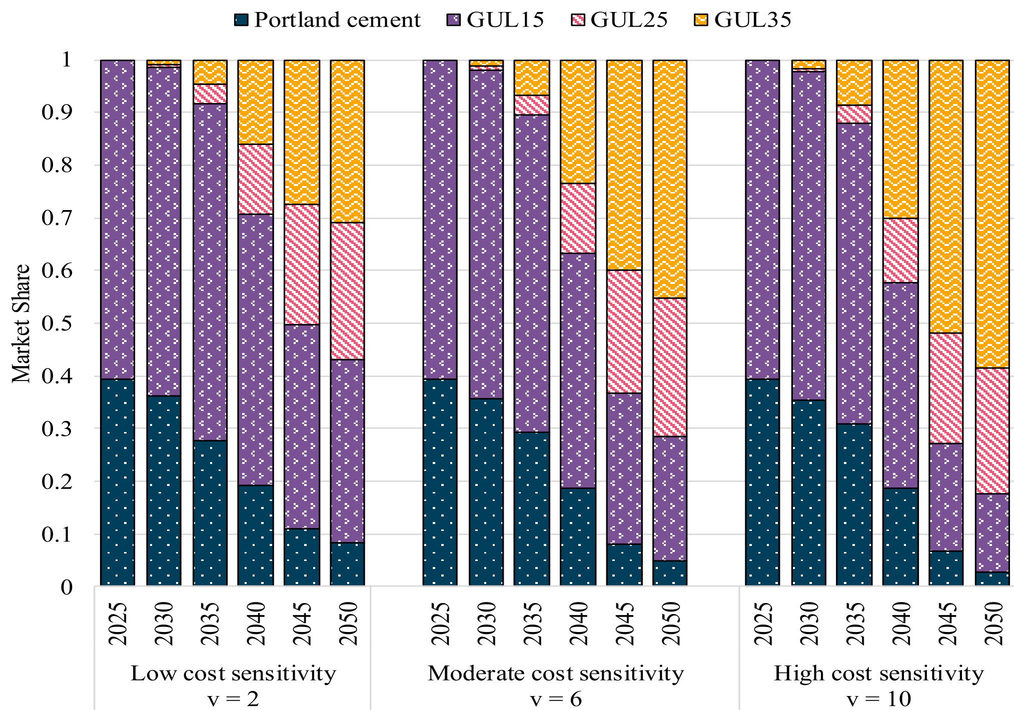

Figure 42. Cost-driven market share of Portland cement, Portland limestone cement (GUL), and blended limestone cements (GULb25 and GULb35) under low, moderate, and high cost sensitivity scenarios

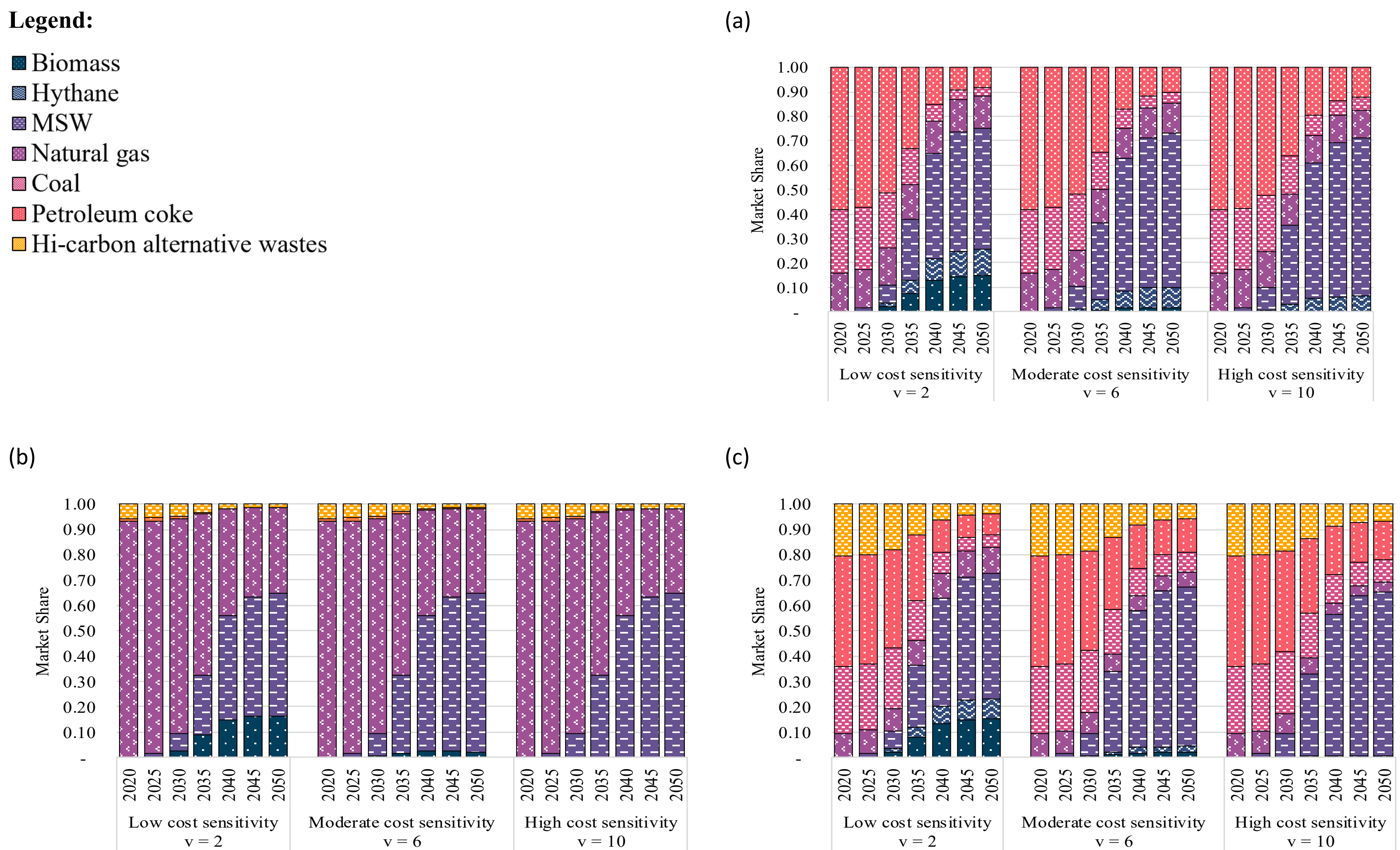

Figure 43. Fuel-switching cost-driven market shares for (a) British Columbia, (b) Alberta, and (c) Ontario. MSW and biomass are limited to use in the precalciner

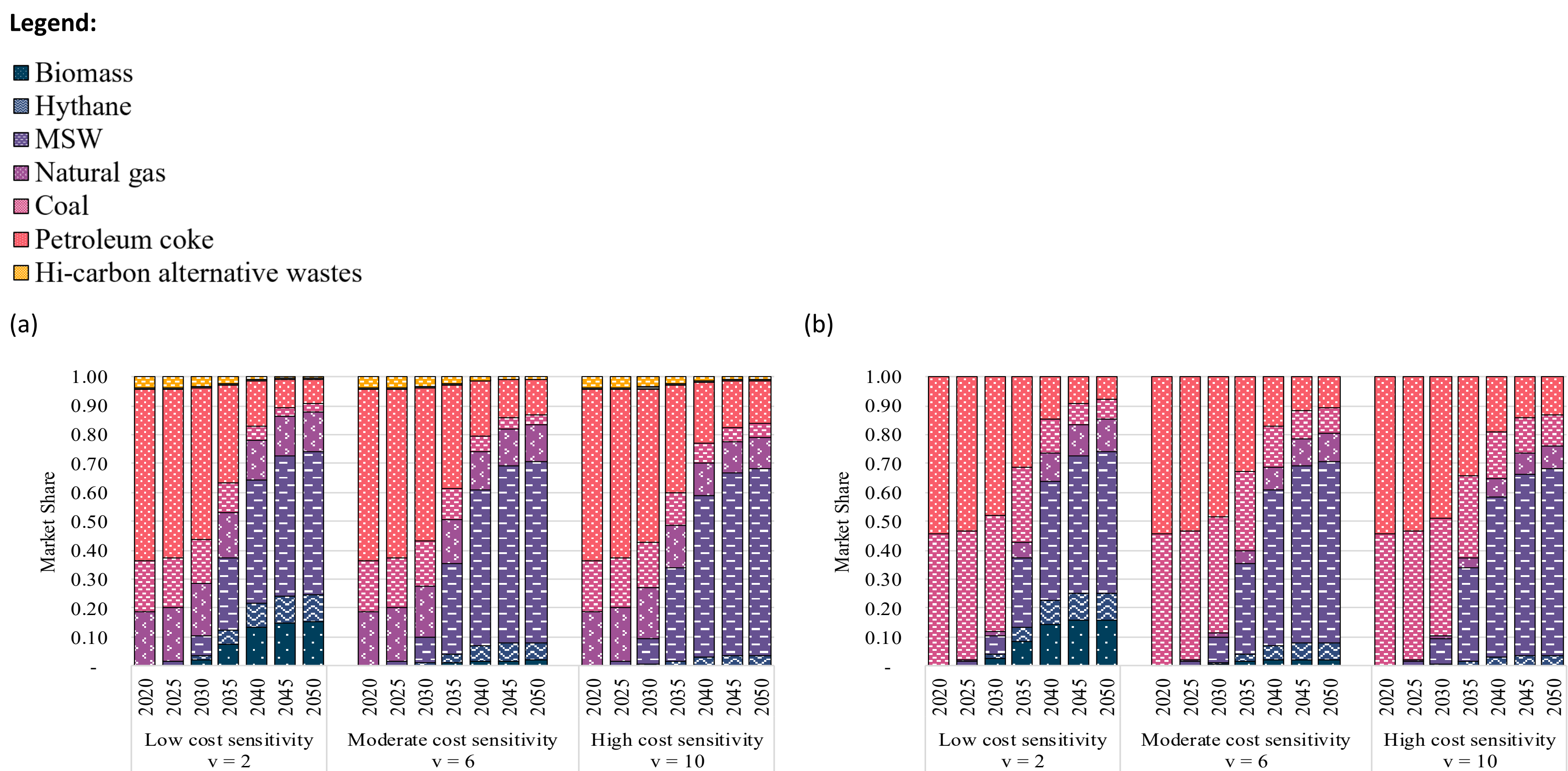

Figure 44. Fuel-switching cost-driven market shares for (a) Quebec and (b) Nova Scotia. MSW and biomass are limited to use in the precalciner

Appendix I – Fuel-switching sensitivity analysis results

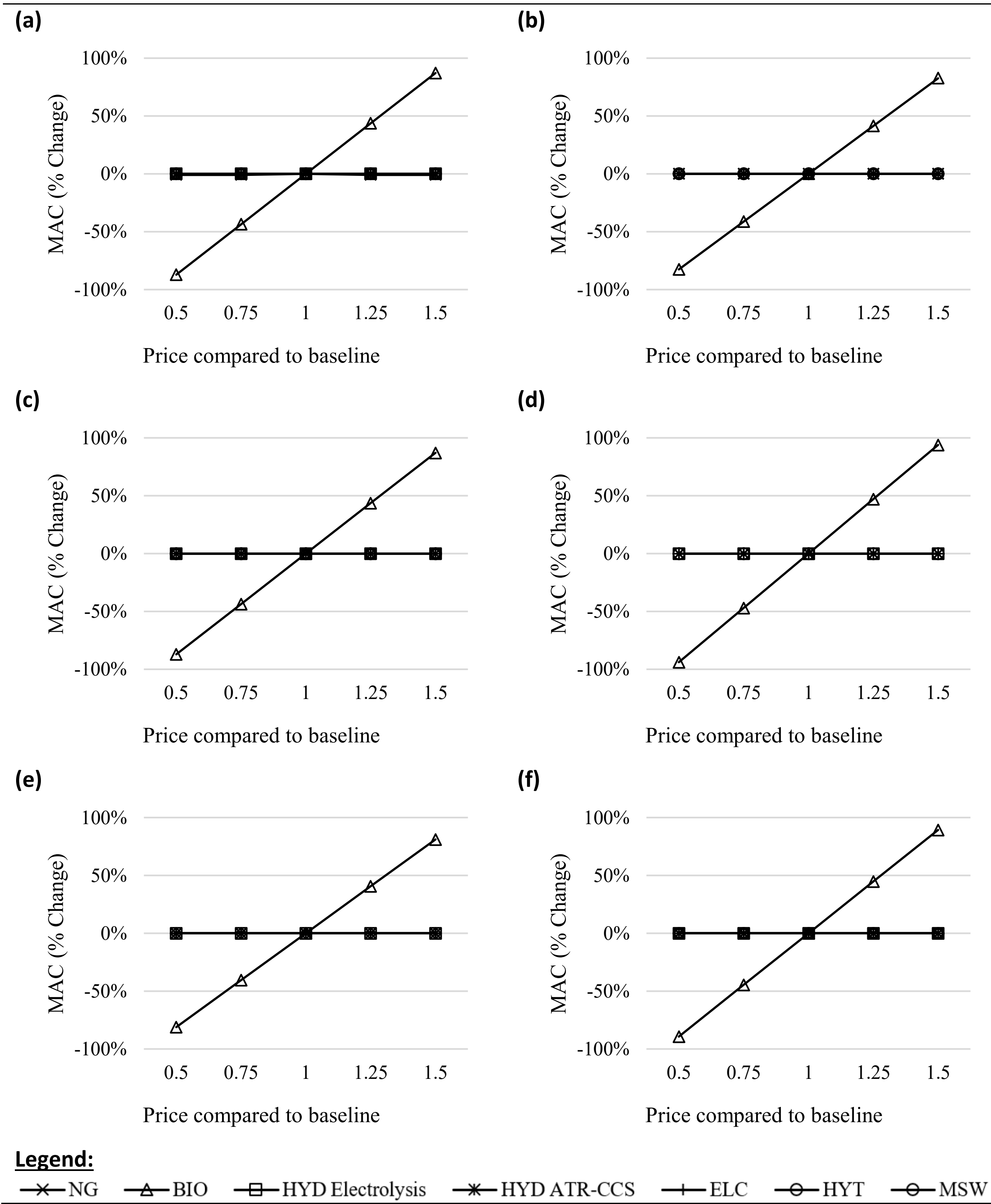

Figure 45. Biomass price sensitivity +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

