Integration of Subnational Endogenous Hydropower into the Global Change Analysis Model for Canada

by

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Abstract

Hydropower currently provides a small majority of all electricity generation in Canada. This gives the nation an early advantage for shifting toward lower-emission energy sources. Energy systems are changing rapidly to adjust to new realities regarding technologies, resource availability and cost, and climate policies related to emissions reduction. Existing hydropower is likely to continue to provide reliable electricity over long lifespans, and its flexibility allows it to be deployed as storage to offset more intermittent renewables like solar and wind power. Few studies address the ability for new hydropower to be developed in Canada, and how that new development might be distributed across regional energy systems. This work aims to bring understanding to the magnitude of hydropower that can be developed, which conditions may lead to more or less development, and to what extent hydropower can play a role in decarbonizing energy systems in Canada.

The objective of this work is to improve how hydropower is represented in an integrated assessment model to better understand its role as a component of energy systems. Model development was conducted using GCAM, the Global Change Analysis Model, but existing versions of this model specified hydropower growth exogenously due to the challenge of supplying the model with good data on resource availability. Having previously developed a capability for endogenous modelling of national hydropower development (Arbuckle et al., 2021), this study refines that work to a finer spatial scale, with regions grouped by river basins in each province and territory. The newly developed model's electricity generation was calibrated with projections from the Canada Energy Regulator Energy Futures (2020). The model was compared to a suite of other energy system models for electricity system outcomes to assess differences and similarities.

In order to complete this modelling, this study developed a dataset of the regional-scale historical generation of hydropower in Canada, which is necessary for calibration, but also yields insights about local trends that are deeply connected to stories of imperialism,

politics, and self-determination. Additionally, a process was developed to produce estimates of hydropower resource cost and supply for subnational regions in a more comprehensive way than has been done before. This was based on a prior gridded dataset (Zhou et al., 2015) with coverage for the world, allowing extension to other uses. This work revealed a total of 1,859 TWh of hydropower resources are theoretically developable in Canada, approximately five times the generation in 2015 of 378 TWh. However, in practice, most of these resources would cost so much to develop, or are located in such remote locations, that other resources would be exploited first. Further, the resources are heterogeneously distributed throughout Canada.

After model development, scenario analysis was conducted for a range of climate policy ambitions as an application of the new model capabilities. Model results show that Canadian hydropower generation grows in all scenarios, with increasing growth correlating with higher climate policy ambition. Model results identified regions that are more likely to support new growth in hydropower, based on cost and historical factors. British Columbia has substantial remaining potential, while Manitoba and Newfoundland and Labrador may be nearing saturation of economically developable hydropower. In all scenarios, hydropower loses total market share of Canada’s electricity generation, as diversification into other assets like wind and solar power increases. For a net zero scenario, the model showed hydropower generation in Canada may grow from 382 TWh in 2015 to 721 TWh in 2050, with electricity prices increasing about 15% from present levels, after accounting for inflation. Model results also show that in scenarios where Canada seeks higher climate policy ambition than the United States, less new growth may be needed, as Canada can reduce its electricity exports to the United States to reduce pressures on domestic demand growth.

Preface

This thesis is an original work by Evan Arbuckle. No part of this thesis has been previously published.

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Parts of this thesis have been worked on while visiting in the lands first inhabited by the First Nations peoples of Treaties 6, 7, and 8, including the Dene, Cree, and Beaver, as well as the Anishinaabe, Piscataway, Ktunaxa, Snuneymuxw, Coast Salish, and many others. Further, the territory of my work extends throughout the territory of all indigenous peoples of what is now known as Canada. I thank the stewards of this land and acknowledge that settlers must do better to remove systemic inequities and allow indigenous peoples space to thrive in the way that they choose. This thesis discusses the historical development of hydropower in Canada, which has a history of indigenous displacement and other injustices. Results from this work should not be interpreted as advocacy to develop hydropower in any location without approval of the indigenous peoples and other local communities that call these places home.

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Abbreviations

Acronym	Definition
BC	British Columbia (Canadian province)
CAD	Canadian dollar
CSP	Concentrated solar power
ECCC	Environment and Climate Change Canada
EPRI	Electric Power Research Institute
GCAM	Global Change Analysis Model, previously known as the Global Change Assessment Model
GDP	Gross domestic product
GWP	Global warming potential, based on comparison to CO_2 over a 100-year time horizon unless otherwise stated, consistent with IPCC AR4 unless
IAM	Integrated assessment model
IPCC	Intergovernmental Panel on Climate Change
JGCRI	Joint Global Change Research Institute
LUC	Land use change
MAC	Marginal abatement cost
NDC	Nationally determined contribution, referring to Paris Agreement commitments for emissions reductions by country
NFLD	Newfoundland and Labrador (Canadian province)
PEI	Prince Edward Island (Canadian province)
PSH	Pumped storage hydropower
PV	Photovoltaic solar power
SSP	Share socioeconomic pathway
USD	United States dollar

Résumé

L’hydroélectricité fournit une majorité légère de toute la production d’électricité au Canada. Donc, le pays a un avantage précoce pour se tourner vers des sources d’énergie à faibles émissions. Les systèmes énergétiques évoluent rapidement pour s’adapter aux nouvelles réalités concernant les technologies, la disponibilité et le coût des ressources, ainsi que les politiques climatiques liées à la réduction des émissions. L’hydroélectricité existante continuera probablement à fournir électricité fiable, et sa flexibilité lui permettra d’être déployée comme stockage pour compenser les énergies renouvelables plus intermittentes comme l’énergie solaire et éolienne. Peu d’études portent sur la capacité de développer nouvelle hydroélectricité au Canada et sur la manière dont ce nouveau développement pourrait être réparti dans les systèmes énergétiques régionaux. Ce travail vise à faire comprendre l’ampleur de l’hydroélectricité qui peut être développée, quelles conditions affectent le développement et dans quelle mesure l’hydroélectricité peut jouer un rôle dans la décarbonisation des systèmes énergétiques au Canada.

L'objectif de ce travail est d'améliorer la façon dont l'hydroélectricité est représentée dans un modèle d'évaluation intégré afin de mieux comprendre son rôle en tant que composante des systèmes énergétiques. GCAM, le modèle d'analyse du changement global, est utilisé, mais les versions existantes de ce modèle spécifiaient l’hydroélectricité de manière exogène dans les périodes futures en raison des limitations des données. Ayant précédemment développé une capacité de modélisation endogène du développement hydroélectrique national (Arbuckle et al., 2021), cette étude affine ce travail à une échelle spatiale plus fine, avec des régions regroupées par bassins fluviaux dans chaque province et territoire. La production d’électricité du modèle nouvellement développé a été calibrée avec les projections de la Régie de l’énergie du Canada (CER, 2020). Le modèle a été comparé à une suite d’autres modèles de systèmes énergétiques pour les résultats du système électrique afin d’évaluer les différences et les similitudes.

Cette étude a développé un ensemble de données sur la production historique d'hydroélectricité à l'échelle régionale au Canada, qui est nécessaire pour l'étalonnage, mais donne également un aperçu des tendances locales qui sont profondément liées aux histoires d'impérialisme, de politique et d'autodétermination. Un processus a été développé pour produire des estimations du coût et de l'approvisionnement des ressources hydroélectriques pour les régions infranationales d'une manière plus complète qu'auparavant. Ceci était basé sur un ensemble de données maillé antérieur (Zhou et al., 2015) avec une couverture mondiale, permettant une extension à d'autres utilisations. Ces travaux ont révélé qu'un total de 1 859 TWh de ressources hydroélectriques sont théoriquement exploitables au Canada, soit environ cinq fois la production en 2015 de 378 TWh. Cependant, dans la pratique, la plupart de ces ressources coûteraient tellement cher à développer, ou seraient situées dans des endroits si éloignés, que d'autres ressources seraient exploitées en premier. De plus, les ressources sont réparties de manière hétérogène partout au Canada.

Après le développement du modèle, une analyse de scénarios a été réalisée pour une série d'ambitions en matière de politique climatique en tant qu'application des nouvelles capacités du modèle. Les résultats montrent que la production hydroélectrique canadienne augmente dans tous les scénarios, une croissance plus élevée étant corrélée à une ambition politique climatique plus élevée. Les résultats du modèle ont identifié des régions plus susceptibles de soutenir le développement de nouvelles centrales hydroélectriques, sur la base de facteurs de coût et historiques. La Colombie-Britannique dispose encore d'un potentiel substantiel, tandis que le Manitoba et Terre-Neuve-et-Labrador pourraient être proches de la saturation en matière d'hydroélectricité économiquement exploitable. Dans tous les scénarios, l'hydroélectricité perd sa part totale du marché de la production d'électricité au Canada, à mesure que la diversification vers d'autres actifs comme l'énergie éolienne et solaire augmente. Pour un scénario net zéro, le modèle montre que la production hydroélectrique au Canada pourrait passer de 382 TWh en 2015 à 721 TWh en 2050, les prix de l'électricité augmentant d'environ 15 % par rapport aux niveaux actuels, après prise en compte de l'inflation. Les résultats du modèle montrent également que dans les scénarios où le Canada cherche à atteindre des ambitions climatiques plus élevées que celles des États-Unis, moins de nouvelles capacités pourraient être nécessaires, car le Canada peut réduire ses exportations d'électricité vers les États-Unis afin de réduire les pressions sur la demande intérieure.

Chapter 1 Introduction

1.1 Canadian Hydropower

Over 500 hydropower facilities in Canada provide about 60% of the country's electricity. Canada currently leverages this abundance of developed hydropower to support its economy. In Canadian provinces where hydropower is the dominant source of electricity – British Columbia, Manitoba, Québec, and Newfoundland and Labrador – electricity prices among the lowest in the country have led to strong industrial growth among heavy electricity-using industries. These provinces also produce a surplus of electricity for export to the United States and other provinces, which generates substantial profits and helps to keep the rates Canadian consumers and businesses pay lower (Pineau, 2013). Much of Canada's hydropower capacity is supported with very large reservoirs that contain years of storage. These large facilities allow generating stations to operate flexibly, holding water back in times of lower demand, and releasing it when demand is higher. Hydropower with storage behind large dams can be used to help offset intermittent sources of electricity like solar and wind power (Castro, 2019), giving Canada more flexibility to develop other renewable power sources.

Canada is a vast and heterogeneously distributed country with population centres located far from each other and resources often located in remote regions. It is well-equipped with hydropower and other natural and renewable resources in abundance, relative to its population size, but its geography often makes production and transmission of energy for domestic use and export, by powerline, pipeline, road, rail, or otherwise, expensive. Canada's hydropower is not evenly distributed across the country, but is instead located in a "checkerboard" pattern, with many provinces generating large amounts of hydropower having neighbours that produce very little. Part of this uneven distribution is a result of the federal framework in which electricity systems have developed in Canada, which places jurisdiction for these networks within the control of individual provinces (Pineau, 2013). Most provinces developed electricity networks with internal self-sufficiency as a policy goal. Transmission lines connect the province's electricity grids with each other, but these linkages have capacity limits that prevent rapid changes in the way electricity can be traded interprovincially (Dolter and Rivers, 2018). The three remote northern territories have separate grids, and dozens of remote communities across Canada have no connections to the larger transmission network.

In the 20th century, the development of hydropower in Canada can be described as imperial: not much attention was paid to the effects of hydropower development on local people or the environment. In the 21st century, development of large-scale hydropower can be much more difficult given expectations to collaborate with First Nations and local communities and to mitigate environmental impacts much more robustly. Smaller-scale "run-of-river" dams with low head can be built more cheaply and with fewer effects on the environment and people, making these smaller developments increasingly appealing. More recently, new large hydropower projects have proven to be much more expensive than in the 20th century, with significant cost overruns (Arbuckle et al., 2021).

As Canada grows, it is not clear whether continued hydropower development is sustainable, or how and where new projects might be developed. Policy and business case questions about which electricity technologies, sources, and locations will be selected for new projects are ongoing debates. Many of the best sites for hydropower development have now been exploited or are located in regions of the country very far from population centres, where construction and transmission costs increase drastically. To complicate matters, hydropower is just one component of a complex network of energy systems with many sources.

1.2 Energy Systems and Integrated Assessment Modelling

Energy systems are constantly changing to reflect technological improvements, resource availability, fuel costs, public safety, environmental regulations, government policy, risk mitigation, and other elements that influence how energy is generated and supplied. Energy systems modelling can provide results that help users understand complex energy system interactions, subject to user-specified scenarios and constraints, and in the context of this work can permit exploration of the future of hydropower in Canada. Increasingly, such models are being used not only by decision makers looking for answers to specific questions, but also among the scientific community for facilitating learning and debate (Herbst et al., 2012) for a wide range of topics including climate change adaptations, nuclear phase-out plans, and energy demand anticipation, considering interactions within and among international jurisdictions. In recent years, much of the motivation for development of energy system modelling is to guide policy regarding energy system transitions and strategies for greenhouse gas emissions reduction (Pye et al., 2020).

With an even broader scope than energy system models, integrated assessment models (IAMs) explore the relationships among human-earth, land, energy, socioeconomic, and climate systems together, usually with a global geographical scope. A variety of IAMs are being developed and used as a basis for comprehensive system analysis. Because IAMs are varied in their strengths and weaknesses, a decision to use an IAM for analysis may depend on local geographic representation, ease-of-use, availability, technological detail, or modelling approach, among other reasons. For this work, the Global Change Analysis Model (GCAM), a prominent and open-source IAM that was originally developed by the Joint Global Change Research Institute (JGCRI) is improved and used for analysis. It simulates the evolution of each system based on market equilibrium calculations, proceeding from past calibration periods in 5-year intervals into future periods. Water systems in GCAM include the water demanded by energy systems and agriculture, along with estimates of future water supply (JGCRI, 2020). Most IAMs lack endogenous hydropower representation because of scarce hydrological data to inform resource estimates.

1.3 Context for Growth of Canadian Hydropower as Part of Energy Systems

Canada’s energy systems are transitioning to accommodate changing demands and expectations, while technologies in sectors like renewable electricity generation evolve. Canadians generally expect affordable, reliable, and environmentally responsible energy and electricity (Generation Energy, 2018), although there is debate about how to achieve those outcomes. Canada’s electricity generation sector has a lead compared to many other countries in transitioning away from fossil fuel generation, with about 67% of electricity already generated from renewables (mostly hydropower) and 82% from low-greenhouse gas (GHG) emitting sources (including nuclear generation) as of 2020 (NRCan, 2023). Regardless, Canada has some of the highest global energy usage and GHG emissions per capita, in part because of its harsh climate, sprawling transportation network, and heavy industrial sectors. Canada’s oil and gas production and raw resource extraction sectors produce a surplus of energy products and raw materials for export, which can concentrate GHG emissions locally, despite products being consumed elsewhere. Canada substantially meets its domestic energy demands from local supply and is a net exporter of both electricity and crude oil, with the United States as its largest energy trading partner. Canada trades more electricity through interties to the United States than interprovincially because it is generally more profitable to sell this power to the United States (Dolter and Rivers, 2018). Most of the power sold to the United States is derived from hydropower surpluses.

Canada has committed to the Paris Agreement, for which it must progressively reduce greenhouse gas emissions consistent with the goal of constraining global temperature rise to less than 2 degrees Celsius above pre-industrial levels (UNFCCC, 2015). Canadian strategies for reducing emissions largely consist of demand reduction, energy efficiency improvements, reducing industrial emissions intensity, and production of more electricity from renewables to facilitate fuel switching of other sectors, like transportation and industry, which are heavy fossil fuel users, to electricity (Navius, 2021; Generation Energy, 2018). Electrification occurs when energy inputs to systems are converted from a higher-emitting source to electricity, and can be achieved, for example, by replacing gasoline-powered vehicles with electric vehicles, or converting fossil fuel industrial processes to use electricity. In the last decade, there has been considerable growth in renewable electricity generation, largely helping to accommodate new growth in demand and facilitate reductions in coal power generation, which is being phased out across the country by 2030 (or subject to carbon capture or equivalency agreements). Both energy and emissions intensity per capita have fallen since 2000, but are counteracted by population and demand growth to keep total GHG emissions largely stagnant between about 700 and 750 Mt CO_2 equivalent annually until 2020 (ECCC, 2021a).

Energy system models and IAMs can improve understanding of the costs, impacts, and benefits of policies that reduce emissions, such as carbon pricing, technology subsidies, or transmission interties. A crucial component to understanding the viability of pathways that reduce greenhouse gas emissions is the role of hydropower in energy systems that may require substantially more electricity.

1.4 Knowledge Gaps

In recent years, substantial effort has been devoted to modelling Canadian energy systems, in many cases to better understand the implications of energy transitions that seek decarbonization. However, energy system modelling has also been motivated by a need for trend analysis and anticipation of a broad range of future outcomes by governments, regulators, electricity network planners, and others. In a recent energy system modelling report, Langlois-Bertrand et al. (2021) stated that “considerable potential [hydropower] resources remain in Canada, [but] information is lacking as to the specific characteristics and prices of these various projects” – in other words, data limitations constrain the ability for modellers to incorporate these details. Therefore, detailed datasets of hydropower resource potential and cost estimates for Canada are necessary to allow energy system modelling efforts to incorporate hydropower development as an endogenous component with sufficient detail. Despite reduced growth of hydropower in Canada over the last

20 years (see Section 4.1), hydropower resources remain feasible options for capacity expansion in Canada, and therefore should not be overlooked in modelling work. Increasing uptake of non-hydro renewable electricity generation may limit the need for new hydropower development in some areas, but may increase the need for hydropower in other areas to mitigate against the intermittent availability of wind and solar resources for electricity generation.

The availability of hydropower resources for further development is a complex and poorly understood topic, not only in Canada, but globally. New methods must be developed to supply good data for energy system modelling of hydropower resources. Hydropower resource potential and cost estimates are difficult to determine because they rely on a detailed understanding of location-specific hydrologic, topographic, geologic, and climatic conditions. This makes accurate estimation of hydropower resources more difficult than for other technologies, such as wind and solar, which are not influenced as strongly by so many different types of location-specific data, and which are composed largely of individual prefabricated units that can be installed relatively quickly. Some estimates for developable hydropower generation and capacity have been proposed at highly aggregated scales (often continental or national), with only a few proposing cost estimates. Proponents of hydropower development projects must conduct their own detailed site assessments in a local area of interest to determine feasibility and compare site alternatives, but this is a resource-intensive process involving land surveying, geologic exploration, cost estimation, and collection of local hydrologic, weather, and climate data that is not feasible for extension to global scales. Therefore, assessment of resources and costs must be completed using global datasets and geographic information systems, largely using data collected by satellites to ensure consistency. A handful of such estimates have been conducted, including Gernaat et al. (2017) and Zhou et al. (2015), but, for application to energy system or integrated assessment modelling, they must be disaggregated to appropriate scales.

