A capacity expansion model to explore Canada’s electricity system decarbonization pathways

by

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Abstract

Canada has announced carbon reduction targets of 40-45 percent below 2005 levels by 2030 and net-zero emissions by 2050. To achieve these targets, climate plans are designed and introduced in which a significant transition in the energy system is proposed. Canada's electricity system is one of the main sectors of the energy system expected to be affected by climate actions and experience a transformation from fossil fuel fired generation to renewable energies. To inform policy decisions and facilitate the transition of the electricity system, modelling and analysis of potential pathways are required. This thesis proposes an electricity system planning model entitled COPPER, Canadian Opportunities for Planning and Production of Electricity Resources, designed based on Canada's electricity system characteristics to explore challenges and opportunities associated with the transition. COPPER is developed and deployed in three iterations to assess the impacts of (1) climate plans, (2) carbon pricing mechanisms, and (3) technological development on the electricity system transition. In the first iteration, the base COPPER is employed to analyze whether the policies announced in Canada's latest climate plan are enough to achieve the set carbon reduction goals. The results highlight that although in-place policies are enough to reach the 2030 carbon reduction goal, they need to be strengthened to achieve net-zero emissions by 2050. This study models carbon pricing as a universal carbon tax for all provinces while Canada's federal carbon pricing system is a flexible program allowing provinces to design their pricing systems. Therefore, in the second iteration, COPPER is enhanced to incorporate in place carbon pricing mechanisms across Canada. Through enhanced COPPER, we explore whether provincially designed carbon pricing systems improve carbon reduction and economic outcomes for provinces compared to the federal pricing system. Analysis shows that provincially designed carbon pricing mechanisms result in lower carbon emissions while their associated costs are less than the federal pricing system. Also, we flag that in order to achieve carbon reduction goals, the emissions benchmark for provinces with the output-based pricing system needs to be tightened. The version of COPPER used for the first and second iterations includes conventional generation types alongside wind, solar and battery storage. However, emerging technologies have the potential to facilitate the transition of the electricity system toward a cleaner system. Therefore, in the third iteration, to explore the extent to which emerging technologies contribute toward Canada's electricity system decarbonization, COPPER is improved to incorporate combustion hydrogen, natural gas fire with carbon capture and storage, small modular reactors, offshore wind, and geothermal. Through exploring scenarios, we find that although the penetration of these technologies in

the future mix of Canada’s electricity system is uncertain, their contribution can be significant under some scenarios. Low- or non-emitting thermal technology types such as natural gas with carbon capture and storage and hydrogen combustion have the highest share of capacity among modelled emerging technologies.

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III. Arjmand, R., McPherson, M., 2022. The role of technological development in Canada's electricity system transition. Energy, Submitted.

In the above manuscripts, my contribution includes conceptualization, methodology, design and development of the model, data curation, validation of the results, formal analysis, visualization, and writing the original draft. In manuscript II, my committee member Dr. Rhodes contributed by supervising, writing, reviewing and editing the manuscript. Also, in all manuscripts, my supervisor, Dr. McPherson, contributed by supervising, funding acquisition, writing, reviewing, editing, providing resources and software, and conceptualization.

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VI. Madeleine, M., Rhodes, E., Istanislaw, L., Arjmand, R., Saffari, M., Xu, R., Hoicka, C., Esfahlani, M., 2022. Modeling the transition to a zero emission energy system: a cross-sectoral review of building, transportation, and electricity system models in Canada. Renew. Sustain. Energy Rev. Submitted.

In manuscripts IV and V, I provided the COPPER software and required support. In manuscript VI, I was responsible for the review of capacity expansion models in Canada.

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Dedication

To my love of life, Bahareh, and my beloved parents, Rasoul and Shahnaz.

Chapter 1: Introduction

The governments of Canada have committed to reducing economy-wide emissions by 40-45 percent below 2005 levels by 2030 and achieving zero-emission by 2050. To meet the carbon reduction commitments, the federal and provincial governments of Canada have introduced a set of actions. These actions target various sources of emissions including the electricity system. On the national scale, Canada's electricity system is a relatively clean system in which most of the demand is supplied by non-emitting resources such as hydro, nuclear, and renewables. This sector accounts for 8.4 percent of Canada's emissions, with 56 megatonnes of carbon dioxide equivalent (Mt CO2e) emitted in 2020 (Government of Canada, 2022a). On the provincial scale, provinces such as Alberta, Saskatchewan, Nova Scotia, and New Brunswick relay on fossil fuel generation technologies such as coal, diesel and natural gas to meet the electricity system demand and need to be decarbonized. Also, electrification in the other sectors affects the electricity system demand in the mid to long-term. Therefore, exploring alternative pathways through modelling can help to understand the impact of carbon reduction actions on Canada's electricity system in the long term and facilitate the transition by providing information regarding the generation and transmission mix, costs, emissions, and technical challenges.

Various frameworks have been used by researchers and utilities to study power system transition including but not limited to electricity system planning, integrated assessments and energy-economy models. These frameworks entail different levels of detail. While the Integrated assessment and energy-economy models simulated the entire energy system and capture the interdependencies between energy sectors, their representation of the electricity system is simplified. In contrast, electricity system planning models (ESPMs) just simulate the power system with a high spatial and temporal resolution and consider generation, transmission and storage operational details (Dagoumas and Koltsaklis, 2019; Madeliene et al., 2022). Depending on the research goal, one of these frameworks can be implemented to provide insights regarding the electricity system transition. Since the focus of this study is the electricity system, and we aim at providing technically robust insights regarding the transition of Canada's electricity system, an ESPM framework is more suitable.

A review of ESPMs developed or applied to Canada's electricity system highlights a gap in the suite of available modelling tools and analysis. None of the existing models capture special characteristics of Canada's power system (a detailed literature review is presented in chapter 2). Therefore, this study tries to address the gap by proposing an electricity system planning model developed to fit well with Canada's electricity system characteristics. The model is deployed to explore the future of Canada's electricity system under different policy and technological development scenarios discussed in the following chapters.

Chapter two provides a background of existing capacity expansion models in Canada and highlights these models' limitations in capturing specific characteristics of the Canadian electricity system. Then, a framework that addresses these limitations is designed and implemented in the Python environment. The proposed model is deployed to assess the effectiveness of Canada's latest climate plan, "A healthy environment and economy", to achieve set carbon reduction goals. The electricity system generation and transmission mix, emissions, and costs under different carbon tax scenarios are reported on the national scale.

Chapter three focuses on carbon pricing mechanisms across Canada and provides a methodology to model in place pricing systems including the carbon tax, output-based pricing system, and carbon cap and trade within an electricity system planning framework. The proposed methodology is implemented in COPPER, and through scenario exploring, the provincially designed carbon pricing mechanisms are contrasted against the federal system. Results under different carbon pricing mechanisms scenarios are presented at both federal and provincial levels.

Chapter four investigate the role of emerging technologies in Canada's electricity system transition. To do so, reports published by the government, independent organizations, and utilities are reviewed to determine and prioritize potential electricity generation technologies in Canada. Then COPPER is modified to incorporate major emerging technologies including hydrogen combustion, offshore wind, small modular reactors, and fossil fuel fired with carbon capture and storage. A set of scenarios are designed and run to explore the possible contribution of these technologies to the electricity system mix of provinces across Canada. A breakdown of generation and storage capacity, associated costs and emissions are provided at the national and provincial scale.

Finally, chapter five summarizes the main insights and highlights research topics that are out of the scope of this study and remains for future work.

Chapter 2: Canada's electricity system transition under alternative policy scenarios

The content in this chapter was published in the following journal:
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2.1 Abstract

To meet Canada's emissions reduction targets, governments at the federal and provincial levels have developed climate plans and implemented a series of policies and regulations. Canada's latest climate plan, entitled "A Healthy Environment and a Healthy Economy" aims to decarbonize various sectors of the economy including the electricity sector. In this paper, we explore the extent to which implementing announced policies and regulations could drive investment in the electricity sector needed to achieve Canada's climate objectives. To do so, we propose a multi-period, optimization-based capacity expansion model specifically designed for the Canadian context entitled COPPER for the "Canadian Opportunities for Planning and Production of Electricity Resources." We employ COPPER to analyze Canada's electricity system transition under various carbon management policies. Results show that current and announced policies significantly increase renewable energy capacity, which in turn decrease the electricity system emissions by 40 percent in the mid-term. However, in the long-term, more ambitious actions will be required to achieve the emissions reduction targets. Natural gas-powered generation facilities persist at the proposed carbon tax levels, and thus supplementary regulations or policies will be needed to achieve deep decarbonization.

Keywords: Capacity expansion, Canada's electricity system, Greenhouse gas emissions, Generation mix, Renewable energy, Carbon policies

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2.2 Introduction

The Government of Canada has established targets for greenhouse gas emissions (GHG) reductions of 40-45 percent below 2005 by 2030 and net-zero emission by 2050 (Environment and Climate Change Canada, 2021a, 2020a). To achieve these targets, Canada strengthened the carbon reduction actions by announcing a climate plan entitled “A Healthy Environment and a Healthy Economy (HEHE)”, which targets various economic sectors including the electricity system. While several studies have shown that implementing carbon management policies including a carbon tax (CT) reduces carbon emissions, there is a lack of understanding as to how Canada’s strengthened climate plan will affect the electricity system transition. By using an electricity system planning model, this study examines the mid- and long-term impact of Canada’s climate plan on the electricity sector transition and shows that the proposed actions are not sufficient to achieve all the established carbon reduction targets.

Electricity system planning models (ESPMs) are one of the main tools that can be used to assess the impact of policies and uncertainties on the future generation and transmission mix, system costs, and GHG emissions of the electricity system. Four ESPMs, including CREST (Dolter and Rivers, 2018), IESD (Navius Reserach Inc, 2020a), ReEDS (Short et al., 2011), and SWITCH (Fripp, 2012), have been used to explore the future of Canada’s electricity system. Among these models, CREST and IESD were developed in Canada, while ReEDS and SWITCH are well-known models applied to Canada’s (Zinaman et al., 2015) and Alberta’s (Nelson et al., 2012) electricity systems, respectively.

CREST is a static (single period), linear programming model with an hourly (8760 hours of the target year) temporal resolution, which enables a good representation of hydroelectric plants. Additionally, CREST has a resolved spatial resolution representing more than 2000 renewable energy cells across the country. However, the model includes a limited suite of generation technologies, excludes the potential for new hydroelectric development, and optimizes a single target year rather than a temporal pathway. IESD is a linear programming electricity system planning model including a demand module that can be linked to the supply module, allowing for consideration of feedback between electricity supply and demand. Like CREST, IESD is a static model that optimizes for a specific target year (e.g., 2030 or 2050), but ignores the investment required between the reference and target year by assuming that generation and transmission capacity are sufficient to meet the demand in the modeled period preceding the target year. This assumption limits the insights needed for long-term planning since during the modeled period significant generation capacity will be retired and demand will increase significantly. However, IESD is not open source and has limited documentation, so there is not sufficient information to review it adequately.

ReEDS and SWITCH represent specific time-slices rather than full hourly chronology, ignoring inter-temporal constraints. This use of time slices rather than a full hourly chronology is a common method to reduce the computational burden of ESPMs. However, it is not suitable in the Canadian context because hydroelectric and nuclear facilities, which play key roles in this system, require consideration of chronological correlations and sequences within the model. For example, the fact that hydroelectric plants reserve energy to be dispatched at a later time according to the demand profile requires inter-temporal resolution. This simplification leads to an underestimation of the flexibility that reservoir hydroelectric plants can provide to the system. A recent analysis demonstrates that proper modelling of hydroelectricity is necessary to fully grasp the role that hydroelectric generation units can play in providing the required flexibility for integrating more renewable energy (Maluenda et al., 2018).

In addition to ESPMs, integrated assessment models (IAMs) including ENERGY2020 (Systematic Solutions INC., 2017), OSeMOSYS (Palmer-Wilson et al., 2019), NATEM (Vaillancourt et al., 2017), and CanESS (whatIf? Technologies Inc., 2020) have also been used to chart the future of Canada's electricity generation mix and energy sector more broadly. IAMs simulate the entire energy system from the energy sources to the demand side. These models can be formulated as partial equilibrium or optimization problems. Investment decisions, emissions, demand, and marginal price of different forms of energy, including electricity, are the main output of these models (Madeliene et al., 2022). Unlike ESPMs, IAMs can capture the interaction between different sectors of the energy system though their representation of the electricity system is simplified, which limits the technical robustness of model results (Dagoumas and Koltsaklis, 2019). Since the focus of this study is power system transition, we limit our detailed review to ESPMs.

Overall, the suite of modelling tools and analysis are limited in terms of technical details, spatial and temporal resolution and scale, and policy assessment. None of the existing models incorporates the complete list of considerations that are important in the Canadian context for the long-term planning of the electricity system. Furthermore, none of the studies has explored the impact of HEHE plan for the electricity system transition on the national scale using a model of the electricity system with the required spatial, temporal, technical, and policy assessment details.

To bridge the gap in the modelling effort and to provide insights into the future of Canada's electricity system, this paper presents a novel capacity expansion model designed to explore decarbonization pathways specifically in the Canadian context. The Canadian Opportunities for Planning and Production of Electricity Resources (COPPER) encompasses several features and formulation choices, as described in the model formulation section below, that focus on several key aspects of the Canadian power system.

The primary question motivating the model development focuses on the extent to which recently announced carbon management policies and regulations will drive required investment in the electricity system and whether these investments will achieve Canada's mid to long-term carbon reduction targets introduced in HEHE. The main objectives of this paper are to:

1. Develop an ESPM model that fits well with Canada's electricity system characteristics and present a detailed analysis of Canada's electricity system transition under carbon management policies.
2. Provide insights into how Canada's recent climate plan affects the evolution of the electricity system in the mid to long term and whether these policies are enough to achieve set targets.

Based on these objectives, the contribution of this paper is twofold. First, we have developed a dynamic long-term planning framework for the Canadian electricity system that improves upon existing models, specifically by enhancing the representation of Canada's power system characteristics. The main improvements of COPPER compared to existing models are summarized below (more detail in Table 1).

1. Formulates a dynamic model that distinguishes between run-of-river, small reservoir hydroelectric, and large storage hydroelectric.
2. Models hydroelectric greenfield development, renewal, and repowering as integer variables (project-specific) using a new formulation (Appendix equations A. 14-20).
3. Distinguishes between land-based and submarine transmission expansion.
4. Has the highest spatial resolution for variable renewables among all long-term planning models for Canada.

Each of these modifications also requires improved data, which we have gathered and incorporated into the model.

Second, we provide insight into Canada's electricity system transition under recently announced carbon management policies. To our knowledge, this is the first investigation of Canada's recently announced carbon management policies (in the HEHE climate plan). This paper poses the question: are these policies sufficient to achieve ambitious climate targets (carbon reduction targets) in the electricity system? We discuss Canada's electricity system generation, transmission, and storage mix under announced carbon management policies. For the first time, we evaluate how hydroelectric renewal can contribute to the future mix of Canada's electricity system. We also investigate the possible contribution of Small Modular Reactors (SMRs) and Carbon Capture and Storage (CCS) in Canada's electricity generation mix.

The remainder of this paper is organized as follows. Section 2 describes the methodology, including the optimization problem, policy representation, and uncertainty modelling. Section 3 details the data that has been gathered and used to populate the model. Section 4 describes the scenario mixes, while section 5 presents the results of the model per defined scenarios. Finally, the main outcomes are summarized in the conclusion and policy implication section 6.

2.3 Methodology

COPPER is a dynamic (multi-period), optimization-based ESPM that co-optimizes investment in thermal generation, renewable generation, transmission expansion, storage technologies, and operation and maintenance (O & M) of these assets. Several characteristics of Canada's electricity system require particular representations in the model formulation; these are summarized in Table 1.

Table 1: COPPER representation of specific Canadian electricity system characteristics, as compared to other model frameworks

Canada's electricity system-specific characteristic	Representation in COPPER	Representation in other models
Hydroelectric dominated - Approximately 60% of Canada's power is generated from hyd**roelectric** sources, making the representation of hydroelectric facilities a priority. Hydroelectric plants vary in their reservoir capacity, ranging from water storage for a day, a week, a month, or even a season, during which time they can produce energy whenever needed. A model designed for	Considers three types of hydroelectric plants including run of river, hydroelectric small and large reservoirs. Includes hydroelectric greenfield development, renewal, and repowering	CREST: Excludes option of hydroelectric renewal, greenfield development, or repowering. Omits data on the share of each type of hydroelectric facility.

application in a hydroelectric-dominated context should be able to consider this ability since it provides extensive grid flexibility, which can be critical for facilitating the integration of more renewable resources onto the power system (Dolter and Rivers, 2018).	Simulates hydroelectric development as site-specific (project-based, integer variable). Formulates representative days instead of time slices to enable the representation of reservoir characteristics.	ReEDS: Time slice formulation, excludes reservoir modelling and repowering option. SWITCH: Time slice resolution, excludes reservoir modelling, excludes hydroelectric renewal, greenfield development, and repowering option. IESD: No information
Spatial Resolution - The spatial resolution of the electricity system regions needs to account for the geographic diversity and provincial boundaries inherent to Canada's power system. Canada is a geographically large country with extensive variability in weather conditions. Appropriate siting of renewable energy, demands a resolved spatial representation.	13 balancing areas are defined as discrete but connected nodes to characterize the electricity system. Renewable energy is modelled in grid-cell resolution, entailing more than 2000 cells for the whole country.	CREST: same as COPPER. ReEDS: 47 regions for renewables in Canada. SWITCH: two load areas, British Columbia and Alberta IESD: No information
Policies – The model needs to account for are a variety of carbon management policies and regulations in Canada that aim to transition the power system.	Includes all known and available carbon management policies affecting Canada's electricity system.	CREST, ReEDS, SWITCH, IESD: None includes a complete suite of policies in Canada, or the methodologies to model them
Thermal units' operational constraints - Ontario is dominated by nuclear assets which have limited ramp rates. The operational implications of this on-grid flexibility need to be accounted for in the modelling framework.	Ramp-rates of thermal units are modelled for representative days.	CREST: considers ramp-rate. ReEDS, SWITCH: do not consider ramp-rate IESD: no information; likely considered
General modelling improvements	**Representation in COPPER**	**Representation in Other models**
Technologically diverse: The model creates scenarios for an uncertain future that will likely be technologically diverse. The model must be able to choose between various possible options.	Considers 13 generation technologies including technologies that are currently under development such as	CREST: nine generation technologies for the future. ReEDS, SWITCH: technologically rich, various

	SMRs. Also, models pumped hydroelectric and lithium battery as storage options.	types of renewable energy including solar, bioenergy, wind and geothermal. IESD: no information.
Transmission expansion: Transmission system investment will likely be an important aspect of decarbonization, and the model should consider its constraints and investment.	Simulates the transmission system using power corridors between balancing areas. New transmission capacity can be built/added according to the possible routes defined by the user. Differentiates between sub-marine and regular (land-based) transmission lines. Considers the intra-provincial transmission cost for renewables.	All models consider the inter-provincial transmission system and investment in it. None of them distinguishes sub-marine transmission expansion.
Dynamic formulation: A static formulation considers investments in the target year and ignores the transition. This leads to impractical outputs for the long-term planning studies because the solution for the target year is not independent of the other years (Seifi and Sepasian, 2011).	Uses dynamic formulation, which means the model can capture the transition and required investment to meet the demand between the reference and target year, so making the results reliable for long-term studies.	CREST: Static, just models the target year. ReEDS: semi-dynamic, optimizes each period separately. SWITCH: dynamic IESD: No information but likely static.

2.3.1 General formulation of COPPER

COPPER uses a mixed-integer linear programming formulation to explore optimal mixes for the future of Canada's electricity system under various uncertainties. The linear formulation guarantees that the model will converge to an optimal solution, while the integer formulation allows the model to make binary decisions such as the complete development of a hydroelectric asset or not (rather than giving incremental options). The optimization problem, temporal and spatial resolutions, and policy representation of COPPER are explained below[1].

2.3.1.1 Optimization problem

COPPER optimization formulation is built based on the CREST formulation that is presented in (Dolter and Rivers, 2018). We have added a set of periods instead of a single year to the equations to make it dynamic. Also, we have added planning reserve margin and hydroelectric development constraints to the formulation (more information about the methodology and equations can be found in the Appendix).

Objective function: The objective function minimizes total system planning and operation costs over the planning period, including investment in transmission, generation, and storage technologies, as well as operational costs associated with power production, carbon emissions, and fixed and variable operation and maintenance costs. As the model is dynamic, this objective function includes costs of all periods from the start year to the target year.

$$Min\ total\_system\_costs = InvestmentCost + MaintenanceCost + ProductionCost + CarbonCost \quad (1)$$

Constraints: A set of constraints are used to capture technical detail and limitations. The main constraints are as follows:

- The hourly balance of demand and supply in each balancing area
- Planning reserve margin in each balancing area
- Thermal unit constraints including maximum generation, minimum and maximum capacity factor (CF), and ramp-rate
- Hydroelectric constraints for run-of-river, small and large reservoir facilities including operational and development constraints
- Renewable energy maximum generation and land-use constraints
- Transmission and energy storage constraints

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[1] In this study, we have used CPLEX 12.9.0 to solve the optimization problem. A sample scenario includes about four million constraints, two million variables and take 30 hours to be solved on Compute Canada when asking 18 cores and 100 GB of ram.

2.3.1.2 Resolution

Temporal resolution: COPPER uses agglomerative hierarchical clustering to pick representative days for each period. This approach is widely used in recent studies to find representative periods for planning/operation purposes in power system modelling to minimize computational burden (Liu et al., 2018; Pfenninger, 2017; Pineda and Morales, 2018; Tso et al., 2020).

The method used in this analysis is based on (Pineda and Morales, 2018), in which according to the hourly demand profile of all provinces in Canada, similar days in each month are grouped into a few clusters by employing the agglomerative hierarchical clustering. Once the cluster labels of days are determined, we calculate each day's distance with other days in the same cluster by measuring the sum of straight lines length between their vectors (Euclidean distance metric). In each cluster, the day that has the minimum distance with the rest of the cluster is introduced as the representative day. Clustering the days in each month instead of the whole year allows for modelling the dispatchabilty of large reservoir hydroelectric facilities during each month.

Spatial resolution: COPPER models south of the 60th latitude in Canada using 13 balancing areas for the electricity demand, transmission lines, and conventional generation dispatch. Wind and solar energies are modelled using 2278 grid cells, each with a surface area of 2050 to 3050 square kilometers[2]. This spatial resolution enables provincial analysis and the representation of renewable resource availability that differs locationally while remaining computationally feasible. Figure 1 depicts the spatial resolution of COPPER.

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[2] This resolution is based on the CREST and weather data source.

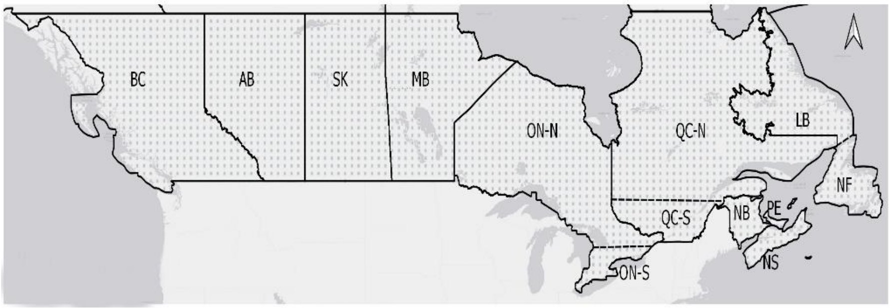

Figure 1: The spatial resolution of COPPER includes balancing areas (separated by lines and dash-lines) for conventional generation units and grid cells for renewables (small dots show the center of grid cells)

2.3.1.3 Policy representation

To capture the effect of carbon management policies and targets on Canada's electricity system, all major carbon management policies have been modelled. The main policies incorporated in the model include the following:

Carbon tax is modelled according to the emission intensity of each fuel type. If the model dispatches a certain amount of a thermal unit in a given hour, the related carbon price is added to the fuel price in the objective function. Note that COPPER just accounts for electricity generation emissions (combustion-related emissions).

Coal power plants phase-out is modelled by phasing out all coal power plants in the thermal plant retirement constraint. By activating this policy, the retirement constraint forces the model to phase out all coal power plants before a specific time.

The gas power plants performance standard policy ensures that new natural gas power plants use efficient technology with low carbon emission intensity. This regulation is modelled by banning development of new facilities that emit more than the standard level.

In addition to these policies, carbon reduction targets, renewable portfolio standards, and energy-saving (demand reduction) targets are modelled using a set of constraints. By activating these constraints, we can run scenarios to analyze the costs and technical issues associated with different levels of carbon reduction targets.

2.3.2 Uncertainty modelling

Power system planning entails uncertain parameters, including demand forecast, renewable energy uncertainties, economic parameters, fossil fuel prices, technological evolution, electricity prices, and climate patterns (Seifi and Sepasian, 2011). Integrating variable renewables and restructuring the power system are adding new uncertainties associated with its operation and investment decisions (Aien et al., 2016). The following summarized how the sources of uncertainty are addressed in COPPER.

1. Demand forecast: On the one hand, demand-side management efforts, climate change, and electrification are changing the demand pattern. On the other hand, long-term planning models including COPPER build their results based on the demand forecast (Seifi and Sepasian, 2011). Hence, the demand forecast is one of the main sources of uncertainty in COPPER. In this analysis, we have used network operators' (utilities) latest demand forecast in which they usually consider different impactful parameters, including electrification, efficiency enhancement, demand-side management, and post COVID-19 recovery plans. The level of detail and inclusion of different factors in the projection make the utilized demand forecasts robust against uncertainties and reduce the error. Therefore, although a deterministic demand profile is used in this study, the results are reliable.
2. Technology evolution: The historical data show that the costs and performance of technologies such as wind, solar, and lithium battery storage are subject to change over time. For instance, during the last decades, the cost of solar panels decreased while their performance improved at a faster rate than was anticipated by many in the early 2000s. In addition, other technologies such as SMRs are still under development and could enjoy significant cost reductions in the future. A comprehensive framework for dealing with technological evolution uncertainty in capacity expansion models is discussed in (Santen and Anadon, 2016). To capture the impact of this uncertainty on the results, sensitivity scenarios on alternate technology evolution pathways are run and the results are discussed (section 2.7.7).
3. Variability of renewables: To capture wind and solar variability during the day and different seasons, the model uses historical data with a high spatial resolution for days in all seasons. An hourly capacity factor profile for each grid cell is fed to the model to estimate the potential electricity generation at different times and locations. The spatial and temporal resolution is

sufficiently high to capture the variation in the wind and solar generation profile due to changes in location, season, and during the day. Thus, the high resolution handles this uncertainty.

4. Policy and regulations: Different carbon management policies and regulations are impacting Canada's electricity system operations and investment decisions. We have compiled a list of policies that affect the electricity sector and ran the model under various scenarios. Since. The carbon tax is the main policy that affects the electricity system transition, we provide results under different carbon tax scenarios (sections 2.6).

2.3.3 Model limitations

COPPER uses an optimization framework with two inherent limitations that need to be considered when analyzing the results. First, COPPER explores the system-wide least-cost solutions from the point of view of a central operator. This optimization framework is limited in modelling many of the other objectives of stakeholders, including federal and provincial electricity authorities, commercial generators, distributors, and end-users. Despite this limitation, ESPMs are widely used and important tools for energy policy analysis. They can be run by stakeholders to provide insights about the optimal evolution and expected path of an efficient power market under different investment decisions, policy instruments, and technology developments (Gacitua et al., 2018).

Second, the results of an optimization model might be biased specifically when there are uncertainties in the objective function coefficients (Hobbs and Hepenstal, 1989). Hobbs and Hepenstal (1989) recommend performing a sensitivity analysis on uncertain parameters and verifying the objective function coefficients. Thus, since we consider costs as coefficients in our objective function, we have used reliable resources for our cost data detailed in section 2.5.1. Also, we have performed a sensitivity analysis on these costs that shows the optimization results are rational under a wide range of parameter values.

Considering the limited computational resources and complexity of the planning models, in addition to the optimization framework limitations, COPPER has other limitations that remain. First, due to the finite computational resources, the number of balancing areas is limited. This means the model is unable to fully capture transmission system (power flow) and generation unit constraints, and this may overestimate the flexibility of the network.

Second, the model ignores some constraints/costs of thermal units such as startup/shutdown costs, minimum on/off-time, and minimum generation because adding these constraints/costs to the model requires integer variables and significantly increases the computational burden. These are operational details usually ignored by planning models. As the costs of these operational parameters are small compared to investment, maintenance, and other production costs, their omission results in a minor error in the objective function value.

Third, some emerging and evolving technologies (tidal turbines, offshore wind, geothermal) are not modelled in the current model version and will be added to future versions. Finally, due to policies, regulations, ecological, social, or cultural conservation values, renewable energy can be developed in limited areas across the country. Although we have excluded lake and river areas, the land-use limitation is not fully addressed. The model also excludes the northern Canadian territories, which are remote from the North American grid, and focuses only on the ten interconnected provinces.

Fourth, imports from and exports to the United States (US) are modelled as exogenous parameters using historical data. The regression-based approach presented in (Chen, 2009) can be used to improve modelling imports and exports over the interties between Canada and the US. Also, this study uses utility demand growth forecasts which include different factors. Climate change is an important factor that will likely affect electricity demand. Hence, modelling the demand growth using future climate data can provide valuable insights (Chen et al., 2015) although it is out of the scope of this study and we do not forecast the demand (demand growth is an exogenous parameter in COPPER). However, some of the demand forecasts by utilities used in this study might include the climate change impact, there is no publicly available detail about their methodology to confirm this. The absence of the climate change impact on the demand forecast can cause an error in the projection that in turn affects the capacity expansion model results. In future iterations of the model, the utility demand forecast can be replaced with the outputs of a model that explicitly includes climate change. In this section, we tried to mention the main model limitations; however, there might be other limitations that are not listed here.

2.3.4 Model Validation

To validate COPPER and ensure the results are reliable, a set of feasible methods is used. First, the model is run under various test scenarios. In addition to the standard conditions in which we assume the current status of the power system, these test scenarios include runs that by manipulating input data, we check whether designed and implemented constraints work properly. Note that due to the computational burden and limited availability of resources, most of these test scenarios are run with lower temporal resolution (two days in each planning period). A list of technical constraints and the methodology used to check them are detailed below.