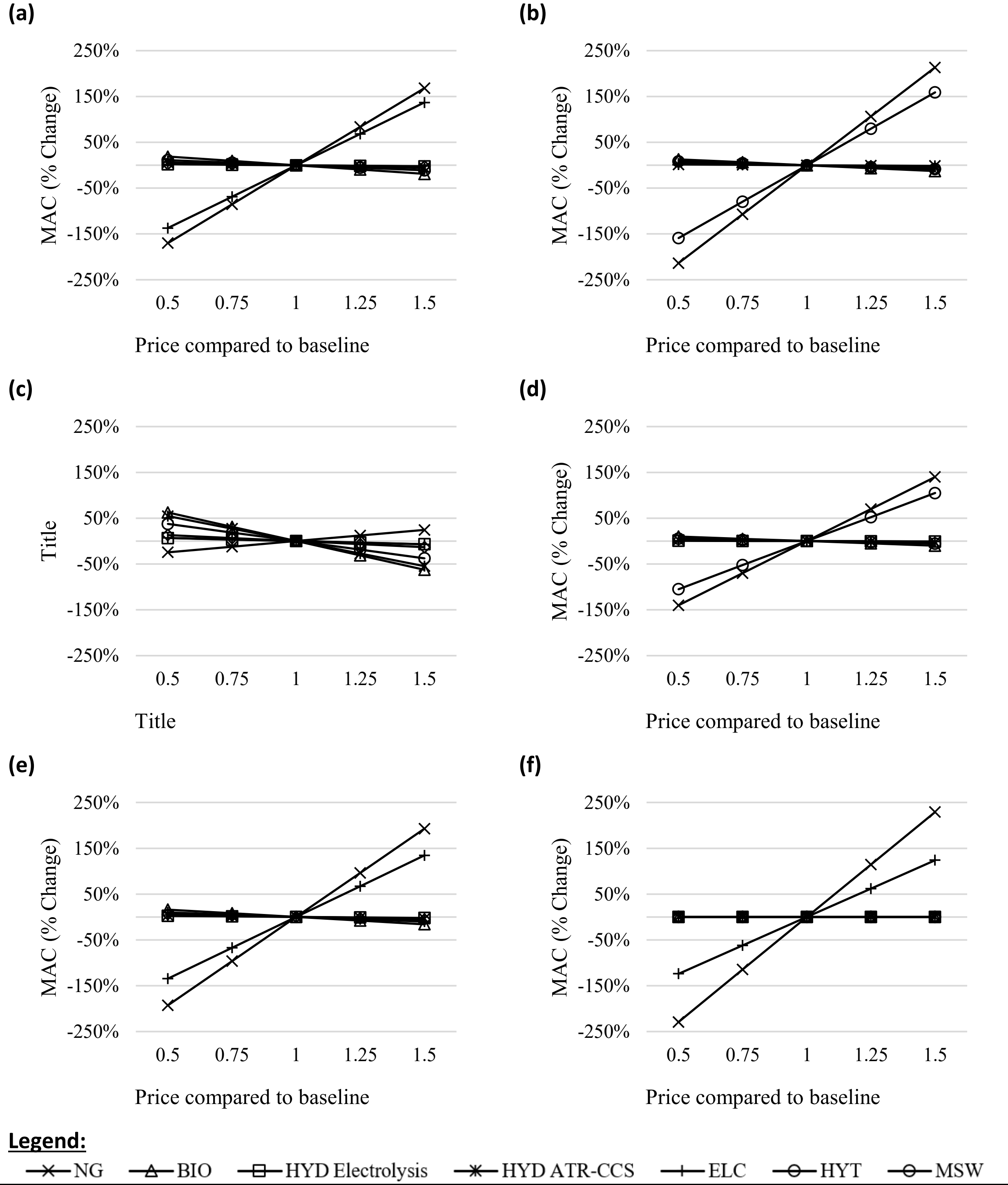

Figure 46. Natural gas price sensitivity +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

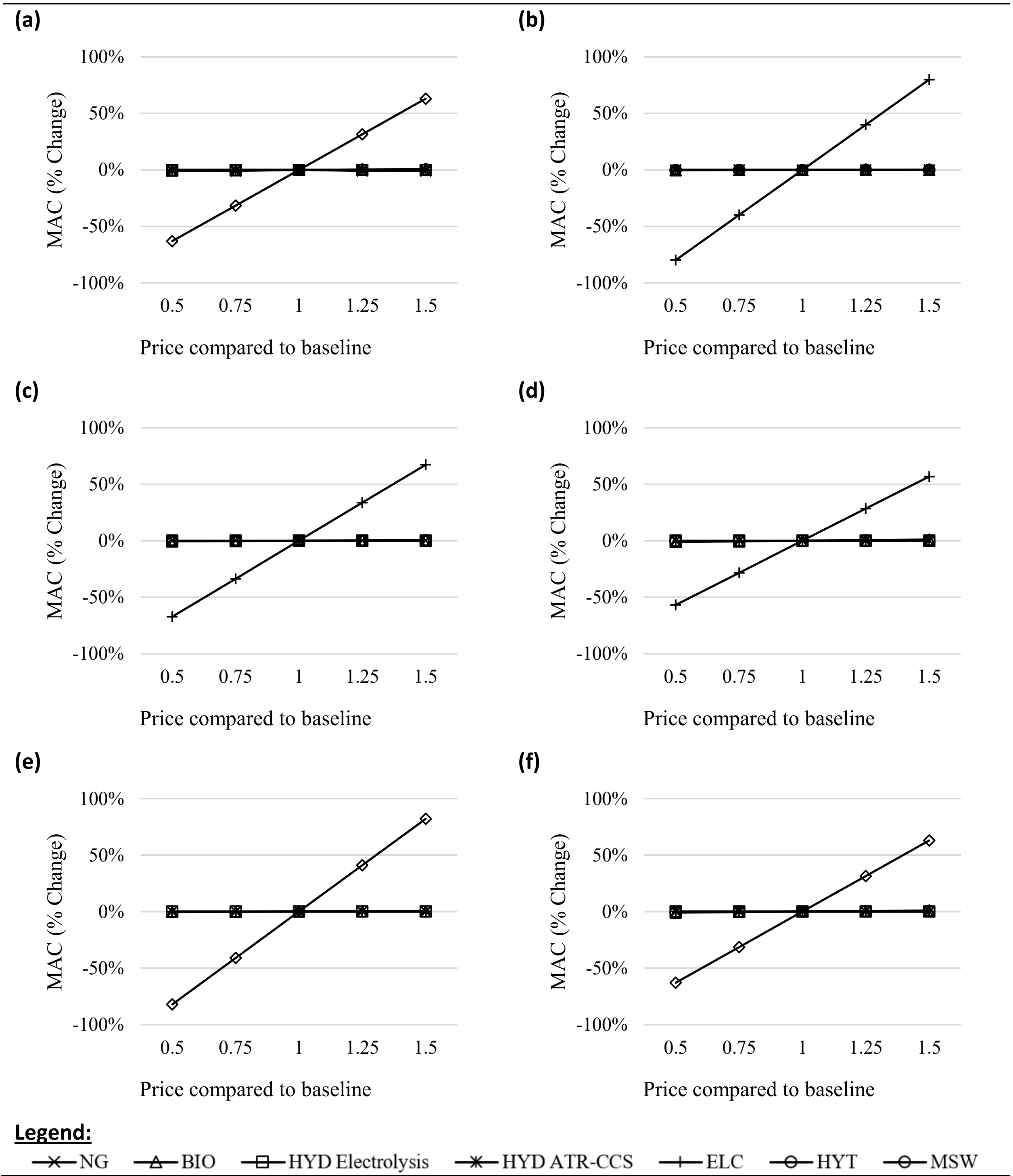

Figure 47. Electricity price sensitivity +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

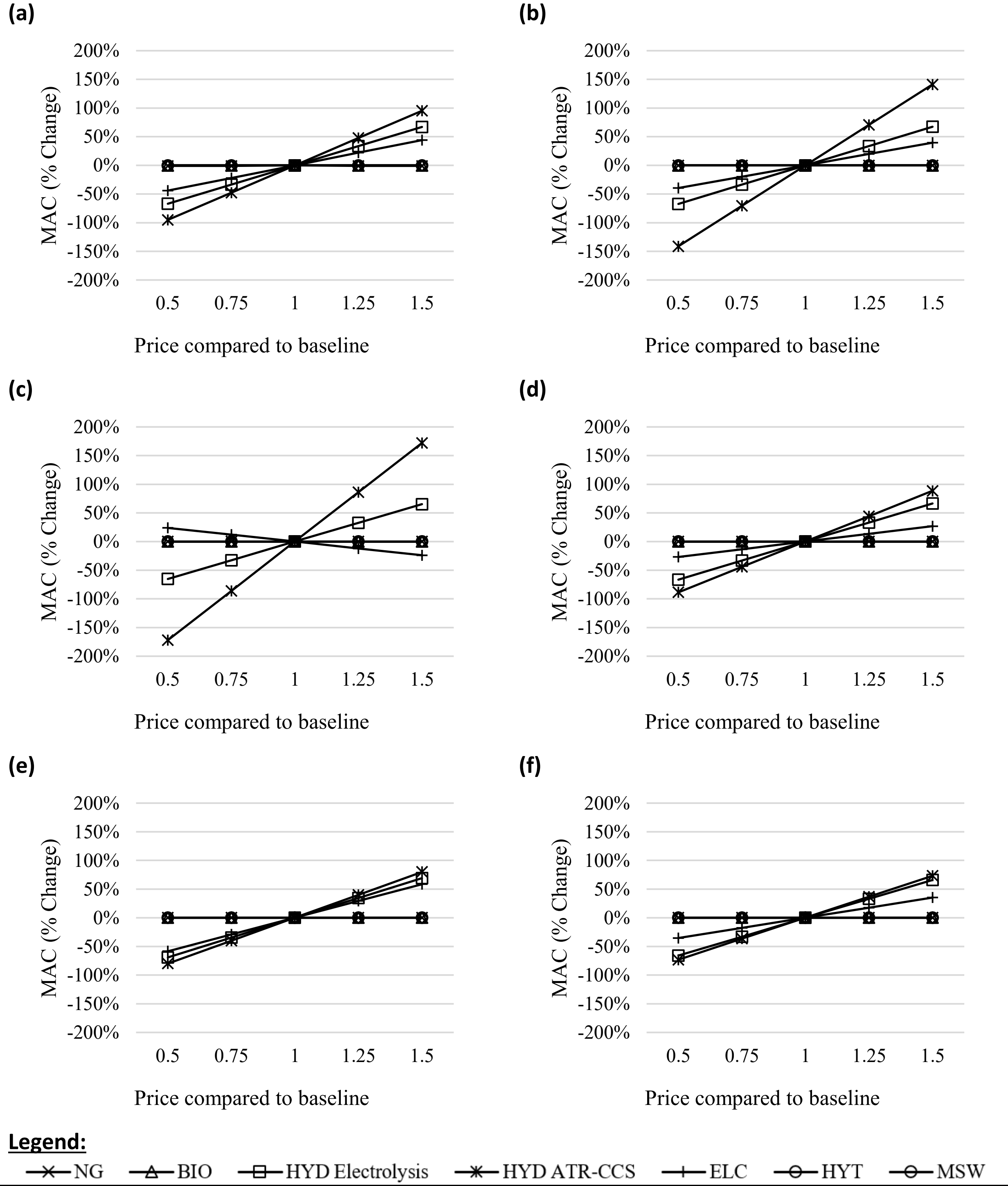

Figure 48. Hydrogen price sensitivity +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