The utility of modelling efforts increases when model representation is applied to local levels. Some nations, including Canada, have significant internal heterogeneity of attitudes, approaches, and actions toward decarbonization or energy system transitions, and therefore, subnational considerations are important for assessment of broader outcomes (Peng et al., 2021). Models with finer-scale geographic detail and results command more legitimacy by more comprehensively incorporating internal dynamics. While some Canadian energy system modelling efforts have attempted to represent hydropower development on a provincial basis (CER, 2020; Langlois-Bertrand et al., 2021), they have done so with limited resource supply or cost data. In Arbuckle et al. (2021), we provided a modelling study applying hydropower cost-supply estimates at the national level for Canada, but highlighted weaknesses regarding the viability of resource development in remote and sparsely populated regions. Finer scale modelling that incorporates local availability and competition would better represent the prospects of development by region. No modelling effort has previously assessed hydropower development in Canada with detailed subnational supply data, and none has been conducted with subnational detail relevant for river basins. Therefore, a dataset which provides locally detailed estimates for hydropower resource potential with cost estimates is needed to better represent the evolution of hydropower in modelling work.

1.5 Research Objectives

In partnership with JGCRI and Environment and Climate Change Canada, we are developing "GCAM-Canada," which improves model resolution, calibration, and technology and resource characterization for Canada. For this larger project, we develop and apply subnational resource supply and cost estimates to GCAM-Canada to gain insight into hydropower planning as integrated holistically with other systems. In the present research, the goal is to develop a robust and endogenous model framework for hydropower within GCAM-Canada and to supply data for the improvement of other energy system modelling. The specific objectives are the following:

- Develop the first comprehensive and subnationally detailed dataset of historical hydropower development in Canada
- Establish regionally and economically detailed resource estimates for future hydropower development in Canada for usage in integrated assessment and other energy system modelling work
- Develop GCAM-Canada to account for subnational hydropower resource economics; develop the spatially detailed historical generation profiles that are required for calibration and consideration of non-market preferences
- Conduct model scenario analyses to explore subnational hydropower resource development in the context of electricity generation development, energy systems, and climate outcomes to the year 2050

After developing the model capabilities described in the above objectives, scenario analysis of model output is guided by the following research questions:

- How and where might Canada's hydropower sector develop to 2050? How does this development relate to broader electricity generation networks, energy systems, and climate outcomes?
- What role can hydropower be expected to play in Canadian electricity generation development and emissions reduction, considering current and proposed federal energy and climate policies?

Work is ongoing by the research groups involved (Dr. Davies' University of Alberta team, JGCRI, and ECCC) to continue developing GCAM-Canada capabilities. A fully regionalized, provincial model of GCAM-Canada, which will more completely characterize market supply and demand at the provincial level for all model sectors, is in development at the time of this writing. Concurrently, this research team is also developing improved modelling frameworks and details for technologies and sectors of particular interest to Canada, including unconventional oil production (including oil sands) and water markets.

1.6 Thesis Organization

Following this introduction (Chapter 1), the chapters of this thesis are organized as follows:

- Chapter 2 provides important context as summarized in a literature review covering the topics of Canadian electricity systems, hydropower technology and resources, and integrated assessment modelling;
- Chapter 3 describes the experimental apparatus used in this research, the Global Change Analysis Model (GCAM);
- Chapter 4 explains the methodology used to aggregate historical hydropower development, estimate resources and costs, and to develop the model enhancements that allow for subnational hydropower detail in GCAM-Canada;
- Chapter 5 presents results and analysis related to historical hydropower and characterization of hydropower resources;
- Chapter 6 presents results and analysis from the enhanced GCAM-Canada in the context of answering the research questions, to highlight the benefits of obtaining subnational level detail for the hydropower sector and leveraging that for further climate policy consideration;

- Chapter 7 is a brief discussion with some comparisons and implications; and
- Chapter 8 draws conclusions, identifies limitations of the modelling work, and identifies opportunities for further research.

Chapter 2 Literature Review and Background

This chapter provides important background regarding Canadian electricity systems, hydropower technology and resource potential, modelling methods, and GCAM, the model that forms the basis for methodological improvements and analysis in the rest of this thesis. This chapter starts in Section 2.1 with an overview of Canadian electricity systems as a component of wider energy systems, along with a discussion of climate policy and electrification, which are important motivations for systems modelling. Context for hydropower technology, resources, and impacts are then presented in Section 2.2. An introduction to energy-economy and integrated assessment modelling is provided in Section 2.3, before ending with a methodological review of the Global Change Analysis Model (GCAM) in Section 2.4 to provide adequate context for the explanation of the methods in Chapter 3.

2.1 Canadian Electricity Systems

In 2018, electricity accounted for 22.4% of the energy consumed in Canada, a smaller portion than both refined petroleum products and natural gas (StatCan, 2018). In 2016, about 503 TWh of electricity was used to meet domestic demand (NRCan, 2020). Electricity was consumed in the following shares by sector: 40.8% industrial, 33.3% residential, 23.7% commercial, 1.9% agricultural, and 0.2% transportation (NRCan, 2020). In that year, net electricity export to the United States accounted for about another 60 TWh. Strategies to decarbonize the Canadian energy sector primarily rely on electrification: the conversion of fossil fuel consumption pathways to electricity to benefit from renewable electricity generation (ECCC, 2021b). For a scenario with aggressive decarbonization, the Canada Energy Regulator (CER, 2020) expects that substantial new electricity generation developments would be required to supplement the present generation fleet to about 733 TWh by 2050, allowing for growth and electrification in the as-yet largely fossil fuel-dependent transportation sector.

2.1.1 Canadian Electricity Networks and Trade

Canada's electricity generation systems are the jurisdiction of each province and territory, with little federal oversight, which results in a patchwork of mostly isolated systems with disparate objectives. Some provinces control a majority of internal generation with corporations that act on behalf of or directed by those provincial governments. These provinces include British Columbia (BC), Manitoba, Québec, and Newfoundland and Labrador, and are characterized by hydropower generation forming a substantial portion of total output (Pineau, 2013), much of which was established several decades ago. Other provinces have various systems of privatized, but regulated, or public electricity systems that generate from a broader mix of sources, including fossil fuels, wind, solar, and nuclear power. Characteristics peculiar to the electricity networks of Canada's three northern territories and other sparsely populated areas are discussed separately in Section 2.1.3.

While there is modest interprovincial electricity trade in Canada, it is limited by transmission infrastructure capacity (NRCan, 2020). Provinces that produce a surplus of electricity (especially Manitoba, Ontario, and Québec) usually export electricity to the United States in a higher quantity than to other provinces (CER, 2023; Gorski et al., 2021). The smallest province by population, Prince Edward Island (PEI), is a unique case, as it relies on imports from New Brunswick because its local generation consists almost exclusively of variable wind power and would therefore be unreliable without external connections or extensive local electricity storage. Another unique case regarding interprovincial electricity trade concerns the large Churchill Falls generating station in Labrador, which generates about 35 TWh per year, a majority of Newfoundland and Labrador's total electricity generation. Due to financial constraints during that plant's construction in the late 1960s, Hydro-Québec became involved in the project's financing and has since retained rights to much of the electricity output because of a controversial contract signed at the time that will remain in force until 2041 (Feehan, 2011). Thus, a significant portion of the Churchill Falls output is exported to Québec.

Canada conducts direct international electricity trade exclusively with its only land neighbour, the USA. This relationship has recently been characterized by a net export of electricity from Canada to the USA, although Canada also imports electricity. In 2019, Canadian exports were 60 TWh and imports were 13 TWh (NRCan, 2020). There is interest in increasing transmission capacity for trade between these countries for economic and climate policy objectives, which will be discussed in Section 2.1.2. Canada's only other foreign neighbour that could conceivably form an electricity trading partner is the very small French overseas collectivity of the archipelago of Saint-Pierre-et-Miquelon, off the southern coast of Newfoundland, which generates its electricity largely from Canadian-sourced diesel fuel (SPM, 2018).

2.1.2 Climate Policy and Electrification

In recent years, many Canadians have shown a desire for greenhouse gas emissions reduction to limit anthropogenic contributions to climate change. Canadian climate action policy has become an important part of Canadians' voting choices. The 2015 federal election unseated a Conservative majority government that was skeptical of climate multilateralism and resulted in a Liberal majority government which moved to join the Paris Agreement and institute a plan for federal carbon pricing by 2019 (Lemphers, 2020). Carbon pricing is a common policy tool implemented to internalize the costs of greenhouse gas emissions to the activities which produce them; they are intended to incentivize switches to lower-emitting alternatives and drive innovation (Boyce, 2018). Carbon pricing is generally regarded as the least-cost policy instrument for emissions abatement (Gugler et al., 2021), owing to its greater flexibility than more specific policy applications. In addition to carbon pricing, this subsection introduces two other important climate policy considerations for Canada: interprovincial trading policy and oil and gas methane emissions reduction. Other climate policy tools like renewable energy subsidies, electric vehicle subsidies, and emissions cap-and-trade systems also have a history of implementation in Canada, but will not be discussed in detail here.

In Canada, as of 2023, a federal carbon emissions pricing system ensures a minimum stringency requirement for pricing most direct carbon emissions, but allows provinces to institute alternative mechanisms provided there is an equivalent GHG emissions reduction objective (Government of Canada, 2021). In BC, carbon prices initially exceeded federal requirements, but started matching the federal minimum in 2022 (Government of BC, 2023a). Some provinces have implemented alternative emissions reduction systems only for certain sectors, like Alberta's policy for large industrial emitters (Government of Alberta, 2023), while otherwise being subject to federal stringency requirements. The federal government and Government of Alberta agreed in 2015 to accelerate a coal power generation phase-out to 2030 in that province, with similar coal power phase-outs elsewhere, while allowing for some exemptions for equivalent emissions reductions (Lemphers, 2020). In Ontario, a previously implemented cap-and-trade program, recent phase-out of coal power generation, and generous wind power subsidies have had some success encouraging shifts from fossil fuel electricity generation, but led to a rapid increase in consumer electricity prices, which played a role in shifting public support to defeat that province's Liberal government in the 2018 provincial election (Raymond, 2020). Canada's division of powers between federal and provincial governments has led to conflict between these levels of government. This has been exemplified recently with a group of provincial governments (Alberta, Saskatchewan, and Ontario) supporting a legal offensive to repeal the federal government's carbon pricing system. The Supreme Court ruled the federal minimum carbon pricing system constitutional in 2021 (SCC, 2021), indicating that the federal government can continue to impose minimum carbon price stringency requirements upon provinces in order to support federal climate policy initiatives, even if some provincial governments do not support them.

This paragraph introduces some of the emissions reduction and carbon pricing plans indicated by Canadian political parties during the 2021 federal election campaign to provide some context for climate policy scenario design in Chapter 3. All references to carbon prices in this thesis are in Canadian dollars per metric tonne of carbon dioxide equivalent, unless otherwise noted. In the 2021 federal election campaign, the Liberal Party campaigned on maintaining a plan to achieve 40-45% emissions reduction between 2005 and 2030 and net zero emissions by 2050 (ECCC, 2021c). The carbon price is currently $65 in 2023, but will increase by $15 every year until reaching $170 in 2030 as a result of a commitment made in 2021 that expanded original ambitions (ECCC, 2021b). The opposition Conservative Party campaigned on a reversion to Canada's original 2016 Paris Agreement commitments (CPC, 2021) to achieve 30% emissions reduction by 2030. They suggested an alternative method for carbon pricing which would return individual consumers' carbon expenses (capped at $50/tonne) to a "personal low carbon savings account," with separate strategies for sectors like industry and buildings (CPC, 2021). Their plan considered application of higher carbon prices for industrial emitters compared to other consumers. In the 2021 election, the New Democratic Party and Green Party campaigned on 50% and 60% emissions reduction from 2005 by 2030 (Jaccard, 2021). The Liberal Party retained a minority government in the 2021 election, meaning that legislative changes will require support from at least one other party to pass, and therefore the status quo is likely to be maintained for carbon pricing in the near term.

There are some criticisms and complications about the way that carbon prices are implemented in Canada. A report prepared for ECCC by Sawyer et al. (2021) noted that some provinces apply point-of-sale rebates to fuel purchases using carbon price revenues. This practice diminishes the price signals that carbon prices are intended to send to consumers, and therefore mitigate the incentives for behavioural changes that carbon prices should encourage. There are also some exemptions for large emitters and special cases so that the price is not distributed among emissions types evenly (Sawyer et al., 2021). While the implemented carbon prices are generally designed to be rebated such that lower-emitting families, persons, and corporations benefit, some revenues are used to fund emissions reduction and climate adaptation programs (Sawyer et al., 2021). Further, if carbon prices reduce fuel sales, revenue from excise taxes on fuels will be reduced and may need to be collected elsewhere to maintain revenues for infrastructure maintenance, as these funds are often ear-marked for transportation budgets (McKitrick and Aliakbari, 2021).

Significant GHG emission reductions could be achieved by establishing more transmission capacity and encouraging interprovincial and electricity trade (Dolter et al., 2021; Gorski et al., 2021; Pineau, 2013), rather than continuing to use the provincially compartmentalized frameworks that have dominated electricity development in Canada. The Pan-Canadian Framework on Clean Growth and Climate Change (PCF, 2016) acknowledges the benefits of interprovincial electricity trading as a part of emission reductions strategies. Canada's most recent federal climate action plan (ECCC, 2021b) includes some funding to assist with development of interties to establish more interprovincial electricity trade to help bring lower-emitting electricity to areas of the country that are more dependent on fossil fuel generation. Dolter and Rivers (2018) used a linear programming optimization model of Canada's electricity system and found that least-cost strategies of decarbonizing Canada's electricity network rely on increasing interprovincial electricity trade. Increasing the capacity of transmission links between provinces would allow for usage of Canada's existing and extensive hydropower fleet to better balance new additions of intermittent renewables like wind and solar. This is because large reservoir hydropower can operate like energy storage when other sources are generating electricity, holding water back, and can rapidly be deployed when intermittent sources are not available to maintain generation.

At present, most provinces lack the political will to increase interprovincial electricity trade, partially because in some provinces, local electricity self-sufficiency is a point of pride or identity (Pineau, 2013), and partially because some provinces are mandated by existing legislation or local policies to achieve internal self-sufficiency (Antweiler, 2016; Sopinka et al., 2013). Further, increased international electricity trade between Canada and the United States would likely assist higher net decarbonization at lower total cost (Aarons and Vine, 2015; Beiter et al., 2017). Dimanchev et al. (2021) expect that decarbonizing the grids of

Québec, New England, and New York can be achieved at lower net cost by increasing transmission interties to more optimally use hydropower reservoirs to offset variable renewable intermittencies. Some US states are increasingly considering these options for decarbonization (Aarons and Vine, 2015). However, international barriers for transmission and trade are similar to that between provinces, partially because of asymmetric benefits that reduce interest in establishing stronger integrations (Rodríguez-Sarasty et al., 2021). For example, hydropower-dominant Québec can benefit from some increased exports to the northeastern United States, but has disincentive to operate as storage for other jurisdictions to an extent that would affect its ability to continue to provide reliable electricity to its own customers at lower cost than is available in surrounding jurisdictions.

Acknowledging that methane emissions in the oil and gas sector can be reduced substantially with relatively low cost compared to other emissions reduction pathways, Canada has implemented regulations to reduce methane emissions in that sector by 40–45% below 2012 levels by 2025 (MacKay et al., 2021). The majority of these methane emissions are associated with upstream (wellsite) operations and most importantly from intentional methane venting—the avoidance of which allows greater production of natural gas—and fugitive emissions (MacKay et al., 2021) that can be reduced with already-developed technological improvements to existing infrastructure (Kemp and Ravikumar, 2021).

2.1.3 Electricity Systems in Remote Regions

Canada's three northern territories each possess unique and isolated electricity systems. Electricity generation is produced wholly or mostly by each territory's respective publicly owned generating companies (Senate of Canada, 2015). Distribution is mostly publicly owned, but private distributors are also present in some communities. In the Yukon and the Northwest Territories (NWT), hydropower supplies some larger communities, but more remote areas (and all of Nunavut) are served primarily by diesel generation, and by natural gas in just two communities in the NWT. Combined, these three territories have a population of only about 117,000 spread roughly evenly among each, over a land area of almost 4 million square kilometres of mostly remote tundra (Senate of Canada, 2015), a land area larger than India. While the Yukon and the NWT have electrical grids connecting communities in denser areas, Nunavut has no internal connections between communities. Further, the transmission grids of each of these territories are isolated from the rest of

Canada, and from each other (Senate of Canada, 2015). Some small-scale wind and solar power projects have recently begun to contribute some generation to the territories.

The isolated electricity systems of the northern territories are analogous to some small, remote communities located in the provinces that are located outside of areas connected to broader electrical grids. Such areas include some First Nations communities located along coastlines in British Columbia, Québec, and Labrador, as well as other isolated communities, such as Québec's Les Îles-de-la-Madeleine, some Newfoundland outports, and others (AANDC, 2011). Energy costs to ship diesel to these communities (and the territories) are much higher than in other areas of Canada; these costs are heavily subsidized, however consumers still pay very high costs relative to communities within grids (AANDC, 2011, Quitoras et al., 2020). Remote communities are exposed to energy security concerns because of their dependence on diesel, so that a missed shipment or plant outage can very easily lead to power outages.

Efforts are increasing to connect some of these remote communities to wider grids or alternative sources, such as a federal fund with $520 million to support clean energy proects in remote communities (NRCan, 2023b) and a small hydropower plant being built in the Inuit community of Inukjuak, northern Québec (Innavik Hydro, 2021). There is financial incentive to improve and diversify the generation systems in remote communities: Quitoras et al. (2020) estimated that conversion of a village in the NWT from its present diesel generation to a hybrid wind-solar-battery-diesel system could roughly halve the local cost of electricity generation.