1- Supply and demand equality: A test run that assumes the current status of the power system with no changes to the input data (standard test, similar to the HEHE scenario in section 2.5) is used to check the supply and demand balance and planning reserve margin constraints. By assessing the output of this run, we ensure the demand and supply equality constraint is met. To do so, for each balancing area, we subtract demand from the total supply (including generated power, net imported power, and net energy storage output) and check whether all values are greater than equal to zero.
2- Planning reserve margin: By comparing the total installed capacity with the peak demand in each planning period, we validate that the model installs enough capacity to satisfy the planning reserve margin constraint in each period (total installed capacity is greater than equal to the peak demand plus 15 percent default reserve margin). Also, in a test run, we changed the reserve margin to 25 percent and confirmed the output changes accordingly.
3- Transmission capacity: Through the standard test we ensure no transmission corridor has exceeded the capacity limit. Also, to further investigate, we lower a transmission limit to a point that it reaches the limit in the test run and check the results to ensure the capacity constraint doesn't allow transmission flow excess available capacity.
4- Thermal unit constraints: To validate thermal unit constraints, we have checked the generation profile of different thermal units and ensured in all hours and planning periods the generation is less than the capacity, the ramp-up and down constraints are met, and the capacity factor is within the limit. To further test the constraints, we have changed the input data (for example natural gas units ramp rate and minimum and maximum capacity factor) and confirmed that these changes will properly affect the outputs.
5- Hydroelectric modelling: By reviewing the hydroelectric units' generation profile, the minimum generation constraint is checked. The outputs show that all reservoir units maintain the 10 percent minimum generation constraint. Also, the available reservoir is contrasted against the generated power in each day and month for small and large storage hydro facilities, respectively, to validate that the model properly simulates the available reservoir.

Finally, the maximum generation limit is checked and confirmed that no unit generates more than the maximum installed capacity.

6- Energy storage operation: We review the energy storage charge and discharge profile to check whether the total discharged energy is less than available stored energy in each hour and the total charge does not exceed the energy storage capacity. Also as a metric, we review that in a given time period (e.g., a year), the net generated power is negative (due to the loss in the charge and discharge cycle). Also, through test runs, we confirm a change in the input parameters properly affects the outputs. For example, by reducing the investment cost, total installed capacity increases, while assuming lower efficiency decreases the total installed capacity. These trends show that all constraints work properly.

7- Renewables: Two main constraints for renewables are checked. First, we ensure in all hours, wind and solar generation are less than equal to the maximum generation based on the weather condition. To do so, the wind and solar capacity factor for each hour and grid cell are multiplied by the installed capacity to estimate the maximum feasible generation. Then we compare this input with the model outputs for wind and solar and confirm that the constraint is satisfied. Also, the land use constraint is checked by comparing the total installed capacity with the maximum capacity that can be developed in each grid cell. In a test scenario, we lower the maximum allowed capacity for the grid cells and confirm that the model does not exceed set limitations.

Second, the solver log report is generated and reviewed to confirm the convergence of the models and the termination condition after runs. Due to the complicated optimization problem and different constraints, the feasible region of the problem might become null which will result in an infeasible termination condition in the solver report. This check helps to validate that all the constraints are defined correctly and there remains a non-null feasible region. Two samples of the solver report are presented in the Appendix. Also, the created model using the Pyomo package in the Python environment is compared to the formulation detailed in the Appendix to validate the optimization problem that COPPER creates. Third sensitivity analysis on some parameters is performed to confirm that model results are valid considering variation in the input data. The results of the sensitivity analysis can be found in section 2.6.7. Regardless of a wide range of input data for investment and fuel costs, the results remain rational which validates the model performance. Fourth, although due to the size of the problem it is not feasible to compare the numerical results, the high-level insights that COPPER creates are contrasted against other existing reports and papers that study the future of Canada's electricity system.

The main studies used to validate COPPER have different frameworks including electricity system planning models like CREST, ReEDS, and SWITCH or integrated assessment models like ENERGY2020 and OSeMOSYS. The results of test runs show COPPER tends to develop wind, solar and natural gas-fired units as generation options (mostly wind) to meet the increase in demand and replace the retired capacity. This is consistent with the results reported in other studies (Canada Energy Regulator (CER), 2021a, 2020; Dolter and Rivers, 2018; Ibanez and Zinaman, 2016; Nelson et al., 2012; Palmer-Wilson et al., 2019). Also, transmission expansion is cost-optimal under many scenarios which is aligned with the findings in (Dolter and Rivers, 2018; Ibanez and Zinaman, 2016). More details of the comparison can be found in the Appendix, Figure A.1. Overall, the comparison reveals that despite the difference in the framework, methodology, set of input data, resolution, and assumption the main results of COPPER are consistent with other models. More details can be found in the discussion section of each chapter.

2.4 COPPER Data

The data sets required to run COPPER were collected from a variety of sources, including an open-access data set[3], modellers, publicly available repositories, utilities and system operators. In cases where we were unable to locate appropriate data, we filled data gaps with reasonable assumptions based on the literature. All the data are updated and transformed into a reference year (i.e., 2018). The following section details the main data sets used in COPPER.

2.4.1 Available Data

Generation and storage data: available and possible future generation types are categorized into 13 different types. The operational and cost data associated with each type are summarized in Table 2. All cost data are in Canadian dollars and collected from Canadian and American sources (Dolter and Rivers, 2018; Doluweera et al., 2018b; National Renewable Energy Laboratory (NREL), 2020; U.S. Energy Information Administration (EIA), 2020). In the case of mature technologies with well-established data for

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[3] A preliminary version of it is introduced in (Hendriks et al., 2020) and updated version of it is described in (McPherson et al., 2021).

costs (such as coal and natural gas-fired units), we assume fixed costs[4] over the planning periods. However, in the case of technologies that are under development or are rapidly evolving (such as wind, solar, and lithium battery storage), we assume a drop in price based on the reference technology evolution projections in (Canada Energy Regulator (CER), 2020) for wind and solar and (National Renewable Energy Laboratory (NREL), 2020) for lithium battery storage. Also, to estimate the electricity system emissions, we consider carbon dioxide equivalent (CO2e) and data presented in (Dolter and Rivers, 2018) are used.

Table 2: Generation and storage technology data

Type	Max CF (%)	Min CF (%)	Ramp-Rate (%)	Efficiency (%)	Fuel CO_2e (kg/MWh)	Fixed O & M ($/KW/year)	Variable O & M ($/MWh)	Fuel price ($/GJ)	Annualized Capital cost ($/KW/year)
Coal	90	50	5	39	830	75	6	2.6	447
CoalCCS**	90	50	5	30	110	106	13	2.6	789
Diesel	95	5	10	39	664	19	19	16.6	86
GasCC	80	20	10	51	360	14	3.5	Local	154
GasCCS	80	20	10	45	33	46	9.5	Local	314
Nuclear	95	75	5	33	0	139	3.2	0.9	776
SMR	95	40	5	33	0	145	0	0.8	1548*
GasSC	30	20	100	28	650	16	9	Local	108
Biomass	90	20	5	39	0	154	7.7	2.8	550
Wind	N/A	N/A	N/C	N/A	0	48	0	0	212*
Solar	N/A	N/A	N/C	N/A	0	19	0	0	152*
Hydroelectric	N/A	N/A	N/C	N/A	0	55	5.8	0	Project-specific
PHS-new	N/A	N/A	N/C	80	0	9	0.9	N/A	201
PHS-retrofit	N/A	N/A	N/C	80	0	9	0.9	N/A	141
Lithium battery	N/A	N/A	N/C	85	0	34	0.9	N/A	216*

* Basic value and subject to change over time according to the **technology evolution** projections.

** Coal with carbon capture and storage (CoalCCS)

Sources: (Dolter and Rivers, 2018; Doluweera et al., 2018b; National Renewable Energy Laboratory (NREL), 2020; U.S. Energy Information Administration (EIA), 2020; McPherson et al., 2021, Arjmand et al., 2019)

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[4] All costs in this thesis are Canadian dollar in year 2018 unless otherwise stated

COPPER incorporates two types of energy storage including lithium battery and pumped hydroelectric storage (PHS). Lithium battery storage is modelled using the 4-hour battery storage data from NREL (National Renewable Energy Laboratory (NREL), 2020); the battery can be discharged at rated capacity for four hours before being completely drained. PHS is a mature technology, and there are many potential development locations in Canada; thus, COPPER considers PHS-retrofit (adding new components to existing hydroelectric facilities to enable storage) in addition to PHS greenfield development (PHS-new). We assume PHS-retrofit capital cost of 70% of PHS-new based on the information published by British Columbia (BC) hydro for one potential PHS project at its existing Mica Generation Station (BC Hydro, 2013). Also, to account for the fact that not all hydroelectric facilities can be upgraded to provide storage, the maximum retrofit capacity was limited to 25 percent of the existing hydroelectric reservoir capacity in each province[5]. PHS is assumed to generate for 8 hours at full capacity before being drained.

These two options give the model the flexibility to choose between a short-period or long-period storage type with different costs and efficiencies. The results of modelling these two storage types can provide valuable insights about the cost range that makes storage part of the optimal mix.

Fuel price data: the price of each fuel type is assumed to be consistent among all provinces except for natural gas where there are significant cost differences between western and eastern provinces. Natural gas power plants are one of the main generation types in Canada's electricity system, and under different scenarios, various studies report it as a main source in Canada's future generation mix. Thus, accounting for the natural gas price diversity is important to providing reliable insights about the future; this needs to be considered in the model.

Transmission data: all inter-balancing area transmission lines are aggregated and the total corridor capacities between balancing areas are calculated. Transmission capacity is assumed to be available until the end of the planning period (i.e., 2050). Transmission line losses are calculated using the method presented in (Dolter and Rivers, 2018), which assumes 2% fixed loss and 0.003% variable loss (per km) in high voltage transmission lines.

Demand and import/export data: hourly provincial demand data are collected and split between balancing areas (for provinces with two balancing areas) according to the residential population. To create

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[5] We were unable to find proper data and just assumed 25 percent.

the demand profile for all years in the planning period, the utilities' demand forecasts are used. COPPER uses different demand growth coefficients for the 2030 and 2050 horizons. Table 3 shows annual demand growth in percentage for each province and planning periods. For import/export to the US, historical data for the connection points are collected and assumed that remain the same for the planning period.

Table 3: Provincial annual demand growth in percentage

Provinces	2018-2025 (%)	2025-2030 (%)	2030-2035 (%)	2035-2050 (%)
British Columbia	0.73	0.95	1.36	1.59
Alberta	1.05	0.79	0.87	0.65
Saskatchewan	1.09	1.07	1.20	1.20
Manitoba	0.16	0.59	1.36	1.36
Ontario	0.10	1.10	0.77	0.61
Quebec	0.93	0.64	0.64	0.64
New Brunswick	-0.07	-0.43	-0.47	-0.33
Prince Edward Island	2.77	2.11	2.11	2.11
Nova Scotia	-0.08	0.04	0.97	0.88
Newfoundland and Labrador	0.17	0.59	0.59	0.59

Renewable energy data: The hourly wind and solar capacity factors mirror the sources and methods that are presented in (Dolter and Rivers, 2018).

Hydroelectric data: The reservoir size and water resource availability data for each type of hydroelectric facility and within each balancing area are collected from the model presented in (Dolter and Rivers, 2018). To capture potential hydroelectric development, project data were collected from various sources, including but not limited to utilities, regulatory filings, and government reports (Arjmand et al., 2019). Hydroelectric developments are represented as integer type decision variables meaning that the model makes binary yes/no decisions for each of the 114 possible projects (Figure 2) across Canada.

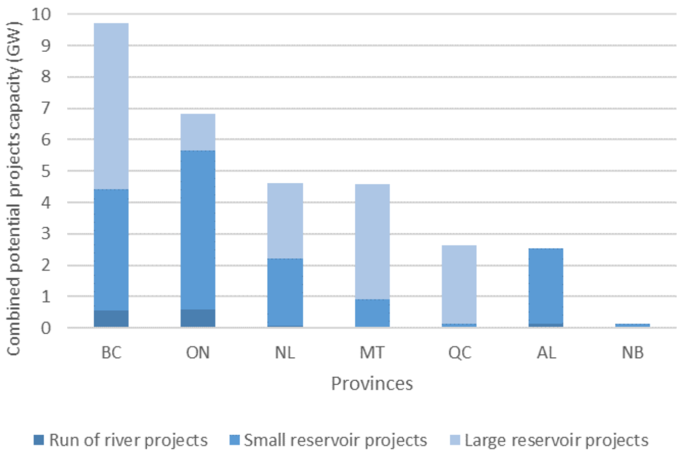

Figure 2: Total capacity of potential hydroelectric projects for different types of hydroelectric facilities in provinces across Canada

Policy data: A list of carbon management policies, regulations, and targets that pertain to the electricity system is compiled and summarized in Table 4.

Table 4: Canada's carbon management policies, regulations, and targets

	Carbon pricing	Other Regulations	Objectives and targets
Federal	Federal carbon pricing system: 1- A trading system for large industry emitters (OBPS). 2- A regulatory charge on fossil fuels.	Natural gas-fired and coal power plants performance standard: 1- Limits emission intensity of natural gas-fired generation on a per MWh basis and ensures that new units use efficient technologies. 2- Forces to phase out conventional coal-fired electricity generation facilities by 2030.	40-45% GHG emissions reduction by 2030 from the 2005 level. 11 Megatonnes of electricity sector GHG emissions by 2030, the HEHE plan projection. 90% clean sources for power generation by 2030, 100% in the long-term. Contribute to the target of 50% clean power generation by 2025 in North America. Net-zero economy-wide emissions by 2050.
Sources: (Environment and Climate Change Canada, 2021a, 2020a, 2019)			

2.4.2 Data Limitations

Despite the comprehensive search for complete and proper data, gaps remain. The main missing data and the ways that they might affect the results are discussed below.

Hydroelectric water availability data with hourly resolution: Since hydroelectric generation comprises about 60 percent of Canada's generation mix, water availability data with better resolution can improve hydroelectric representation and make the final results more reliable.

Nuclear units end of life: The scheduled retirement date of the existing units is required to model the gradual retirement of them due to the end of life. For some nuclear units, especially in Ontario, we were unable to find retirement dates. Based on planned refurbishment schedules, these facilities are expected and assumed to remain operational beyond 2050.

Land use data: Renewables are less dense compared to conventional generation types and, under some scenarios, the share of renewable energy in the future of the electricity system mix is significant. Hence, location-specific land-use data can help inform appropriate locations for new renewables, including any land-use constraints on deployment.

2.5 Scenarios

There are many parameters and modelling limitations that can affect planning model results. The selection of parameters in the following scenario matrix has been such that they deliver valuable insights in support of the objectives of the modelling. To explore the impact of Canada's latest climate plan on the electricity system transition and to assess specifically whether current and announced policies are ambitious enough to achieve set targets, the seven scenarios described below are analyzed:

1- HEHE: Accounts for all current and announced policies. The carbon tax increases $15/tonne annually until it reaches $170/tonne by 2030 at which point it remains constant until 2050.
2- Low Carbon Tax (LCT): Considers a $15/tonne annual increase by 2030 and a $5/tonne increase in carbon tax after 2030 until it reaches $270/tonne in 2050.
3- Moderate Carbon Tax (MCT): Considers a $15/tonne annual increase by 2030 and a $10/tonne increase in carbon tax after 2030 until it reaches $370/tonne in 2050.
4- High Carbon Tax (HCT): Considers a $15/tonne annual increase by 2050 until it reaches $470/tonne in 2050.

5- Target Scenario (TS): The model is constrained to achieve the announced carbon reduction targets (i.e., 11 Megatonnes by 2030, zero by 2050).

6- Constrained Transmission Expansion (CTE): Transmission expansion is limited to double the extant transmission capacity.

7- Advanced Technology Evolution (ATE): Assumes advanced (optimistic) forecasts for the cost of evolving and under-development technologies into the future (note: the other scenarios use a reference technology evolution forecast). To capture the drop in wind and solar costs, the forecasts presented in (Canada Energy Regulator (CER), 2020) are used. Lithium battery storage and SMR costs for ATE are drawn from (National Renewable Energy Laboratory (NREL), 2020) and (Economic and finance working group, 2018).

2.6 Results

This section intends to deliver insights but not to project the future. The scenario analyses explore uncertainties of possible decisions (on carbon policy) and pathways on future outcomes. The following section will discuss the main insights of the scenarios.

2.6.1 Emissions and costs

Emissions and cost are two important metrics that help us determine whether Canada’s latest climate policies (HEHE) are sufficient to achieve set targets. Figure 3 depicts Canada’s electricity system emissions and costs for the HEHE, LCT, MCT, and HCT scenarios. The net zero-emissions target by 2050 and 11 Megatonnes (Mt) projected GHG emissions of the electricity system by 2030 (Environment and Climate Change Canada, 2020b) are marked for reference.

The policies and regulations announced in HEHE are modeled to decrease emissions from the electricity system by 38 percent by 2025 and 40 percent by 2030. This leaves a 26 Mt gap between projected emissions by 2030 and HEHE scenario emissions. This gap decreases to 22 Mt in LCT, MCT, and HCT scenarios for which an increase in the CT is imposed after 2030. In the long-term, if CT remains constant at $170/tonne after 2030, an additional 10 Mt decrease in emissions is expected between 2030 and 2050, leaving a 27 Mt gap between the zero-emission target in 2050 and modeled actual emissions. However, any yearly increase of $5-15/tonne in CT after 2030 will reduce this gap to 12 Mt in the LCT scenario, 7 Mt in the MCT, and less than 5 Mt in the HCT.

Coal, natural gas, and diesel (oil) units are the main source of Canada's electricity system emissions (Figure 4). Coal phase-out (replacement with natural gas units) leads to significant emissions reduction by 2025. After 2025, natural gas units become the main GHG emissions source of electricity generation in Canada. A break-down of emissions by technology type shows that gas combined cycle (gasCC) and gas with carbon capture and storage (gasCCS) are the main technologies that remain operational in 2050 despite the fact that the CT reaches $370/tonne.

To facilitate comparison costs, the total cost of each scenario has been normalized against the HEHE scenario by dividing by the HEHE scenario cost (bar chart in Figure 3). Zero-emissions by 2050 (TS scenario) and removing 30 Mt of HEHE emissions increases the total system costs by 6 percent. In LCT, MCT, and HCT compared to HEHE, the cost will increase 2, 3, and 4 percent, respectively, which is the cost of removing more than 20 Mt GHG emissions from the electricity sector. In fact, Canada can achieve zero-emissions by 2050 by spending 6 percent more than the amount that has to be spent to run the electricity system under current and announced policies and regulations (HEHE).

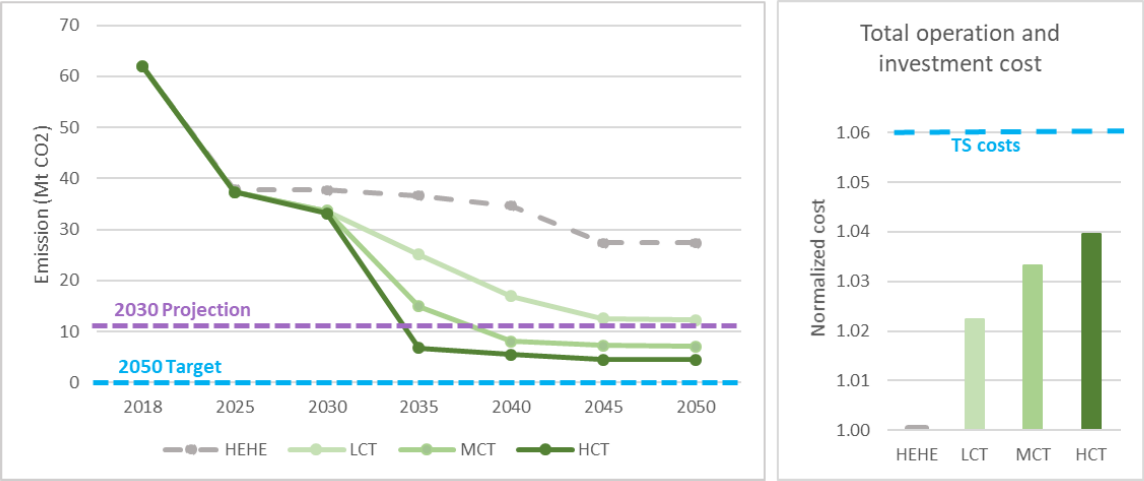

Figure 3: Canada's electricity system emissions and nominalized costs against the HEHE scenario for different CT levels

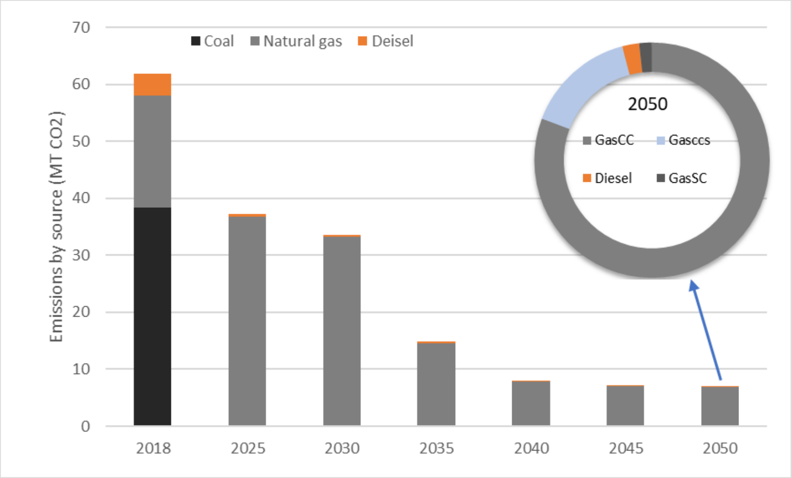

Figure 4: Emissions by fuel source for the MCT scenario and a break-down of the 2050 emissions by technology

The average emissions intensity of the Canadian electricity system (Figure 5) drops to under 60 kg/MWh by 2025 under all scenarios, which is a decrease of about 40 percent. Under the HEHE policies, emissions intensity decreases to 33 kg/MWh by 2050 while under LCT, MCT, and HCT it decreases to under 15 kg/MWh. Overall, Canada's electricity system experiences a significant emissions reduction in the coming decades stemming from the transformation of the generation mix.

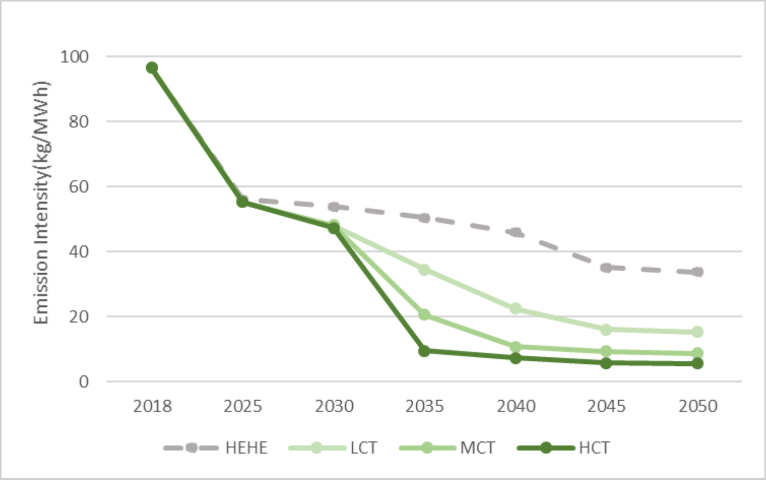

Figure 5: Carbon intensity of Canada's electricity system under different CTs

2.6.2 Canada’s generation mix

The future generation mix of Canada’s electricity system depends on many factors, including but not limited to carbon management policies, regulations, technology evolution, fuel prices, and renewable resource availability. Carbon pricing is one of the main carbon reduction policies in Canada and has a significant impact on Canada’s generation mix transition, as shown in Figure 6. Regardless of the carbon price, most of the coal, natural gas simple cycle (gasSC), and diesel plants become uneconomical and retire before 2025. These retirements are the reason for the dramatic emissions reduction by 2025 (Figure 3). Current and announced policies (HEHE scenario) are enough to phase out most or all of the emissions intensive technologies such as coal, diesel, and gasSC, in the mid-term. In the long-term, more intermittent renewable energy is integrated which demands more flexibility. The HEHE policies are not adequate to phase out or even prevent building new gasCC power plants.

To avoid building new gasCC power plants, Canada needs to increase the CT after 2030. A $5/tonne annual increase after 2030 will prevent building of new gasCC and replace part of it with gas with carbon capture and storage (gasCCS) units. A larger increase in CT results in more gasCC phase-out and replacement by gasCCS and renewables. Nevertheless, even in the HCT scenario, a small capacity of natural gas units remains operational. To achieve zero-emissions by 2050 and retire this capacity, a regulation similar to the current coal phase-out regulation but for natural gas units seems to be necessary.

In all scenarios, wind, solar, and gasCCS are a part of the optimal mix needed to meet the increase in the demand and replace the retired capacity. Wind capacity is projected to range from 47 gigawatts (GW) for HEHE to 73 GW for HCT, solar from 28 GW for HCT to 49 GW for HEHE, and gasCCS from 2 GW for HEHE to 7 GW for HCT depending on the CT that is imposed between 2030 and 2050. There is a clear correlation between gas and solar capacity; a combination of solar and gas units seems to be a cost-effective option. In scenarios with more natural gas capacity, the model builds more solar capacity (more detail in section 0).

Large nuclear power plants and SMRs are non-emitting technologies that are typically excluded from the cost-optimal mix generation regardless of the CT, due to their high investment and maintenance costs[6]. However, the modelled investment decisions are sensitive to the assumed cost trajectories for all

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[6] The nuclear capacity depicted in the chart are existing capacity that we assume remain operation until the end of the study period. Nuclear refurbishment is not modeled.

technology types, which could differ from our current parametrization of the model. In particular, for immature technologies such as SMRs, the costs are particularly uncertain and may have a different penetration. The ATE results show that SMR technology becomes part of the optimal mix when its investment cost is below \$550/kW/year, which is close to the SMR investment cost reported in the evolutionary scenario of Canada's SMR roadmap report (Economic and finance working group, 2018).

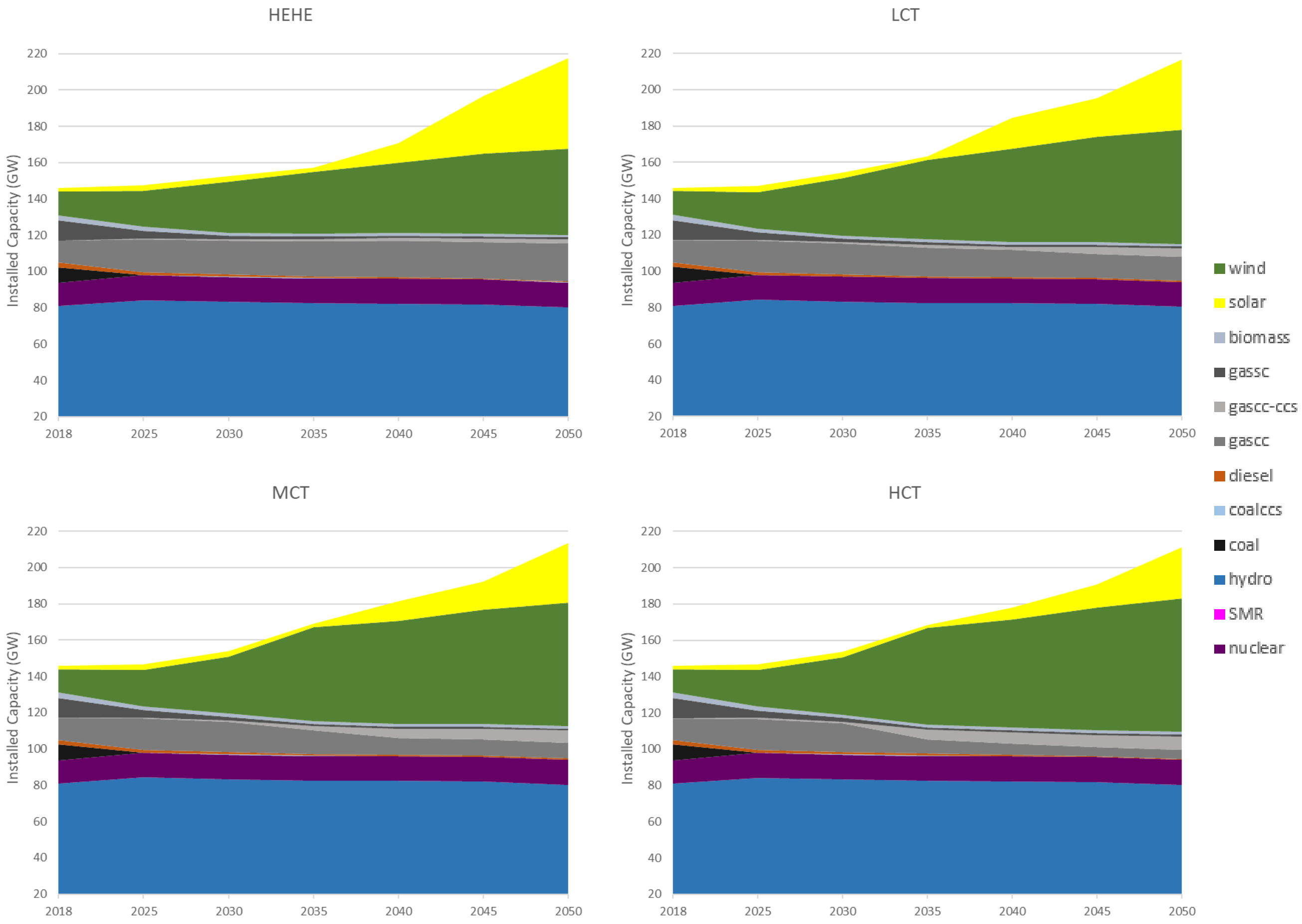

Figure 6: Canada's electricity generation mix under different carbon tax scenarios (note that to make the changes more visible, we have excluded 20 GW of installed hydroelectric capacity from the bottom of the charts)

2.6.3 Hydroelectric development

Hydroelectric renewal is consistently an optimal part of Canada's future energy mix, in all scenarios. However, hydroelectric greenfield development projects prove to be too expensive in the COPPER cost-optimization formulation. Table 5 lists the hydroelectric projects that are cost-optimal components of the system for at least one scenario. The last column of this table shows how robust (independent from uncertain parameters) the hydroelectric project is against different scenarios. Regardless of policies, regulations, and uncertainties, there are a few hydroelectric projects with a total capacity of about 1400 MW that contribute to the cost-optimal generation mix, and all of them except one are large storage hydroelectric facilities. The rest of the hydroelectric projects are not cost-effective enough to be built even in the HCT and zero-emission (TS) scenarios.