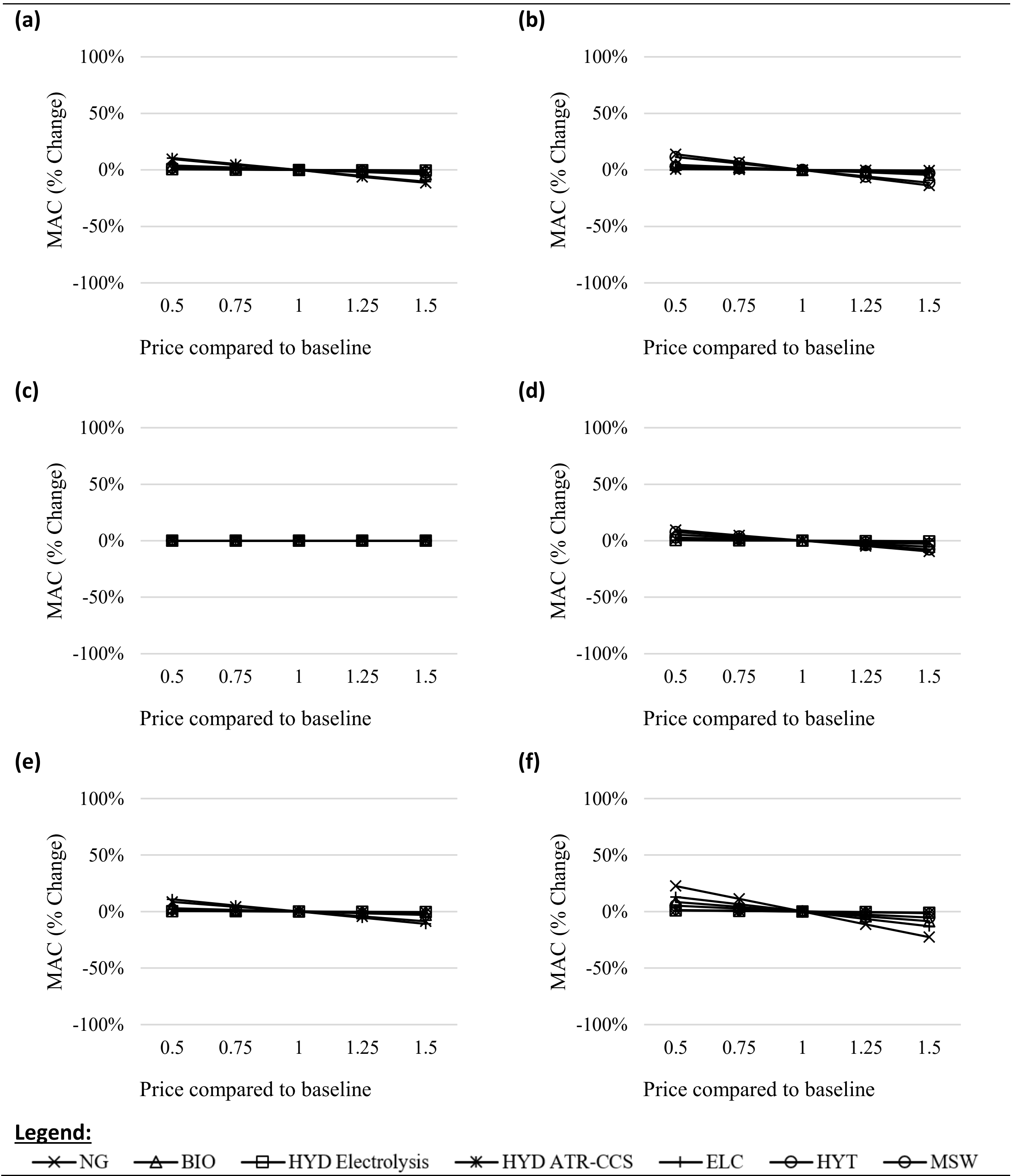

Figure 49. Coal price sensitivity +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

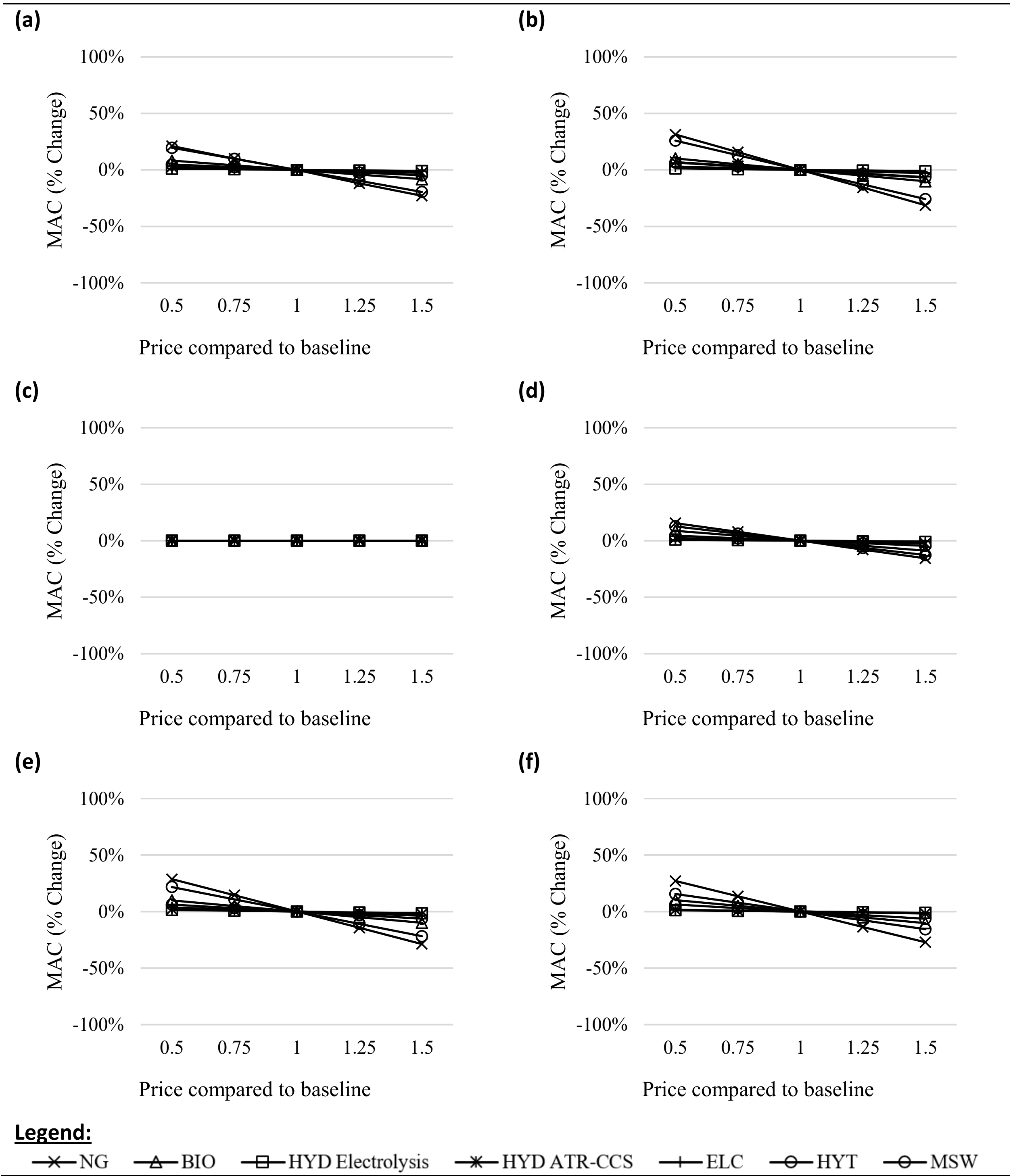

Figure 50. Petroleum coke price sensitivity +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

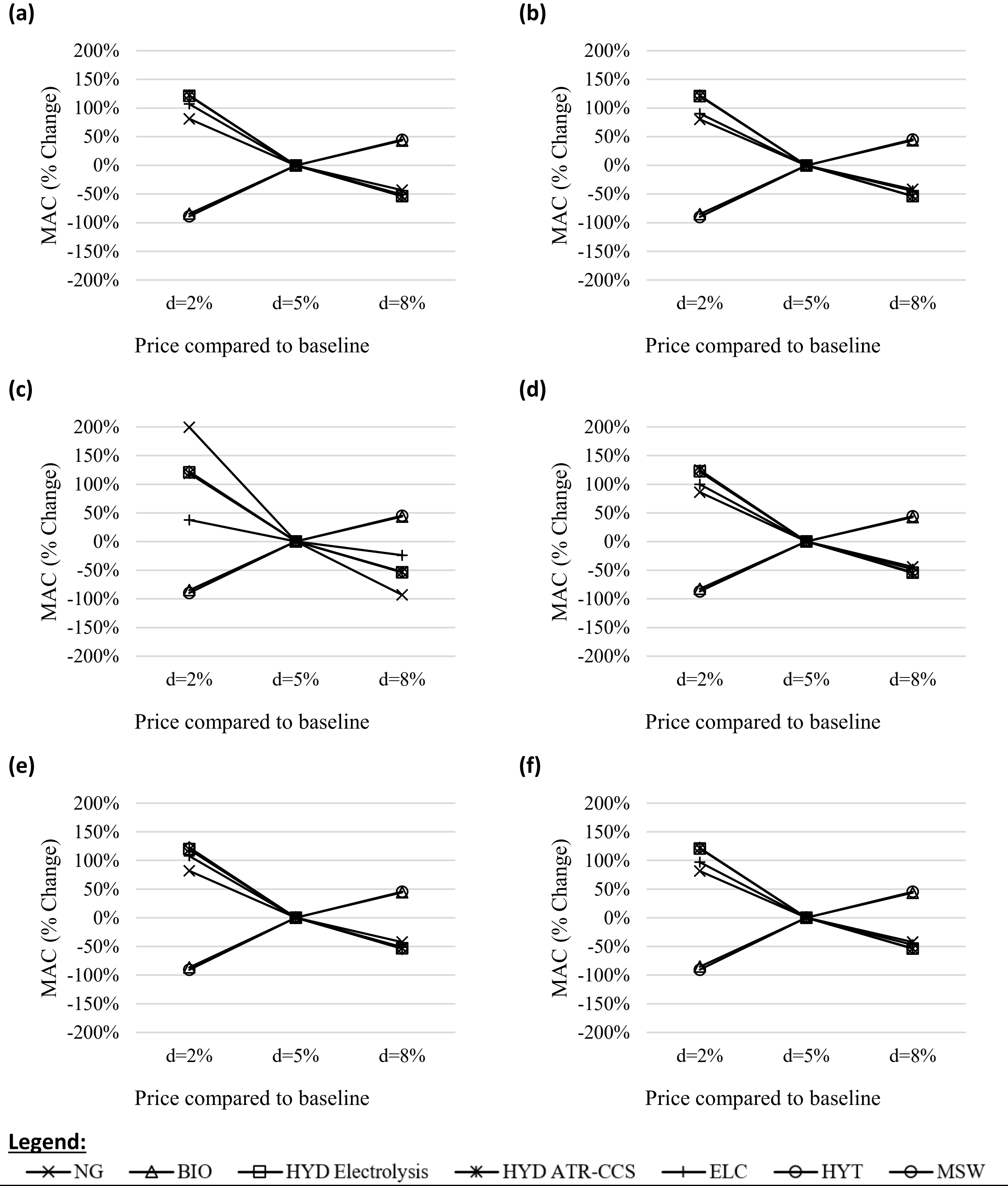

Figure 51. NPV discount rate sensitivity for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