2.2 Hydropower

The ability of falling water to provide power has been known for over 2,000 years, dating back to when water wheels were first used to grind grain (IRENA, 2015). Water can be used for electricity generation by using the flow of water to spin a turbine, which provides the rotation needed to induce electrical current from an electromagnetic generator (USGS, 2018), which can then be delivered by a transmission system for consumption. With the rise of uses and demand for electricity in the late 19th century, the first power line in North America was constructed to connect the city of Portland, Oregon to a new hydropower generating station (Nichols, 2003). Figure 2.1 provides a schematic of the important parts of the process of hydropower generation.

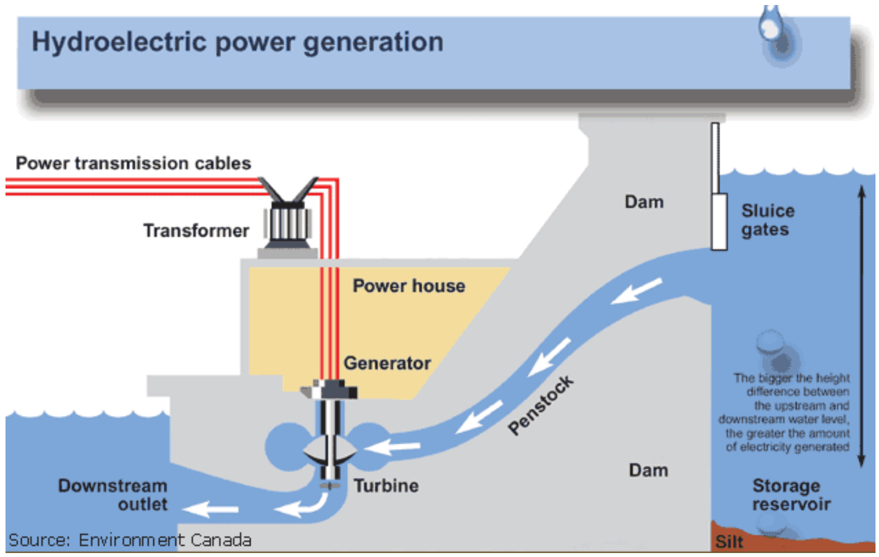

Figure 2.1. Schematic of hydropower generation (from USGS, 2018; originally sourced from Environment Canada).

2.2.1 Hydropower Technology and Turbines

The power generated by a turbine is given by Equation (2.1) (from Potter et al., 2011):

$$\dot{W}_T = \gamma Q H_T \eta_T \qquad \text{Eq. (2.1)}$$

Where $\dot{W}_T$ is the power (in Watts, W), γ is the specific weight of the fluid (about 9800 N/m^3 for water), Q is the flow rate of the fluid through the turbine (m^3/s), H_T is the turbine head, or height difference between the water level in the impounded section of flow and the downstream outlet, and η_T is the efficiency of the turbine.

Equation (2.1) shows that the electricity that can be generated by falling water is linearly proportional to both the head and flow rate of the water passing through a turbine. The *capacity factor* of a generating station is a coefficient between 0 and 1 that describes the amount of power that is being generated as a fraction of the power that would be generated if the installed capacity of all turbine units was being perfectly exploited at all times. Capacity factors are influenced by the amount of water stored in a reservoir, variable head, variable flow rates, turbine efficiency, and operational decisions to store or release water at certain times of day or year. For the years between 2005 and 2016, Canadian hydropower had an average capacity factor of 0.556, much higher than the national average in the United States, which was 0.381 (Uría-Martínez et al., 2018). Regional and international capacity factors can vary for many reasons, including reservoir size, siltation, management strategy, turbine efficiency, climate, and co-purposes (e.g. irrigation water supply or controlling water levels for recreational or commercial boating traffic).

The type of turbine used at a generation station is a design choice based on expected stream flow rates and head: the main types are impulse and reaction turbines. Impulse turbines (including the Pelton wheel) are driven by high velocity water jets created by nozzles, while reaction turbines (including Francis, Kaplan, and propeller types) are submerged in the flow (US DOI, 2011). Impulse turbines are best suited for high-head, but relatively low-flow conditions, and reaction turbines elsewhere. An individual turbine unit has optimal efficiency for a certain head and power production level (related to generator speed), below or above which efficiency will decrease. Multiple turbines can be installed in parallel at hydropower plants so that individual units can be switched off or brought online to adjust to flow conditions, demand, or maintenance while maintaining high efficiency (US DOI, 2011). Hydropower turbines are able to quickly respond to demand, with very little time required to start up a generator unit to provide power, such as for short-term demand peaks, or for reserve capacity to rapidly replace supply losses due to generator or transmission outages elsewhere in a grid (US DOI, 2005). Pumped storage hydropower (PSH) is a method of electricity storage where a hydropower facility can be operated to generate power, or operated in reverse: the advantage of this is that water can be pumped to the upper reservoir when power costs are lower, and produce power during peaks, to help ensure that power supply is available at high-demand times (US DOI, 2005) and to help reduce peak-demand electricity price shocks. Pumped storage hydropower effectively acts as a battery, but uses the potential energy stored in water at height rather than chemical storage. The work presented in this thesis avoids explicit representation of pumped storage hydropower technology.

Lifetime hydropower operations and maintenance costs are generally low compared to other electricity generation technologies (Killingtveit, 2019), although major refurbishment projects can take entire turbine units out of service for long periods of time. Nonetheless, hydropower generally achieves high reliability over long lifespans (Killingtveit, 2019), with few stations having ever been decommissioned in Canada, despite a long history. Small hydropower facilities often have shorter lifespans (Killingtveit, 2019) of only about 40 years, but even this would be considered a long lifetime among most other electricity sources.

As hydropower plants age, siltation can reduce the power produced by turbines. Over time, sediments accumulate in reservoirs because the additional residence time of water in reservoirs and reduced flow velocity allows for settling of these materials to the bottom of the channel. When these sediments accumulate in a reservoir, the available storage in the reservoir decreases over time, and can operationally stress power generating equipment. Methods of controlled sediment release are now practiced at some facilities to help reduce sediment accumulation and restore sediments to downstream reaches of river (Espa et al., 2019), where sediments are an important contribution in preventing streambank erosion and maintaining or advancing deltas (Anthony et al., 2015).

Some terms related to hydropower technology have ambiguous meanings, so this list provides definitions for usage of some of these terms in this thesis:

- *Hydropower* is used to refer to electric power generated by falling water, exclusive of alternative mechanical uses (such as flour mills or water wheels), unless otherwise specified. It is intended to have synonymous meaning with *hydroelectric power* and *hydroelectricity*.
- *Large hydropower* is used to refer to any hydropower generating station with reservoir storage of over about one day or longer.
- *Run-of-river* is used to refer to hydropower generating stations with reservoir storage of about one day or less.

Despite the usage of this language, it is possible for run-of-river hydropower generating stations to be very large, especially where they are located at sites along high flow rivers with gradual slopes. For example, the Beauharnois generating station located along the St. Lawrence River in Québec is considered run-of-river, despite having an installed capacity of 1,912 MW (Hydro-Québec, 2021), a higher capacity than many large reservoir powerhouses.

This work does not explicitly consider hydrokinetic turbine technologies. Hydrokinetic turbines are alternatives to traditional hydropower for generation of electricity from the flow of rivers without a dam (Niebuhr et al., 2019), more similar to wind turbines. These turbine technologies are undergoing technological development and testing (Niebuhr et al., 2019), but uses are at present confined to small-scale or off-grid operations.

2.2.2 Hydropower Resources and Development

Decisions for siting hydropower plants are made with careful consideration for the hydraulic, hydrologic, topographic, and climatic conditions of potential sites. Estimates for hydropower resource potential at a site must include detailed consideration of runoff data (ideally represented seasonally or subannually) and elevation data (Zhou et al., 2015). Attempts to characterize hydropower resource potential on a global basis have recently been made possible by better data inputs from satellites, with consideration being given to more accurately reflect not only total hydropower resource potential, but to consider practical constraints on resource development, including technological limitations, minimum environmental stream flows, protected areas, urban areas, and estimated development costs (Gernaat et al., 2017; Zhou et al., 2015).

Hydropower is one of a variety of uses that can be derived from the impoundment of a flowing water course. Many dams were and are constructed not only for hydropower generation, but also for other purposes, including reservoir storage of water for consumption by humans and human processes, flood management, irrigation, (IRENA, 2015) and recreation.

There is evidence that new hydropower developments are usually finished over-budget and with schedule delays (Arbuckle et al., 2021). Dolter et al. (2021; 2022) found that the Site C project in BC, now under construction near Fort St. John, is not likely to provide value exceeding its investment costs, given that cost overruns have far surpassed initial projections. They found that only in a scenario where the electricity grids of British Columbia and Alberta are more optimally integrated with increased transmission capacity and very high decarbonization targets could the Site C project provide positive value to compensate for remaining avoidable costs of abandoning the project as of early 2021 (Dolter et al., 2021).

2.2.3 Hydropower Impacts and Environmental Considerations

While hydropower generation is derived from an emissions-free and naturally replenishing fuel source, the process of constructing dams can be an energy intensive process. Earthfill dams often require thousands of truckloads of material to be excavated, quarried, and transported, while concrete dams generate significant greenhouse gas emissions associated with cement production. Large dams are often constructed far from population centres, which adds the financial and environmental costs of transporting many workers to and from site and operating temporary construction camps. Further emissions are derived from operations and maintenance, deforestation and land use change, and, especially in tropical regions, production of methane from biomass decomposition in oxygen-depleted reservoirs (Ramos et al., 2009). Nonetheless, lifecycle assessment estimates to compare generating sources in Ontario have placed large hydropower GHG intensity at about 22.5 t CO_2e/GWh and natural gas at about 400–600 t CO_2e/GWh over project lifespans (Mallia and Lewis, 2013). Hendriks (2016) noted that, during the lifecycle of a hydropower station, most of the emissions release is concentrated in the construction and early operations. This "front-loading" of emissions can make hydropower less appealing in the context of achieving emissions reductions in the near term.

Compared to other common electricity sources, hydropower has the largest physical footprint. Considering all land uses that contribute to electricity production, Strata (2017) concluded that, in the US, hydropower uses about 315 acres of land per MW installed, while wind uses 71 acres and natural gas uses 12 acres. Further, the land lost to hydropower reservoirs is unavoidably located in river valleys, which are high-value and critical habitats for ecological diversity compared to the areas that surround them (Lenaghan, 2012), while other forms of electric generation can often make use of land that is less critical to local flora and fauna. If many countries are simultaneously motivated to reduce emissions by electrification, there is worry that a boom in hydropower development could lead to significant impacts to rivers and aquatic habitats (Thieme et al., 2021). Hydropower dams can have significant impacts on the aquatic habitats, flow regimes, and natural features of the rivers they impound, including the following:

- Blockage of fish movement, isolating populations on either side (Liermann et al., 2012). Some structures are designed to facilitate fish movement across large dams, but these are not always very effective.
- Changes to thermal and chemical composition. Native aquatic species are adapted to well-mixed river channels, but reservoirs can be much deeper and slower-moving, leading to temperature, oxygen, and chemical conditions that are not suitable for native species (Liermann et al., 2012).
- Blockage of nutrient transport, causing a reduction in primary productivity in downstream reaches (Young et al., 2004).

- Anoxic conditions typical of deep reservoirs can cause methylation of mercury attached to sediments, converting it into forms that are especially toxic to humans (Fearnside, 2014), which can then bioaccumulate.
- Flow regulation. Natural hydrological cycles are disturbed significantly by large reservoirs as annual wet and dry periods are replaced by relatively consistent flow. Some operators mitigate these effects to some extent by using seasonal hydrological peaking to better mimic natural process (Mueller et al., 2017). In temperate climates, reduced spring flooding and higher winter flows can have negative impacts on local aquatic species and throughout a food chain. The people that rely on environments downstream of dams for subsistence and transportation often receive little support for adapting because these effects can be very distributed, difficult-to-measure, or can cross political boundaries (Baird et al., 2020).

Thieme et al. (2021) advocate that protection of wild and free-flowing rivers is important to protect biodiversity, promoting healthy fish stocks for human consumption, providing sediment to deltas, and helping to mitigate against estuarine flooding. They encourage consideration of alternative renewable energy options, mitigation of hydropower impacts by efforts such as environmental flow releases, restoration of rivers by removing dams that are no longer useful, and establishing offsets to ensure that comparable habitats are protected (Thieme et al., 2021).

2.3 Energy-Economy and Integrated Assessment Modelling

2.3.1 Modelling of Energy-Economy Systems

To facilitate understanding of the relationships between energy and economy systems, various types of models have been developed, including those which are bottom-up, top-down, or hybrid, with varying degrees of technological, microeconomic, and macroeconomic detail (Rhodes et al., 2021). These types of models are used to provide decision-makers with knowledge to better understand the complex interactions that exist in feedbacks between the energy and economy systems. This is especially important in the context of policy development for climate action, such as greenhouse gas emissions reduction, but also for better understanding other aspects of the systems, like emerging energy technologies, macroeconomic stressors, or grid reliability.

Modelling of the Canadian electricity system is becoming more important as a part of ensuring good policy decisions are made with regard to climate action and cost-effective developments. NATEM (TIMES-Canada) is one such model that has been established to assess Canadian future energy pathways, using an optimization framework (Vaillancourt et al., 2017). Another model called LEAP-Canada (Long-range Energy Alternatives Planning) is bottom-up and detail-rich (Davis, 2017; Janzen et al., 2020). Several other models have capabilities to simulate Canadian energy system futures, some of which are used by Canadian government agencies, like EC-MSMR and Energy 2020 (Rhodes et al., 2021), and some that are open source or developed by other research groups, including GCAM, IPM, MARKAL, and ReEDS (Bahn and Vaillancourt, 2020). Further background about integrated assessment models, a category into which some of these models are sorted, follows in the next subsection.

2.3.2 Integrated Assessment Modelling

Integrated assessment models (IAMs) are tools used to facilitate comparison of alternative future pathways. Through relationships linked by various computer modelling techniques, IAMs simulate broad-system interactions between socioeconomic, energy, water, land, and climate systems. IAMs have been used extensively to explore the relationships between climate science and policy, owing to their interdisciplinary flexibility, ability to incorporate socioeconomic trends, and potential to be used proactively to guide policies (van Beek et al., 2020). The development of IAMs has proceeded from early attempts to develop models that simulate global interactions, born in the context of rising awareness of pollution as a globalized problem. Interest in energy-economy models for policy analysis grew during and after the oil crisis of the early 1970s (van Beek et al., 2020). As modelling techniques and computer technologies evolved, these emerging models were applied for acid rain mitigation policy development in the late 1980s. During the 1990s, the first of what are now called IAMs were established and much of the research was motivated by the needs of the Intergovernmental Panel on Climate Change (IPCC) to track global emissions (van Beek et al., 2020). Efforts were undertaken to integrate the more physically detailed General Circulation Models (GCMs) with IAMs to address concerns that climate systems in IAMs were inadequate. Early IAMs were useful for assessment of long-run multi-system scenario outcomes; in recent years, efforts have been focused on improving the models for shorter-term policy analysis that can provide decision-makers with actionable advice (Fisher-Vanden and Weyant, 2020). Many recent developments have focused on bettering the temporal and spatial resolution of models (Fisher-Vanden and Weyant, 2020). IAMs are now being used to help governments assess progress toward achieving nationally determined contributions (NDCs) as part of the Paris Agreement obligations and for guidance to update climate policy (Fisher-Vanden and Weyant, 2020; Krey et al., 2019, Ou et al., 2021), among other energy, water, and climate system analyses of interest to academics, policy-makers, and curious minds. NDCs are set to be more ambitious at a faster pace for developed countries than for developing countries.

Development in the integrated assessment modelling community is now moving toward more integrated feedbacks between model components (Fisher-Vanden and Weyant, 2020). This increases the utility of the models to broad and interconnected system analyses. As model linkages are improved and component parts increase in complexity, there are trade-offs between computational expense and spatial, temporal, and sectoral detail (Fisher-Vanden and Weyant, 2020), which can form criteria for model selection when analysts are considering choices between integrated assessment models. Recently, interest in usage of IAMs for applications outside of climate policy has been increasing, with modelling being developed to assess the impacts of extreme weather events (Fisher-Vanden and Weyant, 2020) and other applications, such as the food-energy-water nexus (Kling et al., 2017), non-GHG air pollution policy (ApSimon et al., 2021), and even for proactive anticipation of policy analysts' future needs (van Beek et al., 2020). Increasingly, there has been development of IAMs for subnational and regional analysis for understanding spatial heterogeneity (Jeon et al., 2020), which can be significant because of diverse local geographic, climatic, and political conditions, even within single nations.

There are some criticisms of the methodological approaches of IAMs. Ghambir et al. (2019) presented a recent review of these criticisms. Their study found that IAMs have been negatively perceived for a lack of methodological transparency, inappropriate or out-of-date input assumptions, lack of realistic representation of socioeconomic behaviour, and lack of system detail at fine scales, among other limitations. For instance, electricity systems in the real world operate with hourly fluctuations, while IAMs often model systems on an interannual basis. Hydropower, and especially run-of-river plants with little ability to store water in a reservoir, can be influenced by daily weather patterns and interannual climate variation that is not often captured in integrated assessment modelling. A criticism by Ackerman et al. (2009) is that IAMs are often used for climate policy analysis, but have incomplete information regarding the costs and probabilities of potential adverse climate events. Many IAM modellers are aware of these criticisms and are taking action to implement solutions, although this can take modellers years to implement or require data that are not readily available on the global basis that IAMs capture.

When designing IAMs, modellers are increasingly trying to represent realistic behaviours, which are often driven by non-rational preferences (McCollum et al., 2017). For example, McCollum et al. (2017) presented a study that proposed a method to account for non-rational behaviour toward adoption of low-carbon emission vehicles, finding that higher carbon prices or other policy instruments would be required to meet goals than rational cost analyses would determine. Thus, a well-calibrated IAM for simulating future outcomes should consider behavioural tendencies and biases that can impact future decisions on national and consumer scales.