Table 5: Hydroelectric renewal projects that contribute to the cost-optimal generation mix

Project Name	Province	Type	Additional Capacity (MW)	Annualized Capital Cost ($M/year)	Fixed and Variable O & M ($/MW-year) ($/MWh)	Robustness against different scenarios
GMS Units 1-5 Capacity Increase	British Columbia	Large storage	100	3.77	2,824 8.8	Very high[7]
Revelstoke 6			488	58.34	2,682 7.7	High
Seven Mile Turbine Upgrades			48	12.12	5,596 9.6	Moderate
Kelsey Additional Units	Manitoba		178	27.95	8,670 5.0	High
Sainte-Margeurite-3 Unit 3	Quebec		440	59.66	4,822 5.3	Very high
Bay Despoir	Newfoundland and Labrador		154	28.58	6,191 8.9	Very high
Wahleach Additional Units	British Columbia	Small storage	14	0.55	21,066 11.5	High

2.6.4 Renewable energies

Wind and solar generation make a significant contribution to the electricity mix under different scenarios, as shown in Figure 7. Under current policies and regulations, wind power generation grows significantly due to its competitive investment costs. In all CT scenarios, most of the wind investment happens in the first 15 years of the study period. Twenty-nine GW of new wind capacity will be added to the network by 2035 in HEHE, 39 GW in LCT, 46 GW in MCT, and 48 GW in HCT. Also, Figure 7 shows a

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[7] Very high means the project is built in all scenarios, high mean in most of them and moderate means in some of them.

positive correlation between CT and new wind capacity. The HCT scenario integrates 19 GW more new wind capacity to the network compared to the HEHE scenario.

In contrast, new solar power plants are developed mostly in the last 15 years of the study period when the investment cost of this technology has dropped and become a cost-effective generation source. Also, solar capacity is negatively correlated with the CT, such that in the HCT scenario, the total solar capacity by 2050 is almost half of the HEHE scenario. With a higher CT, the model retires more capacity of flexible and dispatchable units like gasSC and gasCC, reducing their contribution to the network flexibility and planning reserve margin. The flexibility that gas units add to the network can cover the absence of solar plants during the night or cloudy days. Also, due to the low power generation potential, especially during winter, solar power plants only slightly contribute to the planning reserve margin. Therefore, in more carbon-constrained scenarios, the model needs to either increase the capacity of the energy storage along with the solar capacity or shift to other non-emitting resources with a higher capacity value (e.g., wind). The results of this study show that shifting to a source with a higher capacity value is the cost-effective option.

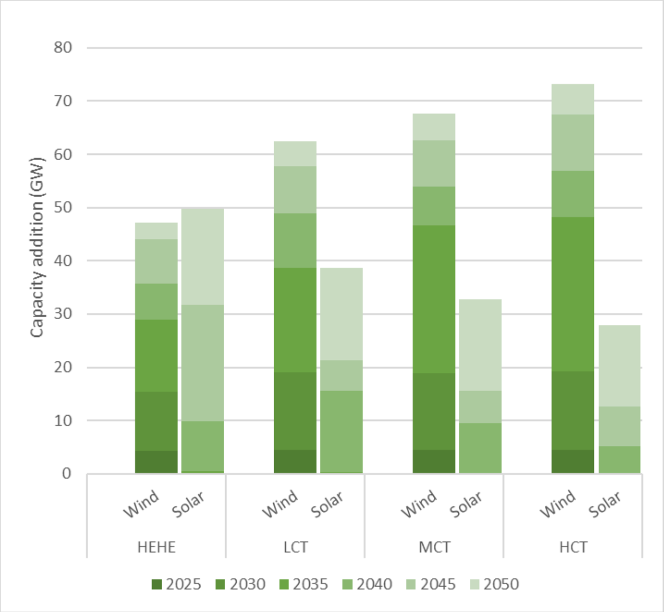

Figure 7: Total new wind and solar capacity added to the generation mix under different CT scenarios

All the above analyses for the future of renewable energies in Canada are based on the reference technology evolution scenario cost projections, although actual investment cost forecasts will almost certainly differ from what we have at our disposal now. To assess the implications of technology development uncertainty, we ran the ATE scenario. Where compared to MCT, the total wind and solar capacity in the ATE scenario increased by 13 percent and the emissions dropped by 50 percent. The emissions gap between the ATE scenario and the 2050 target reduced to 3.2 Mt. Also, the cost of the ATE scenario is 9 percent less than the MCT scenario due to the lower investment cost of wind, solar, SMR, and battery storage. Altogether, in all scenarios, a total of 100 GW installed capacity of wind and solar across Canada is likely by 2050, but the share of wind and solar varies according to the policies and investment cost projections.

2.6.5 Transmission system

Typically, the objective of transmission expansion is to improve system reliability, decrease total investment and operations costs, meet environmental constraints, and mitigate network congestion (Mahdavi et al., 2019). The cost-optimal mix expands several transmission lines between balancing areas under different scenarios, as presented in Table 6. Noticeable transmission capacity is added to the corridor between the west and central provinces to strengthen the connection between British Columbia, Alberta, Saskatchewan, and Manitoba. Also, the Ontario connections to Manitoba and Quebec are expanded. In the eastern provinces, New Brunswick connections to Prince Edward Island (PEI) and Quebec south are strengthened, and a new line between PEI and Nova Scotia is built. Finally, the intra-provincial connection of Quebec north and Quebec south is expanded significantly.

All transmission expansions or new builds are either positively (with higher CT, more capacity is built) or negatively correlated (with higher CT less capacity is built) to the CT level. Overall, results show that new transmission lines between balancing areas are part of the optimal mix for the future of Canada’s electricity system.

Table 6: New transmission capacity between balancing areas

From	To	New Capacity range (MW)	Current Capacity (MW)	Correlation with CT
Saskatchewan	Alberta	1300-7850	153	Positive
Quebec north	Quebec south	6000-6650	29750	Positive
British Columbia	Alberta	1600-2350	1200	Positive
Manitoba	Saskatchewan	700-2050	225	Positive
Prince Edward Island	Nova Scotia	1000-1150	New line	Positive

Ontario north	Manitoba	100-650	200	Positive
Prince Edward Island	New Brunswick	500-600	222	Negative
Ontario north	Quebec north	250-450	110	Negative
New Brunswick	Quebec south	50-250	785	Positive
Ontario south	Quebec south	0-250	2060	Positive

COPPER is constrained to expand transmission lines between pre-defined routes but is unconstrained in the capacity that is added; however, in some cases, due to environmental, social, and technical concerns, unconstrained capacity addition might not be feasible. To explore the implication of constrained transmission expansion, the CTE scenario limited transmission expansion to double the current value. This scenario resulted in roughly 10 percent more emissions in the target year (2050) compared to the MCT scenario (the same scenario with no limit on transmission expansion). In addition, the constrained transmission expansion increased the total system cost by 0.6 percent.

2.6.6 Energy Storage

In all scenarios, the model builds energy storage in different areas. In scenarios with higher CT and carbon constraints, the renewable energy penetration increases, which in turn necessitates greater grid flexibility to handle uncertainty and variability, so the model builds more energy storage.

Lithium battery is the dominant technology for required storage capacity because the investment cost of this technology is expected to drop significantly and its efficiency is higher than PHS. Under MCT, the model builds 2 GW of energy storage capacity by 2050 in which the share of lithium battery storage is 1.97 GW and 0.03 GW is PHS. However, to achieve net-zero by 2050, more storage capacity is required such that in TS the model builds 5.2 GW of energy storage capacity across the country in which the share of lithium battery storage is 4.6 GW and 0.6 GW is PHS. Figure 8 shows the amount and distribution of energy storage for the TS scenario. Ontario and New Brunswick are provinces that require noticeable investment in new storage capacity since the generation mix of these provinces includes a high capacity of nuclear, which is highly inflexible. Also, storage is part of the optimal mix for Saskatchewan and Nova Scotia while they integrate more variable renewable capacity in the future. In hydroelectric-dominated provinces such as BC, Quebec and Manitoba, energy storage is not in the optimal mix due to the flexibility that reservoir hydroelectric contributes to the grid.

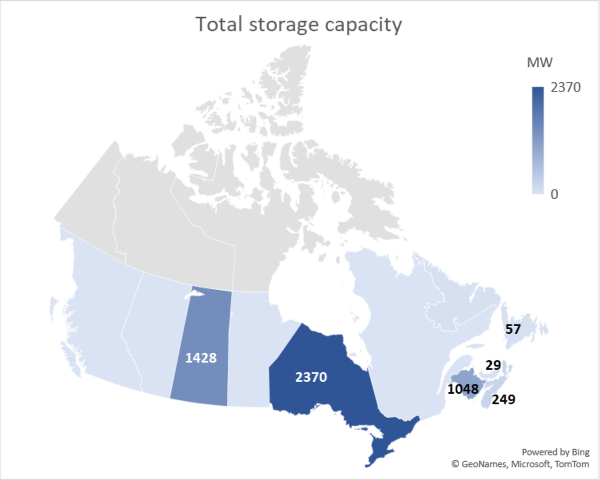

Figure 8: Total capacity addition of storage across Canada

2.6.7 Sensitivity analysis

Similar to other planning models, COPPER incorporates uncertain costs as input parameters that influence the results. Capital and fuel costs are the main costs whose variation might lead to noticeable changes in the results. Although in the case of technologies that are under development or are rapidly evolving (such as wind, solar, and lithium battery storage), we investigate two technology evolution scenarios, there remain some uncertainties in these costs moving forward. Higher demand for wind and solar generation equipment, for example, might influence their investment costs in the future. To account for this, we have performed a sensitivity analysis on these costs. We have also performed a sensitivity analysis on natural gas price, since with the planned phase-out of coal units, natural gas generation is the primary fossil fuel generation in Canada, and the historical data indicates that prices have ranged widely over the previous decades (Statistics Canada, 2016).

In the analysis, we have run ten scenarios on renewable capital costs from 50% to 150% of assumed costs, with 10 percent steps covering all conservative, moderate and optimistic cost forecasts for these technologies. Also, for the natural gas price, based on 15 years of historical data from 2000 to 2015 (Statistics Canada, 2016), we have run 15 scenarios from 50% to 200% of assumed price in this study which covers the variation range in the historical data[8].

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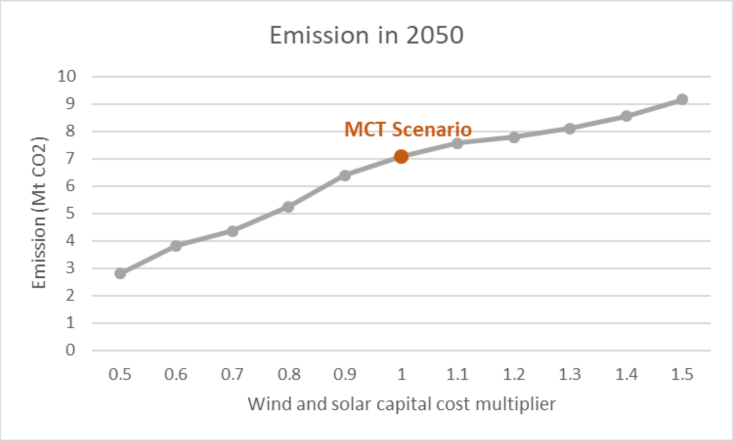
[8] Sensitivity scenarios are built based on the MCT scenario.

The variation in capital costs changes the penetration of renewables in the grid and the retirement and operation of natural gas units. In case of a revolutionary reduction in wind and solar capital costs, wind and solar replace some natural gas units, and Canada's electricity system GHG emissions under the MCT scenario decrease to 2.8 Mt carbon dioxide equivalent (CO_2e) in 2050. In contrast, higher investment costs of renewables in the future will lower their penetration and add more gasCCS units, which in turn results in to up to 9.2 Mt CO_2e in 2050 (Figure 9a). In the case of natural gas sensitivity (Figure 9b), the GHG emissions in 2050 vary between 8.4 Mt CO_2e at half of the current natural gas price to 4.8 Mt CO_2e for double current price because with higher natural gas prices the model replaces gas units with renewables and gasCCS units operate less often.



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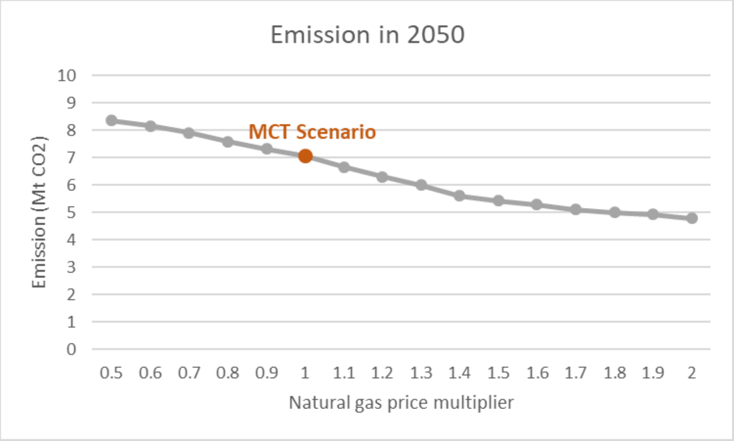

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Figure 9: Capital cost and fuel price sensitivity analysis. a. Wind and solar capital cost sensitivity analysis. b. Natural gas price sensitivity analysis

2.7 Conclusion and Policy Implications

Canada has set ambitious carbon reduction targets of 40-45 percent below 2005 levels by 2030 and net-zero emissions by 2050. To achieve these targets, Canada has strengthened its carbon policies and announced a \$15/tonne increase in the CT after 2022 reaching 170 \$/tonne by 2030. We studied whether the current and announced policies are sufficient to drive the required investment to achieve set targets and decarbonize the electricity system by 2050. To do so, we developed COPPER, a capacity expansion model designed to simulate Canada's electricity system characteristics.

Based on the modelling results, the announced HEHE plan is able to remove 20-30 Mt CO_2e of emissions from the electricity system by phasing out part or all of the coal, diesel, and gasSC units before 2030. This reduction is at least 22 Mt lower than the projected reduction in the HEHE plan. GasCC units will become the main source of emissions by 2030. Therefore, to cut these emissions, Canada needs supplementary regulation to limit the generation from gasCC units and to phase out this generating capacity. However, Canada already has regulations on natural gas units' emissions (gas power plants performance standard) that target the development of the gasSC units, not gasCC.

Although the price of carbon is regulated until 2030, it is not specified after, even though the 2030 results are sensitive to the carbon price after 2030. Using four different carbon tax scenarios, we studied the 2030-2050 period to test the impacts of increasingly stringent policy. Keeping the CT fixed at 170 \$/tonne after 2030 will fail to phase out gasCC units that lead to about 27 Mt CO_2e emissions in 2050, which is far from the zero-emission target. A yearly increase of 5 \$/tonne or more in CT after 2030 will retire a portion of the gasCC units or replace them with gasCCS units that result in an additional 15-22 Mt of emissions reductions by 2050. However, none of these scenarios leads to zero carbon emissions. Even at a 470 \$/tonne CT, gasCC and gasCCS units emit about 5 Mt CO_2e in 2050. Overall, to achieve zero-emissions by 2050, Canada needs supplementary policies and regulations along with carbon taxes to target thermal units such as gasCC and gasCCS that are not emissions intensive.

In the short- to mid-term, wind generation is the cost-effective option to replace conventional units while future declines of solar investment costs make this a more competitive technology such that Canada's electricity generation will be dominated by hydroelectric, wind, and solar power plants by 2050. New large hydroelectric projects are not selected due to their high investment cost; however, there are hydroelectric renewal projects across Canada that can contribute to the transition toward a clean electricity system. Also, SMRs are not in the optimal generation mix unless they experience a drop in the investment cost, as some studies project.

Inter- and intra-transmission lines and energy storage are built under all scenarios. Transmission lines are developed for different routes that involve all provinces while storage is built in provinces with high levels of inflexible generation, such as Ontario, or to integrate significant future renewable capacity such as Saskatchewan.

Overall, the recently announced HEHE plan can significantly reduce Canada’s electricity system emissions over a 10-year horizon. In order to achieve zero-emissions by 2050, Canada needs to increase the carbon tax after 2030 and introduce supplementary policies and regulations that target less emission intensive generation technologies.

Acknowledgment

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Chapter 3: Federal vs. provincial: the impacts of carbon pricing mechanisms in Canada’s decarbonization transition

The content in this chapter was submitted to the following journal:
Arjmand, R., Rhodes, E., McPherson, M., 2022. Federal vs. provincial: the impacts of carbon pricing mechanisms in Canada’s decarbonization transition. Climate Policy, Submitted.

3.1 Abstract

Canada’s carbon pricing system allows provinces to design their own pricing policies, as long as they meet the minimum national stringency standards, or choose the federal output-based pricing system. Three distinct carbon pricing mechanisms have emerged as a result. Thus far, there has been limited assessments on how the selection of mechanism impacts the transition of the power system. To address the gap, this paper uses a power system planning model, COPPER, to assess if and to what extent provincially designed pricing systems improve economic and GHG emissions reduction outcomes. Our results show that provincially designed mechanisms are cost-effective at the national scale and lead to significant carbon reductions over the long-term, provided output-based standards are tightened. However, the cost-optimal infrastructure pathway that result differ across the provinces depending on the carbon pricing mechanism. Some provinces achieve maximal carbon reductions primarily by switching from emissions-intensive technologies to renewables, while others are better served by replacing emissions-intensive technologies with low-emissions fossil fuel alternatives. Furthermore, a carbon-constrained province affects the transition of neighbouring provinces. Policies should be designed at the provincial level based on available assets, resources, and measures of neighbouring provinces.

Keywords: Canada’s electricity system, Carbon pricing mechanisms, COPPER, Generation mix, Renewable energy, Decarbonization

3.2 Introduction

The Canadian electricity system is composed of a set of provincial power systems spanning vast geographic distances and, as such, are typically minimally interconnected and vary substantially in terms of generation mix. These differences drive significant variations in the power sector greenhouse gas (GHG) emissions. Hydro-dominated provinces including British Columbia (BC), Manitoba (MB), Quebec (QC), and Newfoundland and Labrador (NL) together produce only four percent of Canada’s electricity system emissions; fossil-dominated provinces including Alberta (AB), Saskatchewan (SK), Nova Scotia (NS), and New Brunswick (NB) are responsible for 91 percent of Canada’s power sector emissions; in particular, AB was responsible for roughly 50 percent of Canada‘s electricity system emissions in 2019 (Environment and Climate Change Canada, 2021b). Additional government policies, both at the federal and provincial levels, are needed to maintain low power sector emissions in the former group while aggressively reducing emissions in the latter (Arjmand and McPherson, 2022).

Carbon pricing is one of the key carbon reduction policies in Canada enforced at the federal level. Canada’s federal carbon pricing approach is flexible, allowing for provinces to design their own pricing systems as long they meet minimum national stringency standards set by the federal government; otherwise, the federal output-based pricing system is imposed (Government of Canada, 2022b). This flexibility protects provinces from potential adverse impacts of a uniform federal pricing system. For example, a given federal carbon pricing system might have a significant impact on an emissions-intensive province such as AB, while it is not efficient enough for a low-emission province like BC. Provinces can avoid this by designing a local pricing system. To ensure carbon pricing drives efficient emissions reductions in all provinces, different systems in provinces across Canada can be designed to fit their unique circumstances. Three main carbon pricing system types are currently in place across Canada including carbon taxes, output-based pricing systems, and carbon cap and trade systems (Government of Canada, 2022b). Despite similar objectives among these policies, they vary in terms of impacts on emissions levels, generation and transmission mixes, and cost implications.

Several studies using a variety of modelling frameworks and scales of analysis have examined the likely short-, medium-, and long-term impacts of carbon pricing on the future development of the Canadian electricity system. Electricity system planning models (ESPM) are widely used and have been applied to model the Canadian grid as a whole (Arjmand and McPherson, 2022; Dolter and Rivers, 2018), specific regions (Doluweera et al., 2018a; Rodríguez-Sarasty et al., 2021), and integration between Canada and the US (Nelson et al., 2012; Zinaman et al., 2015). Most of these studies represent carbon pricing mechanisms simply, as an added fuel cost (i.e., carbon tax) for all provinces. Arjmand and McPherson (2022) explored the future of Canada's national electricity system with varying carbon tax levels, showing that Canada's carbon management policies need to be strengthened to achieve long-term carbon reduction goals. Similarly, Dolter and Rivers (2018) analyzed the cost of decarbonizing Canada's electricity system under different scenarios and concluded that Canada needs to increase carbon prices modelled the Western provinces in Canada using an ESPM including carbon price, a carbon cap, and a renewable portfolio standard. The results show hydropower, natural gas and renewable generation are dominant sources in the future supply mix in these provinces. Rodríguez-Sarasty et al. (2021) assessed deep decarbonization scenarios for the northeastern grid (Canada and the US) using an ESPM which directly represents varying levels of carbon reduction, rather than specific carbon management policies employed, showing that strengthening interconnection between electricity regions can significantly lower the decarbonization costs.

At the international scale, the Regional Energy Deployment System (ReEDS) model has been applied to the North American electricity system to study the importance of the transmission lines between Canada and the US (Beiter et al., 2017), the effects of renewable policy coordination at the regional and international levels (Bistline et al., 2020a), changes in North American energy infrastructure (Siddiqui et al., 2020), and the transition of the integrated US and Canada power sector (Ibanez and Zinaman, 2016). The ReEDS model includes a carbon tax for BC and renewable portfolio standards for some other Canadian provinces (Cohen et al., 2019) and uses the average carbon intensities of neighbouring regions to account for the carbon cost of imported power (Zinaman et al., 2015). The results of these modelling efforts highlight the future importance of wind generation and transmission expansion across the border. The SWITCH model (Nelson et al., 2012) has been applied to northwestern grid (Canada and the US) to explore the future electricity supply mix assuming a constant carbon tax, showing that higher carbon taxes increase the renewable penetration and reduce carbon emissions. In addition to these ESPMs, various integrated assessment and energy-economic models have provided insights regarding the future of Canada's electricity system.

Integrated assessment models (IAM) can be used to simulate Canada's energy system, including the electricity system, while implementing both carbon taxes and output-based pricing systems. Arbuckle et al. (2021) modified the Global Change Analysis Model (GCAM) integrated assessment framework to assess Canada‘s future electricity supply mix under different cost scenarios. The subsequent policy scenario analysis, including a carbon tax, coal phaseout, and wind power subsidy, highlights the necessity of considering cost overruns for making appropriate policy decisions. Similarly, Davis et al. (2020) used the Long-range Energy Alternatives Planning (LEAP) IAM to analyze four carbon pricing scenarios, based on a carbon tax and output-based pricing system, for Alberta’s electricity system transition. The results show renewable-based scenarios are cost-effective alternatives to reducing emissions. In addition, the Canada Energy Regulator (CER) (2021, 2020, 2019) uses the ENERGY2020 model (Systematic Solutions INC., 2017) to project future Canadian electricity supply and energy demand under different scenarios, published as an annual report series. While the 2021 report (Canada Energy Regulator (CER), 2021a) claims that the modelling framework accounts for provincial policy settings and regulations, it contains little detail on specific province-level modelling choices and their impacts. The report projects wind and solar dominating new generation capacity in Canada’s electricity system, supported by significant new storage capacity.

Like IAMs, energy-economy models can be used to investigate carbon tax and output-based pricing system mechanisms. These models are capable of assessing the effects of climate policies, including carbon pricing systems, performance standards, regulations, and subsidies (Rhodes et al., 2022). For instance, carbon taxes and output-based pricing mechanisms are implemented in the US-REGEN model to investigate long-term electrification and decarbonization opportunities across sectors (Electric Power Research Institute, 2021a), and to simulate North American electricity supply and end-use (Bistline et al., 2020b; Electric Power Research Institute, 2021b). Bistline et al. (2020b) modelled an output-based pricing system along with a carbon tax in Canadian provinces to identify possible carbon leakage from Canadian provinces to emission-unregulated US states, finding that output-based pricing system significantly reduces carbon leakage compared to a carbon tax scenario.

ESPMs focuses on just power system and include more technical, spatial and temporal details, making their results technically robust (Dagoumas and Koltsaklis, 2019) which is important for some studies including this study. On the other hand, although various carbon pricing mechanisms are in place across Canada, models, especially ESPMs, are limited when it comes to representing these mechanisms and actions. Among the three types of reviewed frameworks used to study the future of Canada‘s electricity system, energy-economy models and IAMs considered two out of three in-place carbon pricing mechanisms including output-based pricing systems and carbon taxes while ESPMs were more limited and modelled all carbon pricing mechanisms as an additional charge on fuel (based on the emission intensities of each fuel type; equivalent to a carbon tax). This leaves a gap in the literature – none of the reviewed studies explicitly consider all carbon pricing mechanisms currently in place in Canada and allow investigation of electricity system evolution given the provincial heterogeneity of such mechanisms. This gap implies that current studies underrepresent the flexibility of the Canadian federal carbon pricing system, potentially resulting in over- or under-estimation of the impacts of carbon pricing on the provinces' electricity systems transitions. This study attempts to address this gap by incorporating diverse provincial carbon pricing mechanisms to providing insights into the future of the Canadian power system on both national and provincial scales.

The main research questions motivating this study are: 1) How effective are the default federal carbon pricing system in reducing emissions considering differences in built infrastructure and available renewable energy resources across the provinces? 2) Can provincially designed provincial carbon pricing systems improve emissions reductions and economic outcomes compared to the federal carbon pricing system? The four main scenarios presented in this study are designed to answer these two research questions. Three scenarios focus on different carbon pricing mechanisms, and one addresses the target of zero-emissions by 2035. This paper makes two primary contributions to the literature in answering these questions. First, we introduce improved COPPER, an ESPM that is capable of representing diversity in provincial carbon pricing mechanisms, carbon taxes, output-based pricing systems, and carbon cap and trade systems. Second, we analyze the implications of various carbon pricing mechanisms for each province by simulating the resulting electricity system transitions. We conclude with several suggested provincially specific policy options to accelerate emissions reductions in the electricity sector.

The remainder of the paper proceeds as follows. Section 2 provides details on the modelling methodology and limitations. Section 3 details the data and scenario design used for this study. Section 4 presents the modelling results and key insights. Finally, section 5 discusses the policy implications and summarizes findings.

3.3 Methodology and limitations

The dynamic ESPM presented in Arjmand and McPherson (2022), COPPER, is used in this study to explore the impact of carbon management policies on provincial electricity systems in Canada. COPPER is designed to represent some of the unique characteristics of Canada's power system detailed in (Arjmand and McPherson, 2022). The mixed-integer linear programming formulation used in COPPER co-optimizes generation, transmission and storage[9] expansion (to the least-cost solution) over the selected planning period. This framework models the electricity system with higher spatial and temporal resolutions than alternative ESPMs, while taking into account operational constraints, resulting in more robust study results. However, the base formulation of COPPER is limited in terms of modelling carbon pricing mechanisms and requires modification to study these effectively.

Although there are three carbon pricing mechanisms in place in Canada, the base formulation of COPPER models carbon price as carbon tax by adding to effective fuel prices based on the emission intensity of fuels and carbon price levels. This method is typically used across a variety of models to capture the effects of carbon price on the electricity system transition pathways and can provide valuable insights when studying such pathways at the national scale. However, an improved representation of all three types of provincial carbon pricing mechanisms allows assessment of the effectiveness of policies in achieving provincially determined decarbonization goals. The associated methodology is detailed below.

3.3.1 Carbon pricing

Carbon pricing mechanisms currently in place for large industrial emitters in Canada include carbon taxes (CT), output-based pricing systems (OBPS), and carbon cap and trade (CCAT) systems. While these mechanisms all set prices on carbon emissions, each entails a different implementation and has distinct benefits and drawbacks:

- With a CT, an extra cost is charged on the fuel price in proportion to the emission intensities of each fuel type.
- In an OBPS, generation assets that exceed predefined emissions levels are penalized with costs added to the generation price, while generation assets that emit less than the defined emissions level receive credits that can be sold to high-emitters.
- In CCAT systems, emitters pay a carbon charge for all emissions in addition to purchasing carbon credits on a market where they exceed the standard. Furthermore, CCAT systems include hard caps on carbon emissions.

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[9] Energy storage options in this study include pumped hydro storage (PHS) and lithium battery (LB)

With a CT, the carbon price is predetermined; in CCAT systems, the carbon price is set by the market; and in an OBPS, the carbon price can be either predetermined or market-determined. Emissions reductions are directly specified in the CCAT mechanism but not for a CT (although a target emissions reduction may inform the carbon price); for OBPS, emissions reductions are in some cases directly specified. Among these carbon pricing mechanisms, a CT has the lowest administration and implementation cost, while through emission allowance in CCAT carbon leakage can be minimized (Wood, 2018).

A CT is already modelled in COPPER by adding a carbon cost to the fuel price of each technology detailed in Arjmand and McPherson (2022). OBPS and CCAT mechanisms are added to the COPPER model for this study using the methods explained in Sections 3.3.1.1 and 3.3.1.2 below.

3.3.1.1 Output-based pricing systems

Using the OBPS mechanism, a carbon price is applied to penalize the portion of the emissions that exceed the benchmark level for each technology type in each planning period.

$$CarbonCost = \sum_{pds} \sum_{th} \sum_{h} (EI_{th} - BM_{th,pds}) \times S_{h,th,pds} \times CP_{pds} \quad (2)$$

Where pds, th, and h denote sets of planning periods, thermal units, and hours respectively. EI is the emission intensity of the thermal type, BM represents the benchmark level for that thermal type, CP is the carbon price level in the planning period pds, and S is the generation of thermal type th in hour h of planning period pds.

To model OBPS, benchmarks for different fossil fuel types are collected for provinces implementing OBPS. Since the OBPS benchmarks will likely be tightened as the zero-emissions target year (i.e., 2035) approaches, this needs to be represented in the model. A consultation paper published by the Government of Canada (Environment and Climate Change Canada, 2021c) has reviewed OBPS regulations and proposed an annual tightening rate of 2% for the benchmarks starting in the 2023 compliance period. However, based on this paper, this tightening does not apply to the electricity system standards and another revision based on the zero-emission target by 2035 would be considered for the electricity system. As the zero-emissions target for the electricity system is 15 years earlier than other sectors, we expect a higher tightening rate for the electricity system, so to account for this in our modelling, we have assumed emissions benchmarks for all technologies will converge to zero by 2035[10]. The electricity system benchmarks (output-based standards) are presented in Table 7.