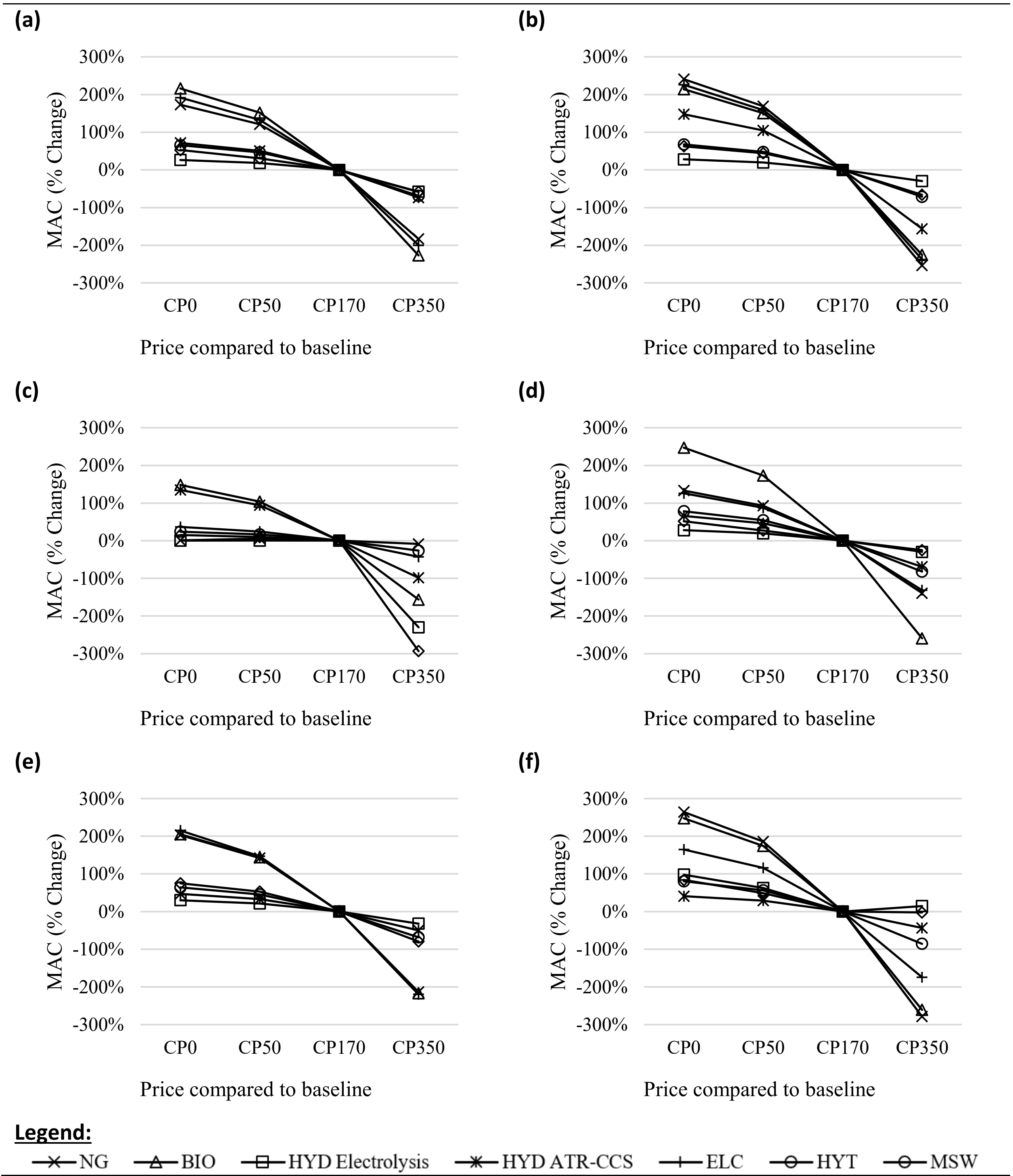

Figure 52. Carbon price sensitivity for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

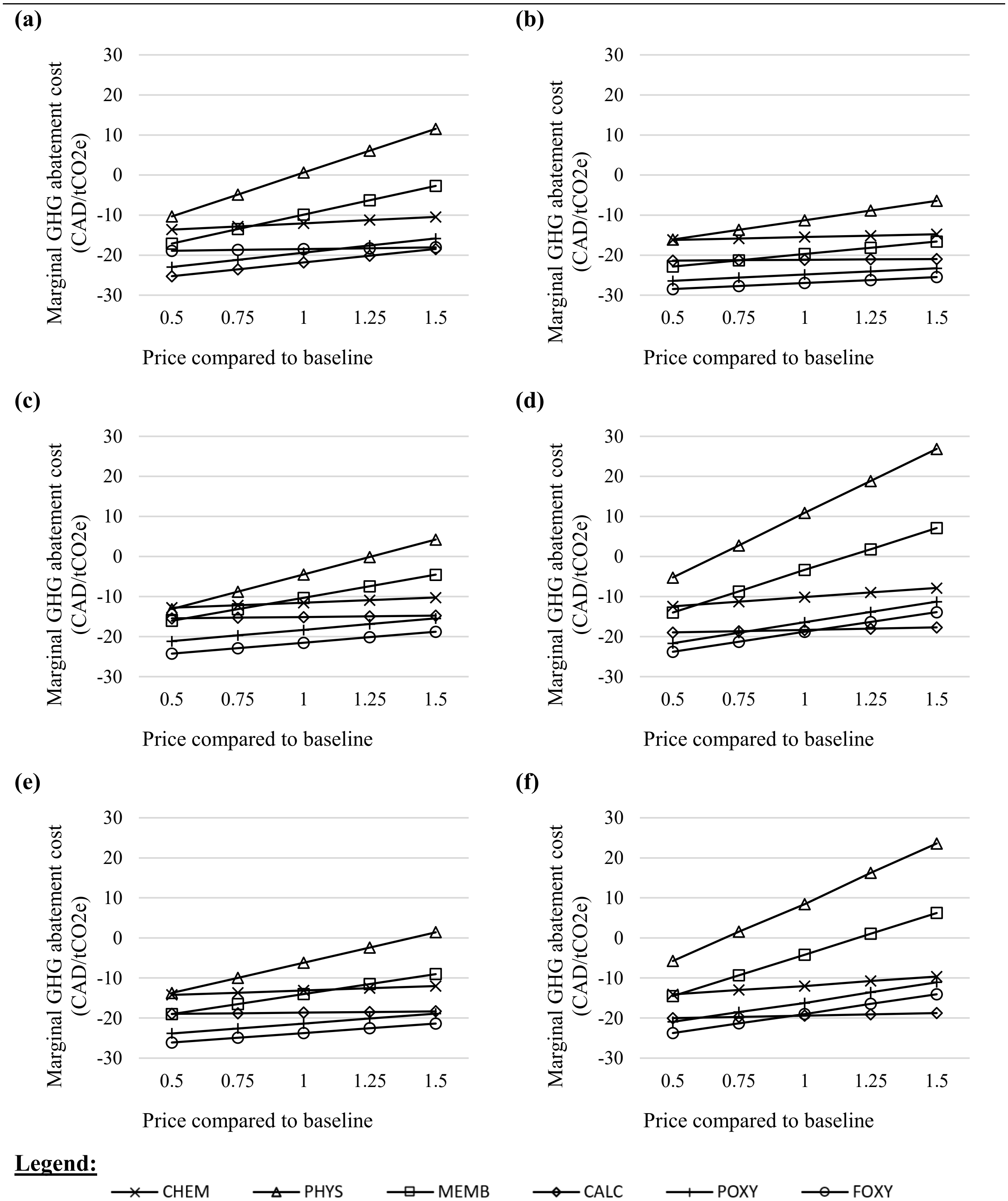

Figure 53. MAC sensitivity to electricity prices +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

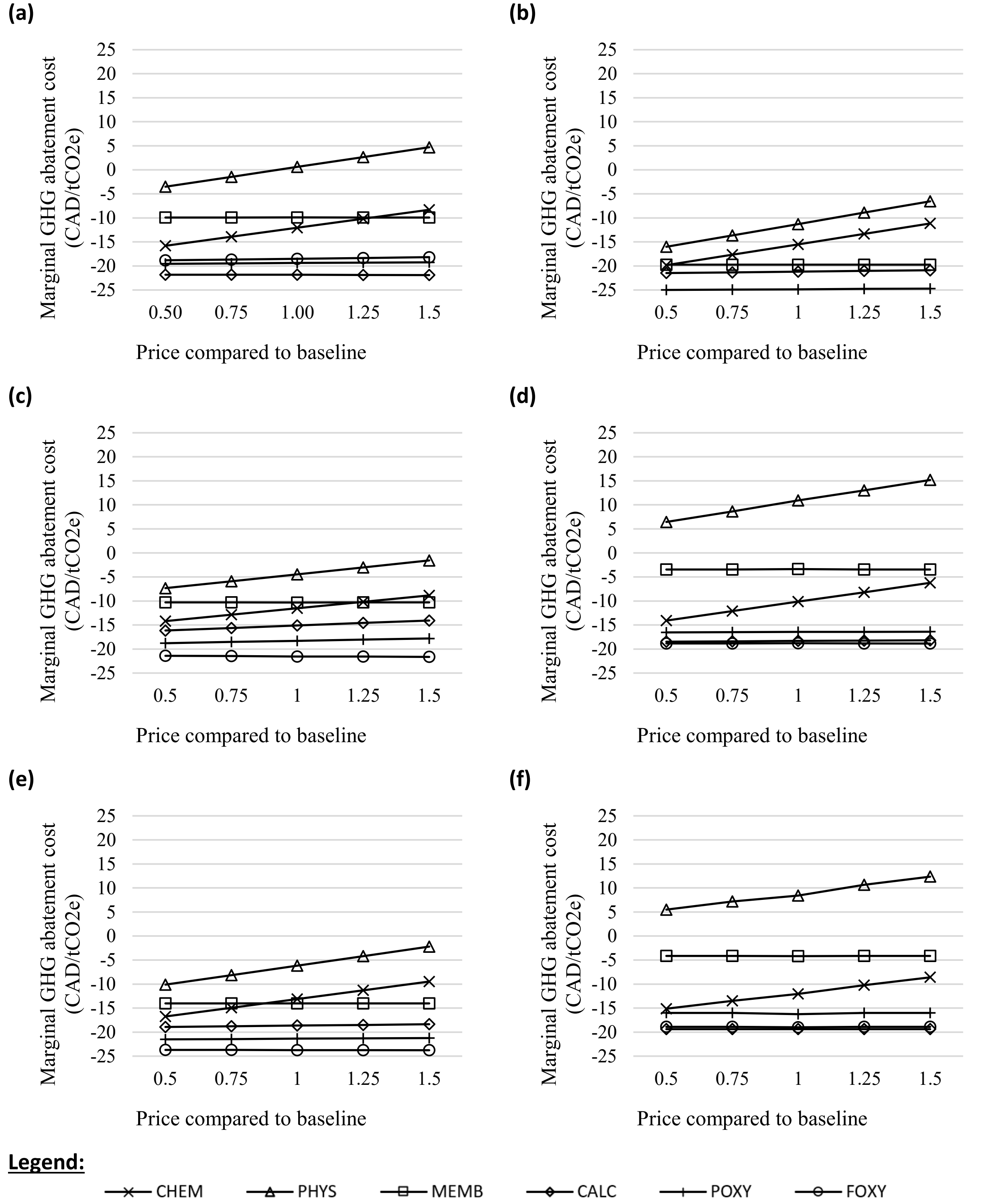

Figure 54. MAC sensitivity to natural gas prices +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