2.3.3 Hydropower in Integrated Assessment Modelling

Hydropower has been modelled exogenously in many IAMs, including current public releases of GCAM, AIM, IMAGE, MESSAGE, and WITCH (Arbuckle et al., 2021). It can be difficult to assign hydropower costs endogenously, partly because the data from existing plants is often not differentiated by function: dams and reservoirs can be installed for many purposes, including power production, irrigation, flood control, and municipal water supply, making it difficult to segregate costs for historical power production from those for other purposes. Further, detailed hydrological and topographical data capable of providing global estimates of hydropower potential that have been associated with estimated costs have been explored only recently (Gernaat et al., 2017; Zhou et al., 2015). Efforts are currently underway to incorporate endogenous hydropower features in some IAMs: the first application for GCAM was presented in Arbuckle et al. (2021) for Canada only, while preliminary work has been conducted for IMAGE (Niessink, 2014). Carvajal and Li (2019), using TIMES, and Köberle et al. (2018), using MESSAGE, have applied endogenous hydropower in regional applications for Ecuador and Brazil, respectively. Limited spatial detail among available hydrological cost-supply data sources could make extending regional hydropower model improvements to global inclusion challenging.

Chapter 3 The Global Change Analysis Model (GCAM)

The Global Change Analysis Model (GCAM) is an IAM developed by the Joint Global Change Research Institute (JGCRI), located in College Park, Maryland. Since its inception around 40 years ago (Edmonds et al., 1994; Edmonds and Reilly, 1985), GCAM has evolved into a community model that is developed and applied by academics and researchers around the world. GCAM is freely available as open-source software (Calvin et al., 2019). The model is available for download from JGCRI (2020). Hundreds of academic papers in peer-reviewed journals have been published in the preceding decades, detailing developments made to GCAM and analyses that have leveraged GCAM for understanding energy, water, climate, and land systems interactions. GCAM has formed an important part in modelling used by the Intergovernmental Panel on Climate Change (Edmonds et al., 1994) for its Assessment Reports and is used by government agencies as a tool to guide climate policy development and assess progress toward goals.

GCAM was formerly known as the Global Change Assessment Model, but the name was changed along with the update to GCAM version 5.3 on 25 June 2020 (JGCRI, 2020). This model update most importantly changed the final historical year, used for calibration, from 2010 to 2015. The standard version of the model that is available for public release is sometimes called "core GCAM" to help distinguish it from developments to branches of the model that have not been incorporated into the public model.

JGCRI typically hosts an annual Community Modelling Meeting at which developers, analysts, and researchers share features that have been made available in new version updates, methodological developments, and share findings or recommendations from model applications. At the event in 2019, a tutorial was presented and made available that provides information about how to get started using model version 5.3 (JGCRI, 2019), which is the version that forms the basis for model development in this thesis. In addition to downloading GCAM itself, modellers must also have Java Runtime Environment, R, RStudio, and an XML editor installed as a minimum to run the model.

3.1 GCAM Model Processes

GCAM takes input related to population, labour productivity, technology characteristics, and policies as external scenario assumptions (JGCRI, 2021a). GCAM integrates five main systems: macro economy, energy systems, agriculture and land systems, water systems, and physical Earth systems (JGCRI, 2021a). 32 geopolitical regions are established in the core GCAM to model the macro economy and energy systems, including individual large countries (such as Canada, the USA, China, India, and Japan), while other regions are aggregations of multiple countries, such as "Australia-New Zealand" and "Europe-non-EU." Water and land systems are organized according to more refined regions, with 235 hydrologic basins and 384 land regions grouped by climate and land type.

GCAM simulations seek market equilibrium to balance supply and demand. GCAM is typically classified as a "partial equilibrium" model because, while connections between internal markets are well-represented, there are no feedbacks to influence several basic macroeconomic inputs including GDP and labour productivity growth rate (JGCRI, 2021a; Rhodes et al., 2021). Figure 3.1 presents a high-level concept of the linkages between model sectors. Each of these sectors contain more specific details that are organized into subsectors and technologies.

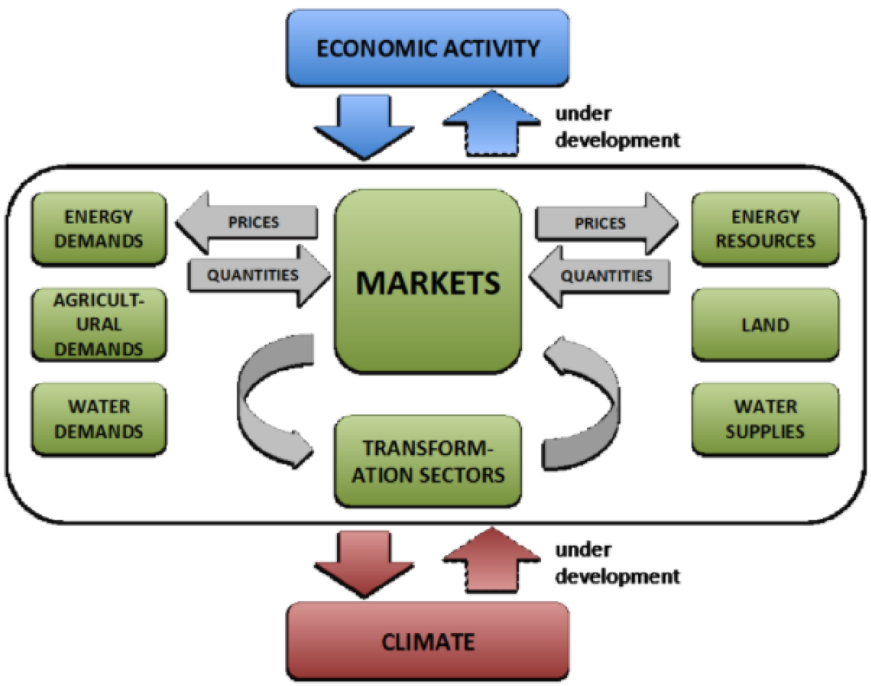

Figure 3.1. Conceptual diagram of GCAM sectoral interaction (JGCRI, 2021a).

GCAM solves for future conditions by making choices between alternatives. For example, in the energy sector, end-users must choose which fuels to use among a wide variety of options with varying costs. Model choices are defined by logit functions designed to capture that decisions are made using internal model indicators (such as costs), but are also influenced by non-market factors (including socioeconomic factors, public perception, or political will; McFadden, 1980). Choice functions assume partially random distributions which, based on observed distributions, follow the Generalized Extreme Value distribution when using the Logit function and the Weibull distribution for the Modified Logit function (Clarke and Edmonds, 1993; Train, 1993). The Logit formulation relies on incremental difference between alternatives while the Modified Logit formulation, preferred for energy system applications, uses the ratio between choice indicator values (JGCRI, 2021a). Being the formulation applied by the energy system applications explored later in this thesis, Equation (3.1) provides the Modified Logit (from JGCRI, 2021a):

$$s_i = \frac{\alpha_i p_i^{\gamma}}{\Sigma_{j=1}^{N} \alpha_j p_j^{\gamma}} \qquad \text{Eq. (3.1)}$$

Where s_i is the share of choice alternative *i* (with cost p_i), α_i is the shareweight of a choice, the j indices represent all choice alternatives, and γ is a value known as the logit exponent.

GCAM is a dynamic recursive model, meaning that the model solves for each period knowing only the information from the last model period, and unaware of future changes that might influence decision making. Some other IAMs operate using intertemporal optimization, which assume perfect foresight and a known future when making decisions. GCAM solves iteratively within each time step using the Broyden Solver method (Press et al., 1992), usually making hundreds or thousands of iterations before proceeding to the next time step. Users can adjust model solution tolerance and maximum iterations, considering that finer model solution tolerances require additional computational expense.

The spatial scale at which GCAM operates can generally be developed without changing the model structure significantly, by adding details to the GCAM Data System to create finer detail in regions of interest (JGCRI, 2021a). Such a regional improvement is available for the USA (known as GCAM-USA). Other regional improvements are being developed for China, India, Korea, and at the city-scale for Boston (Jeon et al., 2020), as global research teams, policy analysts, and governments take interest in using GCAM for local policy analysis, with better understanding of subnational interactions.

3.2 Major Non-Energy Systems in GCAM

Economic activity in GCAM is modelled exogenously by specifying population and GDP per capita growth in both historical and future time periods. These then act as drivers for demand in other model sectors (JGCRI, 2021a). The core model is shipped with default configurations to align with the Shared Socioeconomic Pathways (SSPs), which present several trajectories for possible development pathways (van Vuuren et al., 2017). The typical setting for GCAM scenarios is to apply the "Middle of the Road" scenario, SSP 2, as a baseline, although any SSP or alternate user-specified estimates can also be chosen by the user.

Interregional trade is applied in GCAM through a variety of methods. Many trades are conducted between regions and a "world market," without tracking trade between individual regions, including primary energy trades (JGCRI, 2021a). Trade of secondary energy products like electricity are assumed not to be traded interregionally in the core model (JGCRI, 2021a). A more robust approach (based on Armington, 1969) is used to track agricultural and livestock trade, which allows for preferences for domestic goods and tracking regional flows of commodities, developed using a logit framework.

GCAM is integrated with a model called Hector to represent its climate system (Hartin et al., 2015). Hector is an open-source simple climate model (SCM), which represents atmospheric climate parameters with carbon-cycle linkages to land and ocean (See Figure 3.2). Hector is used to represent the most important climate interactions on a global scale without too many fine details to prevent the model from becoming too complex and computationally expensive, which would make integration with IAMs impractical. In addition to the carbon-cycle interactions, Hector models atmospheric temperature and important inputs from other atmospheric species such as sulfate aerosols, nitrous oxides, methane, and halocarbons to compute radiative forcing (Hartin et al., 2015). Emissions can further be influenced by user constraints like policies to reduce methane emissions (JGCRI, 2021a) in specific sectors, which then feedback into the model's economic decision framework. Model results regarding emissions are commonly used to assess scenario alternatives on the basis of climate and environmental impacts.

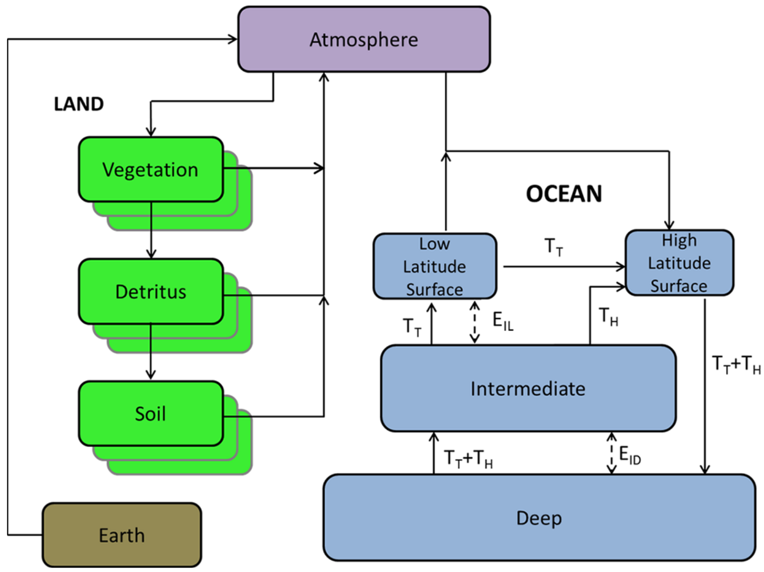

Figure 3.2. Conceptual diagram of carbon-cycle relationships in Hector, where the atmosphere is a measure of ambient carbon dioxide concentration. The "Earth" element represents a carbon mass balance check (from Hartin et al., 2015).

GCAM's water module represents water demand for agriculture, electricity generation, primary energy production, and end-use sectors, including industry and municipal uses (JGCRI, 2021a). Electricity sector water demands are driven by water withdrawals and consumption by cooling systems (Davies et al., 2013; Kyle et al., 2013), but neglect withdrawals and consumption from hydropower. Water supply is provided by estimates of water availability for the 235 major river basins specified in GCAM, including surface and groundwater, non-renewable groundwater, and desalinated groundwater. Runoff supplies are based on estimates from a global hydrology model called Xanthos (Vernon et al., 2019), which computes global components of the water cycle in 0.5-degree-by-0.5 degree grid resolution. Most of the water demands are assigned at the scale of the 32 GCAM geopolitical regions (except irrigation, which remains consistent with river basins) in order to set up a modelled water market (JGCRI, 2021a). The water market is modelled with "shadow prices" to reflect that water is usually not traded on direct open markets, while allowing the distribution to be influenced by constraints on supply in areas where constraints exist. Most GCAM water demand is modelled only at the region-level and is not spatially disaggregated to transfer directly to basins. Therefore, demands for basins are estimated from a "mapping" that estimates water demands at the basin-level based on gridded population and electric power plant locations (JGCRI, 2021a). GCAM regions and basins often overlap, which can result in the splitting of a single basin between regions. Any basin shared between two or more regions is assumed to have its total supply available for usage in any of the shared regions (JGCRI, 2021a). Finer considerations regarding direction of flow or local water supply within an overlapping basin are not considered by GCAM version 5.3.

3.3 Energy System in GCAM

GCAM's energy system relates energy production from resources, transformation of energy, energy consumption, and trade (JGCRI, 2021a). Energy production is assigned costs based on development of both depletable and renewable resources, including oil, natural gas, coal, uranium, wind, solar, and biomass resources, among others. Depletable resources available for production can be directly exploited or converted to other forms of energy for use by end-use sectors (industry, buildings, and transportation), or traded on a global market, while renewable resources are considered only for domestic electricity production. Energy technologies are integrated through supply sector markets. Each supply sector is composed of subsectors, within which technologies can be specified and configured to compete for market share (Calvin et al., 2019; JGCRI, 2021a). Technologies can be specified as global representations or fine-tuned for individual regions. Technology definition requires input regarding fuel, capital, and operating costs for the model to compute average levelized costs. Some types of technologies require more input information: electricity technologies require specification of capacity factors, fixed charge rates, and both fixed and variable operating costs (JGCRI, 2021a). For all energy flows, core GCAM is calibrated in historical periods according to the International Energy Agency (IEA) World Energy Balances (Calvin et al., 2019; IEA, 2019) to ensure global consistency.

Technologies in the energy system are related to each other as inputs and outputs, starting from primary resource production, moving through various phases of energy transformation and intermediate uses to final energy demand (Calvin et al., 2019). The emissions of energy production, transformation, and usage, including carbon dioxide, non-carbon dioxide greenhouse gases, and other pollutants, are accounted for in these processes. This, combined with accounting of emissions from land use and land use change, can be used to assess climate policy effectiveness in model scenario comparison (Calvin et al., 2019). Carbon capture and storage (CCS) and other carbon sequestration can be added to capture the additional costs of emissions reduction with these emerging technologies.

In the core model's energy system, electricity generation is divided firstly into subsectors, including hydropower, coal, nuclear, and so on, which are calibrated for shareweights separately for each of the 32 GCAM regions. In core GCAM, varying assumptions were made for each of these subsectors according to the calibration deemed appropriate by the model developers at JGCRI, which undergoes internal peer review. Shareweights were set for future periods based on values calibrated in the most recent historical period, and are extended to 2100 following fixed, linear, or s-curve pathways (JGCRI, 2021a) based on expert judgement. For example, shareweights for rooftop-photovoltaics and wind power rise linearly from calibrated values in 2015 to 1 in 2100, while refined liquids are assigned fixed shareweights.

Energy production from primary sources is modelled based on costs related to amortization, operations and maintenance, and energy input costs, including the cost of developing further resources, which are specified by resource supply curves (Calvin et al., 2019). Despite escalating development costs on supply curves, emerging technologies can reduce in cost over time as a result of exogenously decreasing technology costs (Calvin et al., 2019), or can gain higher market access through shareweights. Depletable resources are represented with "graded" supply curves based on estimated reserves (including unconventional sources), extraction costs, and increasing marginal costs associated with resource scarcity, including estimates from Rogner (1997) for fossil fuel supply. Wind and solar resources are represented with smoothed supply curves, which are defined to estimate the marginal cost of developing renewable energy within a region in excess of base technological capital and operations costs, to represent sites becoming decreasingly optimal for production or more expensive to develop (JGCRI, 2021a). Core GCAM specifies hydropower development for regions exogenously based on economic estimates from IHA (2000).

3.4 Input Data Processing and Management: gcamdata

The GCAM core is the model component in which system relationships are represented, computed, and output from (Calvin et al., 2019). It is written in C++ and is informed by hierarchically structured XML (".xml") input files which detail all required inputs, synthesized from raw input data into a format usable for model computation. Raw input data are saved as comma-delimited CSV (".csv") files, which also contain metadata to record the purpose and source of each file. Ideally, the basic input files require no or minimal pre-processing before being added to the model data system to ensure that data can be easily updated as new data becomes available, as well as to minimize errors that might occur during more manual computations. The input data are processed as required to produce any intermediate and final forms necessary to be read into GCAM using a data system called "gcamdata," which operates in R (Calvin et al., 2019).

R is a freely available computer language well-suited for data handling and analysis (R Foundation, 2021). gcamdata is a package available for R, which defines a series of user functions and processes to ensure that data are processed using consistent, reproducible, and verifiable methods (Bond-Lamberty et al., 2019). Data are processed using R scripts in units called "chunks," which each take a series of inputs and produce consistently formatted output files that are subsequently converted to XML files by separate chunks that conduct those processes. Metadata in the chunks account for dependencies on other chunks, as input files to one chunk can consist of output files from another. The GCAM Data System allows for a user to easily update raw data, alter assumptions by modifying input files, and to add features or create alternative scenarios by adding to existing chunks or developing new chunks (Bond-Lamberty et al., 2019).

3.5 Climate Policy Application

GCAM is well-suited for analysis of climate policy scenarios by applying carbon prices and GHG constraints, but further scenarios regarding specific sectors and technologies, such as direct air capture (DAC), can also be explored. Carbon prices can be implemented in GCAM by attaching costs to markets associated with emissions, but carbon price revenues are not explicitly attributed to any model components, effectively implying that they are revenue neutral. GHG constraint scenarios are often used in GCAM applications to simulate the effects of climate policy actions, including recent studies by Delgado et al. (2020), Kaufman et al. (2020), Arbuckle et al. (2021), and Fuhrman et al. (2021). GHG constraints are implemented in the model by setting maximum carbon emissions for a model region (or regions) and allowing the model to solve for the effective carbon prices that would be required to meet those constraints (Delgado et al., 2020). Policies for emissions constraints can be set for CO_2 alone, or also to include non-CO_2 GHGs according to their respective global warming potentials (GWP). Further, land use change (LUC) emissions can be included or excluded from GHG constraint or carbon price scenarios (Santos da Silva, 2021). Application of carbon prices to LUC is typically conducted in GCAM with a lower carbon price than on other sectors of the economy to avoid improbably rapid afforestation or conversion of agricultural land to bioenergy production (Binsted et al., 2020). The application of carbon price or GHG constraint scenarios in GCAM neglects that real-world climate policy strategies are often much more complicated, for example, with specific sectoral measures (Santos da Silva, 2021) which may distribute effects differently.