Table 7: The OBPS benchmarks for the electricity system across Canada (tonne CO2e/MWh)

		Natural gas		New natural gas		Coal		Diesel		All
Region	**Mechanism**	**2025**	**2030**	**2025**	**2030**	**2025**	**2030**	**2025**	**2030**	**2035-2050**
British Columbia (BC)	CT	0	0	0	0	0	0	0	0	0
Alberta (AB)	OBPS	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0
Saskatchewan (SK)	OBPS	0.37	0.37	0.206	0	0.51	0.37	0.55	0.55	0
Manitoba (MB)	OBPS	0.37	0.37	0.206	0	0.51	0.37	0.55	0.55	0
Ontario (ON)	OBPS	0.42	0.42	0.42	0.42	0.42	0.42	0.37	0.37	0
Quebec (QC)	CCAT	0	0	0	0	0	0	0	0	0
New Brunswick (NB)	OBPS	0.42	0.42	0.42	0.42	0.79	0.79	0.79	0.42	0
Prince Edward Island (PE)	OBPS	0.37	0.37	0.206	0	0.51	0.37	0.55	0.55	0
Nova Scotia (NS)	CCAT	0	0	0	0	0	0	0	0	0
Newfoundland and Labrador (NL)	OBPS	0.37	0.37	0.206	0	0.51	0.37	0.55	0.55	0
Federal	OBPS	0.37	0.37	0.206	0	0.51	0.37	0.55	0.55	0

3.3.1.2 Carbon cap and trade systems

A two-stage modelling framework is required to represent CCAT systems in the COPPER. First, the model considers CCAT with no limit on interprovincial imported power to determine the average carbon intensity (per MWh) of all provinces in each planning period. In the second stage, to limit carbon emissions in provinces via the CCAT mechanism, in each planning period, the model uses the average carbon intensity of neighbour provinces for imports to calculate and limit total GHG emissions (Figure 10).

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[10] All the benchmarks remain the same until 2030 and converge to zero from 2030 to 2035.

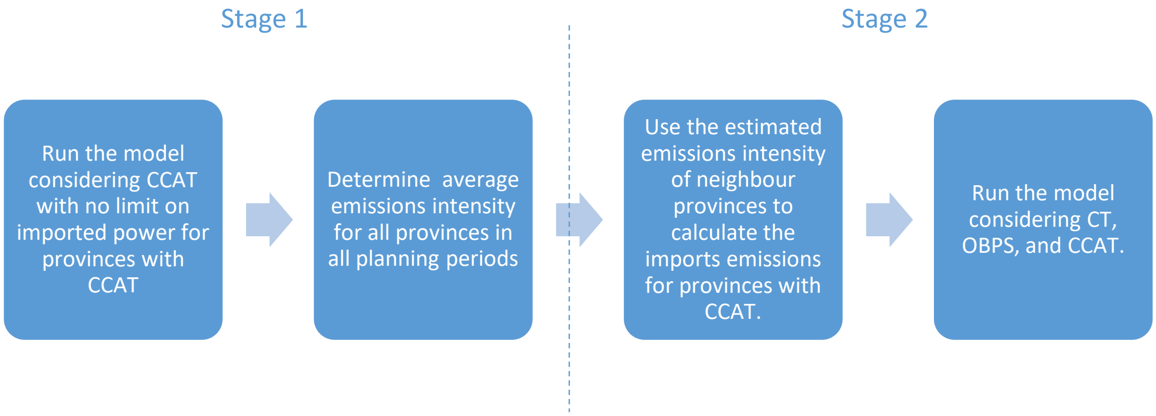

Figure 10. The flowchart of the two stages framework for modelling CCAT

Based on the above framework, the model uses the following equations to penalize carbon emissions (eq. 3) and limit the total emission to the regulated cap (eq. 4):

$$CarbonCost = \sum_{pds} \sum_{th} \sum_{h} EI_{th} \times S_{h,th,pds} \times MCP_{pds} \quad (3)$$

$$TotalEmissions = \sum_{th} \sum_{h} EI_{th} \times S_{h,th,pds} + \sum_{np} \sum_{h} EI_{np,pds} \times IP_{h,np,pds} \leq \; CC_{pds} \; \forall \; pds \quad (4)$$

MCP represents the market price of carbon in each period which is assumed to equal the federal carbon price. For each province with a CCAT system, np denotes a set of neighbour provinces. IP stands for the imported power from neighbour provinces np in hour h and period pds, and CC represents the carbon cap limit in period pds.

A list of carbon pricing mechanisms modelled in COPPER along with carbon reduction targets for each province is presented in Table 8. We have selected the most salient policies affecting the electricity sector. Other sector-specific policies (zero-emission vehicles mandate, low carbon fuel standard, etc.) may also affect the electricity sector emissions but were excluded from the study to maintain the manageable scope.

3.3.1.3 Modelling assumptions

The set of assumptions listed below is required to incorporate provincial carbon pricing mechanisms within an optimization framework, given available data:

- Since the carbon price level is not introduced, based on the historical approach of the government of Canada, a 10 dollar per tonne CO2e ($/tCO2e) increase in carbon price is assumed beyond 2030.
- The benchmark for diesel in NB is set based on federal benchmarks due to the lack of other data.
- There is a free emissions allowance in NS that enables NS power to emit 5.1 MtCO2e in 2022 free of carbon cost (listed in Table 8) modelled using a scenario based on the two-stage modelling framework in Figure 10.
- In NL, benchmarks are based on a historical approach or sectoral benchmarks. Historical emissions data are unavailable for NL, as are sectoral benchmarks. As such, NL benchmarks were assumed to be the same as federal benchmarks.
- All benchmarks approach zero from 2035 onward.
- For provinces with CCAT systems, we assume the carbon allowance price is the same as the federal carbon price, and we limit provincial emissions based on the respective carbon reduction goals (i.e., zero by 2050 for NS and QC).
- Fossil fuel combustion for electricity generation produces three distinct GHGs: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), with different residence times and heat-trapping potentials. The total emissions of these three GHG emissions are aggregated using the carbon dioxide equivalent (CO_2e) measure, which is the equivalent amount of CO_2 that will result in an equivalent warming effect over a specified timeframe, typically 100 years (Environment and Climate Change Canada, 2017).

Table 8. Policy data assumptions included in COPPER

	Carbon pricing	**Other regulations and actions**[*]	**Commitments and targets**[**]
Federal	The federal carbon pricing system includes (Environment and Climate Change Canada, 2020c): 1. An OBPS for large industries (i.e., larger than 50 kt CO_2e per year), including the electricity system.	Performance standard emissions limits on natural gas-fired power plants to ensure high-efficiency technologies are used for new units (Government of Canada, 2020). A phase out of all conventional coal units by 2030 (Environment and Climate Change	1. Total Canadian emissions 40-45% below the 2005 level by 2030 (Environment and Climate Change Canada, 2021d). 2. Net-zero emissions by 2050 for the entire economy and zero emissions by 2035 for the

	2. Fuel charges added to fossil fuels prices.	Canada, 2021d).	electricity sector (Environment and Climate Change Canada, 2022). 3. 90% non-emitting electricity generation by 2030 (Environment and Climate Change Canada, 2021d).
BC	A carbon tax applies to all fossil fuels, including gasoline, diesel, natural gas, coal, propane, and home heating fuels. The tax started at $10 per tonne CO2e in 2008 and will increase to $170 per tonne by 2030 (Government of British Columbia, 2021).	100% clean electricity delivery standard achieved by phasing out remaining gas-fired units by 2030 (Government of British Columbia, 2021).	1. BC Economy wide emissions 16% below 2007 levels by 2025, 40% below by 2030, 60% below by 2040, and 80% below by 2050. 2. Sectoral carbon reduction targets (industry: 38-43 % below 2007 levels by 2030). (Government of British Columbia, 2022)
AB	A provincial OBPS has been instituted for the electricity sector, subject to a sector-wide benchmark of 370 tonnes CO_2e per GWh (tCO_2e/GWh) (Government of Alberta, 2020a).	Coal-fired sources of electricity will be phased out completely by 2030 (Government of Alberta, 2015).	1. 30% of electricity will be generated from renewable sources by 2030; interim targets are 15% by 2022, 20% by 2025, and 26% by 2028 (Government of Alberta, 2020b).
SK	The federal OBPS applies to the electricity sector (Government of Canada, 2022b).	Electricity sector GHG limits: cumulative emissions for the 2020-2024 period less than 77 million tonnes (Mt), and less than 64.5 Mt for the 2025-2029 period. Saskatchewan and Canada agreement in June 2019: SaskPower can decrease the use of coal on a fleet basis, rather than on a facility basis as per the default federal regulations (effective January 1, 2020). (Government of Canada, 2019)	1. A 50% reduction in total SK emissions by 2030, from 2005 levels. 2. 50% of electricity generation from renewable sources by 2030. 3. The SK government is evaluating options to achieve net-zero emissions by 2050. (Government of Saskatchewan, 2022)
MB	The federal OBPS for industries, including the electricity sector (Government of Canada, 2022b).	Reduce domestic electricity demand by 22.5% over 15 years (Environment and Climate Change Canada, 2019).	1. A 33% reduction in total MB emissions by 2030, from 2005

		Phasing out older gas-fired units (Environment and Climate Change Canada, 2021a).	levels; 50% by 2050, and carbon neutral by 2080. 2. 2.3 GW new hydroelectricity capacity and 1 GW of new wind power capacity 3. An early coal phase out (completed by 2018). (Environment and Climate Change Canada, 2019)
ON	A provincial OBPS (the Emissions Performance Standards program, or EPS) has been instituted for large emitters, including the electricity sector, with a benchmark of 420 tCO$_2$e/GWh (Government of Canada, 2022b).	Collaborate with other provinces to advance SMRs as a clean energy alternative (Environment and Climate Change Canada, 2021a).	1. A 30% reduction in total ON emissions by 2030, from 2005 levels. 2. 10.7 GW total installed RE capacity (wind, solar, and biomass) by 2021 and 20 GW by 2025, and 9.3 GW total hydroelectricity capacity by 2025 (Environment and Climate Change Canada, 2019) 3. An early coal phase out (completed by 2014).
QC	A CCAT system has been in effect since 2013 and was linked to California‘s system in 2014 for carbon credit trading (Environment and Climate Change Canada, 2019).	10% of gas supply from renewable natural gas (RNG) by 2030 (Government of Quebce, 2020).	1. A 37.5% reduction in total QC emissions by 2030, from 1990 levels, and carbon neutral by 2050. 2. A 25% increase in renewable energy production by 2030 relative to 2013. 3. A 50% increase in bioenergy production by 2030 relative to 2013. (Environment and Climate Change Canada, 2019)
NB	A provincial OBPS is in place with a benchmark of 420 tCO2e/GWh for natural gas and 793 tCO2e/GWh for solid fuels (Government of New Brunswick, 2019).	Coal phase out in the electricity sector by 2030, or an equivalent electricity generation emissions reduction. NB is negotiating with the federal government to keep the Belledune coal-fired generation	1. Total NB emissions reduced to 10.7 MtCO2e in 2030 (47% below 2005 levels) and 5 MtCO2e in 2050 (Environment and Climate Change Canada, 2021a). 2. 40% of electricity sales to come

		plant operational, at a reduced output level, until the end of 2040. (New Brunswick power corporation, 2020)	from renewable energy by 2020 (completed).
NS	A CCAT system is in place covering about 80% of GHG emissions in the province, with no linkages to other jurisdictions (Environment and Climate Change Canada, 2019). A 5.1 $MtCO_2e$ free emissions allowance is applied in 2022 for the electricity sector (Nova Scotia Power, 2020).	An annual cap of 4.5 $MtCO_2e$ or below by 2030 (Nova Scotia Power, 2020). Coal plants to remain operational beyond 2030; Nova Scotia is required to achieve equivalent emissions reductions in other sectors.	1. A 53% reduction in total NS emissions by 2030, from 2005 levels, and net-zero by 2050. 2. 80% electricity supply from renewables by 2030. (Environment and Climate Change Canada, 2021a)
PE	The federal output-based system is applied to large emitters (Government of Canada, 2022b).	Utilities must pay a minimum purchase price for large-scale renewable energy generation (Environment and Climate Change Canada, 2019).	1. Total PE emissions reduced to 1.2 MtCO2e/year by 2030 and net-zero by 2040 (Environment and Climate Change Canada, 2021a). 2. A goal of 2% electricity demand reduction per year (Environment and Climate Change Canada, 2021a).
NL	A provincial OBPS for large industrial emitters, including the electricity sector, with a benchmark based on a historical performance standards (12% below the average 2016 to 2018 emissions intensity in 2022) or a performance standard based on the sector benchmark (Government of Newfoundland and Labrador, 2018).	NS will explore options to reduce off-grid diesel electricity generation (Government of Newfoundland and Labrador, 2019).	1. A 30% reduction in total NL emissions by 2030, from 2005 levels, and net-zero by 2050 (Environment and Climate Change Canada, 2021a).

* Except for coal phase-out and natural gas fired units' performance standard, we do not impose a hard constraint based on the regulations mentioned in this column.

** Carbon reduction targets are not hard constrained.

3.3.2 Supplementary constraints

In addition to the carbon pricing mechanisms described above, additional constraints, beyond the constraints in COPPER‘s base formulation presented in (Arjmand and McPherson, 2022), are implemented to account for varying provincial carbon management policies, regulations, and restrictions. These constraints are summarized below:

- The provincial planning reserve margin sets a minimum planning reserve margin for each province.
- A thermal phase out forces the retirement of specific, high-emissions generation types over a predefined planning period.
- National and provincial carbon caps define emission limits at the relevant scales for a selected years.
- Renewable portfolio standards set minima and/or maxima on renewables penetration in each province and planning period.
- Limited thermal development prevents the construction of new capacity for specified generation types after given years.
- Non-emitting limits sets minima for electricity generation from non-emitting resources (e.g., 90% non-emitting generation by 2030).

3.3.3 Modelling limitations

General COPPER model limitations due to inherent optimization framework limitations and computational resource availability are detailed in Arjmand and McPherson (2022). Namely, COPPER is limited in terms of: (1) number of balancing areas, (2) diversity of generation technologies, (3) thermal technologies technical constraints, and (4) representation of international transmission flow. Limitations associated with COPPER modifications specific to the current study include the following:

- For OBPS, it is assumed that the emitting units exceeding their benchmark level will buy carbon credit at the current year’s carbon price (i.e., no credit stockpiling). This means the model might overestimate or underestimate the carbon costs.
- For CCAT systems, currently, economy-wide caps are introduced while COPPER focuses on the electricity system, and it is unable to enforce economy-wide caps. Therefore, due to the absence of sector-specific caps, electricity production emissions are capped to zero by 2050, which will impact the transition of the electricity system. Nevertheless, it is likely that carbon caps are imposed based on the set carbon reduction goals.

- For CCAT systems, since the market dynamics can not be captured in an ESPM framework, it is assumed that the market carbon price is equivalent to the federal carbon price. Although this assumption affects the carbon cost estimations, the hard cap on emissions enforce by this policy will have the main effect on the electricity system transition.

3.4 Data and scenario design

3.4.1 Data

The version of the COPPER framework modified for this study needs to be populated with real-world and up-to-date data to provide robust and reliable insights. The existing electricity system, demand, renewable resource data and spatial resolution – 13 balancing areas (electricity network regions) and more than 2000 renewable resource locations – are identical to that presented by Arjmand and McPherson (2022). The policies and target data are updated based on the most recent government announcements as of March 2022 (detailed in Table 8). The temporal resolution is hourly, with 26 representative days per planning period modelled.

In this iteration of the model, provinces' carbon reduction targets are updated by collecting data from the latest versions of provinces' integrated resources plan or climate plans. For provinces with their own carbon pricing system and regulation, we reviewed available reports and collected announced policies and regulations that apply to the electricity system.

In addition improved representation of carbon management policies, the modified COPPER formulation assesses the planning reserve margin on a provincial basis: each province must maintain a minimum installed generation capacity equal to the peak demand plus the relevant planning reserve margin. To do so, planning reserve margins for all provinces (Figure 11) are collected from the North American Electric Reliability Corporation (2019) except for Newfoundland and Labrador, which is collected from Newfoundland and Labrador Hydro (2019).

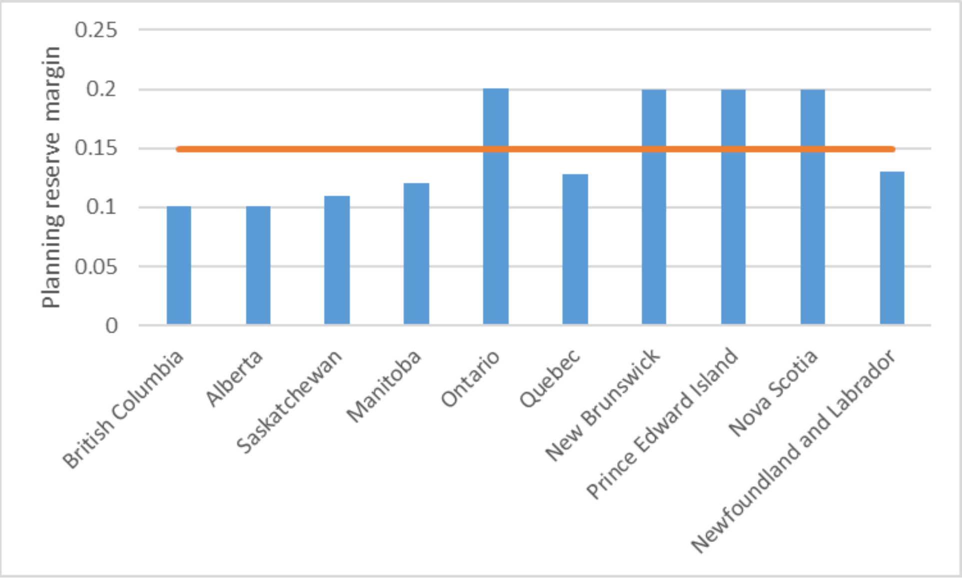

Figure 11. Planning reserve margin in provinces across Canada (red line shows the average value)

3.4.2 Scenarios

The following four scenarios are designed to explore the impacts of carbon management policies and regulations in provinces across Canada. Table 9 summarizes the carbon pricing mechanisms and other regulations in place within each scenario.

- **National carbon tax (NCT) scenario**: This scenario is designed to explore Canada's electricity system transition with a universal tax on carbon emissions. This scenario is used to assess how the electricity system evolves with no free emissions allowances.
- **Federal backstop (FB) scenario**: This scenario analyzes the effectiveness of the default federal OBPS for the electricity system applied to all provinces.
- **Provincial carbon pricing (PCP) scenario**: This scenario includes the actual in-place carbon pricing mechanism for each province as of 2022, as summarized in Table 8, and acts as a baseline scenario. This scenario identifies potential improvements in emissions reductions and economic outcomes achieved by provincially designed policies relative to the NCT and FB scenarios.
- **Carbon reduction target (CRT) scenario**: This scenario enforces a zero-emissions electricity system by 2035 (as hard cap on the electricity system emissions). This scenario assesses the implications of achieving stated decarbonization goals.

Table 9: Scenario design

	Carbon pricing mechanism	**Other policies/regulations**	**Carbon Price**
National Carbon Tax scenario (NCT)	CTs (as an extra charge on fuel) for all provinces	Coal phase out by 2030 and performance standards applied to gas-fired power plants	2025: 95 $/tCO2e 2030: 170 $/tCO2e 2035: 220 $/tCO2e 2040: 270 $/tCO2e 2045: 320 $/tCO2e 2050: 370 $/tCO2e
Federal Backstop scenario (FB)	OBPS for all provinces, using the default federal benchmarks		
Provincial Carbon Pricing scenario (PCP)	A CT for BC, CCAT systems for Quebec and Nova Scotia, and OBPS for other provinces using provincially established benchmarks		
Carbon Reduction Target scenario (CRT)		A hard cap on emissions (zero emissions by 2035) in addition to a coal phase out by 2030 and performance standards applied to gas-fired power plants	

3.5 Results

In this section, COPPER model results are compared for the four scenarios to explore potential electricity system transitions for different provinces across Canada. GHG emissions and total costs are the two key metrics used to compare the scenarios and contrast the efficacy of various carbon pricing mechanisms in their provincial contexts. Also, the electricity system transition under the PCP scenario (baseline scenario), including changes in generation, transmission, and storage, are reported in more detail to provide insights into the cost-optimal pathway for the evolution of provincial electricity systems.

3.5.1 Emissions

GHG emissions reduction is among the most important goals in planning for the future of Canada‘s electricity system. Canada‘s modelled electricity system GHG emissions, on both national and provincial scales, are reported in this section to assess the effectiveness of various carbon pricing mechanisms. Figure 12 illustrates modelled GHG emissions for Canada‘s electricity system under defined scenarios.

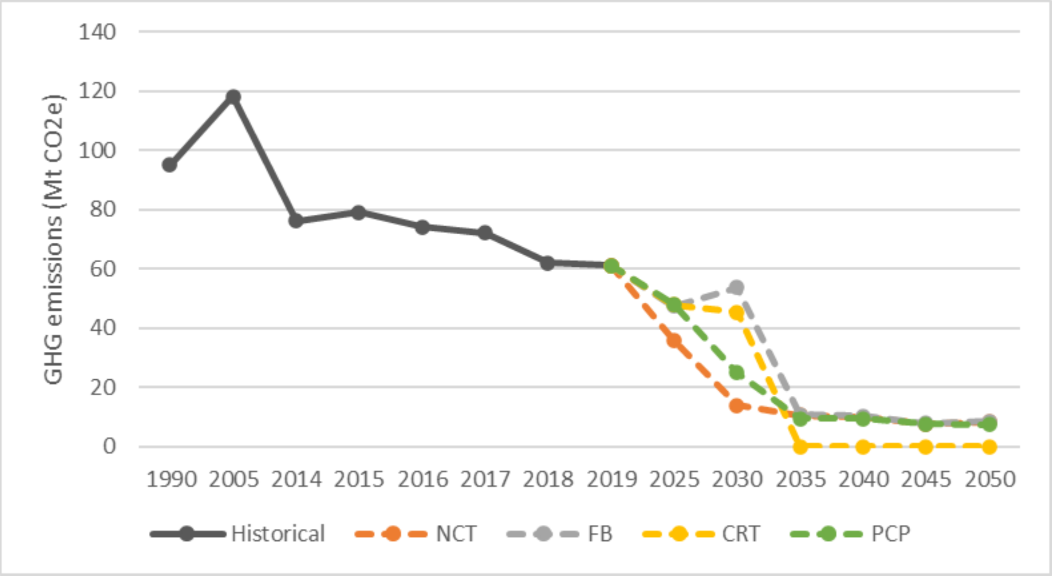

Figure 12: Historical and modelled GHG emissions from Canada's electricity system under four defined carbon management policy scenarios

All carbon pricing scenarios, including the NCT, FB, CRT and PCP scenarios, achieves significant GHG emissions reductions in the long term. In all scenarios, electricity system emissions are below 10 $MtCO_2e$ by 2050. However, while final year emissions are similar for each scenario, the transition pathways differ substantially, and consequently, so do cumulative emissions. The NCT and PCP scenarios exhibit deep emissions cuts between the present and 2030, decreasing to 14 $MtCO_2e$ and 25 $MtCO_2e$, respectively, while emissions in the FB and CRT scenarios remain high (above 40 $MtCO_2e$) by 2030. After 2035, the emissions patterns for the NCT, FB and PCP scenarios are similar, as each trends gradually down towards zero, while emissions in the CRT scenario are forced to zero as of 2035.

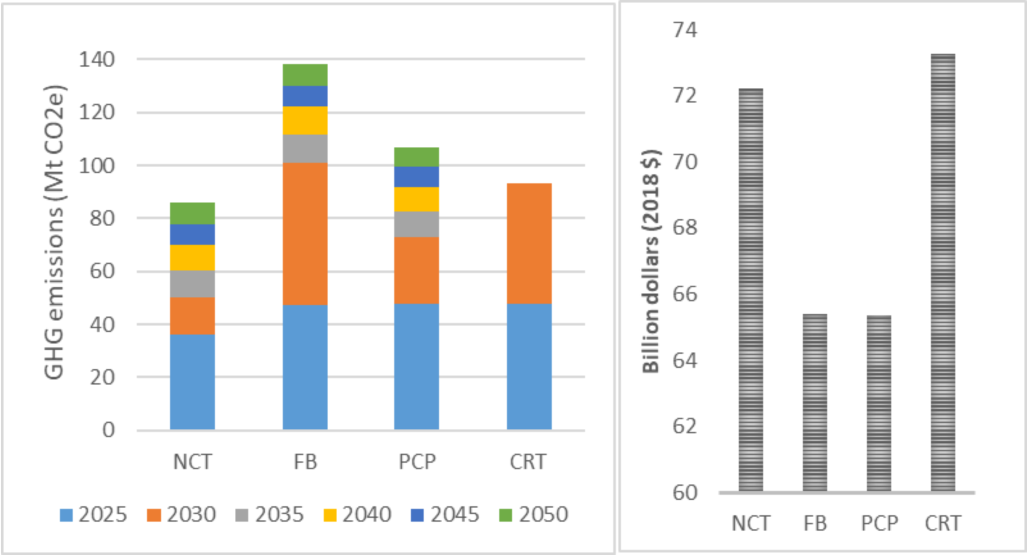

Figure 13. Canada's electricity system cumulative emissions and total costs by scenario (summed for six modelled years; costs discounted to 2018 $ assuming a 5 percent discount rate).

Figure 13 shows cumulative GHG emissions and total system costs, summed over the six modelled years (no interpolation), under the four different scenarios. The NCT scenario exhibits the lowest cumulative emissions due to early emissions reductions (between 2022 and 2030). The CRT scenario's cumulative emissions are higher than the NCT scenario because high-emitting generation units remain in operation until the hard zero-emissions cap in 2035 forces them to retire. The CRT and NCT scenarios are the most expensive pathways, with total costs exceeding 70 billion dollars in costs for the six representative years, owing the zero-emissions cap and the lack of free emissions allowances, respectively. The PCP and FB scenario incur similar costs (65 billion dollars, roughly 10% less than the NCT scenario) but PCP cumulative emissions are significantly less than FB; as such, provincially designed carbon pricing systems appear to perform better than the default federal carbon pricing applied universally.

A provincial breakdown of emissions levels under these scenarios reveals the reason for the difference in cumulative emissions between the FB and PCP scenarios. Under FB, the output-based standard (free emissions allowance per unit of generation) for new gas-fired units in 2030 is zero, while under PCP, the benchmark is 360 kgCO$_2$e/MW or higher. This difference makes gas with carbon capture and storage (CCS) units cost-effective five years earlier in the PCP scenario compared to the FB scenario. The results show around 10 GW of new gas CCS units built in AB by 2030 in the PCP scenario. In FB, the model postpones this build to 2035 and meets the demand by adding more gas CC units and operating gas CC units at higher output levels (increased capacity factor). Figure 14 shows cumulative emissions in each province by scenario. The PCP scenario exhibits the lowest emissions for BC, QC and NS – the provinces that did not elect to implement OBPS. In AB, SK, and MB, when provincially designed carbon pricing mechanisms are in effect (PCP scenario), total emissions are less than the FB scenario but more than the NCT scenario. ON, NB, and NL, experience higher emissions levels when provincially designed carbon pricing systems are in place compared to the FB scenario. In fact, provinces using provincially designed carbon pricing systems interconnected with a province that implements a CCAT system appear to have increased emissions relative to the FB scenario. The reason for this behaviour is that a hard cap on emissions in provinces using CCAT systems tends to result in an increase in the emissions of neighbouring provinces due to limited interprovincial imports.

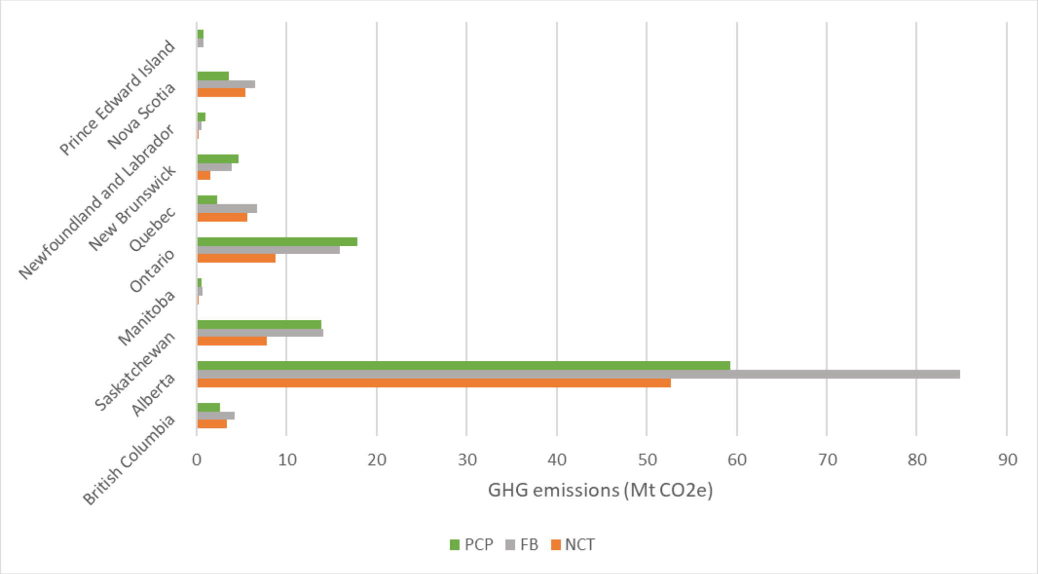

Figure 14. Cumulative GHG emissions by province and scenario (summed for six modelled years)

3.5.2 Generation mix

The future modelled generation mixes of provinces across Canada are strongly affected by the implemented carbon pricing system. This section assesses the baseline generation mixes of provinces under the PCP scenario including retirement schedule, new installed capacity, and total installed capacity for two important years: 2035 (zero emissions target year and the year that the emissions benchmark for all generation types reduces to zero) and 2050 (economy-wide zero-emissions target year and the end of the study period).

3.5.2.1 Transition by 2035

Figure 15 shows modelled changes in provincial generation mixes by 2035 in the PCP scenario, while Figure 16 depicts provincial generation mixes as of 2035. All coal-fired electricity generation in AB, SK, NB, and NS is phased out before 2035. Also, partial retirements of diesel, gas-fired simple cycle (gas SC), and gas-fired combined cycle (gas CC) electricity generation occur in all provinces except for BC, QC, and MB due to end-of-life or cost non-competitiveness by 2035. Gas CC, gas CCS, wind, and solar are the most cost-optimal options to replace retired capacity. Renewables (mostly wind) account for more than 50 percent of new installed capacity by 2035 in all provinces except for BC, AB, and NB, in which gas CCS accounts for most new additions. Despite being an emission-intensive technology compared to renewable sources, new gas CC units are built in six provinces including ON, NS, QC, SK, NL, and PE. Consequently, it appears that in order to achieve carbon reduction goals, including zero emissions by 2035, provincial governments will need to introduce new measures (not modelled) that curtail investment in gas-fired units. As there are significant uncertainties and concerns regarding financing, regulatory support, technology development, and the social and environmental acceptability of CCS technologies (Ihejirika, 2021), the role of these technologies in electricity system decarbonization is as yet undetermined. Model testing shows that when building new gas CCS units is blocked, the model deploys a combination of gas CC, wind, and solar instead.