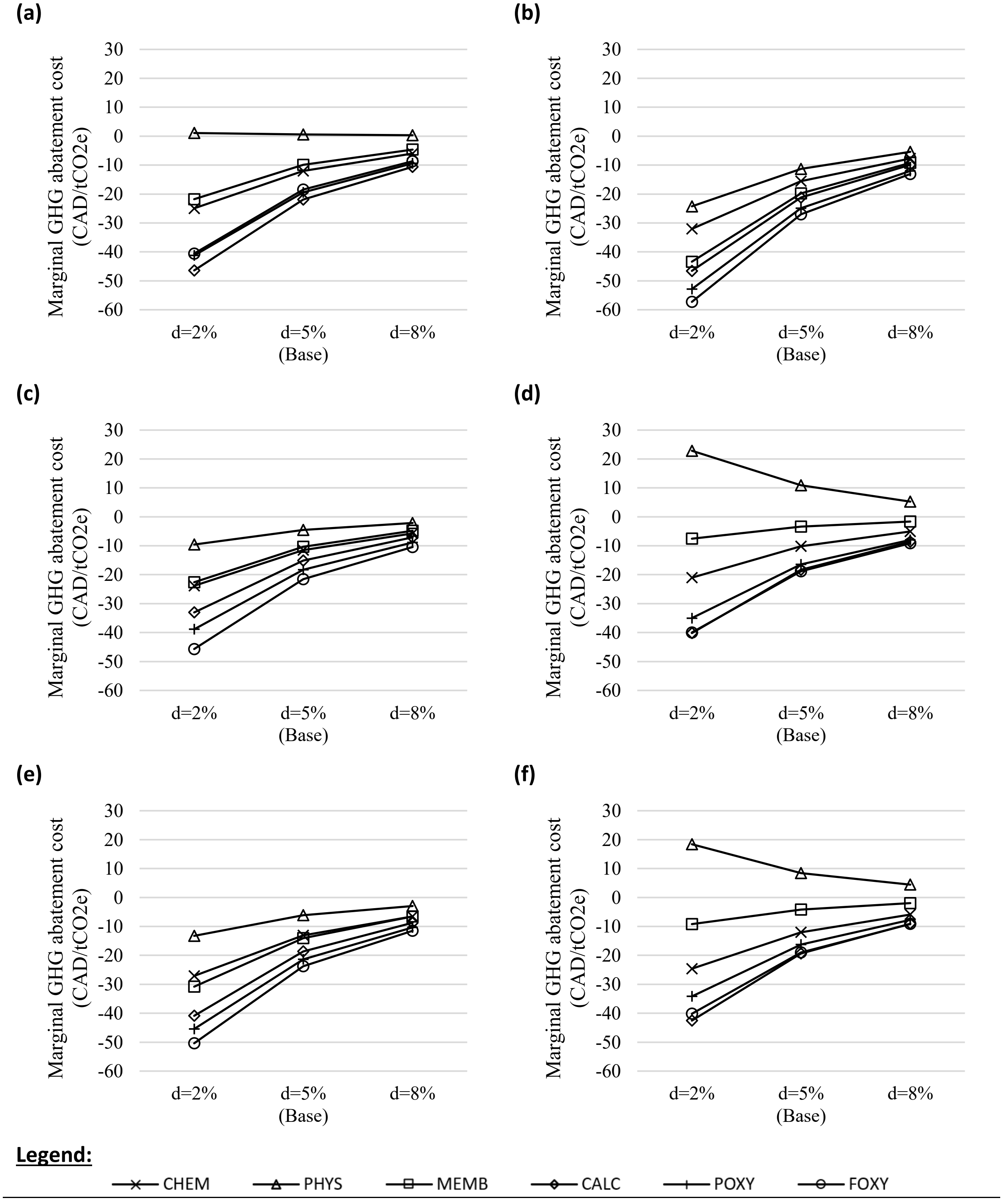

Figure 55. MAC sensitivity to NPV discount rates +/-3% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

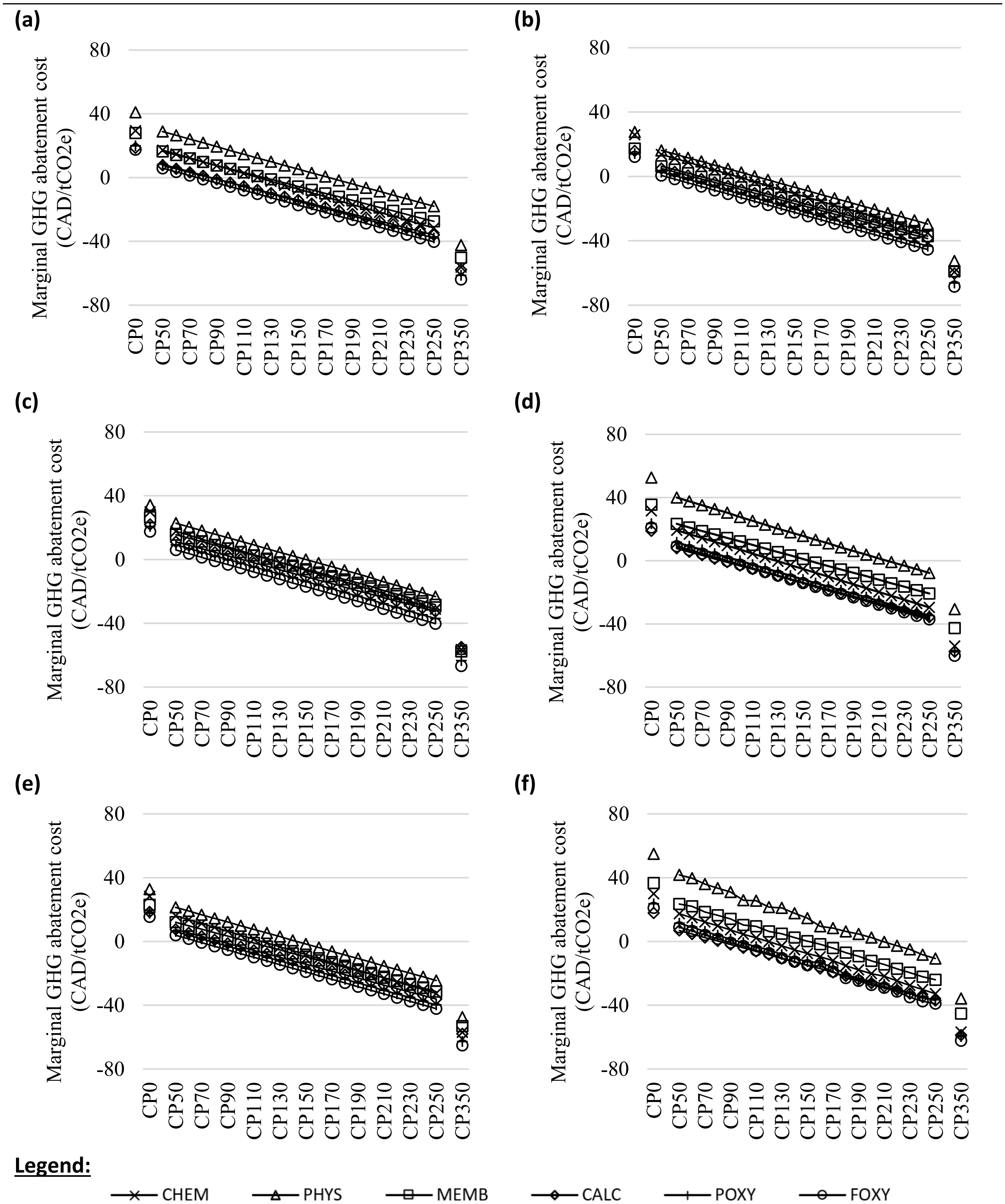

Figure 56. MAC sensitivity to carbon prices for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

Appendix K – Energy-efficient technology, alternative raw materials, and alternative binders and chemistries sensitivity analysis

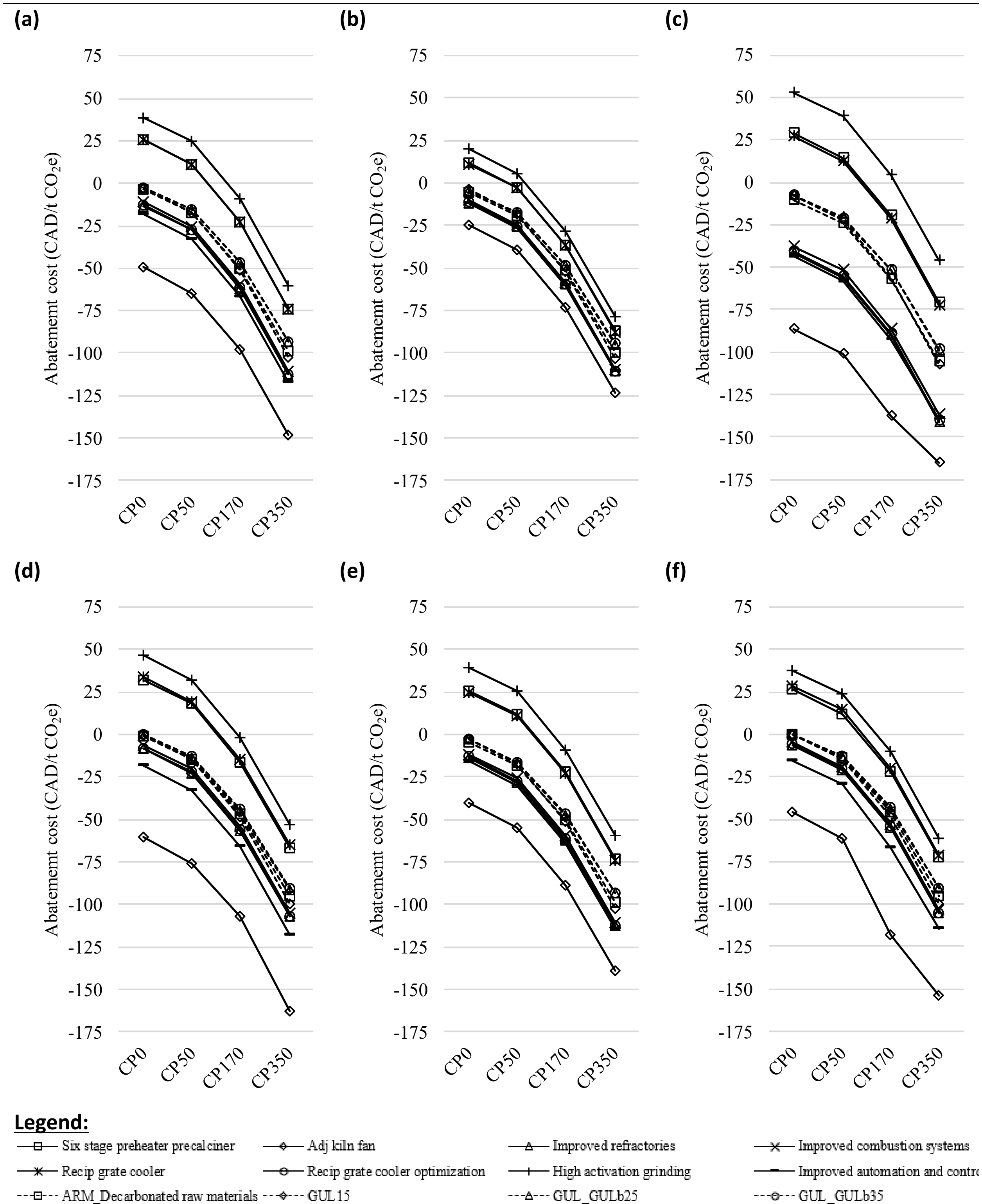

Figure 57. Energy-efficient technology, alternative raw materials, and alternative binders and chemistries abatement cost sensitivity to carbon prices for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

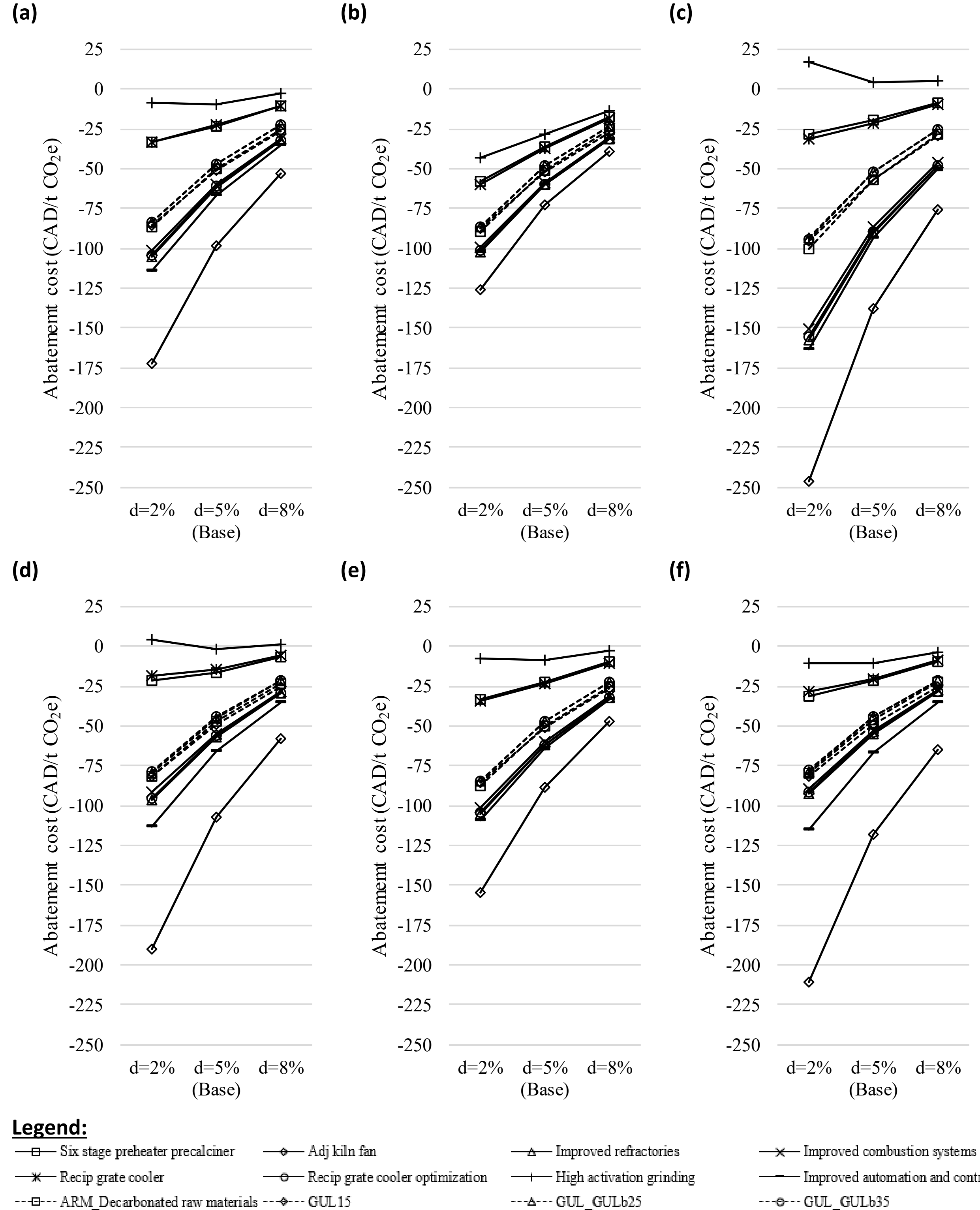

Figure 58. Energy-efficient technology, alternative raw materials, and alternative binders and chemistries abatement cost sensitivity to NPV discount rates +/-3% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