3.6 GCAM-Canada

GCAM-Canada is being developed as an enhancement to the core GCAM model by a group of researchers from the University of Alberta and JGCRI, with support from ECCC. This branch of the model seeks to replicate the improvements made with GCAM-USA to better detail the United States (Scott et al., 2014) by adding subnational representation for Canada. GCAM-Canada model developments have focused on improving representation of technologies and sectors particularly important to Canada, including natural gas and oil sands production, while better detailing Canadian trade flows, policies, and peculiarities (e.g. the off-road transportation sector is improved for Canada, where it comprises a larger share of transportation than in most other GCAM regions). Preliminary work to establish the GCAM-Canada branch was conducted by Haewon McJeon and Christopher Roney, presently and formerly of JGCRI, to improve alignment of the national Canadian model region with historical and near-term model outcomes, as well as to develop baseline policy scenarios. Base year energy and emission balances were aligned for consistency with E3MC, the Energy, Emissions and Economy Model for Canada, which is used by the Government of Canada for modelling greenhouse gas emissions (Government of Canada, 2018) to ensure that GCAM-Canada has historical calibration compatible with other Canadian energy-economy models. Coordinating the historical values between these models allows GCAM-Canada to be compared to those other models for emissions tracking in future applications. Other alignments for GCAM-Canada included emission coefficient adjustments, fossil fuel sector aggregation, and the removal of emissions from unmanaged land for certain accounting procedures to better align with policy directions.

Model developers have recently focused on oil and oil sands production detail, model regionalization to develop subnational regions consistent with Canada’s provinces and territories, endogenization of hydropower, and water sector improvements. The first article published by this group used the improved GCAM-Canada for analysis of cost overrun impacts in the electricity generation sector, on a national scale (Arbuckle et al., 2021), while another explored decarbonization pathways for unconventional oil production (Bergero et al., 2022).While this thesis represents a significant achievement for hydropower representation in GCAM-Canada, these work streams have yet to be fully integrated into the comprehensive GCAM-Canada with 13 subnational regions for Canada, which is under development at the time of this publication.

Chapter 4 Methods

Prior to the work completed for Arbuckle et al. (2021), hydropower was represented in GCAM only exogenously. In that work, we developed a framework to model hydropower resources endogenously in the same manner that other renewable energy resources (wind and solar) have been modelled in GCAM. We applied a hydropower cost-supply curve based on Zhou et al. (2015) data for Canada as a single, national region, without correcting for existing generation, and established a single representative hydropower technology in the model to compete with other electricity technologies endogenously. This single technology was established to be generally representative of the large reservoir hydropower installations that generate the majority of hydropower in Canada, using assumptions for capital and operations and maintenance costs to represent that type of installation. This chapter presents the methodology used to define subnational regions (Section 4.1), develop historical generation profiles (Section 4.2), prepare resource costs (Section 4.3), estimate resource supply curves (Section 4.4), set up scenarios for analysis with GCAM (Section 4.5), configure, calibrate, and simulate with the model (Section 4.6), and to make adjustments for some near-term expectations (Section 4.7).

4.1 Definition of Subnational Regions

In order to endogenously model hydropower within GCAM-Canada at a subnational level, a set of subregions of interest must be defined along appropriate borders. GCAM represents water balances (including water consumption, withdrawal, and use) according to regions defined by 235 major river basins, representing all global land surfaces (Kim et al., 2016). In anticipation of integrating these model developments with ongoing efforts to regionalize GCAM-Canada to provinces and territories, subnational regions for Canada were defined for each possible combination of province or territory and major river basin, to allow for the subnational regions to be scaled to both the province and river basin levels. Each of these combinations are listed in Table 4.1 and shown in Figure 4.1 on a map of Canada.

Table 4.1. Subnational regions used for hydropower definition in GCAM-Canada.

Subnational Region ID	Province/Territory	Basin	Abbreviation
1	BC	Pacific and Arctic Coast	BC_PA
2	BC	Fraser	BC_F
3	BC	Pacific Northwest	BC_PNW
4	BC	Mackenzie	BC_M
5	AB	Mackenzie	AB_M
6	AB	Northwest Territories	AB_NT
7	AB	Saskatchewan-Nelson	AB_SN
8	AB	Missouri River	AB_MO
9	SK	Mackenzie	SK_M
10	SK	Northwest Territories	SN_NT
11	SK	Saskatchewan-Nelson	SK_SN
12	SK	Missouri River	SK_MO
13	MB	Northwest Territories	MB_NT
14	MB	Saskatchewan-Nelson	MB_SN
15	MB	Hudson Bay Coast	MB_HB
16	ON	Saskatchewan-Nelson	ON_SN
17	ON	Hudson Bay Coast	ON_HB
18	ON	Great Lakes	ON_GL
19	QC	Hudson Bay Coast	ON_HB
20	QC	Great Lakes	QC_GL
21	QC	St Lawrence	QC_SL
22	QC	New England	QC_NE
23	QC	Atlantic Ocean Seaboard	QC_AO
24	NB	New England	NB_NE
25	NB	Atlantic Ocean Seaboard	NB_AO
26	PEI	Atlantic Ocean Seaboard	PE_AO
27	NS	Atlantic Ocean Seaboard	NS_AO
28	NL	Churchill	NL_C
29	NL	Atlantic Ocean Seaboard	NL_AO
30	YT	Pacific and Arctic Coast	YT_PA
31	YT	Mackenzie	YT_M
32	NT	Mackenzie	NT_M
33	NT	Northwest Territories	NT_NT
34	NT	Pacific and Arctic Coast	NT_PA
35	NU	Northwest Territories	NU_NT

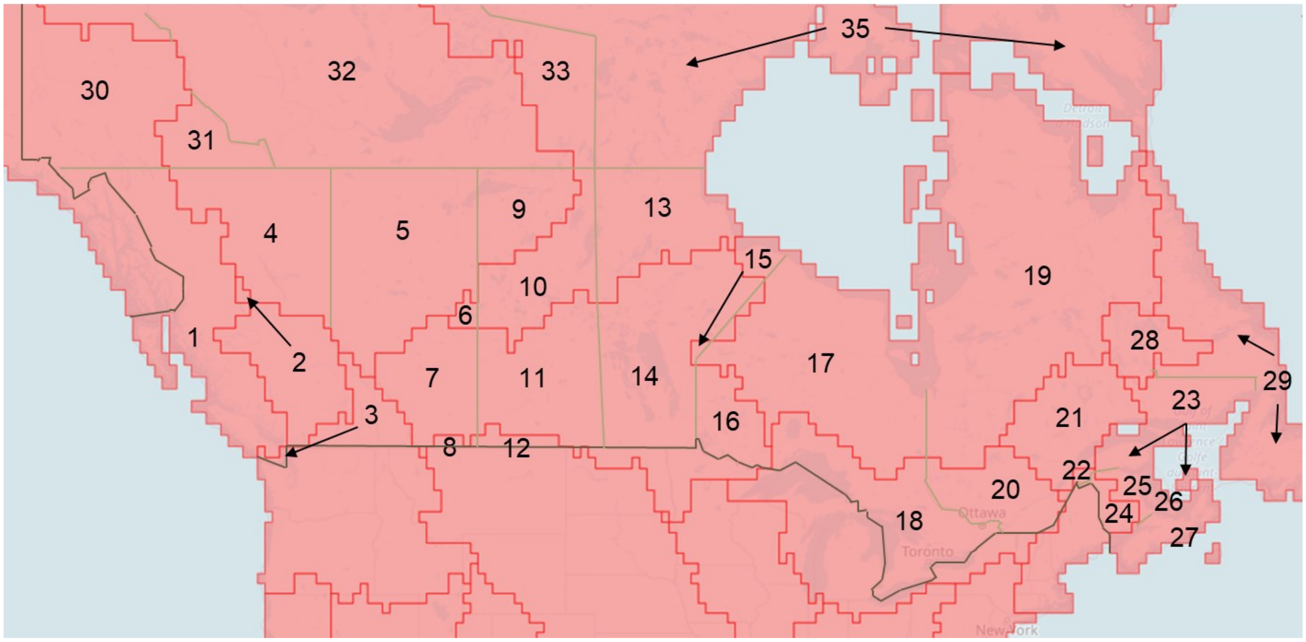

Figure 4.1. Subnational regions used for hydropower definition in GCAM-Canada. GCAM major river basins are outlined as shapes by the red lines. Overlaid values correspond to the subnational region IDs in Table 4.1.

River basins in GCAM are defined imprecisely along 0.5-degree latitidue-by-0.5-degree longitude grid cells, causing abrupt right-angle edges as shown in Figure 4.1. Thus, the hydrological basin boundaries do not match exactly with irregularly shaped real-world divides. More precise definition would require much more data processing from GCAM's water module, specifically from Xanthos, the hydrology model that is used to provide GCAM with runoff estimates along 0.5-degree-by-0.5-degree grid cells (Liu et al., 2018), which may make modelling at finer resolutions impractical.

4.2 Historical Hydropower Data Collection and Processing

Representation of subnational hydropower in GCAM-Canada requires that historical hydropower generation be known in all historical period years, which, for GCAM version 5.3, are 1975, 1990, 2005, 2010, and 2015. No single source provides these data for anything finer than a national scale, so it was necessary to aggregate historical data from a variety of sources. A complication is that generation at individual sites and local regions fluctuates interannually and is often difficult to find data for on a site-specific basis, while installed capacity data is more readily available with fine resolution. Therefore, historical hydropower generation is determined for each of the subnational regions in several steps. First, data for generation and capacity are aggregated at the provincial scale (Section 4.2.1), then capacity is determined for individual generating stations (Section 4.2.2), historical generation is estimated for subnational regions using those capacity estimates (Section 4.2.3), and finally adjustments are made based on local capacity factors in some areas (Section 4.2.4). The results of this work to determine historical hydropower capacity and generation are presented in Section 5.1.

4.2.1 Provincial Generation and Capacity Data Sources

Firstly, historical hydropower generation and capacity profiles were compiled for each province and territory separately. The data were compiled from several sources as identified in the next paragraph into a spreadsheet, with coverage of each year between 1959 and 2020. The provincial generation and capacity profiles were processed and plotted using basic operations in Microsoft Excel and are presented as comprehensive intermediate results (Section 5.1.1) that could be useful for any modelling work which requires calibration of historical hydropower generation by Canadian province.

Hydropower generation and capacity data were taken from Statistics Canada's "Electric Power Capability and Load" series of annual reports, as archived for the period between 1969 and 1999 (Catalogue no. 57-204). In some of these earlier reports, Statistics Canada was referred to by the name of its predecessor, "Dominion Bureau of Statistics," but the reports are consistent in the information presented. Each issue of these reports provide data for a 10-year period prior to publication, allowing this dataset to cover all years between 1959 and 1999. From 2000 to 2004, generation and capacity data were taken from the archived annual "Electric Power Generation, Transmission and Distribution" reports (Catalogue No. 57-202). This data series is also used for capacity data in 2005. Generation data were taken from the online series available at StatCan (2022). From 2006 to 2017, capacity data were taken from the online series available at StatCan (2019), however the year 2012 is missing from this dataset and could not be located elsewhere.

The archived data were only available as photocopies and microfiches of original print documents. This format required that the data be visually read from each of the annual reports, with values read for each province separately, and transcribed individually into a spreadsheet. The image qualities of most reports were generally sufficient for interpretation, but it was sometimes difficult to read all values with certainty, especially for some of the reports from the earliest periods. For this reason, provincial and territorial totals for capacity and generation were each summed and compared to national totals. This served as a form of quality control to ensure that values were internally consistent. Where data from a certain year were reported in multiple issues of the reports, the more recent figures were used to supersede previous values, as Statistics Canada sometimes makes revisions to historical figures based on updated information.

Usefully, data for Newfoundland and Labrador were separated between the island (Newfoundland) and mainland (Labrador) portions. While this does not coincide with the boundaries for the subnational regions defined in this work, the Labrador portion effectively represents region 28 alone, because there are not and have never been commercial hydroelectric facilities in Labrador outside of the Churchill basin. Prince Edward Island has not generated market hydropower in the historical period of interest and is therefore not reflected in the results, although it did have a very small amount of generation in the first half of the 20th century (Historic Places, 2020). The territory that is now Nunavut was a part of the Northwest Territories prior to 1999, however no commercial hydroelectricity has yet been generated from what is today Nunavut, meaning it can also be excluded from historical generation results.

4.2.2 Capacity at Individual Canadian Hydropower Generating Stations

From provincial and territorial data, it was necessary to further disaggregate hydropower generation into the major river basins shown in Figure 4.1. No data could be found that give Canadian hydropower generation disaggregated for river basins on a national basis. The best available data to substitute for the lack of generation data was located as a dataset providing capacity on a site-specific basis. The Atlas of Canada – Clean Energy Resources and Projects (NRCan, 2018) provides a dataset with a nearly exhaustive list of hydropower generating stations, along with information describing each station's province or territory, capacity (in MW), commission date, and geographic location (latitude and longitude). This data was downloaded as a spreadsheet to use as a basis for determining capacity according to the subnational regions of interest. Some data were missing from this set, including some very small hydropower plants. Several isolated pieces of information were also missing from the dataset, such as commissioning dates for relatively small sites. Efforts were made to fill in missing data, especially regarding commission dates. Often, this information could easily be found on the websites of the operators of the stations. Sources used to fill in missing data include Innergex (2020), Transalta Renewables (2023), BC Hydro (2019), and Hydro-Québec (2021b). After adjustments, the modified Atlas of Canada dataset lists 584 hydropower generating stations in Canada, and provides the name, owner, province, rated capacity (MW), commission date, and geographic coordinates for the majority of sites, although some commission dates at very small sites remained unknown after attempts to find them.

There are a few caveats to usage of the modified Atlas of Canada dataset. Capacities for each hydropower site are listed as a single value, which does not capture dynamics about capacity changes at some sites that have been refurbished, expanded, or have otherwise had their installed capacity rating changed since commissioning. Sites are presented in the data as individual generating stations, so, in some cases, expansion projects appear in the data as separate entries from the initial installation at a location. Some larger sites that have undergone expansions have been listed by construction phases, such as the Sir Adam Beck site (Niagara Falls), where separate commission dates were provided for the original plant, commissioned in 1922, and an expansion that was completed in 1954. Similar discretizing has been included for expansions that have occurred at the Brilliant and Waneta projects in British Columbia, and phases of the Eastmain project in Québec. Some smaller expansion projects or refurbishments have been neglected in the modified dataset. The capacity values that are listed are generally the most recent available figures, which, because GCAM is most influenced by the most recent historical periods, should provide the model with good calibration, but may make earlier estimates of capacity less accurate.

From the modified NRCan (2018) data, each hydropower plant was sorted according to the regions in Table 4.1, based on location. The borders of GCAM basins were extracted as a shapefile from Moirai (Di Vittorio et al., 2020; JGCRI, 2021b) and read into the MyGeodata Converter (GeoCzech, 2020), an online tool that was used to visualize the shapes of the basins on an interactive map of the world. This is the same tool that was used to generate the map shown in Figure 4.1. Using this map, boundaries for the basins were used to help sort the individual sites in the dataset into the appropriate regions. For the most part, spreadsheet filter operations were used to help sort the sites systematically. For example, using the MyGeodata Map, it could be determined that in Ontario, any site north of N 50.5 degrees latitude and east of W 90.5 degrees longitude would safely fall into region 17: Ontario-Hudson Bay Coast. Such operations were repeated until most of the sites were sorted. After repeating this process for the larger rectangular areas, sites located near region boundaries and near more complex border geographies remained unsorted. These were individually inspected and sorted appropriately by determining which basin they are located in with the map tool. Attention was paid to include each site in the province it is located in to prioritize provincial electricity jurisdiction, and then to ensure that the site is sorted into the hydrological basin it is physically located in, whether that coincides with the definitions of the basin shapes shown in Figure 4.1 or not. Stations were sited according to real-world hydrological basins to align with the intent of the GCAM water system to account for water balances at the basin-level. On only rare occasions was a generating station sorted contrary to its location according to Figure 4.1, as placement of hydropower stations very close to the headwaters of a basin is uncommon due to small catchment areas. These data are compared on a provincial basis with the StatCan data in Table 5.4 of Section 5.1.2, which shows good agreement between the datasets.

At this stage, the modified Atlas of Canada dataset now included each generating station's installed capacity, sorted by region and commission date. Sites were then sorted by year of commissioning into 5-year increments. These were defined according to the 5 years in advance of each category (for example, the increment for 2005 adds all sites that were commissioned from 2000 to 2004, inclusive) to generate a time series. Installed capacity provides a starting point to estimate generation, but conversion to generation requires good capacity factor estimates on a local basis, which are addressed in Section 4.2.3.

A few considerations regarding the modified Atlas of Canada capacity estimates are listed here:

- In Labrador, the Twin Falls project was commissioned in 1963 as a temporary measure to supply 225 MW of power during construction of the much larger Churchill Falls development that was commissioned in 1970. The newer, 5,428 MW project inundated the Twin Falls project and therefore necessitated its retirement. This is accounted for in the calculation of capacity in the relevant increments.
- Few hydropower plants have been decommissioned in Canada. Some in eastern Canada, where most early capacity was installed, are now approaching end-of-life. The approach taken in this work may encounter more errors if repeated after decommissioning of legacy sites proceeds. One example of this is the decommissioning of the Milltown Generating Station in New Brunswick, which was built in 1881 (NB Power, 2023).
- The method used to assess historical capacity does not account for periods during which hydropower generating stations may have been taken off-line for refurbishment or maintenance activities, which can sometimes be a period of several years for large projects.

- The Kemano site in British Columbia presented a unique case. This generating station is operated privately by Rio Tinto and is located indisputably within the Pacific and Arctic Basin. However, a 16-km underground tunnel diverts water from the Nechako Reservoir, which is located in the Fraser basin and formed by the Kenney Dam located 200 km to the east (see Figure 4.2). This generating station therefore draws its water from the Fraser Basin and is considered part of that basin for this work.