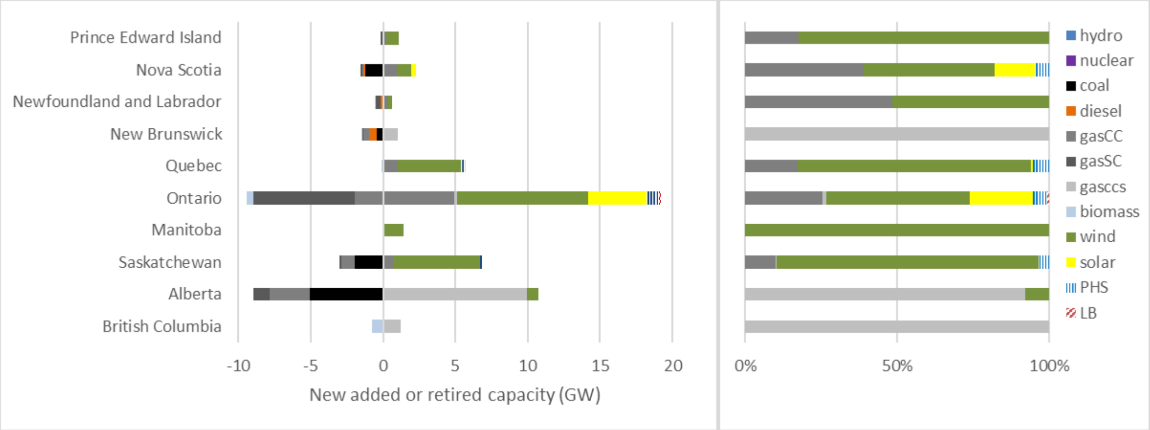

Figure 15: Generation capacity retirements and additions across Canada by 2035 in the PCP scenario. The left panel shows actual capacity and the right panel depicts shares of additions by type.

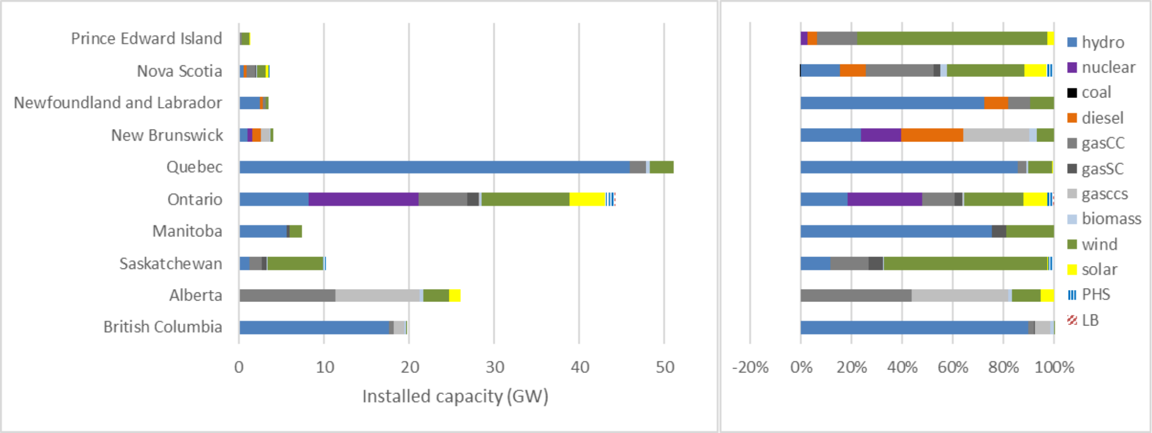

Figure 16: Provincial generation mixes across Canada by 2035 in the PCP scenario

3.5.2.2 Transition by 2050

The PCP scenario shows fossil fuel generation becoming uneconomical and progressively replaced by renewables in the 2035-2050 period. Figure 17 depicts modelled changes in provincial generation mixes between 2035 and 2050 in the PCP scenario. The remaining diesel units in NS and NB are phased out between 2035 and 2050. Also, hard emissions caps force retirement of the remaining gas CC units in QC and NS, while AB with OBPS phases out more than half (6 GW) of its gas CC capacity as it becomes cost non-competitive. Renewables account for 96% of new installed capacity after 2035 due to ongoing declines in their costs, increased carbon price levels, declining emissions benchmarks, and carbon caps in provinces with CCAT systems. Seven provinces add only renewables (mostly solar) in this period, and BC, ON, and NB are the only provinces to install gas-fired generating units after 2035. The share of capacity additions represented by gas-fired units is small in BC and ON (10% and 2%, respectively), while in NB, 73% of new installed capacity is gas-fired (primarily gas SC).

ON, QC, and NS add energy storage to satisfy planning reserve margins and deliver flexibility to handle variability in renewables output. ON has high penetrations of inflexible nuclear and non-dispatchable renewable capacity by 2050, necessitating substantial energy storage capacity additions. The hard emissions caps in QC and NS hard alongside added variable renewables also requires storage additions. Overall, wind, solar, and energy storage will become the most cost-optimal alternatives after 2035 in all provinces except for NB.

Figure 18 depicts modelled provincial generation mixes as of 2050. AB and NB exhibit the smallest shares of non-emitting technologies by this time, 52% and 58%, respectively, while QC and NS achieve

100% non-emitting generation. The penetration of non-emitting generation in other provinces is between 85% and 93%. By 2050, BC, SK, MB, and ON will retain gas SC capacity, an emission-intensive technology, operational to provide needed system flexibility given high renewable penetrations across Canada.

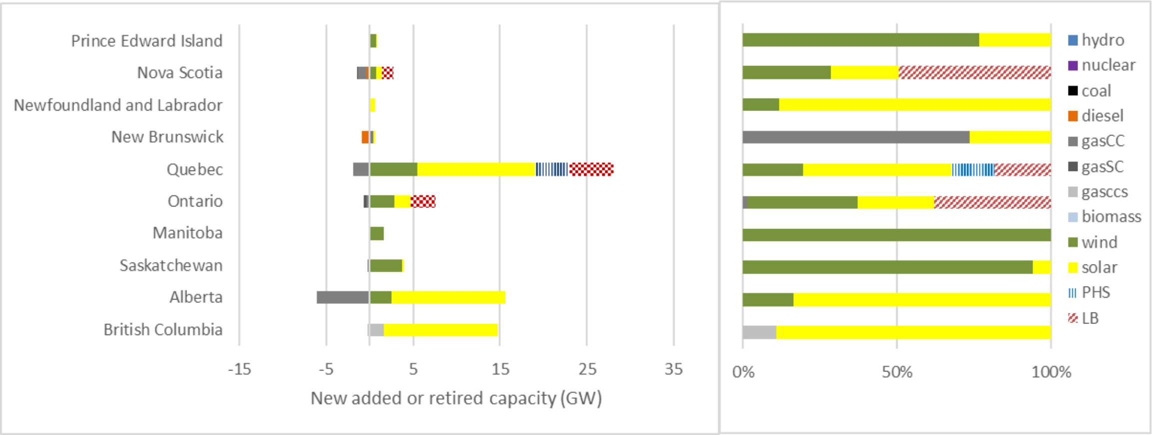

Figure 17: Generation capacity retirements and additions across Canada between 2035 and 2050 in the PCP scenario. The left panel shows actual capacity and the right panel depicts shares of additions by type.

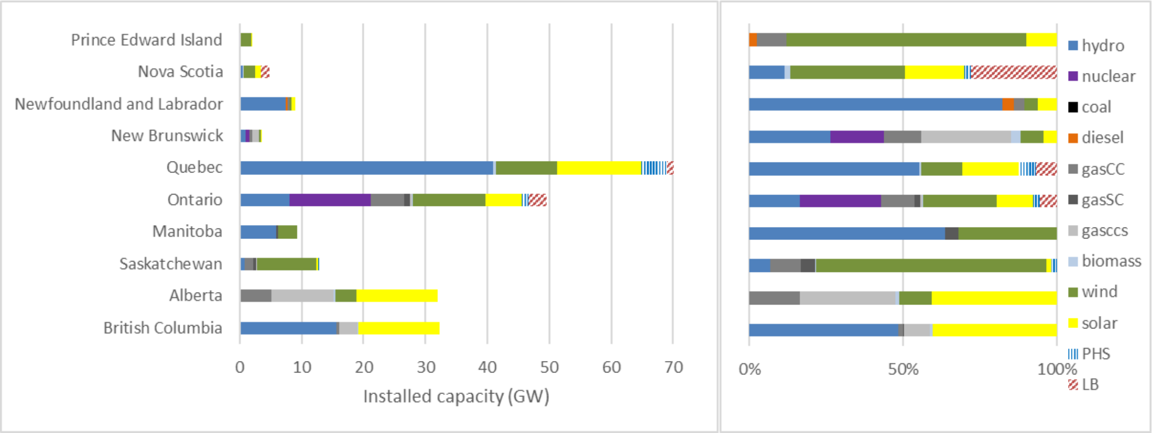

Figure 18: Provincial generation mixes across Canada by 2050 in the PCP scenario

3.5.3 Transmission expansion

The high-voltage transmission network is the backbone of the electricity system, requiring investment in its expansion and reinforcement over time to ensure the delivery of reliable and affordable power to end-users. Under current provincial carbon pricing mechanisms (the PCP scenario), and considering provincial planning reserve margins, 7.6 GW of new inter-and intra-provincial transmission capacity is added to the system by 2050. Figure 19 shows the expansion of transmission capacity between balancing areas (electricity network regions) in Canada. The corridors between the west and central provinces are strengthened by adding capacity between BC, AB, SK, and MB. QC's intra-provincial corridor from north to south and inter-provincial connections to ON are strengthened. Also, around 1000 MW new transmission capacity is added between NS and PE, enhancing the flexibility of the Maritime provinces.

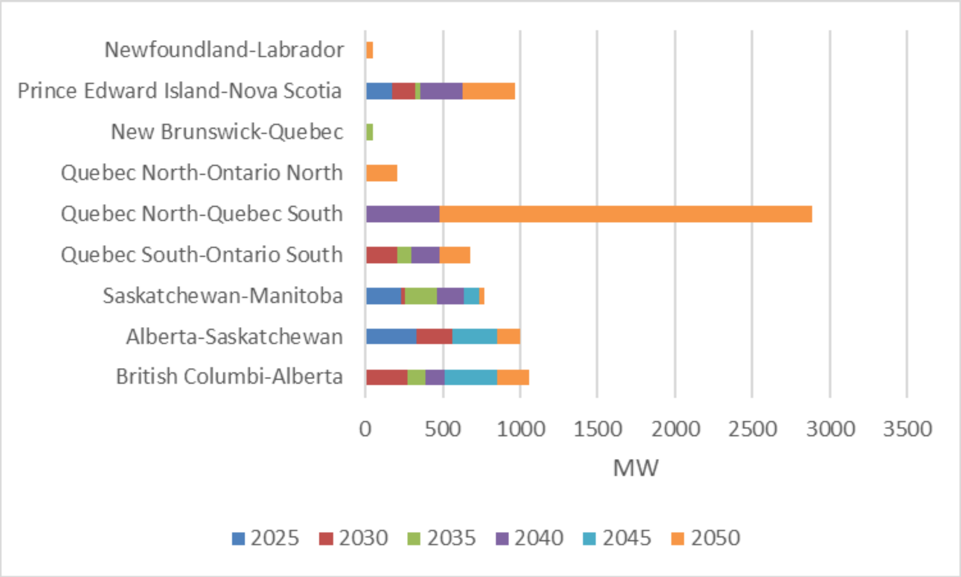

Figure 19: New transmission capacity added between balancing areas in the PCP scenario

3.5.4 Costs

Figure 20 depicts a breakdown of modelled electricity system expenditures on operation, maintenance, and investment during the study period in the PCP scenario. In the short-term, by 2025, no major investments in new generation are required, while between 2025 and 2030, a significant increase investment in new generation is needed as coal is phased out and capacity reaches its end-of-life retirement. By 2030, gas-fired units (mostly gas CCS) are the cost-optimal option to replace phased-out generation. However, after 2030, almost all new investments are in non-emitting generation sources. A large investment of 13 billion dollars in non-emitting generation and storage capacity occurs in the 2035-2040 period. Operation and maintenance (O&M) costs will increase from 16 billion dollars in 2025 to 21 billion dollars by 2050.

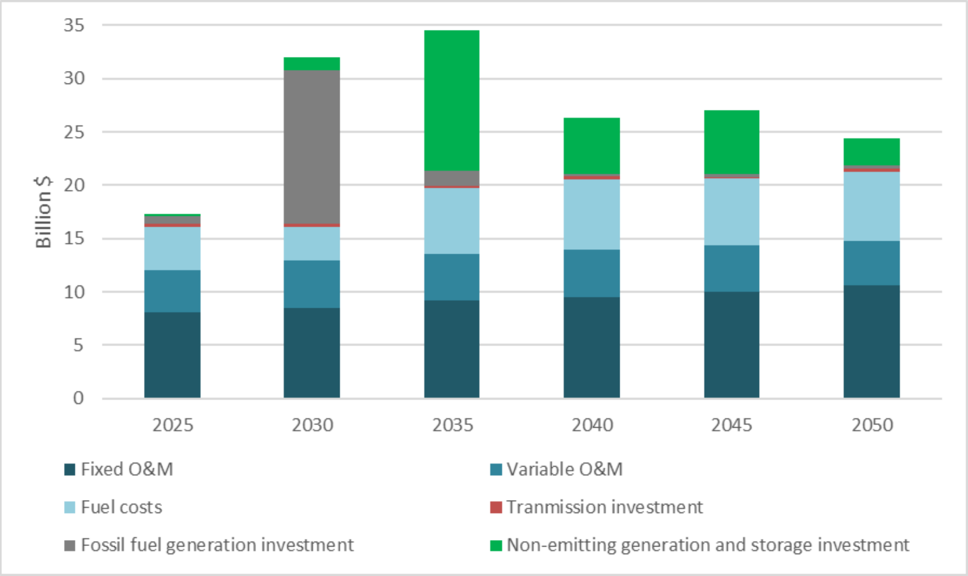

Figure 20: Breakdown of modelled national electricity system costs in the PCP scenario

A provincial breakdown of modelled total costs for the six modelled years is depicted in Figure 21. In all provinces, significant investments in non-emitting sources and storage are cost-optimal except for NB and AB, for which the model selects fossil fuel generation over non-emitting sources. Significant coal- and diesel-fired capacity in these provinces will be phased out by 2030 and will need to be replaced. As wind and solar costs have not reduced sufficiently for these sources to replace all retired units before 2030, and the emissions benchmark for gas is high enough to minimize the carbon price impact on gas CC (and even provides emissions credits for gas CCS units), the model selects a combination of gas CCS and gas CC to meet demand.

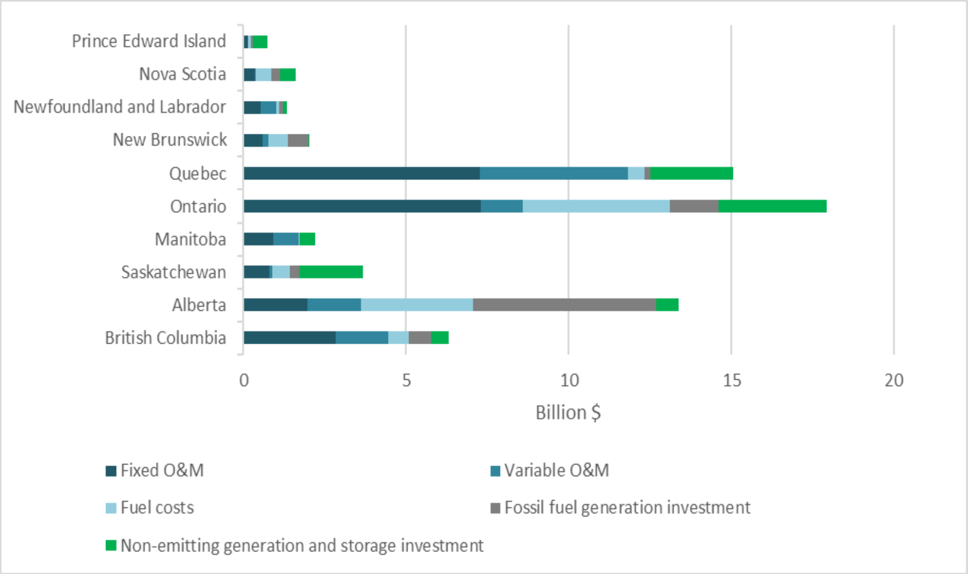

Figure 21: Breakdown of modelled total provincial electricity costs for the six modelled years

To assess the effects of electricity system transition on average electricity generation costs across different provinces in the PCP scenario, the average cost of generation (per MWh) is calculated, as depicted in Figure 22. As shown, the transition has less impact on electricity generation costs in hydro-dominated provinces such as BC, MB, QC, and NL, as these provinces keep most of their existing hydro capacity operational until the end of the study period. Also, in all provinces, electricity generation costs decline towards the end of the study period (i.e., in the 2045-2050 period) such that in six provinces, including two hydro-dominated provinces, SK, and NL, the cost is approximately or less than $20/MWh by 2050. SK and AB experience jumps in electricity generation costs in the 2030-2035 period, due to large investments in wind and the transition from coal- to gas-fired units, respectively. Investment in new generation units results in jumps in electricity generation costs in NS and PE from 2025 to 2030, after which generation costs return to lower levels in the 2045-2050 period. ON and NB‘s electricity generation costs fluctuate between $29 and $61/MWh and $45 to $103/MWh, respectively.

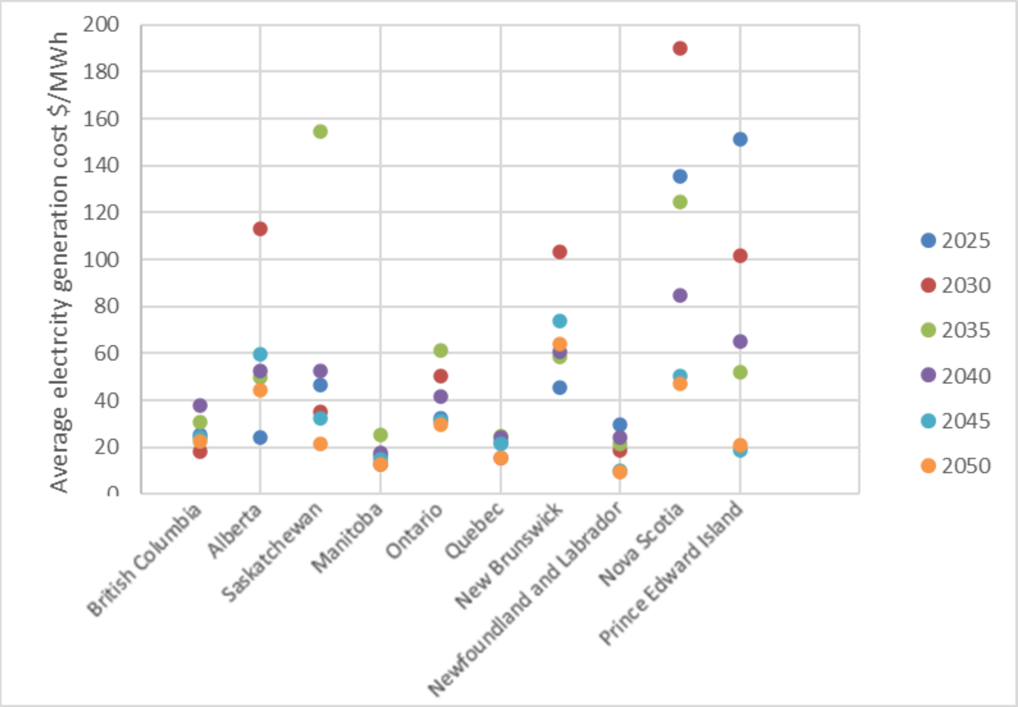

Figure 22: Average provincial electricity generation costs for the six modelled years in the PCP scenario

3.6 Discussion

Canada's flexible federal carbon pricing approach allows provinces to design their own pricing mechanisms or elect to use the default federal system. This flexibility has produced a variety of pricing mechanisms in place across Canada. However, model-based analyses in the literature are limited in terms of modelling these carbon pricing mechanisms. Due to such limitations, there has not yet been a study comparing the different carbon pricing mechanisms across Canada.

To fill this gap, we modified the ESPM COPPER by implementing three carbon pricing mechanisms in place across Canada and studied the implications of each mechanism. While previous studies that focus on Canada's electricity system model carbon pricing systems as a universal carbon tax (Arjmand and McPherson, 2022; Arbuckle et al., 2021; Bistline et al., 2020a; Dolter and Rivers, 2018; Ibanez and Zinaman, 2016; Nelson et al., 2012), this study highlights that:

1) The representation of carbon pricing systems significantly affects the modelling outcomes including costs, emissions, and the electricity system mix. This finding is consistent with

(Bistline et al., 2020b) where under different policy scenarios a noticeable variation in Canada's cumulative emissions is reported.

2) In OBPS and CCAT the design of the mechanisms themselves (e.g., free emission allowance and the hard cap on emissions) impact the emissions reduction and costs outcomes. Literature also discusses the significant impact of output-based standards on the electricity system market (Brown et al., 2018; Xenophon and Hill, 2019) and the effect of free allowance in the CCAT system on the electricity demand, mix and costs (Choi and Thomas, 2012). Also, studies argue that other aspects of carbon pricing affect the success of the CCAT system including administration, carbon revenue management, and stakeholder engagement (Narassimhan et al., 2018) that are beyond the scope of this study.
3) While a carbon cap effectively reduces emissions from the provinces with the CCAT system (Giacosa and Walker, 2022), it might affect the transition of neighbouring provinces. Fais et al. (2014) report a similar trend in Europe where a national policy can impact all countries that are connected through an emission trading system.
4) All policies have advantages and disadvantages depending on various criteria and there is no one size fits all policy (He et al., 2012). Although a uniform policy affects the system as a whole its impact varies in different regions (Szabó et al., 2019). To avoid the adverse impact of policies, we suggest policies should be designed at the provincial level. Previous studies also highlight this. Stringer and Joanis (2022) discuss that carbon pricing schemes should be implemented at the provincial level to achieve specific transition targets in Canada. Similarly, Zhang et al. (2022) show that regionally designed carbon pricing policies result in greater emission reduction in China.

Overall, to study the future of Canada's electricity system, an accurate representation of carbon pricing systems seems to be crucial. The methodology represented in this study allows modellers to implement different carbon pricing mechanisms within an ESPM framework. Also, provided analysis assists policymakers to compare the effects of different carbon pricing systems on the electricity system transition. The main outcomes of this study and policy implications are summarized in the next section.

3.7 Conclusion and policy implications

All carbon pricing mechanisms result in significant carbon reductions at the national scale by 2050, although associated transition pathways vary. Provincially designed carbon pricing mechanisms (represented in the PCP scenario) appear to be preferable compared to a national carbon tax or the default federal carbon pricing system, both economically and in terms of carbon reductions. These in-place mechanisms incur similar total electricity system costs as the federal system applied universally (the FB scenario), but result in cumulative emissions 30 $MtCO_2e$ lower over the six studied years. A national carbon tax (the NCT scenario), on the other hand, results in cumulative emissions 20 $MtCO_2e$ lower than current policies but increases total costs by 10%. None of the studied scenarios resulted in Canada achieving its net zero emissions by 2035 carbon reduction goal. In the FB and PCP scenarios, based on Canada's goal of net-zero emissions in the electricity sector by 2035, we assumed emissions benchmarks for all generation technologies go to zero by 2035 – however, there is still a gap between modelled emissions and Canada's carbon reduction goal. Thus, to achieve stated goals, Canada will need to reduce accommodations for high-emitting electricity generation, for example, by reducing emissions benchmarks more rapidly than modelled (using output-based standards).

Provincially designed carbon pricing mechanisms improved outcomes for all provinces compared to the FB scenario, with the exception of some provinces interconnected with emissions-constrained provinces (i.e., neighbours to provinces with CCAT systems in-place). Affected provinces will need to revise their own carbon pricing systems and/or introduce new measures to diminish the effects of neighbouring provinces' hard emissions caps on their province's electricity system transitions.

Provinces' modelled emissions trends indicate that under current policies, all emissions-intensive provinces experience carbon reductions in the long term, while hydro-dominated provinces maintain low emissions despite increased electricity demand. In some provinces, the carbon reductions are achieved by switching from fossil fuel generation to renewable sources, while in others, they are achieved by transitioning from high-emissions generation sources to lower emissions fossil fuel technologies such as combined cycle gas plants and gas paired with CCS. However, while both transition pathways result in carbon reductions, considering Canada's zero-emissions goal for the electricity sector by 2035, the latter does not appear to be sufficient. For instance, where the model is forced to achieve zero-emissions by 2035 (the CRT scenario), 99% of new installed capacity consists of renewables. Thus, if Canada aims to establish robust measures to achieve net-zero emissions in the electricity sector by 2035, allowing the construction of new fossil fuel electricity generation is not advisable.

The modelled evolution of the Canadian generation mix shows that before 2035, renewables account for around 50% of new installed capacity while the rest consists of fossil fuel generation technologies with lower emissions. Combined cycle gas plants and gas paired with CCS appear in the generation mixes of all provinces except for MB before 2035. To avoid this, provinces need to introduce new measures that target the development of new gas-fired generation. After 2035, emissions benchmarks using in OBPS drop to zero while the costs of renewables keep falling. These changes make renewables cost competitive, accounting for 96 percent of new installed capacity between 2035 and 2050. NB is the only province in which a significant share of its new installed capacity comes from gas-fired units after 2035 and must therefore adopt special measures to prevent this outcome.

The breakdown of electricity system costs shows the importance of consistent investment throughout the modelled period from 2025 to 2050, although 2030 to 2035 is a key period in which the highest levels of investment occurs. Due to the non-zero emissions benchmark used in OBPS in some provinces prior to 2035, most investment is in low emissions fossil fuel generation. In 2035, all benchmarks reach zero and consequently, investment is redirected towards renewables. The federal OBPS distinguishes between new and existing gas-fired units and applies separate benchmarks for new units (zero by 2030) to discourage large investments in new gas-fired capacity. This modification appear to be also necessary for provincial OBPS. Furthermore, there is significant variability in investment across the provinces, with AB, SK, ON, and QC requiring the highest investment levels. Analyzing the electricity generation cost (per MWh) shows that hydro-dominated provinces have lower variation while provinces that require shifting from emissions-intensive to low/non-emitting sources experience temporary jumps in electricity generation costs. However, all provinces arrive at lower electricity generation costs by 2050 compared with 2025.

Overall, the various carbon pricing mechanisms in-place across Canada have pronounced effects on evolving provincial generation mixes, with corresponding impacts on GHG emissions levels and cumulative emissions. The results of this study indicate that there is no one-size-fits-all solution for carbon reduction policy. Policies have to be designed with regard to specific provincial contexts and energy resources to be effective and make progress towards achieving Canada's stated carbon reduction goals.

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Chapter 4: The role of technological development in Canada's electricity system transition

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4.1 Abstract

A significant transition in Canada's electricity system is needed to achieve the zero-emission target that has been set for 2035. Many studies have charted possible decarbonization pathways to achieve this target, but most focus on commercially available generation technologies. In this study, we modify and deploy the electricity system planning model, COPPER, to explore the role of emerging technologies in Canada's electricity system transition under a suite of plausible scenarios. Results show that, if developed and deployed, low- or non-emitting thermal technologies alongside offshore wind could contribute to the transition on the national scale, but specific adoption patterns differ by province: provinces that must phase out fossil fuel generation add natural gas with carbon capture and storage to provide dispatchable capacity with low operation cost; provinces with an emissions cap or inflexible network integrate hydrogen combustion that operates as peaking facilities; offshore wind and SMRs are part of the optimal mix for emissions constrained provinces or provinces with a flexible network, respectively. Since the best-suited technologies differ by region, provinces should explore available opportunities including emerging technology, identify suitable options, and take action to utilize them to facilitate their electricity system transitions.

Keywords: COPPER, Canada's electricity system, emerging technologies, offshore wind, hydrogen, carbon capture and storage

4.2 Introduction

As the transition to net zero takes center stage in policy debates, studies that chart decarbonization pathways are gaining increasing salience. The electricity system is an essential part of the energy system and will be at the forefront of Canada's decarbonization efforts. As such, many studies have focused on the transition of the electricity system in the short-, mid-, and long-term. Such studies often utilize a variety of quantitative modelling tools to highlight opportunities and challenges involved in the process and provide useful feedback to decision-makers.

Electricity system planning models (ESPMs) are among the most useful and frequently deployed models since they generate cost-effective pathways for replacing emissions-intensive sources with low- or zero-emissions technologies. ESPMs outputs identify optimal electricity generation and transmission options from the suite of technologies included in the modelling framework, and thus are very sensitive to the selected technological representations. Electricity generation options include mature technologies expected to experience insignificant technology evolution such as conventional thermal generation and hydroelectricity; evolving technologies projected to benefit from technology evolution such as onshore wind and solar photovoltaics (solar PV); and emerging technologies expected to experience significant technology evolution and have no or small penetration in Canada's electricity generation mix such as offshore wind, hydrogen-based technologies, thermal generation with carbon capture and storage (CCS), and small modular reactors (SMRs).

The suite of studies that have analyzed Canada's electricity system transition have adopted varying degrees of technological detail. Models have tended to include mature and evolving technologies, but are limited when it comes to representing emerging technologies. Table 10 summarizes the inclusion of technologies in studies of Canada's electricity system transition. Most of the reviewed studies incorporate natural gas, coal, nuclear, biomass, diesel, wind, and solar PV, but have diverse considerations of offshore wind (Beiter et al., 2017; Ibanez and Zinaman, 2016; Nelson et al., 2012; Zinaman et al., 2015), SMRs (Arjmand and McPherson, 2022; Bistline et al., 2020b), geothermal (Arbuckle et al., 2021; Beiter et al., 2017; Doluweera et al., 2018a; Nelson et al., 2012; Palmer-Wilson et al., 2019), and hydrogen (Alberta Electric System Operator, 2022). Although the Regional Energy Deployment System (ReEDS) model (Cohen et al., 2019*) can* consider offshore wind, none of the applications of this model in the Canadian context explore the potential of integrating offshore wind sources (Beiter et al., 2017; Ibanez and Zinaman, 2016; Zinaman et al., 2015). Similarly, although the NA-REGEN model is capable of including SMRs (Electric Power Research Institute, 2021a), Bistline et al. (2020) have not reported SMRs in the results of a study using this model. Overall, emerging technologies have been tentatively discussed or modelled in the literature, but the focus of these studies has not been specifically on the potential role of these technologies. As such, prior analyses are limited in terms of the number and variety of scenarios including these technologies, the presentation of relevant results, and subsequent discussion.