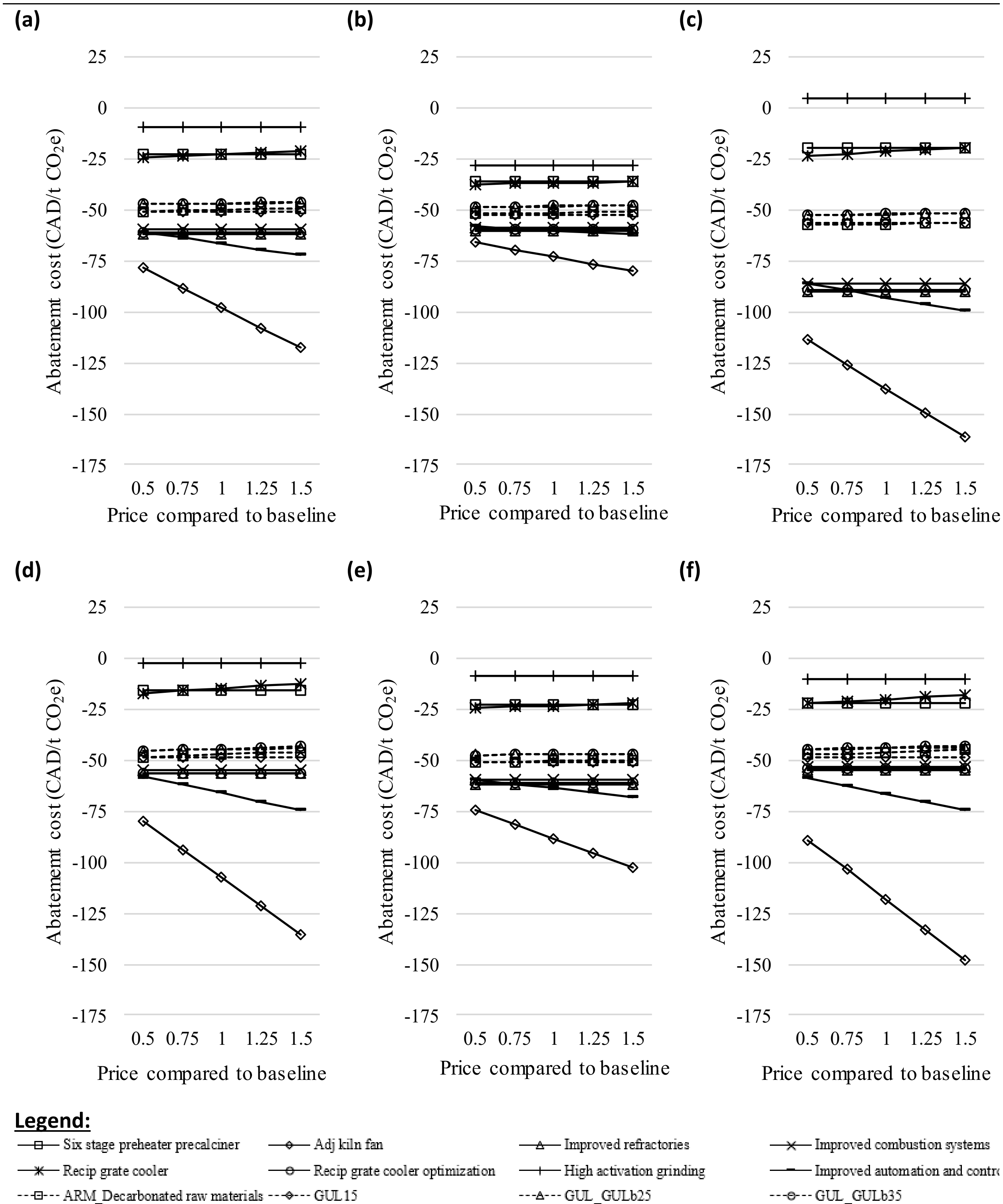

Figure 59. Energy-efficient technology, alternative raw materials, and alternative binders and chemistries abatement cost sensitivity to electricity costs +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

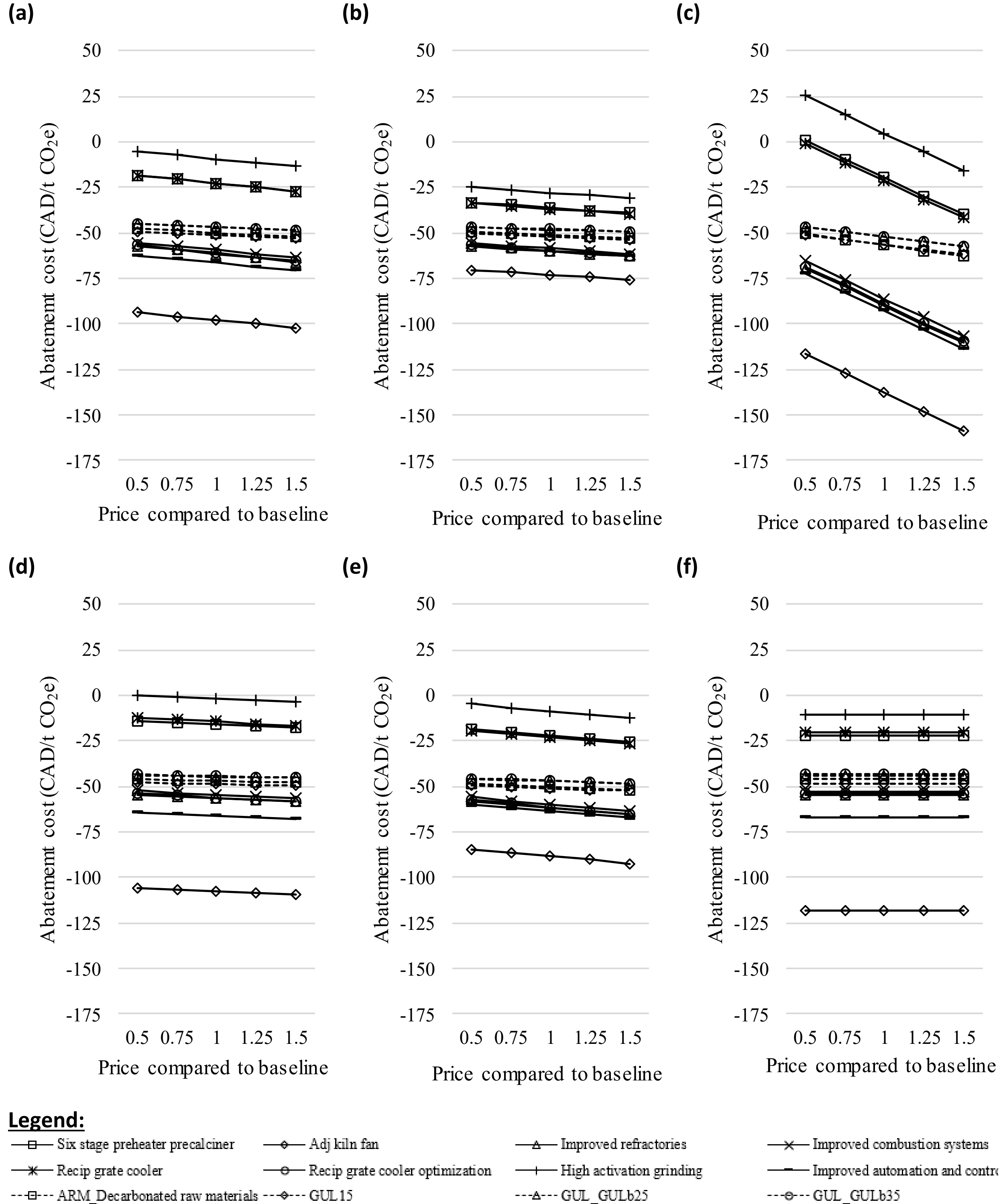

Figure 60. Energy-efficient technology, alternative raw materials, alternative binders and chemistries abatement cost sensitivity to natural gas costs +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

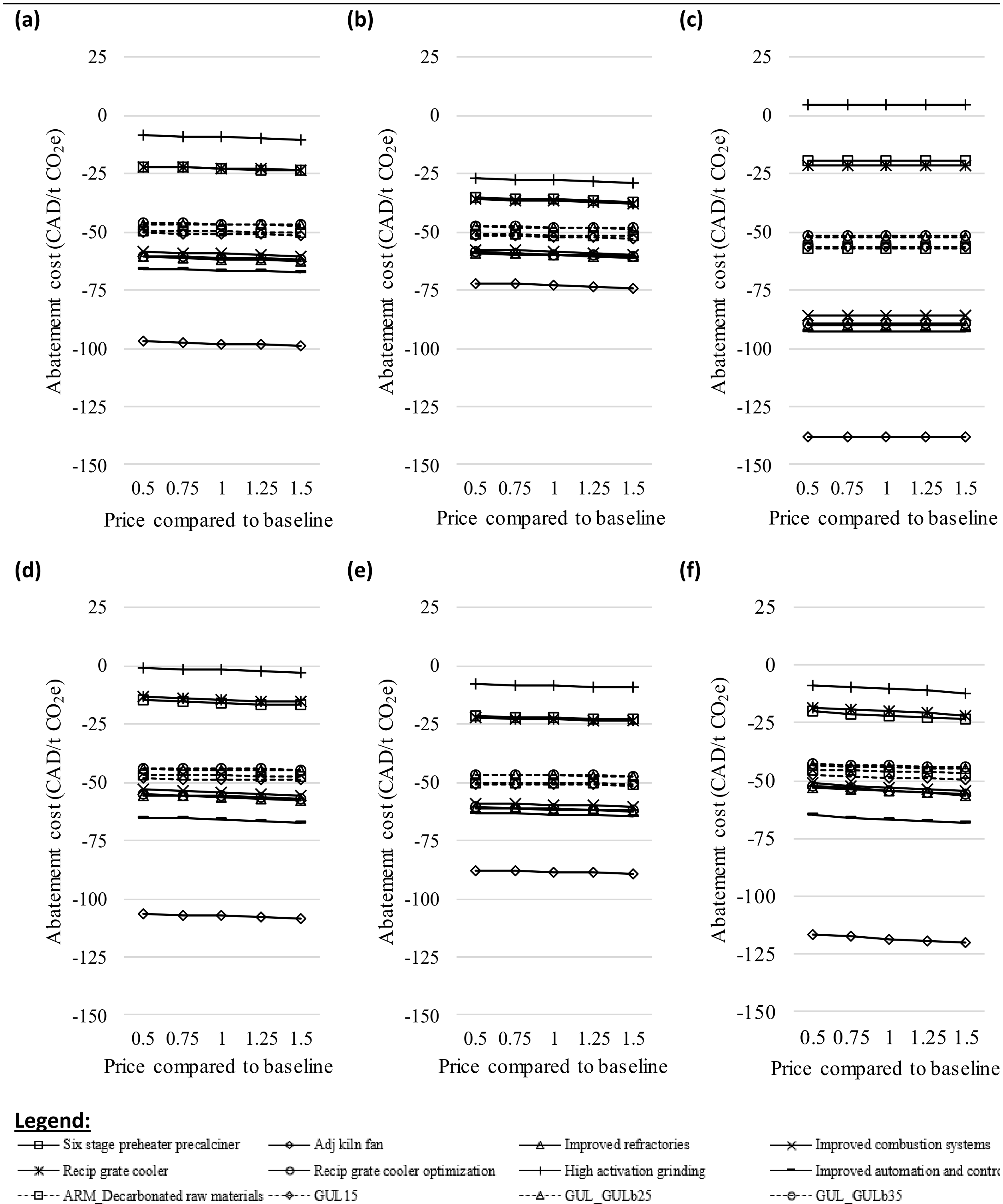

Figure 61. Energy-efficient technology, alternative raw materials, alternative binders and chemistries abatement cost sensitivity to coal costs +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