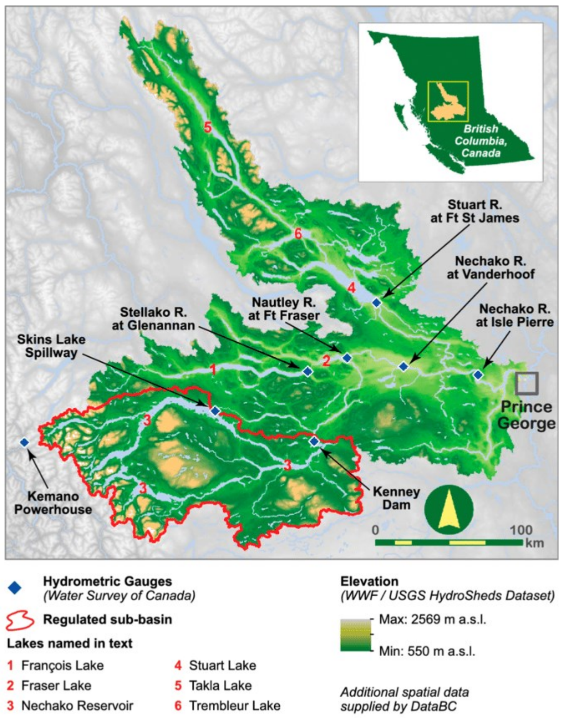

Figure 4.2. Map of the Nechako River basin, a subbasin of the Fraser River. The site of the Kemano Powerhouse is shown to the west of the basin itself. Taken from Albers et al. (2015).

4.2.3 Converting Capacity Estimates to Generation: Capacity Factors

The modified NRCan (2018) dataset can be used to provide hydropower capacity by basin, but does not provide enough information to extrapolate historical generation. Capacity factors vary considerably between generating stations. For this reason, local capacity factors were preferred for conversion of capacity estimates to generation. Computations were conducted using the aggregated StatCan (2022 and 2019) data for generation and capacity to provide hydropower capacity factors for each province and territory (see Section 5.1.3,

Table 5.5), averaged for the 5-year period around 2015 (GCAM's most recent historical period). These capacity factors are representative of all the hydropower generating stations within each jurisdiction combined (rather than other possible measures, such as the average of capacity factors among individual stations). 5-year average capacity factors were computed because hydropower capacity factors can vary substantially from year to year based on interannual climate variation, maintenance outages, or operational decisions. Additionally, planning for hydropower development should consider a long lifetime, and therefore a recent and longer-term average capacity factor is more appropriate for investment decisions, although more detailed and site-specific estimates of capacity factors would be important factors for investment decisions.

The divergent capacity factors among provinces and territories provided justification to, where possible, examine whether capacity factors vary between basins within each province and territory. In several provinces, a single basin contributes most of the hydropower generation, with insufficient development outside of that basin to justify assigning separate capacity factors with scarce data. One such province is Manitoba, where there is about 5,400 MW of installed capacity (StatCan, 2019): only about 10 MW is installed in the Northwest Territories basin (NRCan, 2018), while the rest is located in the Saskatchewan-Nelson basin. For this work, the provinces selected to determine capacity factors at the basin level are British Columbia, Québec, and Newfoundland and Labrador. British Columbia's geography and hydropower development strategies are quite divergent between basins: the Pacific and Arctic Coast basin boasts many small to medium sized developments in a steep, mountainous region with climates moderated by proximity to the Pacific Ocean, while inland regions such as the Pacific Northwest basin have a more dendritic tributary system feeding a major river (the Columbia), in a climate with drier and harsher winters. Capacity factors were distinguished in Québec because it has four basins which collectively account for almost half of the national generation, and the province generally employs different sizes of hydropower developments by basin. The Québec-Hudson Bay Coast region is composed almost exclusively of what may be considered "megadams," with very large reservoirs capable of providing storage to balance interannual runoff variations, while regions such as the Ottawa River in the Great Lakes Basin employ more run-of-river style dams, which are prone to lower capacity factors, as their reduced storage means that short-term dry periods result in less generation.

Newfoundland and Labrador's river basins were separated for capacity factors using the archived StatCan data, which effectively provided both generation and capacity data for the two major basins separately. This disaggregated data was available for the period between 1979 and 2003. Time intervals inside this period were adjusted for the share of total provincial generation attributable to each basin. Given that the difference in capacity factors between the two basins was usually less than about three percent, well within the range of annual variations, it was decided not to extend adjustments outside of the range of known values, but instead to apply the provincial capacity factor for both basins in more recent model periods. The Churchill basin of Labrador will soon see increased generation with full commissioning of the 824 MW Muskrat Falls Generating Station completed at the end of 2021 (NL Hydro, 2021), although there remain some outstanding issues regarding the new transmission line to the island of Newfoundland. Muskrat Falls will likely be able to obtain a high capacity factor (above the provincial capacity factor obtained in recent years) owing to its location downstream of the larger Churchill Falls dam, which will regulate its flow considerably.

The only other province that was a feasible candidate for distinguishing capacity factor on a finer scale, based on having multiple basins that contribute a significant amount of generation, would have been Ontario. Ontario's hydropower is developed by a multitude of private hydropower producers, many of which are relatively small companies, which makes finding generation data for individual sites very difficult, and so this province was omitted from determination of local capacity factors.

For British Columbia and Québec, the list of all generating stations from the modified NRCan (2018) data was used as a base from which to search for generation at each individual stations from other sources. In British Columbia, as of 2015, BC Hydro (2021b) operations account for about 82% of installed hydropower capacity and 71% of generation. On their website (BC Hydro, 2021b), capacity and generation for their facilities were found by navigating through the pages for each of the regions. Most of the remaining private producers in British Columbia sell their power to BC Hydro for distribution through "Electricity Purchase Agreements" (EPAs). Therefore, information about the generation being sold to BC Hydro from each site was documented (BC Hydro, 2014) for many of the smaller companies in one source. Data for the Kemano site, the largest privately-owned hydropower generating station in the province, was obtained separately from the British Columbia Utilities Commission (BCUC, 2008). In total, about 99% of the hydropower capacity in British Columbia (as of 2015) was represented with generation data from these additional sources, although this accounted for only about 90% of generation in the aggregated StatCan data. Such a discrepancy can be reasonably expected: given that generation varies interannually, not all values for generation were available from a consistent year or time period, and the EPAs are not necessarily representative of all generation (excess generation may also be separately sold to the grid or used elsewhere, such as at aluminum smelters). A scaling process was applied to relate sites with known generation to the provincial total, after which generation that was unaccounted for was distributed between the basins accordingly. Scaling factors were defined to represent each basin's contribution to the total generation in a province, accounting for each basin's installed capacity and capacity factor, normalized to ensure that the total contributions from all regions sum to the total (a value of 0 would imply no installed capacity, and a value of 1 would imply that capacity from a single basin contributes all of a province's generation). A rebalancing of capacity factors was applied using the scaling factors to ensure that provincial generation totals agreed with internal basin-scale totals. Finally, the scaling factors were applied to the aggregated generation dataset to determine generation attributable to each basin. This assumes that capacity factors in each basin remain constant over time relative to the others within a province. Table 5.6 in Section 5.1.3 provides a summary of the estimated basin-scale capacity factors for British Columbia.

For Québec, a similar process was conducted as for British Columbia. Generation data for Hydro-Québec were less centralized in a few documents as they were for BC Hydro. Therefore, several sources internal and external to Hydro-Québec were used, including Hydro-Québec (2013, ND) and Gouvernement du Québec (2001). Generation for Alcan sites was found from Régie de l'Énergie du Québec (RÉQ, 2005). Generation data for Innergex sites was obtained by navigating information on their website (Innergex, 2020). For Québec, the sum of capacity and generation accounted for in this manner were 82.9% and 84.1%, compared to 2015 provincial totals. Only about 45.8% of the capacity in the Great Lakes basin was accounted for, giving this estimate much less certainty. Capacity factors for regions in Québec have less variation than for BC, with larger sample sizes due to the higher amount of hydropower generation. As for BC, the generation data collected in this process was used for calibrating historical generation between basins within Québec. Table 5.7 in Section 5.1.3 provides a summary of the estimated basin-scale capacity factors for Québec.

The basin-scale capacity factors discussed for BC, Québec, and Newfoundland and Labrador were used to inform calibration of historical hydropower generation on a regional basis as presented in Section 5.1.4.

4.2.4 Determining Fractions of Historical Generation by Subnational Region

After converting the times series of installed capacity in each subnational region to generation using the appropriate local capacity factor (provincial or basin-specific) for each of the GCAM historical periods, sufficient data was compiled for historical calibration to model hydropower in GCAM-Canada endogenously. However, for inputting calibration data to GCAM, values for each region were divided by the national total to provide, for each subnational region and year, a fraction denoting the hydropower generation attributable to each region. This is conducted because the generation values do not exactly match the hydropower generation in the IEA (2019) World Energy Balances data that GCAM uses. This way, the calibration values are applied in GCAM-Canada as a fraction and are multiplied by the IEA (2019) hydropower values afterward. In effect, this distributes any discrepancy between the datasets broadly across all regions. A comparison of hydropower generation between StatCan and IEA (2019) data is presented in Section 5.1.5 for historical years, along with fractional hydropower generation data for historical periods.

4.3 Hydropower Technology Resource Costs and Model Structure

The author's colleague Matthew Binsted primarily conducted the model development work that allowed for hydropower to be modelled endogenously in GCAM for the Canadian national region (Binsted et al., 2019), while the author's methodological contributions during that stage of work were related to curation and preparation of input data, as well as scenario development and analysis. The methodology to provide GCAM with a hydropower resource supply curve was developed, and scenarios were prepared to investigate cost overruns in the electricity generation sector, which were the focus of a journal article using this initial version of GCAM-Canada with endogenous hydropower for Canada as one region (Arbuckle et al., 2021). An important part of the development of endogenous hydropower was to ensure that input assumptions regarding resource availability, resource cost, technology cost, and shareweights would lend hydropower a reasonable role within the model's electricity and broader energy systems. A sensitivity analysis was conducted to determine reasonable input assumptions, which is presented in full in the Supplementary Notes of Arbuckle et al. (2021). Based on that analysis and literature review of hydropower potential, we reduced the resource availability and shareweight of the hydropower technology to prevent unrealistically optimistic development of hydropower. A significant reason that resource availability may have been too high with the national resource curve was that it included all resources from Canada's northern territories, where large developments would be impractical and prohibitively expensive transmission costs would be required to allow connection with demand centres located far away. We chose not to adjust for resource availability when using the model with subnational resource definitions because the resources in the northern territories were effectively constrained by the very low shareweights obtained by calibration in those regions. However, model calibration was conducted as described later in Section 4.7 to ensure reasonable competition in the electricity generation sector. The core version of GCAM used for the subnational hydropower work is 5.3, while Arbuckle et al. (2021) was based on version 5.1. This section (4.3) describes the data and methods used to determine hydropower costs and resources and describes how the resources were represented in GCAM-Canada.

4.3.1 Hydropower Resource Cost Data

Hydropower resource definitions were developed using a set of data published in Zhou et al. (2015). This data was found to provide the most appropriate globally consistent and comprehensive consideration of hydropower resources among available sources with estimated costs and a suitably detailed degree of resolution (0.5-degree-by-0.5-degree). Data was generously supplied by the lead author of that work, Dr. Yuyu Zhou, of Iowa State University, which provided a list of each grid cell along with exploitable potential (in TWh/year) and estimated cost of development in 2002 USD. This data was limited to sites that were considered reasonably exploitable, excluding sites where hydropower would be likely to cost more than $0.09/kWh in 2002 USD. Data from Gernaat et al. (2017) were also considered to supplement hydropower cost data for this work, but it was decided that their data was not appropriate because they did not provide resource estimates in Arctic watersheds or latitudes north of N 60°, excluding important portions of Canada's landmass. Preliminary work was completed to sort the Gernaat et al. (2017) data points (locations of potential hydropower generation) according to province and basin.

Using the GeoData (GeoCzech, 2020) tool, each grid cell from the dataset was sorted according to province and basin using the same method that was used to sort the individual generating station locations (as in Section 4.2.2), except that these data were grid cells rather than point locations. For grid cells that straddled provincial or national borders, judgement was used to allocate an appropriate percentage of developable potential between the jurisdictions. These data points were split, assigning an appropriate fraction of developable potential to each jurisdiction, ensuring that total developable potential remained the same, while assigning identical estimated costs to the resulting data points. Judgement for resource splitting between jurisdictions was based on a combination of relative area and consideration of hydrology and topography as assessed by a visual inspection of local satellite imagery. There is some discrepancy between the total exploitable potential for Canada in Arbuckle et al. (2021) and this work because the previous work assumed that any grid partially located in Canada could be developed in Canada, yielding a total of 1,610 TWh. The total after allocating some potential to the United States in shared grid cells was reduced to 1,506 TWh.

A noticeable gap in the Zhou et al. (2015) data was observed in the region of the Nelson River Hydroelectric Project in northern Manitoba. Given that this is the primary region identified by Manitoba Hydro for a series of potential further developments, it was decided that it would be reasonable to supplement the Zhou et al. (2015) data in this vicinity. A panel commissioned by Manitoba Hydro (2013) presented a resource assessment with cost estimates for proposed sites along the Nelson and Churchill Rivers. Sites were classified by basin as was done for the Zhou et al. (2015) data. Several of the Manitoba Hydro data points exceeded the upper limit of costs (greater than $0.09/kWh in 2002 USD) considered in the Zhou et al. (2015) dataset used for this analysis, but these were retained.

All of the Zhou et al. (2015), Manitoba Hydro (2013), Gernaat et al. (2017), and modified Atlas of Canada existing site (NRCan, 2020) data have been uploaded onto a single interactive map, using the "Google My Maps" tool, which can be accessed at this link: https://www.google.com/maps/d/edit?mid=1zxrvg3E1A6g8eIt9Ku_jKBsedTxtviWw&usp=sharing. Each of these datasets are presented as map layers in which individual points can be viewed by clicking on colour-coded pins. Various pieces of accompanying information can be viewed when selecting data points on the map, depending on what was available in each dataset. The Gernaat et al. (2017) data are broken into 2 layers (east/west) because the number of sites exceeded the maximum that could be stored in one layer.

4.3.2 Model Structure and Resource Classification

Subnational hydropower was established in GCAM-Canada using a "nested" structure. Hydropower was defined at the subsector level, as in core GCAM, but an additional level of subsector was established for each province and territory. Following this, each province/basin subregion was assigned a technology, itself subsidiary to the appropriate provincial or territorial subsector. In GCAM, this allows hydropower to compete for market share firstly among the provinces and territories, after which generation is computed among the basins internal to those jurisdictions. This method of competition was selected because electricity generation in Canada is primarily developed and operated to satisfy internal provincial electricity demand or commitments, while the basin in which that development occurs is relevant for decision-making only according to the economics between remaining developable sites in those basins. This structure also anticipates eventual integration with the regional GCAM-Canada model, which will model electricity demand provincially, and therefore benefit from provincially segregated hydropower supply.

Where appropriate, a smooth resource curve was determined for each subnational hydropower technology to specify the competitiveness of resources in each basin and enable competition within the model for market share. However, such resource curves could not be generated for all regions based on a lack or small amount of resource-cost data in some smaller regions. Based on the characteristics of the subnational regions being considered, it was necessary to classify how hydropower resources would be represented in GCAM-Canada. Table 4.2 presents a summary of the type of hydropower resources selected for each subnational region in Canada. Some regions had negligible developable hydropower resource identified by the cost-supply data, either because of a lack of any data points, or because they had two or fewer data points (from which a smooth resource curve cannot be generated to be representative of the resource). Of the regions with negligible identified developable resources, there are two categories: those in which there has not been historical generation, which were neglected entirely, and those in which there has been a small amount of historical generation, the latter of which were excluded from curve fitting and instead assigned the generation they had in 2015 as "fixed output." The fixed output regions do not compete in GCAM's market for hydropower resources, but are exogenously specified and accounted for in the same way that GCAM has historically applied hydropower (all model regions outside of Canada also still apply this "fixed output" method for hydropower). In the Canadian subnational fixed output regions, generation as of 2015 is assumed to continue unchanged in all future periods, effectively preventing any new development, expansions, or decommissioning. There are 4 regions that fall into this category, which collectively accounted for only 2.72 TWh of generation in 2015, less than 1 percent of total generation. Most of these regions have few installed plants with relatively disaggregated catchments that do not have a well-established main stream within their areas. One of these regions, the Saskatchewan-Northwest Territories region, has just one hydropower development, the 111 MW Island Falls Hydroelectric Station located on the upper Churchill River (SaskPower, 2021). Several of the regions that did not contain identified resources had very small areas, with only a few grid cells. For example, the Alberta-Northwest Territories and Alberta-Missouri River regions each contain only a few grid cells of area at the upstream reaches of these drier-climate watersheds, making an assumption of negligible resources reasonable.

Table 4.2. Summary of type of hydropower resource assigned by region for GCAM-Canada.

Subnational Region ID	Province/ Territory	Basin	Type
1	BC	Pacific and Arctic Coast	Smooth Curve
2	BC	Fraser	Smooth Curve
3	BC	Pacific Northwest	Smooth Curve
4	BC	Mackenzie	Smooth Curve
5	AB	Mackenzie	Smooth Curve
6	AB	Northwest Territories	Neglected
7	AB	Saskatchewan-Nelson	Smooth Curve
8	AB	Missouri River	Neglected
9	SK	Mackenzie	Smooth Curve
10	SK	Northwest Territories	Fixed Output
11	SK	Saskatchewan-Nelson	Smooth Curve
12	SK	Missouri River	Neglected
13	MB	Northwest Territories	Smooth Curve
14	MB	Saskatchewan-Nelson	Smooth Curve
15	MB	Hudson Bay Coast	Neglected
16	ON	Saskatchewan-Nelson	Fixed Output
17	ON	Hudson Bay Coast	Smooth Curve
18	ON	Great Lakes	Smooth Curve
19	QC	Hudson Bay Coast	Smooth Curve
20	QC	Great Lakes	Smooth Curve
21	QC	St Lawrence	Smooth Curve
22	QC	New England	Neglected
23	QC	Atlantic Ocean Seaboard	Smooth Curve
24	NB	New England	Smooth Curve
25	NB	Atlantic Ocean Seaboard	Fixed Output
26	PEI	Atlantic Ocean Seaboard	Neglected
27	NS	Atlantic Ocean Seaboard	Fixed Output
28	NL	Churchill	Smooth Curve
29	NL	Atlantic Ocean Seaboard	Smooth Curve
30	YT	Pacific and Arctic Coast	Smooth Curve
31	YT	Mackenzie	Smooth Curve
32	NT	Mackenzie	Smooth Curve
33	NT	Northwest Territories	Neglected
34	NT	Pacific and Arctic Coast	Neglected
35	NU	Northwest Territories	Smooth Curve

4.4 Developing Hydropower Resource Supply Curves

For the subnational regions that could be represented by smooth resource curves, a procedure was developed to systematically process the resource data into data tables associating each grid's resources with costs. The hydropower resource datasets were read and processed in GCAM through a pre-built R package called gcamdata (Bond-Lamberty et al., 2019), which converts relevant input data to the files that are used to run GCAM. A module has been developed using gcamdata that processes the gridded and regional data, systematically generates appropriate resource curves to characterize each subnational region, and calibrates output for historical periods.