Table 10: A summary of generation technologies included in electricity system modelling studies in the Canadian context

	Thermal	Hydroelectricity	Wind and solar PV	offshore wind	SMRs	Geothermal	CCS	Hydrogen	Region
(Arjmand and McPherson, 2022)	🟩	🟩	🟩	🟥	🟩	🟥	🟩	🟥	CA
(Dolter and Rivers, 2018)	🟩	🟥	🟩	🟥	🟥	🟥	🟥	🟥	CA
(Nelson et al., 2012)	🟩	🟥	🟩	🟩	🟥	🟩	🟥	🟥	BC, AB
(Palmer-Wilson et al., 2019)	🟩	🟩	🟩	🟥	🟥	🟩	🟩	🟥	AB
(Beiter et al., 2017; Ibanez and Zinaman, 2016; Zinaman et al., 2015)	🟩	🟩	🟩	🟥	🟥	🟩	🟩	🟥	US, CA
(Bistline et al., 2020b; Electric Power Research Institute, 2021a)	🟩	🟥	🟩	🟥	🟥	🟥	🟩	🟥	CA
(Doluweera et al., 2018a)	🟩	🟩	🟩	🟥	🟥	🟩	🟩	🟥	CA
(Arbuckle et al., 2021)	🟩	🟩	🟩	🟥	🟥	🟩	🟩	🟥	CA
(Canada Energy Regulator (CER), 2021a, 2020, 2019)	🟩	🟩	🟩	🟥	🟩	🟥	🟩	🟥	CA

🟩 Modelled 🟥 Not Modelled

Despite the limitations apparent in the scientific literature regarding emerging technologies, reports by electric utilities, governments, and researchers show the potential importance of emerging technologies. In the Integrated Resource Plan (IRP) published by BC Hydro, geothermal and offshore wind are identified as promising options (BC Hydro, 2021), but no associated modelling methodologies or results are presented. Arjmand and McPherson (2022) briefly discuss the potential cost-effectiveness of SMRs under some scenarios, but do not incorporate other emerging technologies such as offshore wind and hydrogen combustion. The Canada Energy Regulator (CER) (2021a) argue that hydrogen-based electricity generation potentially has a place in Canada's future electricity system but other emerging technologies such as offshore wind and geothermal are excluded. Alberta Electric System Operator considers hydrogen combustion generation units and reports that, under some scenarios, this technology will be part of the generation mix in Alberta (Alberta Electric System Operator, 2022), but this study is spatially limited to Alberta. Similarly, Doluweera et al. (2018b) calculate the levelized cost of electricity (LCOE) as a metric to compare technologies including geothermal, offshore wind, SMRs, and CCS across Canada but do not provide modelling results. The Canadian Institute for Climate Choices used a computable general equilibrium model, gTech[11], to model pathways to achieve net zero economy-wide greenhouse gas (GHG) emissions by 2050. In this study, technologies are categorized into two groups: 'safe bets' encompassing commercially available technologies and emerging technologies or 'wild cards' (Canadian Institute for Climate Choices, 2021). The results suggest that safe bets account for most short-term carbon reduction options prior to 2030, while in the longer term (to 2050), wild cards could provide up to two-thirds of the total required carbon reductions to achieve net zero emissions. The authors note they are unable to accurately represent the electricity system or provide details about the future generation mix due to model limitations. The study noted a gap in the current literature regarding modelling and analysis efforts assessing the role of emerging technologies in Canada's electricity system transition.

As far as we are aware, none of the studies reviewed have modelled and evaluated the role of emerging technologies in decarbonizing Canada's electricity system using an ESPM. To address this gap in the literature, this study modifies an existing ESPM to include emerging technologies, and collects available data to populate the model, to answer the following research question: *To what extent can emerging technologies contribute to Canada's transition to a net zero emissions electricity system?* This study contributes to the current literature by providing insights into the potential role that emerging technologies, including offshore wind, SMRs, CCS, and hydrogen, could play in Canada's electricity system transition.

The remainder of this paper is organized as follows. Section two details the study methodology. Section three presents the data required to parameterize the revised modelling formulation. Section four

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[11] Developed by Navius Research Inc. (Navius Reserach Inc, 2020b)

describes the series of scenarios that are formulated and applied. Section five presents the results of the model runs. Finally, sections six and seven discuss the implications of the results, and summarize the main outcomes of the modelling and analysis.

4.3 Methodology

This study utilizes the Canadian Opportunities for Planning and Production of Electricity Resources (COPPER) model; an ESPM presented in (Arjmand and McPherson, 2022) that is designed to co-optimize generation, transmission, and storage expansion. COPPER is a dynamic optimization-based model with a mixed integer linear programming formulation developed in the Python language. This model simulates Canada's electricity system in five-year intervals over 13 balancing areas, and includes conventional generation types alongside high-resolution resource distributions for wind and solar PV development. COPPER has been designed to model the specific carbon pricing mechanisms that have been adopted across Canada, including carbon taxes (as an extra charge on fuel), output-based pricing systems, and carbon cap and trade systems, as well as the other adopted regulations including coal phase-out and natural gas-fired plant performance standards. The formulation, input data, and limitations for the base version of COPPER can be found in (Arjmand and McPherson, 2022), and the extended formulation that includes additional policy nuance can be found in (Arjmanda et al., 2022).

This study modifies COPPER to include a greater diversity of generation and storage technologies. The version of COPPER deployed for this study includes the following generation and storage types:

- Five fossil fuel technologies – coal, coal with 90% CCS (coalCCS), natural gas-fired simple cycle turbines (gasSC), natural gas-fired combined cycle turbines (gasCC), natural gas-fired combined cycle turbines with 90% CCS (gasCCS)
- Ten non-emitting technologies – large nuclear, SMRs, biomass, hydro, onshore wind, solar PV, offshore wind, hydrogen combustion simple cycle turbines (hydrogenSC), hydrogen combustion combined cycle turbines (hydrogenCC), and geothermal
- Four storage types – pumped hydroelectric storage (PHS) greenfield development, PHS retrofit, 2-hour battery storage, and 4-hour battery storage

The investment, operation, and maintenance costs of all technologies are optimized for least cost according to the objective function (eq. (5)). Other characteristics are modelled through constraints detailed in (Arjmand and McPherson, 2022).

$$Objective = TotalCost = \sum_{pds}\left(IC_{pds} + PC_{pds} + CC_{pds} + MC_{pds}\right) \quad (5)$$

Where pds represents the set of all planning periods, IC is investment cost, PC is production cost, CC is carbon cost, and MC is maintenance cost. In the following sections, the modelling formulation for technologies added to, or improved in, the model is outlined.

4.3.1 Offshore wind

Offshore wind is an emerging technology that has been in the world's electricity mix for 25 years. Recent developments have increased the average nameplate capacity of the offshore wind turbine to 9.5 megawatts (MW) while reducing the average generation cost from 200 USD$/MWh to about 75 USD$/MWh (NREL, 2020). Currently, Europe has 25 gigawatts (GW) installed offshore wind capacity while Canada is yet to install any offshore wind farms, although six projects are proposed totalling 3.6 GW capacity (National Energy Board, 2017). Considering Canada's ambitious carbon emissions goal of net zero electricity by 2035 and long coastlines in both the west and east, offshore wind might play a significant role in Canada's future electricity supply mix. Therefore, to assess the potential contribution of offshore wind in Canada's electricity system, we have added it to COPPER according to the data and constraints detailed below.

The investment and maintenance (fixed and variable) costs for offshore wind are added to the optimization objective function. Similar to the onshore wind formulation presented in (Arjmand and McPherson, 2022), two constraints dictate the operation of offshore wind. The first constraint (eq. 2) limits generation output in each hour based on the estimated capacity factor and installed capacity per location.

$$OWG_{pds,h,l} \leq \sum_{pds=1}^{PDS} IC_{pds} \times CF_{pds,h,l} \; \forall PDS \in pds, h, l \quad (2)$$

Where pds is the set of planning periods (i.e., [2025, 2030, … , 2050]), OWG is offshore wind generation in period pds, at hour h, and location l. IC is the installed capacity in period pds and CF is the capacity factor in period pds, at hour h, and location l. The second constraint (eq. 3) limits the offshore wind density to 7 MW/Km^2, a maximum density limit given on the literature (Enevoldsen and Jacobson, 2021).

$$\sum_{pds=1}^{PDS} OWC_{pds,l} \leq SA_l \times MD \; \forall PDS \in pds, l \quad (3)$$

Where OWC is offshore wind capacity, SA is the surface area for each location l and MD is the maximum density limit.

4.3.2 Thermal units

Thermal generation technologies can improve the flexibility of electricity systems by providing firm and dispatchable capacity. This study includes low- and non-emitting thermal technologies including fossil fuel with CCS, biomass, geothermal, SMRs, and hydrogen. Some of these technologies are currently part of Canada's electricity generation mix, namely fossil fuel with CCS and biomass. Importantly, the Government of Canada is committed to exploring CCS in particular to determine its potential to meet carbon reduction targets (Natural Resources Canada, 2013). Among the emerging technologies, CCS has been reported as one that is most likely to contribute to Canada's net zero pathway (Riehl et al., 2021) and future electricity generation mix (Canada Energy Regulator (CER), 2021a). Currently, there are two operational CCS projects in Alberta and Saskatchewan: one is a coal-fired power plant retrofit designed to capture one million tonnes of CO2 per year and the other project captures 1.2 million tonnes of CO2 per year from oil sands upgrading process (Canada Energy Regulator (CER), 2021b). Biomass-fired generation is another dispatchable technology currently present in Canada's electricity system, with a total of 2.8 GW of installed capacity.

Geothermal, SMRs, and hydrogen technologies do not yet have a presence in Canada's electricity system, although deployment potential exists. A report from Natural Resources Canada identifies enormous geothermal resources across Canada which could theoretically be used to generate low-emissions electricity (Grasby et al., 2012). There is limited data to differentiate resource potential by geothermal technology type in Canada. As such, we run the model with no resource constraints.

SMRs are another non-emitting electricity generation source that could represent a future pathway for the nuclear industry in Canada (Government of Canada, 2022c). In 2018, Natural Resources Canada supported a collaboration between provinces, territories, and electric utilities to create a roadmap for SMR technology. The study finds that Canada has all the necessary elements, including nuclear laboratories, supply chain, uranium mining sites, and operations experience, to lead the SMR industry (Canadian Small Modular Reactor Roadmap Steering Committee, 2018). In 2020, the government of Canada turned this SMR roadmap into an action plan outlining the efforts toward developing SMRs in Canada from all participants (Government of Canada, 2022c). These efforts highlight the potential importance of SMRs for the future Canadian energy system. Since both on-grid and off-grid electricity generation are among the main potential applications of SMRs in Canada (Canadian Small Modular Reactor Roadmap Steering Committee, 2018), SMRs are included in the present study.

While not a primary energy source, hydrogen is another option that could be used to produce zero-emissions electricity. Canada has the potential to play a lead role in the development of a hydrogen industry (Natural Resources Canada, 2020). Therefore, assessing the future role of hydrogen in Canada's electricity system transition also appears necessary. Different technologies are potential options for electricity generation using hydrogen in Canada (Natural Resources Canada, 2020). First, hydrogen can be blended with natural gas (up to 15% hydrogen by volume) and be used in most existing facilities and infrastructures. Second, natural gas-fired power plants can be retrofitted to utilize pure hydrogen. Third, stationary fuel cell power plants can be developed to produce electricity directly from hydrogen. The present study models hydrogenSC and hydrogenCC as potential electricity generation options in Canada.

Constraints are used to model all thermal units, including the added emerging technologies, to limit maximum generation in each hour, to set minimum and maximum capacity factors, and to apply generation ramp rates.

4.4 Data

Optimization-based ESPMs require input data to parameterize the generation, transmission, and storage options. Various reports providing financial and technical details for emerging technologies in the North America are available. The U.S. Energy Information Administration (EIA) and National Renewable Energy Laboratory (NREL) publish reports and datasets on electricity generation technologies (National Renewable Energy Laboratory (NREL), 2021; U.S. Energy Information Administration (EIA), 2020). The most recent versions of these reports include cost and performance data for emerging technologies such as CCS, offshore wind, geothermal, fuel cells, and SMRs. This study uses values from the most recent Annual Technology Baseline (ATB 2021) published by NREL to model the majority of the technologies included in this analysis[12]. For the technologies not presented in NREL's ATB, other sources that are detailed in this section are used.

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[12] To covert USD to Canadian dollar, we assume 1 USD = 1.3 Canadian dollar

4.4.1 Offshore wind

Eleven locations with potential for offshore wind development were selected on the west and east coasts for inclusion in the model. Since most existing offshore wind farms are within 40 km of the shore (Díaz and Guedes Soares, 2020), the locations that are selected for inclusion meet this criteria. Three locations are on the west coast: one is a proposed offshore wind project off the coast of Haida Gwaii in the Hecate Strait (National Energy Board, 2017), and the other two are selected based on their proximity to existing transmission nodes. The nine locations off the east coasts of Quebec, New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador were selected based on their average wind speed (data published by Natural Resource Canada (Tang and Kilpatrick, 2021)) and proximity to existing transmission nodes. Figure 23 shows the eleven modelled offshore wind locations. Wind speed data for the locations are extracted and estimated at the wind turbine hub height using the GRETA platform (McPherson et al., 2017). These data were converted to capacity factor values with reference to the power curve of a standard 15 MW offshore wind turbine (Figure 24) presented by NREL (Gaertner et al., 2020).

Investment, operation, and maintenance costs published by NREL in the ATB 2021 (NREL, 2021a) dataset are used to parameterize offshore wind in COPPER. In the ATB table, NREL provides three different learning curves for offshore wind, including conservative, moderate, and advanced assuming 12 MW, 15 MW, and 18 MW wind turbines, respectively (NREL, 2021b). The advanced projection has the lowest cost due to scale efficiencies discussed in (Papi and Bianchini, 2022).

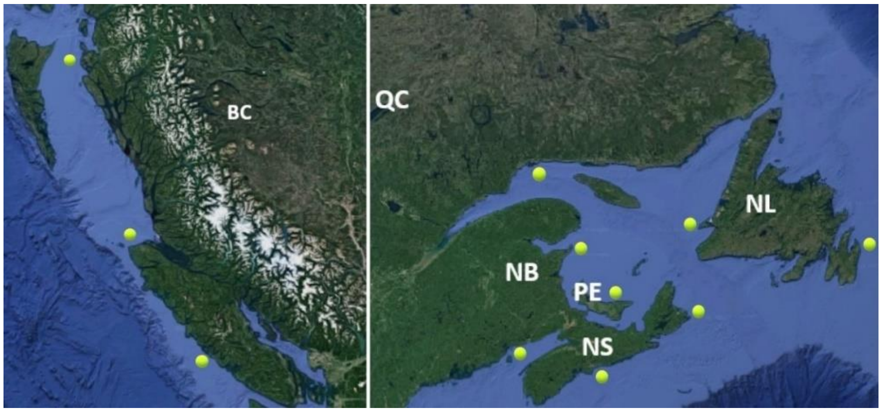

Figure 23: Modelled offshore wind locations in the west and east[13]

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[13] Maps by Google Maps 2022 available online at https://www.google.ca/maps

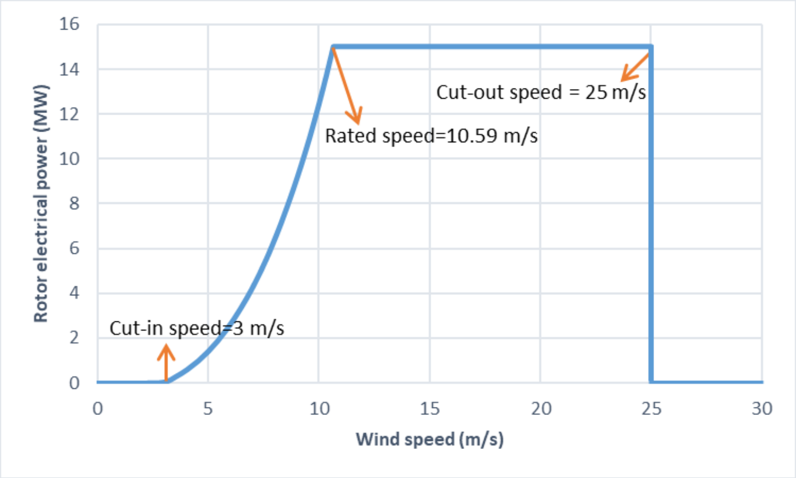

Figure 24: Power curve of the 15MW offshore wind turbine

4.4.2 Thermal units

Thermal generation unit data used in COPPER includes technical data such as efficiency, ramp rate, and minimum and maximum capacity factors, as well as economic data such as investment, operation and maintenance, and fuel costs. For consistency, this study uses the NREL ATB 2021 (NREL, 2021a) dataset to model natural gas with 90% CCS, coal units with 90% CCS, and biomass technology. This dataset suggests flash steam power plants are the most cost-effective of the geothermal technologies and the corresponding data is used to parameterize geothermal in COPPER, except for variable operation and maintenance cost data, which are drawn from (U.S. Energy Information Administration (EIA), 2020).

The NREL ATB dataset does not include SMRs and hydrogen-based generation options, and thus other sources are used. Cost and performance data for SMR technology are collected from (Economic and finance working group, 2018) and (Doluweera et al., 2018b). Hydrogen technologies are still in the early stages of development and are not projected to be available until 2030. Therefore, data for parameterizing hydrogen combustion power plants are scarce. This study uses data reported by Alberta Electric System Operator to parameterize the hydrogenSC and hydrogenCC technologies (Alberta Electric System Operator, 2022). Since natural gas prices vary by location in Canada, this study assumes the local natural gas prices reported in (Doluweera et al., 2018b). For hydrogen generation combustion technologies, blue hydrogen derived from natural gas is modelled as the fuel source. A representative hydrogen price in the middle of the range forecast by Alberta Electric System Operator (AESO) (8.9 $/GJ to 15.6 $/GJ) (The Alberta Electric System Operator, 2021) is assumed. This base price is taken as the local price for Alberta, while for other provinces, the hydrogen price is scaled proportionally to the local natural gas price relative to Alberta (Table 11).

Table 11: Modelled provincial natural gas and hydrogen prices

Province	Natural gas Price ($/GJ)	Hydrogen Price ($/GJ)
Alberta	2.60	12.25
British Columbia	2.69	12.67
Manitoba	2.73	12.86
New Brunswick	6.21	29.26
Newfoundland and Labrador	7.39	34.82
Nova Scotia	7.39	34.82
Ontario	6.77	31.90
Prince Edward Island	7.39	34.82
Quebec	6.73	31.71
Saskatchewan	2.55	12.01
Sources: Hydrogen price for Alberta (The Alberta Electric System Operator, 2021) and natural gas prices (Doluweera et al., 2018b)		

4.4.3 Energy storage

Four energy storage types are included in the modified version of COPPER used in this study: two lithium battery (LB) storage options (with 4-hour and 2-hour duration, LB4h and LB2h, respectively) and two PHS types (greenfield PHS development and PHS retrofit). PHS retrofit assets are hydroelectric facilities that can be upgraded to include storage charge capabilities. Data for LB storage types are collected from the NREL ATB dataset while PHS data are based on (Arjmand and McPherson, 2022).

Table 12 summarizes the parameterization of storage types in COPPER.

Table 12: Modelled costs and performance data for energy storage technologies

	Efficiency (%)	Capacity (hours)	Fixed O & M ($/kW/year)	Annualized Capital cost ($/kW/year)
LB4h	85	4	39	171
LB2h	85	2	23	102
PHS	80	8	9	201
PHS retrofit	80	8	9	141
Sources are **detailed** in **section 4.4.3**				

4.4.4 Technology evolution

Since COPPER is a dynamic model, it can consider declining technology costs that occur over time. However, doing so requires assumptions regarding technology evolution and changes in costs, particularly for rapidly evolving and emerging technologies. This analysis models the fixed operation and maintenance and investment costs based on learning curves reported in the NREL ATB dataset (conservative, moderate, and advanced). Figure 25 illustrates the investment cost multiplier trends for all technologies using the moderate learning curve. Table 13 summarizes performance and cost data for the electricity generation options modelled in COPPER for the present study.

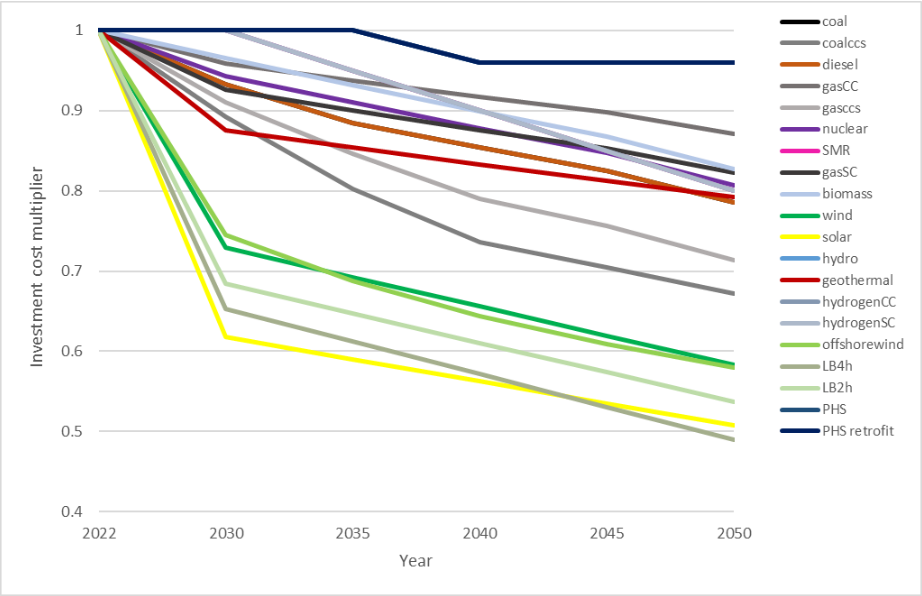

Figure 25: Investment cost multipliers for generation technologies under moderate technology evolution

Table 13: Costs and performance data for all modelled generation technologies

Type	Max CF (%)	Min CF (%)	Ramp-Rate (%)	Efficiency (%)	Fuel CO_2e (kg/MWh)	Fixed O & M ($/kW/year)	Variable O & M ($/MWh)	Fuel price ($/GJ)	Annualized Capital cost ($/kW/year)
Coal	90	50	5	39	830	94	10.4	2.6	324
Coalccs	90	50	5	30	110	159	18.2	2.6	582
Diesel	95	5	10	39	664	19	19.2	16.6	86
GasSC	30	2	100	28	655	27	6.5	Local	102
GasCC	80	20	10	51	360	35	2.6	Local	109
GasCCS	80	20	10	45	33	85	7.8	Local	249
Nuclear	95	75	5	33	0	189	2.6	0.9	672
SMR	95	40	5	33	0	145	0.0	0.8	630
Biomass	90	20	5	39	0	195	6.5	2.9	411
HydrogenCC	80	20	10	53	0	55	2.8	Local	148
HydrogenSC	30	2	100	34	0	30	0.8	Local	80
Wind	N/A	N/A	N/A	N/A	N/A	55	0.0	0.0	137
Solar PV	N/A	N/A	N/A	N/A	N/A	29	0.0	0.0	132

Hydro	N/A	N/A	N/A	N/A	N/A	63	0.0	0.0	-
Geothermal	N/A	N/A	N/A	N/A	N/A	176	1.5	0.0	664
Offshore wind	N/A	N/A	N/A	N/A	N/A	129	0.0	0.0	322
Source: Data is **source**d **from (National Renewable Energy Laboratory (NREL))** unless stated in the text									

4.4.5 Modelling and data limitations

The methods and data that are available to model emerging technologies are limited, due in large part to the uncertainty involved in estimating associated parameters. While this study utilizes reliable resources to represent emerging technologies to the extent possible, limitations remain. The main identified limitations are listed below:

- Other emerging technologies exist, such as tidal turbines, but are not modelled due to computational limitations and/or a lack of available data.
- Some technologies are geographically limited and costs can be expected to vary across different regions; these costs are modelled as homogeneous for simplicity.
- Ramp-rates and minimum/maximum capacity factors for hydrogenSC and hydrogenCC are assumed to be identical gasSC and gasCC, respectively, due to a lack of pertinent data.
- The geothermal ramp rate is assumed to be 100% which might overestimate the flexibility of this generation type.
- One standard turbine class is assumed to estimate offshore wind costs. However, other classes might be more suitable in some locations based on water depth and geological conditions. Also, as a 15 MW turbine is used as a benchmark to calculate capacity factors, this may be inaccurate for other turbine sizes (and optimistic where average turbine capacities are lower than 15 MW).
- Technology evolution multipliers for SMRs, hydrogenSC, hydrogenCC for conservative, moderate, and advanced learning curves are assumed to be 0.9, 0.8, and 0.7, respectively (which imply 10%, 20%, and 30% cost declines between 2030 and 2050, respectively) due to a gap in data. This might overestimate or underestimate the contribution of these technologies to the future mix.

In addition to the listed limitation, the inclusion of emerging technologies in this study is itself subject to uncertainty. We have modelled these technologies for analytical purposes, but all modelled technologies might not reach widespread deployment. This uncertainty around the technology evolution may overestimate the role that emerging technologies might have; such technologies may not evolve as projected and planned.

4.5 Scenarios

Six scenarios are designed to explore the potential contribution of emerging technologies in Canada's electricity system transition to 2050. These scenarios cover a range of technology evolution assumptions as well as alternative installed capacity constraints. Each scenario assumes the same carbon price mechanism and trajectory based on the existing provincial carbon pricing systems. The scenarios that are included are listed below and detailed in Table 14:

1. Reference scenario: moderate technology evolution affecting investment and fixed maintenance costs for generation technologies.
2. Conservative scenario: conservative technology evolution (assuming the smallest costs declines over time).
3. Advanced scenario: advanced technology evolution (assuming the greatest costs declines over time).
4. Target scenario: based on the reference scenario, with electricity system GHG emissions constrained to zero by 2035 (based on the government of Canada's carbon reduction goals).
5. Diverse scenario: based on the reference scenario, with a minimum installed capacity constraints for installed capacity of each emerging technology (detailed in Table 14).
6. Emerging scenario: based on the reference scenario, with a minimum total installed capacity constraint for emerging technologies.

Table 14: Scenario details

Scenario	Technology evolution	Other Constraints	Carbon pricing
Reference	Moderate	None	Provincial carbon pricing systems, as described in
Conservative	Conservative	None	
Advanced	Advanced	None	

Target	Moderate	Zero national GHG emissions by 2035	(Arjmanda et al., 2022)
Diverse		Minimum installed capacity constraints for each emerging technology at 2035 and 2050 as follows (in MW): geothermal.2035: 1000, geothermal.2050: 2000 offshorewind.2035: 2000, offshorewind.2050: 4000 SMR.2035: 1000, SMR.2050: 2000 hydrogenSC.2035: 500, hydrogenSC.2050: 1000 hydrogenCC.2035: 500, hydrogenCC.2050: 1000	
Emerging		Minimum total installed capacity constraints for emerging technologies at 2035 and 2050 as follows (in MW): 2035: 5000 2050: 10000	

4.6 Results

The modelling results presented in this section are organized around technology type. First, an overview of the electricity system transition on the national scale is presented. Then, the trajectories for mature, evolving, and emerging technologies provide insights regarding the relative contribution of these technologies to Canada's electricity system transition under varying cost assumptions, emissions reduction targets, and generation mixes.

4.6.1 Overview of the transition

The transition of the generation and storage mix of Canada’s electricity system under moderate technology evolution scenario is depicted in Figure 26. The gradual phase out of thermal units such as coal and natural gas fired units and integration of evolving and emerging technologies such as wind, solar, hydrogenSC, gasCCS, and LB seems to be the cost-effective transition pathway. A detailed analysis of the role of each technology in this transition is presented in the following sections.

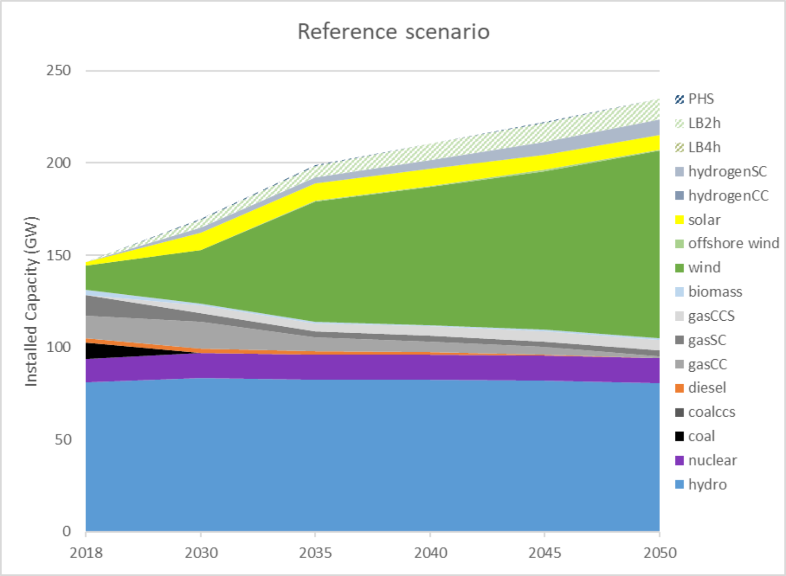

Figure 26: Canada's electricity system generation and storage mix under reference technology evolution scenario

4.6.2 Onshore wind and solar

Onshore wind and solar PV are the predominant technologies in the cost-optimal electricity generation mix under all scenarios. Installed wind capacity increases significantly regardless of technology evolution pathway and emissions constraints, and will likely become the dominant technology in Canada's electricity system by 2050. Wind is a cost-effective generation source that can compete with fossil fuel generation in Canada, with some variation stemming from carbon tax levels. Figure 27 shows the modelled total installed wind capacity from 2018 to 2050 under varying technology evolution pathways. The Conservative scenario leads to the lowest installed capacity of wind by 2050 (just under 100 GW), while the Advanced scenario leads to the highest (127 GW). Despite the significant cost differential between these scenarios, there is relatively little difference in wind installed capacity, which highlights the robustness of wind development against varying cost assumptions and emphasizes the likelihood of high wind penetration in Canada's electricity system. Solar PV, on the other hand, does not exhibit the same robustness.