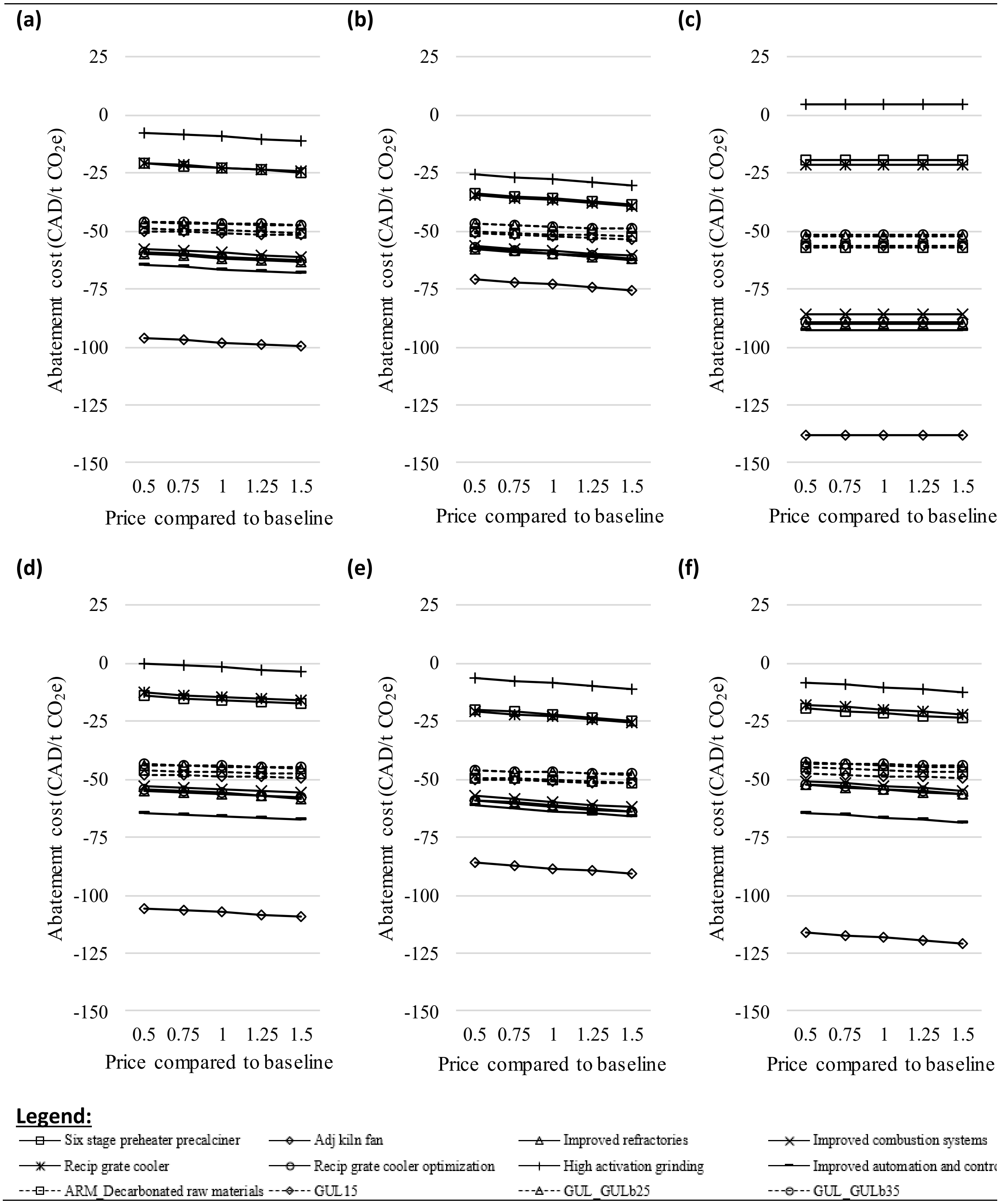

Figure 62. Energy-efficient technology, alternative raw materials, alternative binders and chemistries abatement cost sensitivity to petroleum coke costs +/-25% and +/-50% for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

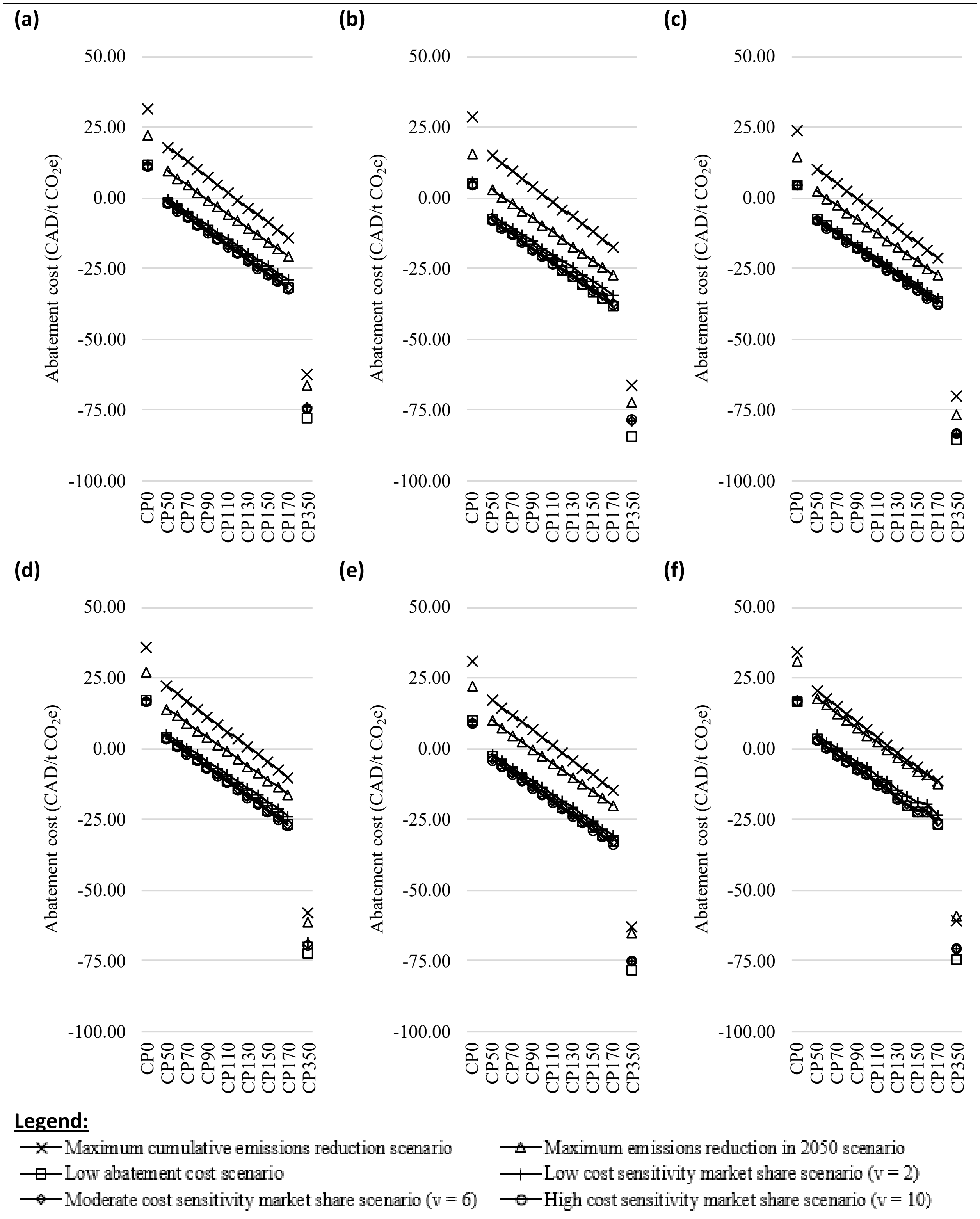

Figure 63. Carbon-neutral scenario abatement cost sensitivity to carbon costs for (a) Canada, (b) British Columbia, (c) Alberta, (d) Ontario, (e) Quebec, and (f) Nova Scotia