4.4.1 Hydropower Resource Data Preparation in R with gcamdata

The datasets based on Zhou et al. (2015) and Manitoba Hydro (2013) were taken as input files to a gcamdata chunk. Within gcamdata, the datasets were merged into a single, gridded, cost-supply resource table for Canada. A dataset of existing hydropower plants in Canada by location (from the modified Atlas of Canada data), with capacity, was also read in as input. Where necessary, unit conversions were conducted to ensure that potential was expressed in EJ and prices were deflated to 1975 USD, the basis used in the model.

From this set of combined hydropower resources, there were a few additional complications to consider. GCAM treats resource information as total availability, not just that available for future development. Therefore, adjustments had to be made to the resource data to ensure that existing generation could be represented within each of the grid cells in the data.

The combined resource data was therefore compared against the modified NRCan (2018) capacity data to check whether resource estimates allow for existing generation at a minimum on a grid-by-grid basis. For these purposes, because the modified NRCan (2018) data provides only capacity, existing generation at each site was calculated by converting from the appropriate capacity factor by province (and basin, for Québec). This ignores that individual generating stations have varying capacity factors, but nevertheless ensures adequate resources are available within each subnational region. In grids where some resource potential was indicated, but not enough to account for existing generation, the resource estimate was increased by the amount required to ensure that the grid allows exactly the amount of existing generation (assuming no further development within that grid). Costs were not altered from the resource estimate. In grids where no resource potential was identified, but generation was already established, the resource estimate was increased to the value of existing generation, and the price was assumed to equal the lowest-cost price point within the subnational region. The relatively low-cost estimate for these sites is based on an assumption that lower-cost sites are more likely to have already been developed.

After all adjustments to the resource data, and including the regions which were assigned fixed output, the total exploitable hydropower potential for Canada was found to be 1,856.7 TWh/year.

From the table of processed cost-supply data, a process within gcamdata was developed to establish smooth resource curves for each subnational region.

4.4.2 Generating Resource Supply Curves in gcamdata

The curve to which the cost-supply data were fitted was chosen to be the same format as is used in GCAM for other renewable energy resources (JGCRI, 2021a). Equation (4.1) gives the general curve form:

$$\mathrm{Q} = R * \frac{P^C}{({m_P}^C + P^C)} \qquad \text{Eq. (4.1)}$$

Where Q is the quantity of electricity produced (EJ) at a price, P, per gigajoule produced (1975$/GJ). R is the maximum resource available for a region, C is a fitted curve exponent, and m_P is a "mid price" at which one-half of the maximum available resource is produced (JGCRI, 2021a).

In this curve format, the price, P, represents only the incremental price of building a hydropower installation capable of producing a GJ per year (averaged among any interannual climatic and operational variations). Prices from the cost-supply data were therefore adjusted so that only the change between prices in each region was used for curve-fitting. Therefore, within each region, the lowest-priced data point was assigned a relative price of 0. GCAM separately considers capital and operations and maintenance costs, and therefore, the purpose of these curves is only to represent incremental prices in addition to base costs (that is, the increment by which prices rise as each successively optimal resource option is exploited). Capital and operations and maintenance cost assumptions are consistent with those used for Arbuckle et al. (2021), which are based on a relevant dataset supplied by Environment and Climate Change Canada by communication with their Economic Analysis Directorate. The costs for the year 2015 are assumed to be valid for all historical and future GCAM time periods.

"Mid prices" are determined using an algorithm which finds the cost-supply points on either side of one-half of the maximum resource for each region. The mid price was then interpolated between these two prices using this formula:

$$\mathrm{m}_P = \frac{R*(P_2-P_1) + 2*Q_2*P_1-2*Q_1*P_2}{2*(Q_2-Q_1)} \qquad \text{Eq. (4.2)}$$

Where the variables are the same as for Equation (4.1), but with subscripts 1 and 2 representing the price point on either side of one-half of the maxSubResource.

With this information, the curve exponents for Equation (4.1) were determined for each region by applying a process to minimize error between cost-supply data points and the smooth resource curve. Derived curve parameters from the smooth resource curves were saved to a file which was then used to inform the hydropower resource definitions for GCAM.

Samples of smoothed resource curves are presented in Figure 4.3. The curves can be compared against Curve A to understand how parameter values are reflected in the shapes of the curves. All curves pass through one-half of the maximum resource at the midPrice. For this example, the maximum resource is defined as "Res" in the legend, the midPrice as "m_P," and the curve exponent as "C." Higher midPrices translate the curve upward. Curve exponents higher than 1 yield rapid initial price increases, followed by a relatively flat marginal price increase, while exponents below 1 yield slow initial price increases until steeply increasing through the midPrice. Higher maximum resources stretch the shape rightward, while lowered maximum resources stretch the shape leftward.

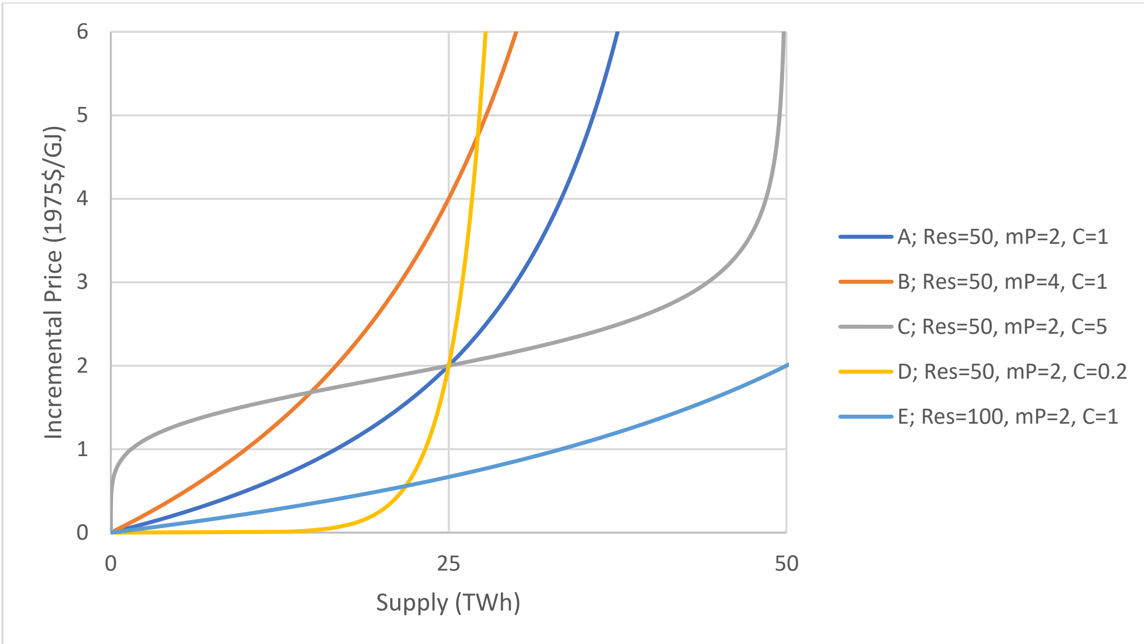

Figure 4.3. Representative smooth resource supply curves. Curves are labelled A to E, along with maximum resource (Res), midPrice (mP), and curve exponent (C).

Hydropower resource supply estimates and costs determined by this process are presented in Section 5.2.

4.5 Scenario Design

Alternative policy scenarios were designed to address the research questions and to highlight the role that endogenous hydropower could play in GCAM-Canada for applied policy frameworks with varying stringency. For this work, scenarios were developed to show model output without climate policies ("NoPol"), with continuing policies applied ("ContPol-"), and with greenhouse gas emissions constraints consistent with Paris Agreement targets ("Paris-") applied. For Canada, the continuing policy and greenhouse gas emissions constraint scenarios include expected coal power phase outs, stronger methane emissions reductions in the oil and gas sector, and a partial wind power subsidy (phased out after 2025). Methane emissions reduction in oil and gas production is incorporated by assignment of a marginal abatement cost (MAC) curve which assigns methane emissions reduction according to carbon price. This method is used for consistency with how GCAM calculates non-CO_2 GHG emissions. The implementation of carbon prices in GCAM was discussed in Section 3.5. For the continuing policy scenarios, carbon prices are applied exogenously, but for greenhouse gas emissions constraint scenarios, they are determined endogenously. The GHG emissions constraint scenarios solve for the carbon prices that would be required to reduce emissions to specified levels. The ContPol scenarios do not include exogenous future climate policy assumptions for model regions other than Canada, but trends until 2015 are included for all regions as part of the model's historical calibration. The GHG emissions reduction scenarios include basic NDC (nationally determined contribution) targets for all global model regions, which were supplied from JGCRI in early 2021, including commitments they were aware of at the time. Notably, these NDCs represent targeted GHG emissions reductions, rather than implemented policies. The ContPol50 scenario is designed to simulate the Canadian carbon pricing plan prior to the 2021 policy change, which saw carbon prices rise to $50/tCO2e in 2022 and then hold constant, effectively deflating over time. The ContPol170 scenario aims to simulate the recent commitment to increase carbon prices to $170/tCO2e by 2030, but a further assumption is made that the carbon prices increase with inflation thereafter to maintain the real price. The Paris2016 scenario is designed to simulate the constraints necessary to achieve Canada's 2016 Paris Agreement target of 30% domestic GHG emissions reduction from 2005 to 2030 and 80% reduction to 2050. The Paris2021 scenario simulates the strengthened 2021 target for 40% GHG emissions reduction from 2005 to 2030 and 100% (net zero) by 2050 for Canada. The Paris2021 scenario assumes that the biomass produced for Canada in Paris2016 is a "ceiling" for what can reasonably be produced in Canada. With high GHG emissions constraints, GCAM tends to rely rather extensively on biomass (including with CCS) to help achieve targets (by sequestering CO_2), perhaps beyond levels that would be considered practical, so this constraint was added to discourage extensive land use changes that could occur if biomass production increased very substantially. Table 4.3 provides a matrix of the climate policy scenarios explored in this work.

Table 4.3. Climate policy scenario matrix.

Scenario	Description	Storyline
NoPol	Standard assumptions from core GCAM apply, with no exogenous policy implementation	No climate policy applications in any future period
ContPol50	Continuing policies with carbon tax increasing to $50 CAD/tonne CO2e (nominal) by 2023 and no subsequent increases to account for inflation	Reference case, most similar to CER Energy Future (2020) Reference case
ContPol170	Continuing policies with carbon tax increasing to $170 CAD/tonne CO2e (nominal) by 2031 and rising with 2% inflation per year thereafter	Impact of stronger carbon pricing on Canadian energy systems
Paris2016	Continuing policies with emissions constraints consistent with Canadian NDCs set in 2016 (30% GHG reduction from 2005 to 2030 and 80% by 2050) and global NDC application	Canada works to achieve its NDCs which were set on joining the Paris Agreement in 2016
Paris2021	Continuing policies with emissions constraints consistent with Canadian strengthened NDCs declared in 2021 (40% GHG reduction from 2005 to 2030 and 100% by 2050) and global NDC application. Biomass production is limited to that determined in Paris2016	Canada works to achieve more ambitious emissions reduction in excess of its original 2016 Paris Agreement commitments with net zero emissions by 2050

Core GCAM does not include electricity trade between regions (JGCRI, 2021). For all of these scenarios, bilateral electricity trade between Canada and the USA is enabled to capture this important dynamic, however this is applied only at an aggregate national level. Therefore, regional dynamics such as transmission line infrastructure and local electricity demand and generation growth rates are not captured.

Carbon prices are applied to non-CO_2 GHGs using global warming potentials (GWPs) from the IPCC's Assessment Report 4 (GHG Protocol, 2016) for consistency with GCAM version 5.3's usage of these GWPs. Carbon prices are applied to LUC emissions at a factor of 1% that applied to other emissions in 2020 and rise gradually to 10% by 2050 to account for the higher difficulty and time required to implement land use changes for the purpose of GHG emissions reduction, which is not likely to respond rapidly to carbon price signals. This profile is consistent with assumptions used by JGCRI in core model scenarios for Canada and most other regions. The carbon prices for each scenario are presented as results in Section 5.4.3 because the carbon prices for the GHG emissions constraint scenarios are determined from model output. Methane emissions reductions for the oil and gas sectors are also shown in the Results chapter because the method by which they are assessed in GCAM is to associate them with carbon prices.

To specify exogenous carbon prices for the model, it was necessary to convert intended carbon price pathways to 1990 USD per tonne of carbon, which is the base unit specified in GCAM for all model periods. For these calculations, the intended carbon price in nominal CAD was deflated from the calibration period and converted using methods consistent with those used for GCAM-Canada in similar currency conversions. Using carbon price assumptions as of the year 2020, Canadian dollar conversions to previous years are deflated to 2010 CAD based on FRED (2021a) to be consistent with the year in which other CAD to USD conversions are presently conducted in GCAM-Canada. Currency conversion in 2010 from CAD to USD is specified at 1 USD = 1.03 CAD, based on USDA (2021) exchange rate data for 2010. USD amounts are converted from 2010 to 1990 to be consistent with the "gdp_deflator()" function in gcamdata, which is based on FRED (2021b). Canada's carbon prices are set in terms of carbon dioxide equivalents (CO2e), so conversion between the molar mass of carbon dioxide (44.0095 g/mol) and carbon (12.0107 g/mol) is conducted to convert to tonnes of carbon for GCAM input. The chosen nominal carbon prices are converted to real 2020 CAD and then to the input data (1990 USD/tonne C) for carbon price scenarios as shown in Table 4.4. Inflation is assumed constant at 2% per year. Carbon prices for Canada are based on ECCC (2021b), which indicates how much the carbon price is planned to rise each year, but are adjusted for the fraction of each year in which they are effective to reflect that price increases are scheduled each April 1, rather than at the start of the year. For the ContPol50 scenario, the peak nominal carbon price of $50 is assumed to be reached in 2023, but the real price falls afterward due to inflation. For the ContPol170 scenario, the maximum real price of $170 is assumed to be reached in 2031, after which real prices are assumed to keep pace with inflation, implying a rising nominal price.

Table 4.4. Exogenous carbon price specifications for climate policy scenarios in nominal and real 2020 CAD/tonne CO2e and 1990 USD/tonne.

Year	ContPol50 (nominal CAD/tonne CO2e)	ContPol50 (2020 CAD/tonne CO2e)	ContPol50 (1990 USD/ tonne C)	ContPol170 (nominal CAD/tonne CO2e)	ContPol170 (2020 CAD/tonne CO2e)	ContPol170 (1990 USD/ tonne C)
2020	27.5	27.5	49.19	27.5	27.5	49.19
2025	50	45.2	80.84	91.25	82.48	147.54
2030	50	40.86	73.08	166.25	135.84	242.98
2035	50	36.93	66.05	184.01	136.12	243.49
2040	50	33.38	59.71	203.17	136.12	243.49
2045	50	30.17	53.97	224.31	136.12	243.49
2050	50	27.27	48.79	247.66	136.12	243.49

Standard GCAM carbon price implementations assume that the carbon price is implemented evenly within an entire region among all emissions, which is a simplification of the system in Canada discussed in Section 2.1.2. Substantial additional model developments and scenario assumptions would be required to accurately account for the more specific subnational policy implementation and taxation nuances discussed there.

4.6 Model Configuration, Computation, and Output

GCAM modelling can be conducted with fairly basic computing systems, provided they are able to install each of the programs mentioned in the prelude before Section 3.1. The computer selected for this work was purchased in 2018 and includes 32 GB of RAM, an Intel Core i7-8700 processor, and a 1 TB solid state drive. With this fairly powerful computer, an individual GCAM v5.3 simulation with endogenous, subnational Canadian hydropower takes about 30 minutes for a complete model run, including the printing of output to the XML database. Weaker computers may take considerably longer to conduct the same simulations.

The process for model development and configuration is shown as a conceptual diagram in Figure 4.4 and explained in detail in the following subsections.

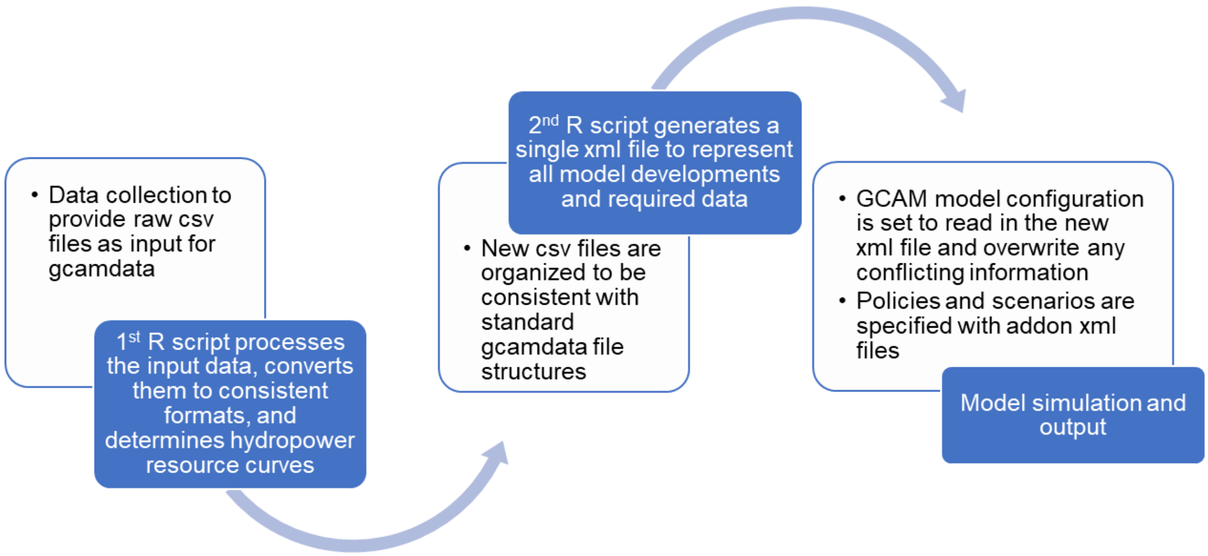

Figure 4.4. Process for model development and configuration.