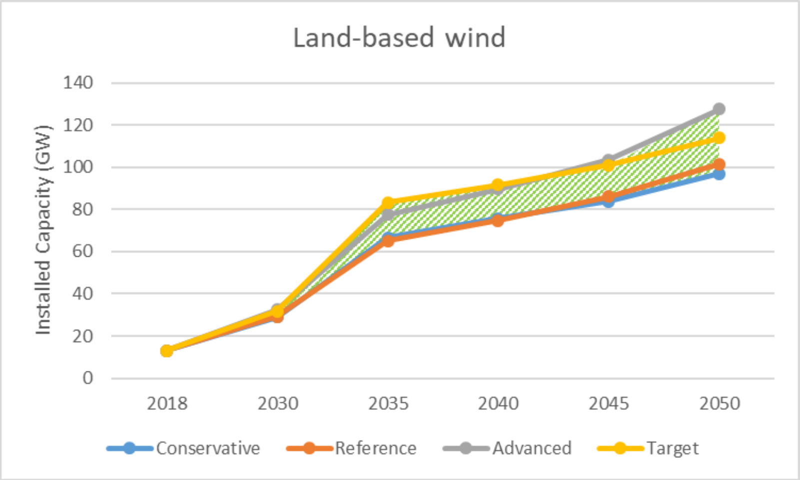

Figure 27: Modelled total installed wind capacity by scenario

Solar PV generation costs have dropped significantly during the last decade and are projected to decrease even more. Nevertheless, in addition to relatively low solar PV capacity factors (in most regions in Canada) and diurnal and weather-dependent patterns, the expansion results for solar PV differ from wind in two key ways. First, solar PV installed capacity reaches only roughly a tenth of wind installed capacity, even in the best-case scenario. Second, solar PV development appears more sensitive to cost assumptions than wind while its ability to compete with other generation sources is uncertain.

Figure 28 shows the total installed solar PV capacity over the planning period. In most scenarios, installed solar PV capacity does not exceed 10 GW by 2050. Furthermore, there is a noticeable gap between different technology evolution pathways, highlighting the uncertainty associated with the role of solar PV in Canada’s electricity system. In the Conservative scenario, solar PV capacity remains relatively constant (between 2-4 GW) until 2050, while in the Reference scenario, installed capacity increases to approximately 8 GW by 2050. The Advanced scenario exhibits less installed solar PV capacity compared to the Reference scenario because other technologies’ evolution outcompetes solar PV. Note that the NREL ATB 2021 data that was used in this study has higher cost projections for solar PV costs than other sources such as the Canada Energy Regulator cost projections (Canada Energy Regulator (CER), 2021a). In a test scenario where CER reference technology evolution projection is used for wind and solar, total solar installed capacity exceeds 32 GW by 2050 (CER scenario in Figure 28).

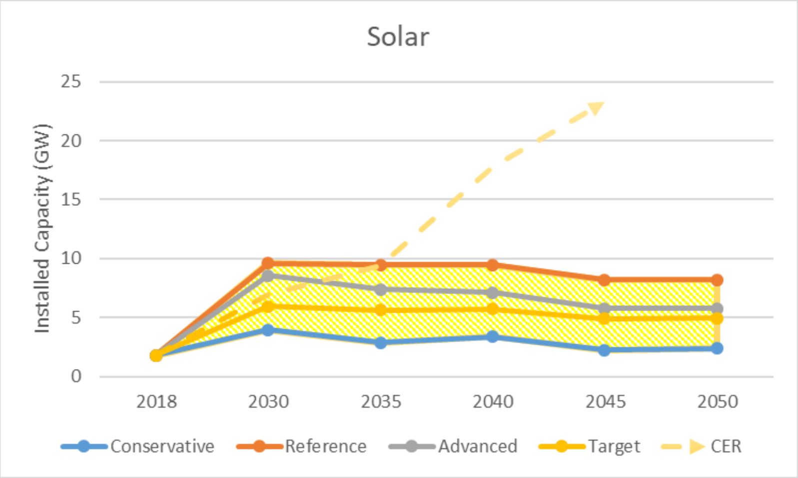

Figure 28: Modelled total installed solar PV capacity by scenario

4.6.3 Offshore wind

Offshore wind has the potential to contribute modestly to Canada's future electricity generation mix in some of the technology evolution scenarios: 1GW is installed in the Target by 2050 but none is installed in the Conservative scenario (Figure 29). Although the Advanced scenario has the greatest decline in offshore wind costs, it does not result in higher offshore installed capacity because other technologies, which also decline in costs, are more cost-competitive. The Emerging scenario, which imposes a minimum total installed capacity for emerging technologies, does not lead to higher offshore wind penetration (750 MW) as the model picks other generation alternatives to meet the constraint. When a specified level of offshore wind capacity is enforced (i.e., the Diverse scenario), the resulting installed capacity is concentrated in eastern Canada.

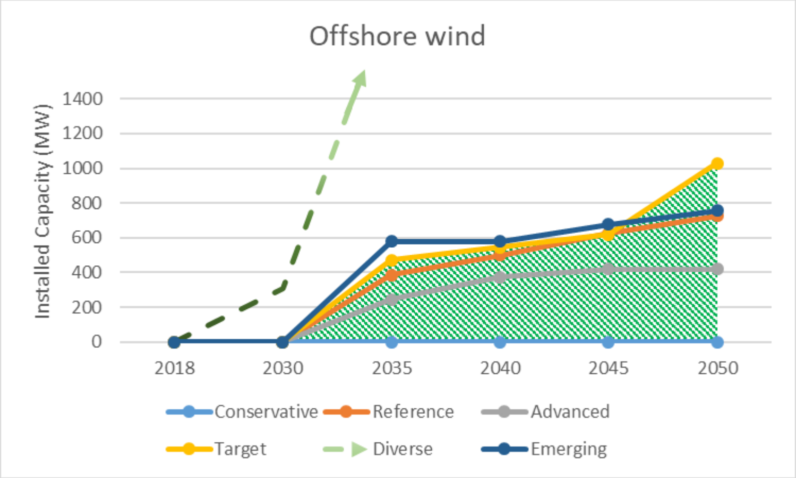

Figure 29: Modelled total installed offshore wind capacity by scenario (note: the Diverse scenario enforces 4 GW by 2050)

All of the provinces that have the potential to develop offshore wind do so, with the exception of Quebec (Figure 30). Due to the carbon cap and trade system imposing a hard cap on Nova Scotia's GHG emissions, the province installs more offshore wind capacity than any other province (averaged across all scenarios). Approximately 500 MW of offshore wind capacity is built in British Columbia when emissions are constrained to zero by 2035 (Target scenario), or when a minimum installed capacity of offshore wind is enforced (Diverse scenario) – a similar amount to a project that was recently approved in the province (National Energy Board, 2017). Newfoundland and Labrador also deploys a modest amount of offshore wind capacity even where there is no minimum enforced. New Brunswick and Prince Edward Island only deploy offshore wind when a minimum capacity constraint is enforced.

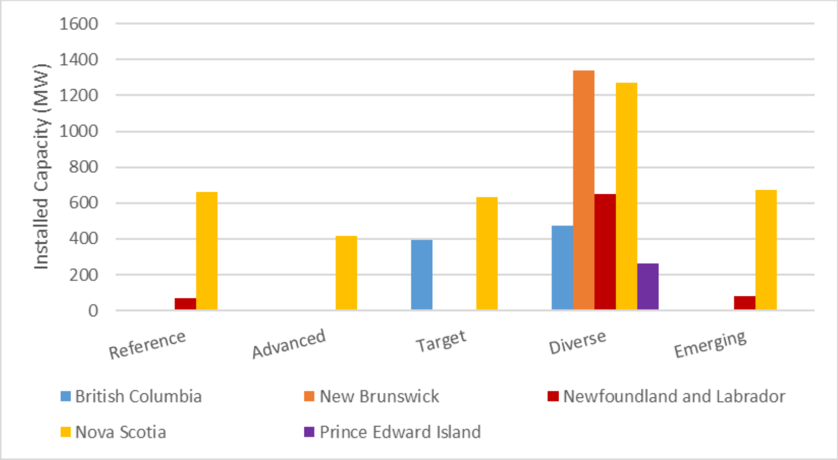

Figure 30: Modelled provincial installed offshore wind capacity in 2050 by scenario

4.6.4 Mature thermal units

Coal, natural gas, diesel, nuclear, and biomass thermal generation are mature technologies, however new capacity is not cost-effective; nuclear remains constant[14] while coal is phased out by 2030, diesel and natural gas capacity decreases, largely due to high carbon prices and falling costs for renewables over time (Figure 31). Combined cycle natural gas is the only conventional thermal technology that the model invests in during the planning period (225 MW new capacity in 2030 in the reference

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[14] We assume nuclear capacity remains operational until the end of study

scenario) owing to relatively low investment and maintenance costs, and lower emissions than other fossil fuel technologies.

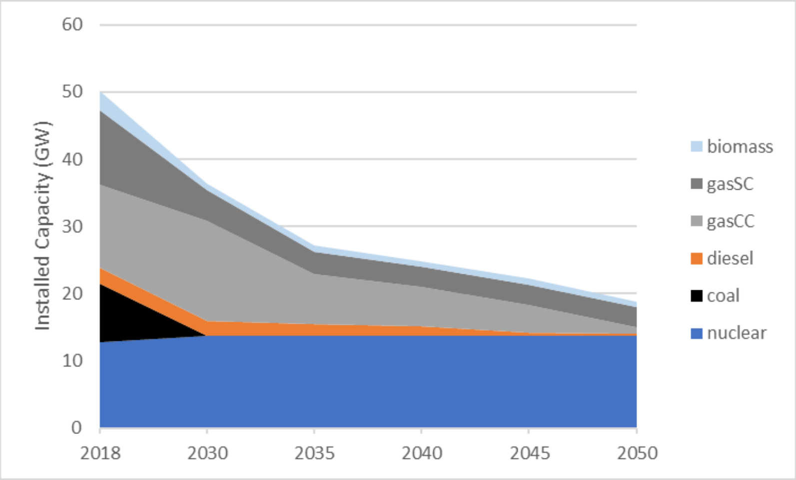

Figure 31: Modelled conventional thermal unit installed capacity in the reference scenario

4.6.5 Emerging thermal units

Thermal technologies are dispatchable, provide network flexibility, and contributes to planning reserve margin requirements. Although the model does not deploy new conventional thermal capacity due to their high emissions intensities, low- or non-emitting thermal technologies including SMRs, hydrogenCC, hydrogenSC, and gasCCS are part of the optimal mix. These technologies are deployed in provinces with flexibility shortfalls, reliability constraints, or where they are cost-effective compared to other options. Among thermal technologies geothermal and coalCCS are rarely selected due to high investment and maintenance costs compared to other options. In all modelled scenarios, the installed capacity of these technologies remains zero, except for the Diverse scenario in which minimum capacities are enforced.

4.6.5.1 Hydrogen

Of the two hydrogen-based technologies modelled in this study, hydrogenCC and hydrogenSC, the former is more efficient and has higher minimum capacity factors, but also higher investment costs and lower ramp rates. Therefore, hydrogenSC is the favoured technology for renewables integration; hydrogenCC capacity remains zero (except in the Target and Diverse scenarios) while hydrogenSC ranges between 4.5 GW and 12 GW by 2050. Hydrogen combustion leverage the technology in mature technologies (i.e., gas turbines), and thus technology evolution is not expected to decrease costs significantly as other emerging technologies (see Figure 25). As such, the lowest installed hydrogenSC capacities are seen in the Advanced scenario while the highest level appears in the Conservative and Target scenarios (Figure 32).

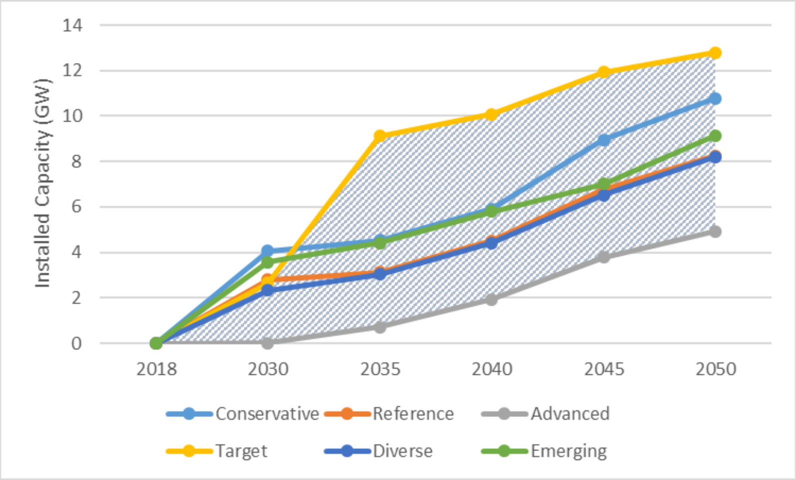

Figure 32: Modelled total installed hydrogenSC capacity by scenario

A breakdown of hydrogenSC development by province in the reference scenario reveals that this technology is built in provinces falling into one of two groups. The first group consists of provinces with a hard emissions cap established via carbon cap and trade systems (i.e., Quebec and Nova Scotia) in which gasCCS is not a feasible option. The second group includes provinces that require improvements in network flexibility that hydrogenSC can provide, such as Ontario (with significant inflexible nuclear capacity). The share of total installed hydrogenSC capacity built in each province by 2050 is depicted in Figure 33.

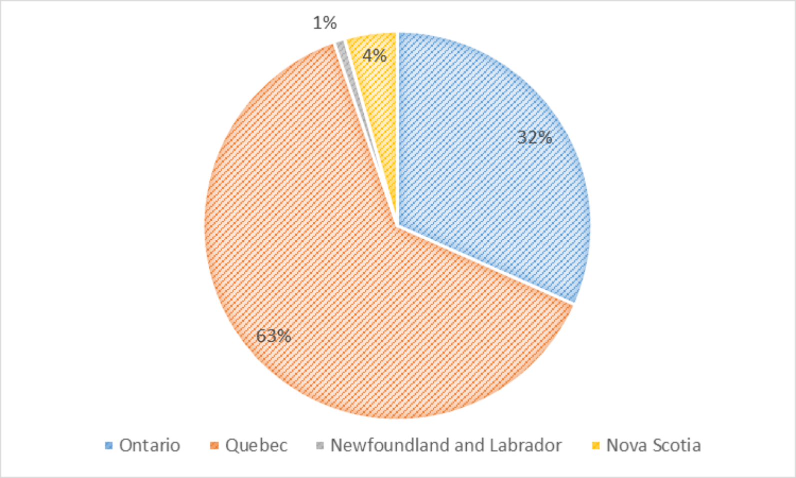

Figure 33: Modelled share of total installed hydrogenSC capacity by province in the Reference scenario

4.6.5.2 SMRs

SMRs have relatively high investment and maintenance costs, they are reliable, dispatchable, non-emitting. Results do not exhibit the installation of SMR capacity except where a minimum capacity is enforced (Diverse scenario). Additional analysis suggests that if revolutionary technology evolution were to occur, in which there was a 70% cost reduction between 2030 and 2050, SMRs would become part of the cost-optimal mix. In all scenarios, the majority (~90%) of SMR capacity is built in British Columbia because, being a hydro-dominated, it has sufficient flexibility to enable the integration of (inflexible) SMRs. Note that the government of British Columbia has prohibited the use of nuclear power and the integration of SMRs into this province’s generation mix depends on future changes to this regulation (Government of British Columbia, 2010).

4.6.5.3 Gas with CCS

Natural gas-fired generation units have cost and performance advantages, making them competitive technologies. First, investment and maintenance costs are low compared to other fossil fuel options. Second, natural gas is an inexpensive fuel in Canada, especially in the western provinces: British Columbia, Alberta, Saskatchewan, and Manitoba. Third, gas turbines are flexible and dispatchable. When carbon prices are low, COPPER develops significant gas-fired capacity; when carbon prices are high less (or no) new capacity is deployed (Arjmand and McPherson, 2022). Considering Canada’s strengthened emissions reduction goals and high carbon tax levels in the coming years (Environment and Climate Change Canada, 2020a), conventional natural gas-fired units will likely not be cost-competitive.

Adding CCS to natural gas-fired units lowers operation costs by reducing costs imposed through carbon pricing policies, making this option cost-competitive and robust to rising carbon taxes. Figure 34 shows the total installed capacity of gasCCS units by scenarios. In all scenarios, a minimum of 3 GW gasCCS is seen in the cost-optimal supply mix by 2050, except for the Target scenario (in which emissions are forced to zero by 2035). The Reference and Emerging scenarios see large capacities of new gasCCS units, indicating the cost-effectiveness of this technology relative to other emerging options. New gasCCS is installed largely in provinces with lower natural gas prices, such as British Columbia and Alberta. New Brunswick also exhibits significant gasCCS development due to large capacities of coal, diesel, and conventional natural gas units being retired.

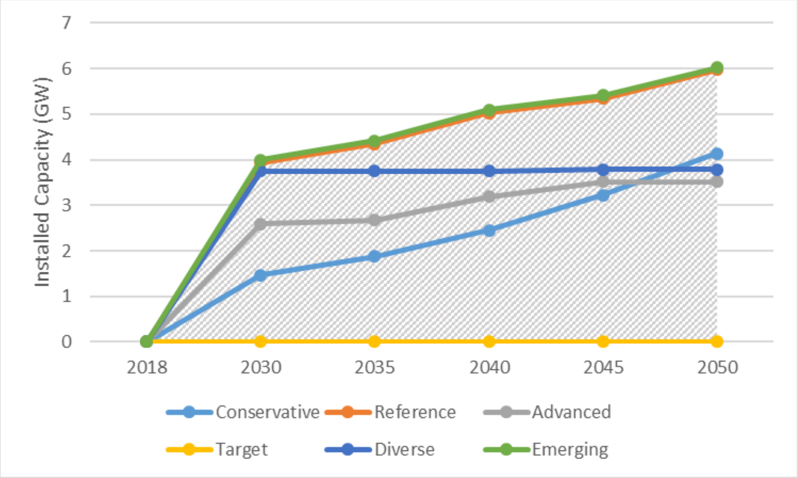

Figure 34: Modelled total installed gasCCS capacity by scenario

4.6.6 Energy Storage

Energy storage can provide the flexibility that is required to balance the variability of renewables while also contributing to planning reserve margin requirements. Most scenarios have significant deployment of 2-hour battery but more limited deployment of 4-hour batteries and PHS retrofits. Greenfield PHS is not present in any scenario. Battery storage costs decline to a greater extent than PHS because of the latter's technological maturity. This makes battery storage a more cost-effective option than PHS in the coming years as more renewables are integrated into the electricity system. In addition, Canada's electricity system already has a high penetration of large-reservoir hydroelectric capacity providing long-term storage. As such, low-cost storage capacity to balance short-term uncertainties and meet planning reserve margins is needed, leading to the preferential development of 2-hour battery storage. Figure 35 depicts the total installed capacity of 2-hour battery in the Reference scenario. Alberta, Ontario, and Quebec all add significant battery storage capacity for renewables integration, increasing their network flexibility, and meeting reliability constraints.

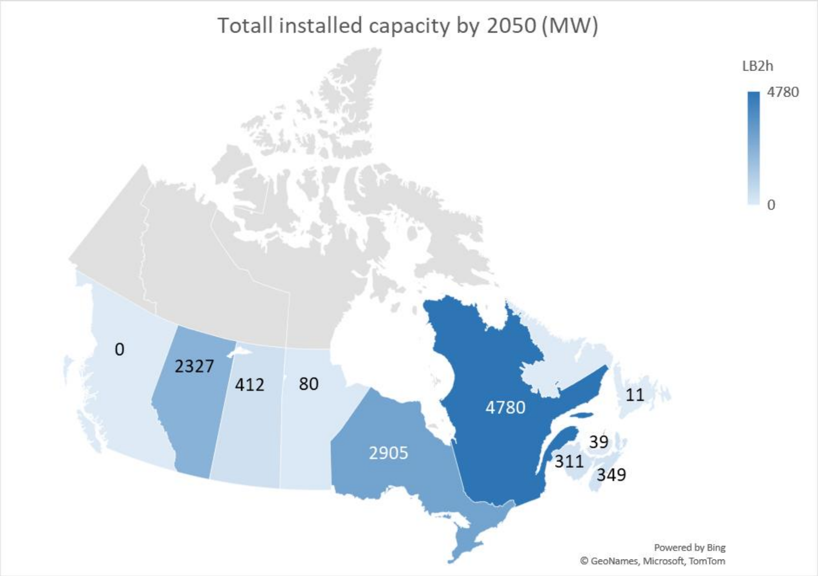

Figure 35: Modelled total installed 2-hour lithium battery capacity by 2050 by province in the Reference scenario

The range of installed energy storage capacities under different scenarios for each province reveals that short-term battery storage is part of the optimal mix in all provinces, except for British Columbia (see Table 15). In contrast, 4-hour battery storage is part of the optimal mix in Ontario, Nova Scotia, and Prince Edward Island. In addition, Manitoba, Ontario, New Brunswick, and Nova Scotia are likely to retrofit their hydro facilities to include PHS capacity providing 8-hour storage capacity.

Table 15: Modelled installed storage capacity maxima and minima by type and province across all scenarios by 2050 (Min-Max; in MW)

	Alberta	**Saskatchewan**	**Manitoba**	**Ontario**	**Quebec**	**New Brunswick**	**Newfoundland and Labrador**	**Nova Scotia**	**Prince Edward Island**
LB4h	0-0	0-0	0-0	0-1691	0-0	0-0	0-0	0-33	0-181
LB2h	954-3180	107-991	0-167	2326-2905	3102-5889	0-450	6-92	107-709	0-60
PHS retrofit	0-0	0-0	0-40	174*-203	0-0	0-143	0-0	0-107	0-0

- British Columbia is omitted as no energy storage is developed in this province under any modelled scenario

* This number represents the existing 174 MW PHS unit in Ontario (assumed to remain operational until 2050)

4.7 Discussion

The role of emerging technologies in Canada's electricity system transition hinges on many uncertain factors. Nevertheless, through energy systems modelling augmented by scenario analysis, valuable insights can be provided to facilitate informed decision-making and electricity system planning. This study explored the extent to which evolving and emerging technologies can contribute to the transition of Canada's electricity system toward a cleaner system.

At the national scale, the two key drivers are large-scale integration of non-dispatchable (wind and solar PV) renewables alongside the phase-out of emissions intensive fossil fuel generation that is also reported in other studies (Arjmand and McPherson, 2022; Arjmanda et al., 2022; Beiter et al., 2017; Dolter and Rivers, 2018). This transition will noticeably affect the dispatchability and flexibility of the Canadian electricity system. To reliably meet demand despite the inherent variability of non-dispatchable units, a minimum penetration of dispatchable electricity generation alternatives will need to be maintained. As the carbon price increases (to 170 $/tonne CO2e by 2030), low- and non-emitting electricity generation options such as natural gas with CCS and hydrogen-based power plants are deployed across Canada in all scenarios. The finding regarding the role of CCS technologies are in line with (Arjmand and McPherson, 2022; Doluweera et al., 2018a; Palmer-Wilson et al., 2019) where fossil fuel fired units equipped with CCS technologies are reported to be part of the generation mix. However, the potential role of hydrogen combustion technologies in Canada's electricity generation mix is not discussed in the literature; The Alberta Electric System Operator (2021) is the only source that reports hydrogenSC as a possible generation alternative that can contribute to Alberta's electricity system. Although other emerging technologies including offshore wind and SMRs are excluded from previous studies or briefly discussed, respectively, findings show that these technologies can assist the transition by diversifying the range of available options, although their modelled penetration remains modest (less than 2%) by 2050.

At the provincial scale, technology deployment depend on many factors, including but not limited to carbon management policies, existing generation fleets, and resource availability. Provincial trajectories depend significantly on the presence or absence of an emissions cap. In provinces with a hard cap on emissions, such as Quebec and Nova Scotia, there is little justification for building gasCCS as it will soon need to be phased out. In provinces without an emissions cap, two broad outcomes are possible. First, if the province requires high capacity factor units to meet baseload demand, as is the case in Alberta and New Brunswick where significant coal and diesel capacities are being phased out, new gasCCS capacity is deployed. Second, if the province has substantial existing inflexible baseload capacity, as is the case in Ontario where peaking capacity for VRE integration is required, hydrogenSC is selected. GasCCS is preferred when high capacity factors are required but hydrogenSC is the cost-effective peaking option because gasCCS have higher investment cost but lower operation cost compared to hydrogenSC (in part, because natural gas prices are lower than hydrogen). This dynamic suggests that gasCCS will likely substitute existing gasCC over time, while hydrogenSC will likely substitute gasSC. The highlighted dynamic is not reported in previous studies since they tend to model carbon cap and trade as a carbon tax with no constraint on emissions and omit hydrogen-based technologies from the set of alternative generation options (Arjmand and McPherson, 2022; Bistline et al., 2020b; Dolter and Rivers, 2018; Ibanez and Zinaman, 2016; Nelson et al., 2012). Eastern and western provinces, but particularly in British Columbia and Nova Scotia deploy offshore wind, but the extent is sensitive to technological evolution and changing costs of this technology and other emerging technologies. Notably, a revolutionary drop in SMR costs is required before it will become a cost-competitive option, which is consistent with previous findings (Arjmand and McPherson, 2022; Economic and finance working group, 2018).

Overall, this study improves the current literature by modelling major emerging technologies and providing associated insights into the future of Canada's electricity system. We found that while many studies ignore these technologies in their analysis, their contribution to Canada’s electricity system could be significant under some cost and carbon reduction scenarios. This high-level finding is aligned with recent research efforts modelling the Canadian energy system, such as (Canadian Institute for Climate Choices, 2021). Since an ESPM is used in the present study, a breakdown of provincial and technological insights was made possible. We demonstrated that certain technologies fit well within each province's future electricity supply mix considering available resources, while others are less suitable. Both federal and provincial policy makers can gain useful information from these results regarding effective actions to accelerate the Canadian energy system transition.

4.8 Conclusion and policy implications

Canada has set a target of reaching net-zero emissions in the electricity sector by 2035. To achieve this target, fossil fuel generation facilities have to be phased out, requiring significant investment in low- or non-emitting electricity generation. In addition to widely deployed electricity generation technologies, there are promising emerging technologies coming forth as governments and electric utilities invest in their development and identify opportunities to utilize them in order to facilitate energy transition. To explore the potential role of these emerging technologies in Canada’s electricity system transition, an ESPM was modified to include various emerging technologies, populated with reliable, up-to-date data, and deployed to explore a set of relevant scenarios.

Three key conclusions can be drawn from this study. First, evolving technologies including wind and solar have the potential to become the dominant electricity generation technologies in Canada electricity system by 2050. While solar penetration depends on the technology evolution scenario, wind is shown to be robust against technology evolution scenarios and significantly contributes to Canada’s electricity system transition. Second, dispatchable low- or non-emitting technologies such as gasCCS and hydrogen-based technologies can support the transition in provinces that need baseload generation units, flexible peak load units, or carbon-constrained provinces. Our finding highlights the importance of policy support and investing in research and development for dispatchable units such as gasCCS, hydrogenSC, and other technologies while exploring the opportunities to utilize them effectively. Third, under current technology evolution projections, the potential of other emerging technologies such as SMR and offshore wind is limited. A revolutionary development pathway resulting in significant cost reduction in SMR technology is required to make it a cost-effective option. Thus, the role of this technology in the future mix of the electricity system is uncertain and the government of Canada and utilities should not overestimate SMR potentials while planning for the future. Similarly, the role of offshore wind in the electricity system transition is insignificant on the national scale, although its contribution to the electricity mix of some eastern provinces including Nova Scotia can be major.

In summary, emerging technologies are expected to play an important role in Canada's electricity system transition at the national and provincial scales by diversifying the generation alternative and providing low- or non-emitting generation options with different characteristics. Provinces across Canada should identify and track the development of emerging electricity generation alternatives that fit well with their electricity network characteristics and carbon reduction goals and introduce policy support to accelerate their development. Excluding emerging technologies while planning for the future can underestimate available opportunities and discourage targeting more ambitious carbon reduction goals.

Acknowledgment

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Chapter 5: Conclusion and Future work

5.1 Conclusion

This research provides insight into the future of Canada's electricity system under different policy and technological development scenarios to assist decision-makers in the decarbonization transition. We highlight gaps in the existing suite of modelling tools and analysis and try to bridge the gap by introducing and deploying an electricity system planning model named COPPER.

In the first paper (chapter 2), the suite of available tools and analysis are reviewed and showed that existing studies are limited in terms of (1) modelling specific characteristics of Canada's power system, (2) assessing the impact of recently announced climate plan on Canada's electricity system transition. To address these gaps, this study introduces a model named COPPER and uses the model to provide insights into the future of the Canadian electricity system. In chapter two, the methodology, data, and limitations of COPPER are detailed and the model is deployed to analyze the effectiveness of Canada's latest climate plan. This paper aims to answer the question: Whether announced carbon reduction policies in the latest climate plan are aligned with carbon reduction goals?

The second paper (chapter 3) reviews the literature and highlights that no electricity system planning model incorporates all carbon pricing mechanisms in Canada. Also, the literature lacks a study that assesses the implications of three emerged carbon pricing systems. Thus, chapter three focuses on the different carbon pricing mechanisms in place across Canada and proposes a methodology to incorporate them in COPPER. This chapter provides results on both national and provincial scales and tries to answer the question: How effective provincially designed carbon pricing mechanisms are compared to the federal backstop?

Finally, the third paper (chapter 4) focuses on the role of emerging technologies in Canada's power system evolution. Since these technologies are relatively new, literature is limited when it comes to modelling and providing analytical insights regarding their potential in Canada. To bridge the gap, this chapter presents a methodology and required data to improve COPPER by adding emerging technologies to the model. The improved model is deployed to study the electricity system transition under different technology evolution and carbon reduction scenarios. Chapter four explores the question: To what extent do emerging technologies contribute to Canada's electricity system transition?

Based on the research questions listed above, several scenarios were designed, run, and analyzed, which resulted in findings that can be used by Canada's electricity system stakeholders. First, results show that in the short- to mid-term, carbon reduction policies announced in Canada's latest climate plan, HEHE, are able to remove 40 percent of emissions from the electricity system by 2030. However, in the long term, Canada needs to increase the carbon price after 2030 to phase out existing fossil fuel units. Also, non-emissions-intensive technologies are robust against high carbon price levels such that even at 470 $/tonne carbon tax level some of the natural gas units remain operational. Thus Canada needs to introduce new policies that target emissions from these technologies to reach the goal of net-zero emissions by 2050.

Second, findings show that provincially designed carbon pricing mechanisms result in lower emissions and total cost by 2050 compared to the federal pricing system. Therefore provinces are advised to design their own policies considering their existing assets, available energy resources, and climate plans of neighbouring provinces. Nevertheless, considering the announced carbon price level, none of the pricing mechanisms results in achieving Canada's enhanced emission goal of net-zero emissions in the electricity system by 2035. In order to achieve carbon reduction targets, governments at the federal and provincial levels need to tighten emission benchmarks of the in-place output-based pricing systems. A breakdown of costs shows a decrease in the average electricity generation cost across Canada by 2050 compared to 2025, although the pathway is different in provinces. From 2025 to 2050, hydro-dominated provinces have the lowest variation, while provinces with a high share of fossil fuel fired units experience temporary peaks in the average electricity generation cost. This variation in cost stems from the changes in Canada's electricity system mix.