Appendix L – Breakeven carbon prices

Table 22. CCS scenario breakeven carbon prices

Region	Model parameter	Scenario / Modification factor	CP0	CP50	CP60	CP70	CP80	CP90	CP100	CP110	CP120	CP130	CP140	CP150	CP160	CP170	CP180	CP190	CP200	CP210	CP220	CP230	CP240	CP250	CP350
British Columbia	Carbon price	CHEM_High thermal pen.	25.9	13.7	11.3	8.8	6.4	4.0	1.5	-0.9	-3.3	-5.8	-8.2	-10.6	-13.1	-15.5	-17.9	-20.4	-22.8	-25.2	-27.7	-30.1	-32.5	-35.0	-59.3
		PHYS_High thermal pen.	27.6	16.2	13.9	11.6	9.3	7.0	4.7	2.5	0.2	-2.1	-4.4	-6.7	-9.0	-11.3	-13.6	-15.9	-18.1	-20.4	-22.7	-25.0	-27.3	-29.6	-52.5
		MEMB_High thermal pen.	17.2	6.4	4.2	2.0	-0.2	-2.3	-4.5	-6.7	-8.9	-11.0	-13.2	-15.4	-17.6	-19.7	-21.9	-24.1	-26.3	-28.4	-30.6	-32.8	-35.0	-37.1	-58.9
		CALC_High thermal pen.	15.8	5.0	2.8	0.6	-1.6	-3.8	-5.9	-8.1	-10.3	-12.5	-14.6	-16.8	-19.0	-21.2	-23.4	-25.5	-27.7	-29.9	-32.1	-34.3	-36.4	-38.6	-60.4
		POXY_High Thermal pen.	14.2	2.7	0.4	-1.9	-4.2	-6.5	-8.8	-11.1	-13.4	-15.7	-18.0	-20.3	-22.6	-24.9	-27.2	-29.5	-31.8	-34.1	-36.4	-38.7	-41.0	-43.3	-66.3
		FOXY_High thermal pen.	12.2	0.7	-1.7	-4.0	-6.3	-8.6	-10.9	-13.2	-15.5	-17.8	-20.1	-22.4	-24.7	-27.0	-29.3	-31.6	-33.9	-36.2	-38.5	-40.8	-43.1	-45.4	-68.4
Alberta	Carbon price	CHEM_High thermal pen.	29.9	17.7	15.2	12.8	10.4	7.9	5.5	3.1	0.6	-1.8	-4.2	-6.7	-9.1	-11.5	-14.0	-16.4	-18.8	-21.3	-23.8	-26.2	-28.6	-31.1	-56.5
		PHYS_High thermal pen.	34.3	22.8	20.5	18.2	15.9	13.7	11.4	9.1	6.8	4.6	2.3	0.0	-2.2	-4.5	-6.8	-9.0	-11.3	-13.9	-16.2	-18.6	-20.9	-23.2	-56.0
		MEMB_High thermal pen.	26.5	15.6	13.4	11.3	9.1	6.9	4.8	2.6	0.5	-1.7	-3.9	-6.0	-8.2	-10.3	-12.5	-14.6	-16.8	-19.5	-21.6	-23.9	-26.1	-28.3	-57.5
		CALC_High thermal pen.	22.0	11.1	8.9	6.7	4.5	2.4	0.2	-2.0	-4.2	-6.4	-8.6	-10.7	-12.9	-15.1	-17.3	-19.5	-21.7	-23.9	-26.1	-28.3	-30.4	-32.6	-54.9
		POXY_High Thermal pen.	20.7	9.2	6.9	4.6	2.3	0.0	-2.3	-4.6	-6.9	-9.1	-11.4	-13.7	-16.0	-18.3	-20.6	-22.9	-25.2	-27.7	-30.0	-32.3	-34.6	-37.0	-63.4
		FOXY_High thermal pen.	17.5	6.0	3.7	1.4	-0.9	-3.2	-5.5	-7.8	-10.1	-12.4	-14.7	-17.0	-19.2	-21.5	-23.8	-26.1	-28.4	-31.0	-33.3	-35.6	-37.9	-40.2	-66.7
Ontario	Carbon price	CHEM_High thermal pen.	31.6	19.3	16.8	14.4	11.9	9.5	7.0	4.6	2.1	-0.3	-2.8	-5.2	-7.7	-10.1	-12.5	-15.0	-17.4	-19.8	-22.3	-24.7	-27.2	-29.6	-54.0
		PHYS_High thermal pen.	52.7	40.0	37.5	35.2	32.7	30.4	27.7	25.2	22.8	20.3	18.0	15.6	13.3	10.9	8.4	6.1	3.8	1.5	-0.8	-3.2	-5.4	-7.8	-30.7
		MEMB_High thermal pen.	35.5	23.4	21.0	18.8	16.6	14.4	12.2	10.0	7.8	5.5	3.3	1.1	-1.1	-3.4	-5.5	-7.7	-9.8	-12.0	-14.3	-16.4	-18.6	-20.8	-42.6
		CALC_High thermal pen.	18.9	7.9	5.7	3.5	1.3	-0.8	-3.0	-5.2	-7.4	-9.6	-11.8	-13.9	-16.1	-18.3	-20.5	-22.7	-24.8	-27.0	-29.2	-31.4	-33.6	-35.7	-57.6
		POXY_High Thermal pen.	23.4	11.6	9.2	6.9	4.6	2.2	-0.1	-2.4	-4.8	-7.1	-9.4	-11.8	-14.1	-16.4	-18.6	-20.9	-23.1	-25.4	-27.9	-30.1	-32.4	-34.7	-57.7
		FOXY_High thermal pen.	21.0	9.2	6.8	4.5	2.2	-0.2	-2.5	-4.8	-7.2	-9.5	-11.8	-14.2	-16.5	-18.8	-21.0	-23.2	-25.5	-27.8	-30.2	-32.5	-34.8	-37.1	-60.1
Quebec	Carbon price	CHEM_High thermal pen.	28.3	16.1	13.7	11.3	8.8	6.4	3.9	1.5	-0.9	-3.4	-5.8	-8.2	-10.7	-13.1	-15.5	-18.0	-20.4	-22.9	-25.3	-27.7	-30.2	-32.6	-57.0
		PHYS_High thermal pen.	32.8	21.4	19.1	16.8	14.5	12.2	9.9	7.6	5.3	3.0	0.7	-1.6	-3.9	-6.2	-8.5	-10.7	-13.0	-15.3	-17.6	-19.9	-22.2	-24.5	-47.4
		MEMB_High thermal pen.	22.9	12.1	9.9	7.7	5.5	3.4	1.2	-1.0	-3.2	-5.3	-7.5	-9.7	-11.9	-14.0	-16.2	-18.4	-20.5	-22.7	-24.9	-27.1	-29.2	-31.4	-53.2
		CALC_High thermal pen.	18.4	7.5	5.4	3.2	1.0	-1.2	-3.4	-5.6	-7.7	-9.9	-12.1	-14.3	-16.5	-18.6	-20.8	-23.0	-25.2	-27.4	-29.6	-31.7	-33.9	-36.1	-57.9
		POXY_High Thermal pen.	17.7	6.2	3.9	1.6	-0.7	-3.0	-5.3	-7.6	-9.9	-12.2	-14.5	-16.8	-19.1	-21.4	-23.7	-26.0	-28.3	-30.6	-32.9	-35.2	-37.5	-39.8	-62.8
		FOXY_High thermal pen.	15.4	3.9	1.6	-0.7	-3.0	-5.3	-7.6	-9.9	-12.2	-14.5	-16.8	-19.1	-21.4	-23.7	-26.0	-28.3	-30.6	-32.9	-35.3	-37.6	-39.9	-42.2	-65.2
Nova Scotia	Carbon price	CHEM_High thermal pen.	29.8	17.4	14.8	12.2	9.8	7.3	4.5	2.3	-0.2	-2.7	-5.2	-7.5	-9.7	-12.0	-15.3	-17.8	-20.1	-21.9	-24.7	-27.6	-30.2	-32.8	-56.9
		PHYS_High thermal pen.	54.9	41.7	39.8	36.0	33.4	31.0	25.9	25.6	21.5	21.1	17.7	14.7	9.4	8.4	6.3	4.8	2.4	-0.2	-2.6	-4.9	-8.4	-10.7	-35.8
		MEMB_High thermal pen.	36.7	23.5	22.0	18.5	16.4	14.2	10.3	9.5	6.3	4.9	2.5	0.2	-1.7	-4.2	-7.0	-9.3	-12.2	-14.4	-17.1	-19.6	-22.1	-24.0	-45.2
		CALC_High thermal pen.	17.8	6.9	4.7	2.5	0.3	-1.9	-4.0	-6.3	-8.4	-10.7	-12.9	-15.0	-17.0	-19.4	-21.7	-23.9	-26.1	-28.3	-30.5	-32.7	-34.9	-37.1	-58.7
		POXY_High Thermal pen.	23.6	11.4	8.9	6.4	4.0	1.5	-0.8	-3.3	-5.0	-8.1	-10.4	-12.6	-13.3	-16.3	-20.6	-23.1	-25.0	-26.7	-29.4	-32.7	-35.2	-36.6	-59.8
		FOXY_High thermal pen.	21.0	8.9	6.5	4.0	1.6	-0.8	-2.9	-5.6	-7.4	-10.4	-12.7	-14.9	-15.4	-19.0	-23.0	-24.6	-27.3	-29.0	-31.5	-35.0	-37.5	-39.0	-62.2

*Transition of marginal abatement costs from positive to negative are highlighted in yellow

Table 23. Carbon-neutral scenario breakeven carbon price

Region	Model parameter	Scenario / Modification factor	CP0	CP50	CP60	CP70	CP80	CP90	CP100	CP110	CP120	CP130	CP140	CP150	CP160	CP170	CP350
British Columbia	Carbon price	**Maximum cumulative emissions reduction scenario**	28.9	15.2	12.5	9.8	7.0	4.3	1.6	-1.1	-3.8	-6.5	-9.2	-11.9	-14.6	-17.3	-66.1
		Maximum emissions reduction in 2050 scenario	15.8	3.1	0.6	-1.9	-4.5	-7.0	-9.5	-12.0	-14.5	-17.1	-19.6	-22.1	-24.6	-27.1	-72.5
		Low abatement cost scenario	5.5	-7.4	-9.9	-12.5	-15.1	-17.6	-20.2	-22.7	-25.3	-27.8	-30.4	-33.0	-35.5	-38.1	-84.1
		Low cost sensitivity market share scenario (v= 2)	5.6	-5.9	-8.3	-10.6	-12.9	-15.2	-17.6	-19.9	-22.3	-24.7	-27.0	-29.4	-31.8	-34.2	-79.0
		Moderate cost sensitivity market share scenario (v= 6)	4.8	-7.9	-10.3	-12.8	-15.2	-17.6	-20.0	-22.4	-24.8	-27.2	-29.6	-32.0	-34.4	-36.8	-78.8
		High cost sensitivity market share scenario (v= 10)	4.9	-8.1	-10.6	-13.1	-15.6	-18.1	-20.6	-23.1	-25.5	-28.0	-30.4	-32.8	-35.2	-37.5	-78.5
Alberta	Carbon price	**Maximum cumulative emissions reduction scenario**	23.9	10.5	7.9	5.2	2.6	0.0	-2.6	-5.3	-7.9	-10.5	-13.2	-15.8	-18.4	-21.1	-69.9
		Maximum emissions reduction in 2050 scenario	14.9	2.4	-0.1	-2.6	-5.1	-7.5	-10.0	-12.5	-15.0	-17.4	-19.9	-22.4	-24.9	-27.4	-76.6
		Low abatement cost scenario	5.0	-7.3	-9.8	-12.2	-14.7	-17.1	-19.5	-22.0	-24.4	-26.9	-29.3	-31.8	-34.2	-36.7	-85.4
		Low cost sensitivity market share scenario (v= 2)	4.8	-7.2	-9.6	-11.9	-14.3	-16.6	-18.9	-21.2	-23.6	-25.9	-28.2	-30.6	-32.9	-35.3	-83.1
		Moderate cost sensitivity market share scenario (v= 6)	4.7	-7.8	-10.3	-12.8	-15.3	-17.8	-20.3	-22.8	-25.2	-27.7	-30.2	-32.6	-35.0	-37.4	-83.3
		High cost sensitivity market share scenario (v= 10)	4.7	-7.9	-10.4	-12.9	-15.4	-17.9	-20.4	-22.9	-25.4	-27.9	-30.4	-32.9	-35.3	-37.8	-83.2
Ontario	Carbon price	**Maximum cumulative emissions reduction scenario**	35.9	22.2	19.5	16.8	14.2	11.5	8.8	6.1	3.4	0.7	-1.9	-4.6	-7.3	-10.0	-58.0
		Maximum emissions reduction in 2050 scenario	27.2	14.2	11.7	9.2	6.6	4.1	1.6	-1.0	-3.5	-6.0	-8.6	-11.1	-13.6	-16.1	-61.1
		Low abatement cost scenario	17.2	4.1	1.6	-1.0	-3.5	-6.1	-8.7	-11.3	-13.8	-16.3	-18.9	-21.5	-24.0	-26.6	-72.0
		Low cost sensitivity market share scenario (v= 2)	17.2	5.1	2.8	0.4	-2.0	-4.4	-6.8	-9.2	-11.6	-14.0	-16.4	-18.8	-21.3	-23.7	-68.5
		Moderate cost sensitivity market share scenario (v= 6)	16.8	3.7	1.1	-1.5	-4.0	-6.6	-9.1	-11.7	-14.2	-16.7	-19.2	-21.7	-24.2	-26.6	-69.1
		High cost sensitivity market share scenario (v= 10)	16.8	3.6	1.0	-1.6	-4.2	-6.8	-9.4	-12.0	-14.5	-17.1	-19.7	-22.3	-24.8	-27.3	-69.5
Quebec	Carbon price	**Maximum cumulative emissions reduction scenario**	30.9	17.4	14.8	12.1	9.4	6.8	4.1	1.4	-1.3	-3.9	-6.6	-9.3	-11.9	-14.6	-62.7
		Maximum emissions reduction in 2050 scenario	22.5	10.0	7.5	5.0	2.5	0.0	-2.5	-5.0	-7.5	-10.0	-12.5	-15.0	-17.5	-20.0	-65.0
		Low abatement cost scenario	10.0	-2.6	-5.2	-7.7	-10.2	-12.7	-15.2	-17.8	-20.3	-22.8	-25.3	-27.8	-30.4	-32.9	-78.3
		Low cost sensitivity market share scenario (v= 2)	9.8	-1.9	-4.2	-6.6	-8.9	-11.3	-13.7	-16.0	-18.4	-20.8	-23.2	-25.6	-28.0	-30.4	-75.1
		Moderate cost sensitivity market share scenario (v= 6)	9.0	-3.7	-6.1	-8.6	-11.0	-13.4	-15.9	-18.3	-20.7	-23.1	-25.5	-28.0	-30.4	-32.8	-75.2
		High cost sensitivity market share scenario (v= 10)	9.0	-3.9	-6.4	-8.9	-11.4	-13.9	-16.4	-18.9	-21.3	-23.8	-26.2	-28.7	-31.1	-33.5	-75.1
Nova Scotia	Carbon price	**Maximum cumulative emissions reduction scenario**	34.7	20.9	18.1	15.2	12.5	9.8	6.9	4.3	1.7	-1.2	-3.9	-6.4	-8.8	-11.4	-60.6
		Maximum emissions reduction in 2050 scenario	31.1	18.0	15.5	12.7	10.1	7.5	4.9	2.3	0.0	-2.9	-5.4	-7.9	-9.2	-12.6	-59.1
		Low abatement cost scenario	16.9	3.6	0.9	-1.7	-4.3	-6.9	-8.7	-12.2	-13.6	-17.5	-19.9	-22.3	-22.3	-26.6	-74.2
		Low cost sensitivity market share scenario (v= 2)	17.1	5.0	2.6	0.2	-2.2	-4.6	-6.4	-9.5	-11.1	-14.5	-16.8	-19.1	-19.4	-23.4	-70.3
		Moderate cost sensitivity market share scenario (v= 6)	16.8	3.3	0.7	-1.9	-4.4	-7.0	-8.7	-12.0	-13.4	-17.0	-19.3	-21.5	-21.6	-25.6	-70.4
		High cost sensitivity market share scenario (v= 10)	16.8	3.2	0.4	-2.2	-4.8	-7.4	-9.2	-12.6	-14.1	-17.8	-20.1	-22.3	-22.4	-26.5	-70.3

*Transition of marginal abatement costs from positive to negative are highlighted in yellow.