Third, among modelled technologies, wind is the primary source of electricity generation to replace phased-out units and meet the increase in the electricity demand. This is consistent among all analyses performed for this thesis. In contrast, solar penetration depends on technology evolution and future cost projections. In most of the scenarios, solar becomes cost-effective after 2030 and the majority of its capacity is installed from 2035 to 2050. Also, emerging technologies have the potential to contribute to Canada's electricity system transition by diversifying the suite of available low or non-emitting generation options. The share of these technologies in each province varies with regard to specific province context and available resources. On the one hand, low or non-emitting thermal units such as hydrogen combustion and natural gas with carbon capture and storage are widely deployed in provinces to meet the baseload or peak demand. On the other hand, offshore wind and SMR technologies need to experience a considerable cost reduction to become part of the optimal mix. The government of provinces should identify and invest in emerging technologies that fit well with their electricity system characteristics and available resources.

Overall, the developed tool (COPPER) and discussed results inform Canada's electricity system stakeholders including modellers, researchers, utilities, technology developers as well as the governments. This thesis assists modellers and researchers in future model developments and research studies by introducing a methodology and model that captures Canada's electricity system characteristics. Further, the policy analysis presented reveals the advantage and disadvantage of in-place policies and recommend new policies and regulations to strengthen Canada's climate plan in order to achieve carbon reduction goals. The hypothetical scenarios that are run and presented can assist policy makers to understand the implications of different policies. The insights regarding the changes in Canada's electricity system mix, the role of technological development, and costs help utilities to plan for the expansion of the network and advise them about the risks and opportunities associated with the utilization of various technologies.

COPPER can be used to answer many other questions and explore a broader area beyond the scope of this study. However, considering frequent climate policy announcements that target different sources of emissions in future years, the model needs to be maintained and updated to ensure that it includes announced and excludes outdated policies and measures. The next chapter lists the main limitations and recommends future work.

5.2 Future work

Due to the optimization framework limitations, data gaps, and finite computational resources, this thesis has limitations that remain. The optimization framework used in this research explores the cost-optimal solution from the point of view of a central operator and ignores other stakeholders' objectives and non-financial costs of technologies. Also, gaps in the hydro resource availability, land use, existing units, and emerging technologies data affect the model outcomes. In terms of technical detail, since electricity system planning models are computationally intensive tools, electricity system networks are aggregated at the balancing area level and some operation details of the power system are simplified.

Finally, due to the framework limitations, some of the presented metrics are limited. For instance, reported GHG emissions just include combustion-related emissions and exclude emissions that happen during the extraction, manufacturing and disposal of the electricity system equipment. A detailed list of model and data limitations is included in each chapter. These limitations can be addressed through future model improvements, linkage with other models, and incorporation of new data releases. The following topics are recommended for further investigation:

1) Since COPPER is limited in terms of modelling the power system at the nodal level, this study does not provide results regarding the locational margin price under different carbon reduction levels. Through a linkage with a production cost model, the effects of the power system transition on wholesale and end-user electricity prices can be analyzed.
2) This study assumes deterministic demand profiles for the planning periods and uses projections from utilities to model the electricity demand in each planning period. Although this method is suitable considering the goal of this study, in future iterations, through stochastic analysis, the impact of electricity demand growth and its uncertainties on the electricity system decarbonization pathways can be assessed.
3) Canadian and U.S. electricity systems are interconnected. This thesis focuses on ten provinces across Canada and uses historical data to model cross-border transmission flow and exclude international transmission expansion. A future study can model the integrated Canada and U.S. to study cross-border transmission capacity and flow changes.
4) Although this study includes density constraints for renewables and limits the maximum development of renewables in each grid cell, it does not fully capture the land use limitations. Rivers and lakes are the only places excluded from locations that can be used for renewable development however there are other places not suitable for renewable development such as areas with high slopes (mountains), preserved areas, national and provincial parks, and cities. In future iterations of the model, the land use data for renewables can be enhanced to assess the impact of land constraints on the electricity system transition in each region.

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Appendix

The COPPER formulation is detailed below.

Notation for sets, parameters, and variables that are being used:

Symbol	**Definition**
Sets	
ab, *abb*	Set of balancing areas
pds	All periods from the reference year until the target year (e.g., [2020, 2025, 2030, …, 2050])
h	Set of running hours
d	Set of running days
m	Set of running months
S	Set of seasons (winter, summer)
p	Set of all power plant types
gc	Set of grid cells for renewables
th(p)	Set of thermal plants (a subset of p)
st	Set of energy storage technology types
re(p)	Set of renewable plant types (wind, solar)
hrp	Set of all hydroelectric renewal, repowering and greenfield development projects
Parameters	
ETC(pds,ab,p)	Existing capacity of thermal plant type th in balancing area *ab* and period *pds*
ERC(pds,gc,re)	Existing capacity of renewable type *re* in location *gc* in period *pds*
ESC (pds,ab,st)	Existing capacity of energy storage typr *st* in *ab,* in period *pds*
EHC(pds,ab)	Total existing hydroelectric capacity in ab and period pds
ETRC(pds,ab,abb)	Existing transmission capacity
CV(ab,s,re)	Capacity value of renewable type re in season s and ab
$\boldsymbol{D_{pds,h,ab}}$	Hourly electricity demand (MW)
$\boldsymbol{DUS_{pds,h,ab}}$	Hourly import/export to the US (MW)
PD(pds,s)	Peak demand of season s in period pds
$\boldsymbol{T_{pds,h,abb,ab}}$	Transmission flow from abb to ab at hour h and period pds (MW)

$\boldsymbol{TL_{ab,abb}}$	Transmission loss between ab and abb (between 0-1)
PRM	Planning reserve margin
CC(pds,ab,p)	capital cost of different generation and storage technologies
CC(pds,ab,st)	
RCC(pds,gc,re)	renewable capital cost
HCC(pds,hrp)	capital cost of potential hydroelectric projects
TCC (pds,ab,abb)	New transmission capital cost for line between *ab* and a*bb* in period *pds*
RCF(pds,h,gc,re)	The capacity factor of renewable type re
HRC(hrp)	Hydroelectric renewal, repowering, and greenfield development capacity for project *hrp*
DRH(pds,d,hrp),	The historical data of small reservoir and large reservoir potential hydroelectric projects(hrp), this parameter shows the available reservoir in each period for all potential projects
MRH(pds,m,hrp)	
MF(hrp)	Minimum flow of potential hydroelectric project (hrp)
FOM (pds,p), SFOM(pds,st), HFOM(pds,hrp), TFOM(pds,ab,abb)	fixed operation and maintenance cost of different assets in power system
VOM(pds,p)	Variable O & M cost of thermal unit type *p*
FC(p)	Fuel cost of plant type *p ($ perMWh)*
TEI(th)	Emission intensity of thermal plant type th (tonne CO_2e per MWh)
Rup(th), Rdown(th)	Ramp up and ramp down rates of thermal units
MaxCF(th), MinCF(th)	Maximum/minimum capacity factor of thermal plant *th*
MRC(gc,re)	The maximum capacity of renewable type *re* that can be built in location *gc due to the land use limitations*
SH(st)	maximum number of hours that energy storage can be discharged from fully charged state
Variables	
NTC(pds,ab,th)	New capacity of thermal unit type th in *ab* in period *pds*
NRC(pds,gc,re)	new renewable capacity

NTRC (pds,ab,abb)	New transmission corridor capacity (MW) between *ab* and a*bb* in period *pds*
NSC(pds,ab,st)	New energy storage capacity of type st in ab
HRB(pds,hrp)	Hydroelectric renewal binary in period *pds* for project *hrp* (binary variable)
R(pds,ab,p)	Total retirement capacity of existing assets
PG (pds,h,ab,p)	Hourly generation of different plants in each period and ab
Rout(pds,h,ab,re)	The generation (MW) of renewable type *re*
SE(pds,h,ab,st)	Stored energy in energy storage type st
ESin(pds,h,ab,st), *ESout(pds,h,ab,st)*	Energy storage charge (ESin) and discharge (ESout) rates in MW
DRout(pds,h,hrp)	Small reservoir hydroelectric renewal/greenfield development projects (*hrp)* generation at hour *h* in period *pds*
MRout(pds,h,hrp)	Large reservoir hydroelectric renewal/greenfield development projects (*hrp)* generation at hour *h* in period *pds*

COPPER optimization problem

COPPER uses a mixed-integer linear programming formulation to explore the cost-optimal mix for the future of the electricity system. The objective function and main constraints of the model are described below.

Objective function

The objective function minimizes total system costs including investment costs, maintenance costs, production costs, and carbon costs over the study period.

$$min\ total\_system\_costs = min(InvestmentCost + MaintenanceCost + ProductionCost + CarbonCost) \text{ (A. 1)}$$

$$InvestmentCost = \sum_{pds,ab,th} NTC(pds,ab,th) \times CC(pds,ab,th) + \sum_{pds,gc,re} NRC(pds,gc,re) \times RCC(pds,gc,re) + \sum_{pds,ab,st} NSC(pds,ab,st) \times CC(pds,ab,st) + \sum_{pds,hrp} HRB(pds,hrp) \times HCC(pds,hrp) + \sum_{pds,ab,abb} NTRC(pds,ab,abb) \times TCC(pds,ab,abb) \text{ (A. 2)}$$

$$MaintenanceCost = Fixed\_O\&M + Variable\_O\&M = \sum_{pds,ab,th}\big(ETC(pds,ab,th) + NTC(pds,ab,th)\big) \times FOM(pds,th) + \sum_{pds,gc,re}\big(ERC(pds,gc,re) + NRC(pds,gc,re)\big) \times FOM(pds,re) + \sum_{pds,ab,p}\big(ESC(pds,ab,st) + NSC(pds,ab,st)\big) \times \mathrm{S}FOM(pds,st) + \sum_{pds,hrp} HRB(pds,hrp) \times \mathrm{H}FOM(pds,hrp) + \sum_{pds,ab,abb}\big(ETRC(pds,ab,abb) + NTRC(pds,ab,abb)\big) \times \mathrm{T}FOM(pds,ab,abb) + \sum_{pds,h,ab,p} PG(pds,h,ab,p) \times VOM(pds,p) \quad \text{(A. 3)}$$

$$ProductionCost = \sum_{pds,h,ab,p} PG(pds,h,ab,p) \times FC(pds,p) \quad \text{(A. 4)}$$

$$CarbonCost = \sum_{pds,h,ab,th} PG(pds,h,ab,th) \times TEI(th) \times CarbonPrice(pds) \quad \text{(A. 5)}$$

Optimization constraints

Power balance constraint: This constraint ensures that enough production is available to supply the demand in each hour for all periods.

$$\sum_{p} PG_{pds,h,ab,p} + \sum_{st}(ESout_{pds,h,ab,st} - ESin_{pds,h,ab,st}) + \sum_{abb} T_{pds,h,abb,ab} \times (1 - TL_{ab,abb}) \geq D_{pds,h,ab} + DUS_{pds,h,ab} + \sum_{abb} T_{pds,h,ab,abb} \quad \forall pds,h,ab \quad \text{(A. 6)}$$

Planning reserve constraint: The planning reserve margin constraint ensures sufficient generation capacity is available to maintain adequate reliability in the power system. One of the main differences between variable renewable energy capacity and conventional generation capacity is that a portion of the installed capacity of the former can be considered as firm capacity while almost the whole installed capacity of the latter counts toward firm capacity. A planning model without this constraint might overestimate the availability of REs and their contribution to the required firm capacity. In a scenario with high penetration of renewable energy, planning reserve margin constraint might affect the results significantly, and thus is important to represent in long-term planning analysis. COPPER models planning reserve margin requirements by considering a capacity value for each renewable energy in each balancing area and season and enforcing the following equation. In this thesis according to the data from the utilities and other studies we enforce a 15 percent planning reserve margin (Doluweera et al., 2018a; Newfoundland and Labrador hydro, 2019).

$$\sum_{ab,th}\big(ETC_{pds,ab,th} + NTC_{pds,ab,th}\big) + \sum_{gc,re}(ERC_{pds,gc,re} + NRC_{pds,gc,re}) \times CV_{ab,re,s} + \sum_{ab} EHC_{pds,ab} + \sum_{hrp} HRC_{hrp} \times HRB_{pds,hrp} + \sum_{ab,st}(ESC_{pds,ab,st} + NSC_{pds,ab,st}) - \sum_{ab,p} R_{pds,ab,p} \geq PD_{pds,s} * (1 + PRM) \quad \forall pds,s \quad \text{(A. 7)}$$

Thermal unit constraints: The following constraint limits the maximum generation to the installed capacity.

$$PG_{pds,h,ab,th} \leq ETC_{pds,ab,th} + \sum_{pds=1}^{PDS}(NTC_{pds,ab,th} - R_{pds,ab,th}) \qquad \forall PDS\ \epsilon pds, h, ab, th \text{ (A. 8)}$$

The following equation limits the retirement to the available capacity in each period and BA for all thermal generation types.

$$R_{pds,ab,th} \leq ETC_{pds,ab,th} + \sum_{pds=1}^{PDS-1}(NTC_{pds,ab,th} - R_{pds,ab,th}) \quad \forall\ PDS\ \epsilon\ pds, ab, th \text{ (A. 9)}$$

Equations (A. 10) and (A. 11) enforce minimum and maximum capacity factors of thermal units, respectively.

$$\sum_{h=1}^{H} PG_{pds,h,ab,th} \ \leq\ (ETC_{pds,ab,th} + \sum_{pds=1}^{PDS}(NTC_{pds,ab,th} - R_{pds,ab,th})) \times MaxCF_{th} \times H \quad \forall PDS\ \epsilon pds, ab, th \text{ (A. 10)}$$

$$\sum_{h=1}^{H} PG_{pds,h,ab,th} \ \geq\ (ETC_{pds,ab,th} + \sum_{pds=1}^{PDS}(NTC_{pds,ab,th} - R_{pds,ab,th})) \times MinCF_{th} \times H \quad \forall PDS\ \epsilon pds, ab, th \text{ (A. 11)}$$

Equations (A. 12) and (A. 13) enforce maximum ramp up and ramp down constraints of thermal units in each hour, respectively.

$$PG_{pds,h+1,ab,th} \ \leq\ PG_{pds,h,ab,th} + \left(ETC_{pds,ab,th} + \ \sum_{pds=1}^{PDS}(NTC_{pds,ab,th} - R_{pds,ab,th})\right) \times Rup_{th} \quad \forall PDS \in pds, h, ab, th \text{ (A. 12)}$$

$$PG_{pds,h+1,ab,th} \ \geq\ PG_{pds,h,ab,th} - \left(ETC_{pds,ab,th} + \ \sum_{pds=1}^{PDS}(NTC_{pds,ab,th} - R_{pds,ab,th})\right) \times Rdown_{th} \quad \forall PDS \in pds, h, ab, th \text{ (A. 13)}$$

Hydroelectric development: In addition to the existing hydroelectric capacity in Canada, several potential greenfield developments are under consideration. Furthermore, repowering and renewal projects can add to existing hydroelectric assets. Considering hydroelectric development in ESPMs requires significant data collection and modelling efforts such that many ESPMs ignore the expansion of hydroelectric (Arjmand et al., 2019). However the contribution of hydroelectric greenfield development to Canada's GHG reduction targets could be significant, COPPER models possible hydroelectric renewal and repowering projects using integer variables to assess which projects are considered part of the optimal mix. For the hydroelectric projects that are part of the optimal mix (their integer value is one), the investment cost including required transmission line cost, if any as well as fixed and variable O & M costs are added to the objective function and the generation of new hydroelectric projects ($DRout$, $MRout$) contributes to the total supply in each hour. Also, their constraints are modeled using the following equations[15].

-The following equations limit the output energy ($DRout, MRout$) of new hydroelectric projects to the maximum available resources (DRH, MRH) for small and large reservoir hydroelectric.

$$\sum_{h\in d} DRout_{pds,h,hrp} \le DRH_{pds,d,hrp} \times HRB_{pds,hrp} \quad \forall pds, d, hrp \in small\_reservoir \text{ (A. 14)}$$

$$\sum_{h\in m} MRout_{pds,h,hrp} \le MRH_{pds,m,hrp} \times HRB_{pds,hrp} \quad \forall pds, m, hrp \in large\_reservoir \text{ (A. 15)}$$

- The following constraint ensures that the hourly generation ($DRout, MRout$) of new hydroelectric projects is less than equal to the installed capacity of the generators for both small and large reservoir units:

$$DRout_{pds,h,hrp} \le HRC_{hrp} \times HRB_{pds,hrp} \ \forall pds, h, hrp \in small\_reservoir \text{ (A. 16)}$$

$$MRout_{pds,h,hrp} \le HRC_{hrp} \times HRB_{pds,hrp} \ \forall pds, h, hrp \in large\_reservoir \text{ (A. 17)}$$

-This set of constraints imposes a minimum flow for new small and large reservoir hydroelectric projects:

$$DRout_{pds,h,hrp} \ge MF_{hrp} \times HRB_{pds,hrp} \ \forall pds, h, hrp \in small\_reservoir \text{ (A. 18)}$$

$$MRout_{pds,h,hrp} \ge MF_{hrp} \times HRB_{pds,hrp} \ \forall pds, h, hrp \in large\_reservoir \text{ (A. 19)}$$

-The following constrain models the fact that a hydroelectric project can be built just once during all periods.

$$\sum_{pds} HRB_{pds,hrp} \le 1 \ \forall \ hrp \text{ (A. 20)}$$

Renewable energy constraints: There are two main constraints for wind and solar power plants. The first constraint limits the output of renewable power plants to the total installed capacity and the

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[15] We use the same set of constraints for the existing hydro assets. The only difference is that for existing assets there is no binary variable.

second constraint caps the amount of wind and solar that can be installed in each grid cell according to the land availability (surface condition).

$$Rout_{pds,h,gc,rp} \leq\ RCF_{pds,h,gc,rp}\ \times\ \left(NRC_{gc,rp} +\ ERC_{gc,rp}\right)\ \forall h, gc, rp \text{ (A. 21)}$$

$$\sum_{pds=1}^{PDS} NRC_{pds,gc,rp}\ \leq\ MRC_{gc,rp} \quad \forall PDS \in pds, gc, rp \text{ (A. 22)}$$

Transmission system constraints: The following constraint limits the flow of power between balancing areas to the total corridors capacity:

$$T_{pds,h,ab,abb} \leq\ ETRC_{pds,ab,abb} +\ \sum_{pds=1}^{PDS} NTRC_{pds,ab,abb}\ \forall PDS \in pds, h, ab, abb \text{ (A. 23)}$$

Energy storage constraints: Energy storage types are modelled using a set of constraints that limit the generation to installed capacity in each hour, maximum energy to the storage capacity, and estimates the hourly available energy based on the charge, discharge and efficiency.

- Equation (A. 24) limits the maximum energy (SE) that can be stored in the storage:

$$SE_{pds,h,ab} \leq \left(ESC_{pds,ab} +\ \sum_{pds=1}^{PDS} NSC_{pds,ab,st}\right) \times\ SH_{st}\ \ \forall\ PDS \in pds, h, ab \text{ (A. 24)}$$

- The following constraint estimates the energy based on the charge ($Pout$), discharge (Pin), and efficiency (η):

$$SE_{pds,h+1,ab,st} = SE_{pds,h,ab,st} -\ ESout_{pds,h,ab,st} +\ ESin_{pds,h,ap,aba}\ \times\ \eta_{st}\ \forall pds, h, ab, st \text{ (A. 25)}$$

- The following constraints keep the charge ($ESin$) and discharge ($ESout$) rate of the energy storage under its installed capacity:

$$ESin_{pds,h,ab,st}\ \times\ \eta_{st}\ \leq\ ESC_{pds,ab,st}\ + \sum_{pds=1}^{PDS} NSC_{pds,ab,st}\ \ \forall PDS \in pds, h, ab, st \text{ (A. 26)}$$

$$ESout_{pds,h,ab,st}\ \ \leq\ ESC_{pds,ab,st}\ + \sum_{pds=1}^{PDS} NSC_{pds,ab,st}\ \ \forall PDS \in pds, h, ab, st \text{ (A. 27)}$$

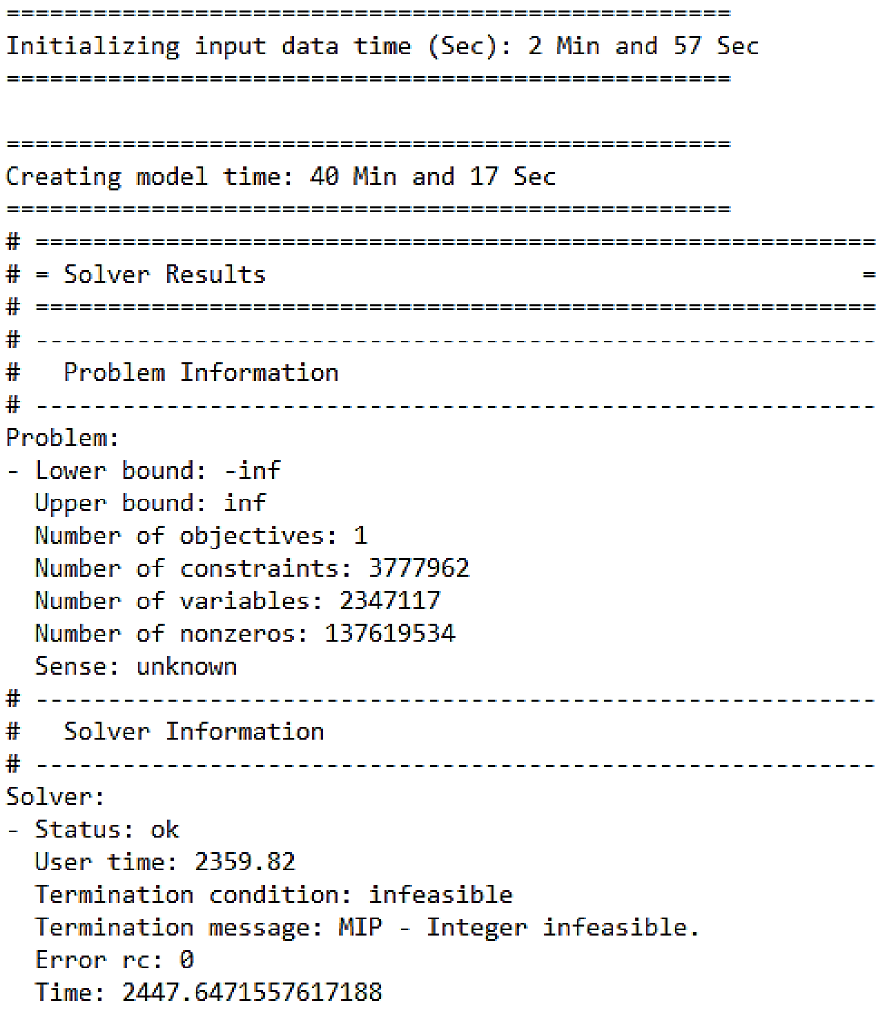
Solver report

Two samples of the solver reports are attached below. Note that CPLEX is used as the solver for linear and mixed integer linear programming problems.

Sample 1: Status ok and termination condition optimal means that the solver has converged to the optimal solution.

```
# ==========================================================
# = Solver Results                                         =
# ==========================================================
# ----------------------------------------------------------
#   Problem Information
# ----------------------------------------------------------
Problem:
- Name: tmp0ux9knak
  Lower bound: 10913284255.254587
  Upper bound: 10913284255.254587
  Number of objectives: 1
  Number of constraints: 3951327
  Number of variables: 2331013
  Number of nonzeros: 144778345
  Sense: minimize
# ----------------------------------------------------------
#   Solver Information
# ----------------------------------------------------------
Solver:
- Status: ok
  User time: 122008.17
  Termination condition: optimal
  Termination message: Dual simplex - Optimal\x3a Objective = 1.0913284255e+10
  Error rc: 0
  Time: 122116.85372424126
# ----------------------------------------------------------
#   Solution Information
# ----------------------------------------------------------
Solution:
- number of solutions: 0
  number of solutions displayed: 0
```

Sample 2: This sample is a result of an optimization problem with a null feasible region and the termination condition is infeasible.

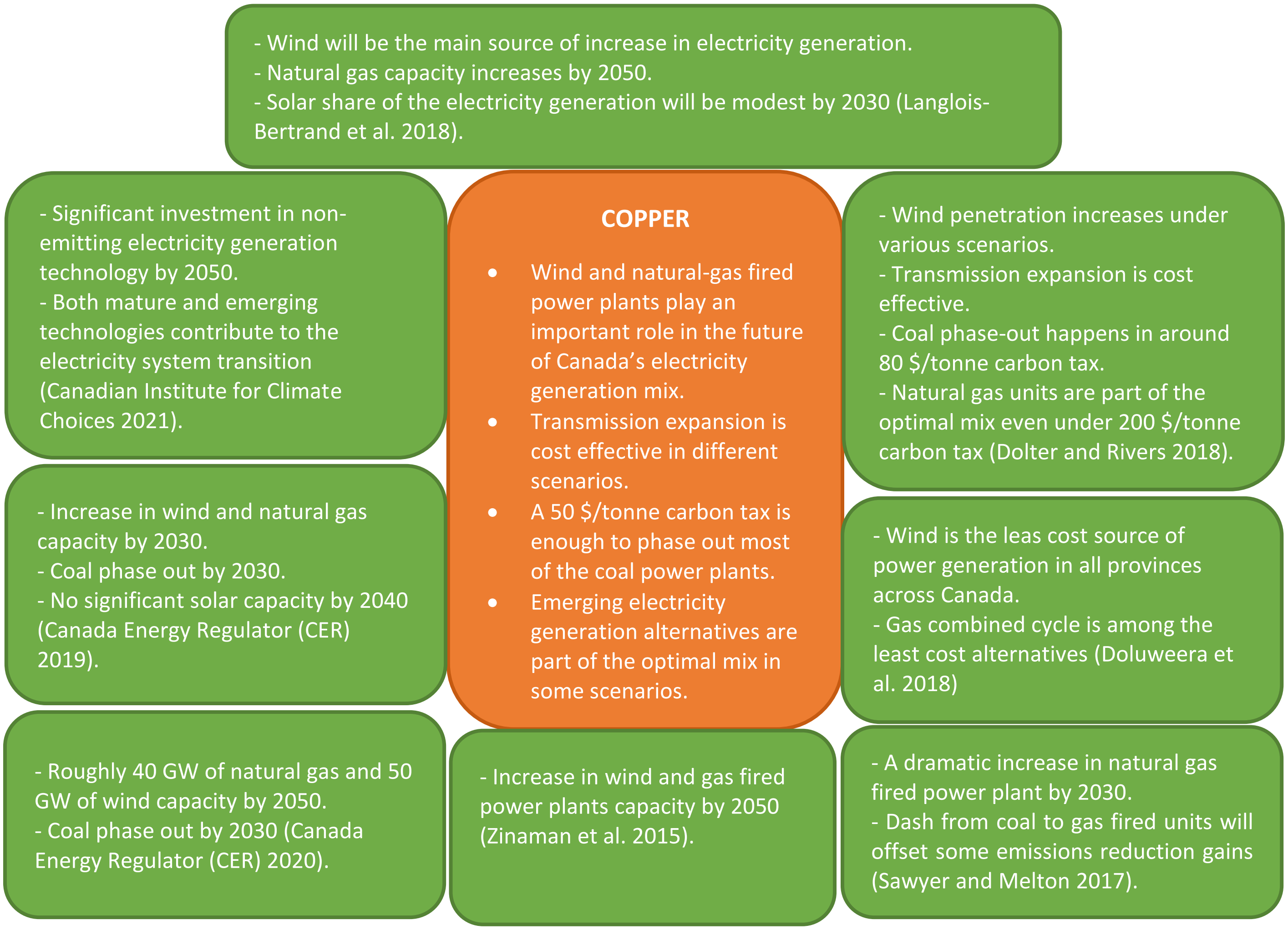


```
==================================================
Initializing input data time (Sec): 2 Min and 57 Sec
==================================================

==================================================
Creating model time: 40 Min and 17 Sec
==================================================
# ==========================================================
# = Solver Results                                         =
# ==========================================================
# ----------------------------------------------------------
#   Problem Information
# ----------------------------------------------------------
Problem:
- Lower bound: -inf
  Upper bound: inf
  Number of objectives: 1
  Number of constraints: 3777962
  Number of variables: 2347117
  Number of nonzeros: 137619534
  Sense: unknown
# ----------------------------------------------------------
#   Solver Information
# ----------------------------------------------------------
Solver:
- Status: ok
  User time: 2359.82
  Termination condition: infeasible
  Termination message: MIP - Integer infeasible.
  Error rc: 0
  Time: 2447.6471557617188
```

Comparison of COPPER results

The following figure compares high-level findings of COPPER with other studies to validate the model performance.



- Wind will be the main source of increase in electricity generation.
- Natural gas capacity increases by 2050.
- Solar share of the electricity generation will be modest by 2030 (Langlois-Bertrand et al. 2018).

COPPER

- Wind and natural-gas fired power plants play an important role in the future of Canada’s electricity generation mix.
- Transmission expansion is cost effective in different scenarios.
- A 50 $/tonne carbon tax is enough to phase out most of the coal power plants.
- Emerging electricity generation alternatives are part of the optimal mix in some scenarios.

- Significant investment in non-emitting electricity generation technology by 2050.
- Both mature and emerging technologies contribute to the electricity system transition (Canadian Institute for Climate Choices 2021).

- Increase in wind and natural gas capacity by 2030.
- Coal phase out by 2030.
- No significant solar capacity by 2040 (Canada Energy Regulator (CER) 2019).

- Roughly 40 GW of natural gas and 50 GW of wind capacity by 2050.
- Coal phase out by 2030 (Canada Energy Regulator (CER) 2020).

- Wind penetration increases under various scenarios.
- Transmission expansion is cost effective.
- Coal phase-out happens in around 80 $/tonne carbon tax.
- Natural gas units are part of the optimal mix even under 200 $/tonne carbon tax (Dolter and Rivers 2018).

- Wind is the leas cost source of power generation in all provinces across Canada.
- Gas combined cycle is among the least cost alternatives (Doluweera et al. 2018)

- A dramatic increase in natural gas fired power plant by 2030.
- Dash from coal to gas fired units will offset some emissions reduction gains (Sawyer and Melton 2017).

- Increase in wind and gas fired power plants capacity by 2050 (Zinaman et al. 2015).

Figure A.1: A comparison of COPPER’s high-level findings with other studies