4.6.1 Model Development in gcamdata

A new chunk was written as an R script to specify new model features and process input data in gcamdata, which was introduced in Section 3.4. This script calls upon input data and input from other chunks it is dependent on, conducts unit conversions, uses functions based on those in the dplyr and tidyr packages (Wickham et al., 2019) to process data into consistent formats, taking as input historical hydropower generation, default shareweights and interpolations, technology lifetime and efficiency assumptions, logit coefficients, capital and operations and maintenance costs, and capacity factors. The chunk also processes the hydropower resource curves as described in Section 4.4.2. This script establishes an additional level of subsectors for Canadian hydropower to enable the nested model structure. Outputs from this chunk are saved as files with standardized columns and naming conventions to ensure that components are associated with the desired model regions, supply sectors, subsectors, and technologies.

A second chunk was then written to call upon the outputs from the first chunk and convert them into a single XML file which can be called upon by GCAM to specify all of the data necessary to include the new subnational hydropower regions for Canada.

4.6.2 Model Computation and Output

A GCAM model run for a scenario is conducted by choosing the desired model input, scenario assumptions, and policy choices to include in the "configuration.xml" file. XML files desired to be used for a model run are added or removed from the configuration XML file. By reading the XML file for endogenous subnational hydropower into the configuration file after the XML which specifies the electricity supply sector (the same as for core GCAM), the new file adds information and supersedes the data anywhere there may be conflicts. Most XML files input to the configuration are produced by gcamdata, but more can be specified by the user as “addon” files. Often, addon files are used to supply the assumptions and policies that are applied to each model scenario. Common types of policies that can be included as addon files are related to emissions (carbon or GHG prices, emissions constraints, or climate constraints), energy production, and land use (JGCRI, 2021a), but can extend to further applications. User specifications for shareweights, input assumptions, and so forth can also be included as addon files that are called in the configuration.

A model simulation is conducted by choosing and saving a configuration file. This file specifies the input data and scenario parameters that the user specifies for a scenario, as well as information regarding which model periods to run the simulation for, what to name the scenario in output, maximum solver iterations to use, and so forth. Many of the input files are prepared and saved in the desired XML format by running the gcamdata package successfully prior to a model run. Once all of the XML files specified in the configuration file are saved in the correct file locations, a “run-gcam” batch file is executed to start computation. This opens a command prompt window, which provides text indicating the progress of a model run. For a successful model run, this will show the parsing of input XML files, and will warn about some possible errors that could result in an inability to solve. If the are no errors, the command prompt will display model solution period-by-period and indicate total iterations required for solution in each period. This textual information is saved to aid in error detection and an accompanying XML file is generated to help with debugging. If no errors occur, model output is printed to the XML database, which saves these files using the “BaseX” system (BaseX, 2021). These databases can include multiple GCAM scenario runs. These databases can become very large, with output for individual model runs taking up over 1 gigabyte to several gigabytes of storage. From the database, output can be viewed from a Java tool packaged with GCAM called the “ModelInterface,” or can be read by alternative programs, such as R or Python, for visualization of results. Model results are viewed as queries for output variables of interest, which call upon attributes of XML output, as defined using the XPath query language (JGCRI, 2019). A variety of useful queries are pre-defined along with core GCAM, including the range of system components, with major categories consisting of energy, agriculture and land use, emissions, socioeconomics, policy, water, and general outputs. Alternate queries can be defined using new XPath commands, if desired.

Figure 4.5 shows a sample of the information available in the ModelInterface for a scenario. In this figure, the user has chosen a sample scenario of interest, model region (Canada), and query ("elec gen by subsector"). In this sample, electricity generation for each subsector in Canada can be viewed in both table and graphical format. This table can be copied and pasted into spreadsheet programs like Excel for interpretation or processing. Between options to use the ModelInterface itself, Excel, R, or Python, there are many ways in which GCAM output data can be explored, visualized, and post-processed.

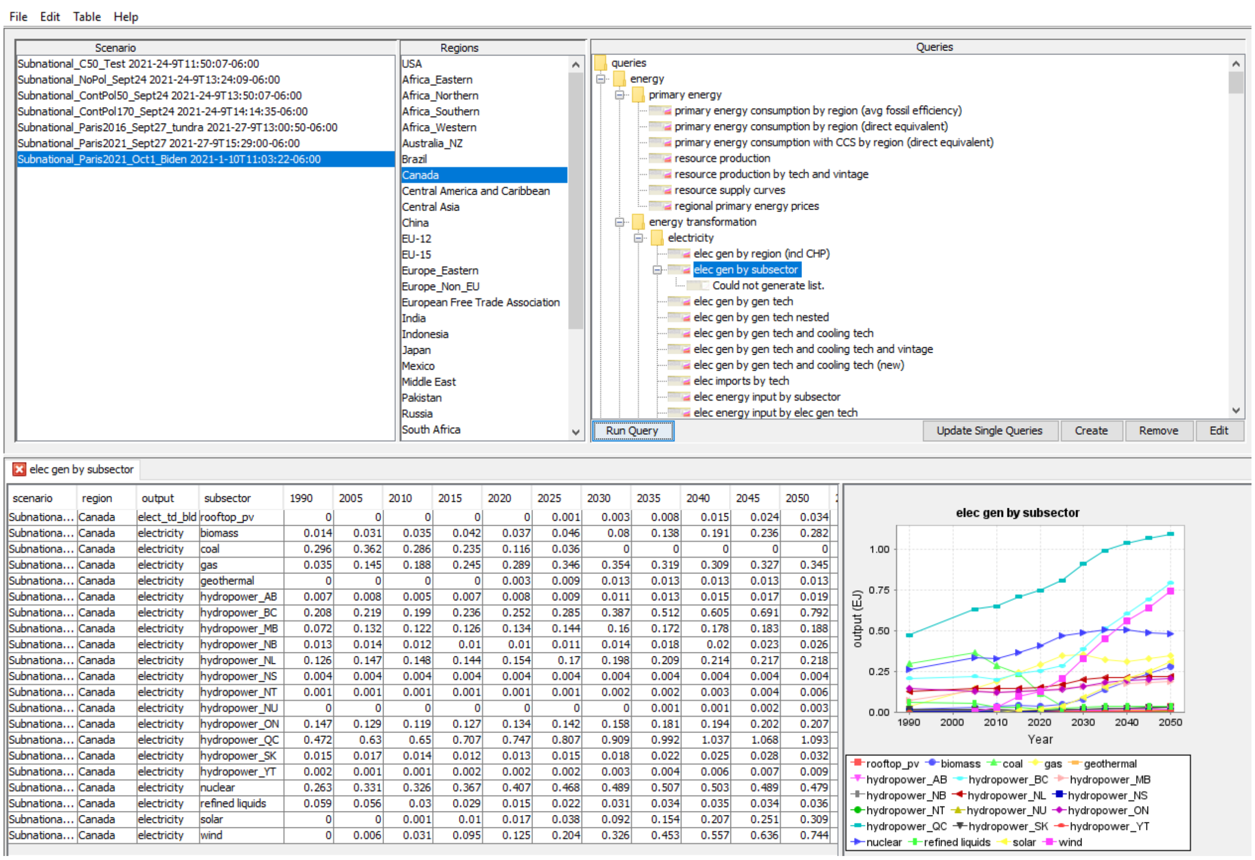

Figure 4.5. Sample of GCAM ModelInterface output.

4.7 Model Calibration for Near-Term Expectations

Once model simulations could be conducted, an iterative process was used to ensure that electricity generation sector results were reasonable. GCAM is trained using data from historical periods with observed data, including IEA (2019) for their World Energy Balances, which helps to set internal model calibrations such as shareweights. Where feasible, future assumptions are informed by historical observations, although in some cases, future model behaviours may be expected to diverge from historical trends. Future periods are calibrated by controlling input assumptions that affect future outcomes, such as cost reduction with technological maturation and shareweight interpolations. Core GCAM calibration choices are determined by and regularly assessed in model updates by JGCRI as part of public releases of the model. In the core version of GCAM, shareweights and shareweight interpolations are assigned by the JGCRI developers for electricity generation technologies based on expert judgement of likely future trends. Because the Canadian hydropower technology developed for this work has been changed considerably from the fixed assumptions in the core model, and hydropower is the dominant technology for Canada, against which all other electricity generation technologies are then calibrated, recalibration is needed to ensure electricity generation technologies compete with each other in a reasonable manner. The intent of these recalibrations is to prevent particularly unrealistic situations from developing in future model periods. The author used values for electricity generation technology from the CER Energy Future (2020) reference scenario to assess whether near-term electricity generation technology trends were reasonable. The reference scenario from CER (2020) uses similar carbon price and policy assumptions as the author's ContPol50 scenario. This comparison was used to help decide which changes could be implemented to help make this work's electricity generation results relatively consistent with expected near-term trends, as indicated in CER (2020). This is not an attempt to have GCAM-Canada output align exactly with CER (2020) values. CER (2020) provides an active projection and therefore include data and more specific assumptions that are not incorporated in GCAM-Canada, such as projected opening dates for discrete electricity generation plants currently being developed, provincial climate policy initiatives, and energy or fuel efficiency standards, and therefore the models should not be expected to behave identically in future periods.

Using the baseline Continuing Policy (ContPol50) scenario, initial model simulations were conducted to assess model behaviour and to determine whether any adjustments should be made to model input to help provide realistic future results, using the near-term trends from CER (2020) as a rough guide. These assessments focused on each major electricity generation technology but did not extend to other sectors. Most of these calibrations were applied not by using gcamdata, but by using addon XML files included in the configuration of scenarios. The following list describes some of the changes that were made using addon files to help provide more realistic model results.

- Coal power phase-out: Initial model runs continued to generate more electricity from coal beyond 2030 than should be expected with Canada's plans for coal power phase-out. The half-life of coal generation was reduced from 15 to 5 years to help accelerate the phase-out.
- Electricity generation capital costs: Initial model runs saw little uptake of wind and solar power. An updated file was supplied by JGCRI that generally reduced some electricity sector capital cost assumptions, especially for renewable technologies to be consistent with falling development costs, according to their latest work in this area. This is consistent with changes that were made to update electricity costs in the update from GCAM 5.3 to 5.4, but this is not an exhaustive update to GCAM 5.4's electricity sector.
- Hydropower shareweights: Early model runs displayed an unreasonable affinity for hydropower in near-term periods, to the exclusion of deployment of other technologies. To address this, the shareweight of the hydropower generation technology (endogenous) was set to a value of 0.25 from 2015 until 2025 to prevent sudden development to values higher than can be reasonably expected based on the fleet of hydropower plants currently under construction (a majority of the capacity of plants that will be operating by 2025 are already under construction, so the expansion in capacity by that time will likely be limited to a value near that amount). This shareweight then raises linearly from 2025 to 2035 until reaching a fixed value of 0.5.
- Natural gas (combined cycle) shareweights: Based on historical calibration, the natural gas (CC) technology is assigned a cheap price, but a very low shareweight relative to natural gas (steam/CT) because combined cycle power plants were not frequently developed in Canada before 2015. Combined cycle natural gas is now the dominant technology developed among new plants and its higher efficiency makes it much more economic than older, less-efficient systems. For this reason, the natural gas (CC) shareweight is adjusted to match that of natural gas (steam/CT), which is calibrated to 1. This encourages more natural gas generation in near-term periods because of the reduced cost of combined cycle plants.
- Solar CSP storage: In initial runs, solar CSP grew unreasonably quickly in Canada (much faster than PV) because this technology is assigned a very high capacity factor. Given the lack of success with solar CSP in Canada and relatively high costs in Canada's climate (Djebbar et al., 2014), this technology was not considered viable in

Canada in the near-to-medium-term. This technology is assigned a shareweight of 0 to exclude its development in Canada.

- USA electricity net own use prices: Initial model runs showed sudden price increases for electricity generation in the USA in the first future model period after 2015. To mitigate this sudden difference, the price of historical generation in the USA was increased by a fixed amount equivalent to the value of the initial sudden increase, preventing sudden changes from 2015 to 2020. GCAM does not calibrate historical periods by price, so this change did not impact electricity generation development in a significant way, but helps to prevent a sudden shock in electricity prices differences between Canada and the USA, which drives the modelled bilateral electricity trade between these countries.
- Wind power retirement: Initial model results show that substantial retirements of wind power would occur simultaneously around 2040. Wind retirement was adjusted to promote smoother transitions between construction and retirement of units. This is achieved by modifying parameters of the modelled wind technology's "s-curve shutdown decider," which is used to specify the rate at which developed units are retired (JGCRI, 2021a).

A further adjustment was made to gcamdata input data. In BC, using basin-scale capacity factors for future GCAM periods was found to be disadvantageous for achieving reasonable model results. For example, the BC-Mackenzie region currently achieves a high capacity factor owing to its control of flow by a very large reservoir, Williston Lake. This reservoir also regulates flow for the other generating station in that basin, in series. With a relatively higher capacity factor, GCAM interprets development for that basin as being relatively inexpensive, but does not adequately consider that potential future dams (except Site C, which is now under construction) would not be able to be developed in series along the Peace River or with such large reservoirs, and would thus likely not be able to obtain such high capacity factors in the future. After testing the model, each basin in BC was assigned the provincial capacity factor for future model periods, which helped to yield more reasonable model results. The provincial capacity factor was applied for the two basins in Newfoundland and Labrador, but Québec basin-scale capacity factors were retained as input to the model for informing future resource development.

After calibration of the model's electricity generation sector, model simulations are conducted as described in Section 4.6 to generate the results that are presented in Sections 5.3 and 5.4.

Chapter 5 Historical Hydropower and Resource Estimates

This chapter presents intermediate results related to historical hydropower development in Canada (Section 5.1), which are necessary as input for calibration of GCAM-Canada, but are also of use for other energy system or integrated assessment models. Results for hydropower resource supply estimates for subnational regions in Canada, along with economic considerations, are then presented in Section 5.2.

5.1 Historical Canadian Hydropower Development

This section presents a profile of historical hydropower generation in Canada with subnational detail, data that until now has been absent from literature. The section begins with provincial/territorial profiles of hydropower capacity and generation and then using estimates of capacity for all hydropower plants in Canada by locations, extends the historical profiles for subnational regions.

5.1.1 Historical Provincial Hydropower Development

This subsection presents figures and tables to summarize the data aggregated for model calibration which comprise a historical profile of hydropower development in Canada with provincial detail. Groupings of provinces and territories within figures are chosen to ensure that the data are easily readable, with values of similar sizes being grouped together. Please note that the y-axis scales between figures which present the same variable are often different from figure to figure to provide profiles with clearer resolution.

Figures 5.1-5.4 present historical hydropower generation for each of the Canadian provinces and territories based on the aggregated StatCan data, with intermittent data starting in 1925, and continuous from 1959 to 2020. Hydropower generation fluctuates significantly from year-to-year in addition to changes from installation of new capacity. This is especially apparent in Figure 5.3, which shows generation in the smaller provinces, where there have been fewer developments with large reservoirs to reduce the effects of interannual climate variability. Hydropower generation is affected on an interannual basis by operational choices to balance competing reservoir uses, changing costs of resource and electricity production among technology options, and fluctuating electricity demand due to changing economic and weather conditions, and consumer behaviours (Bonnet et al., 2015; Mendes et al., 2015).

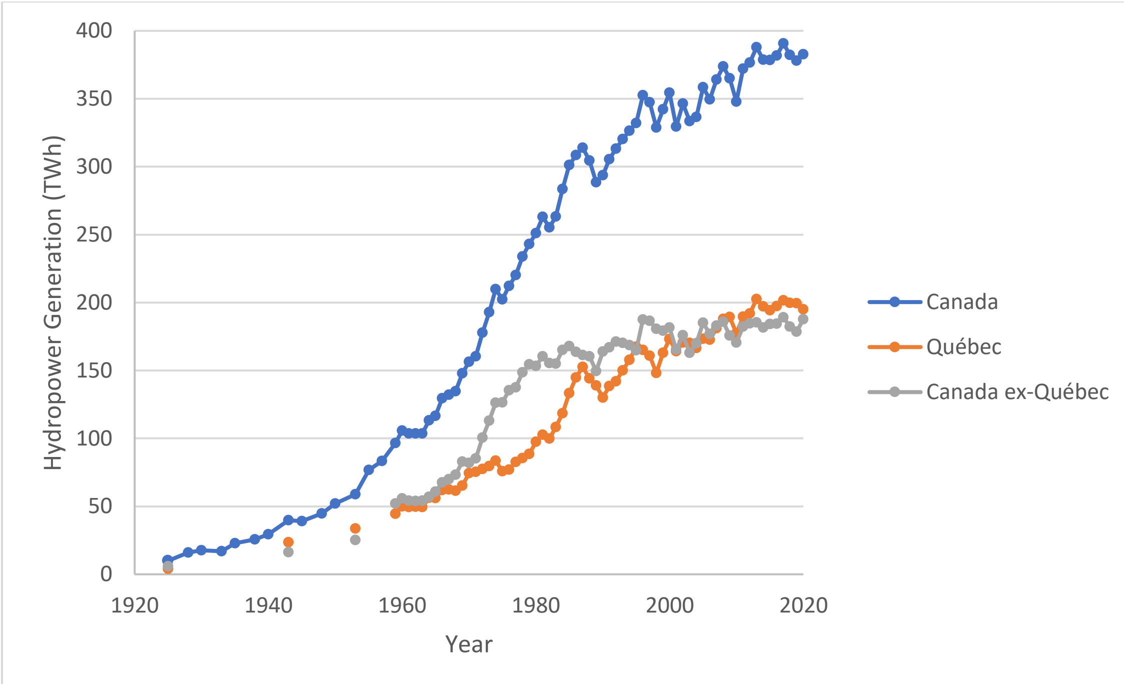

Figure 5.1. Historical hydropower generation (TWh) for Canada, Québec, and Canada without (ex-) Québec (aggregated StatCan data).

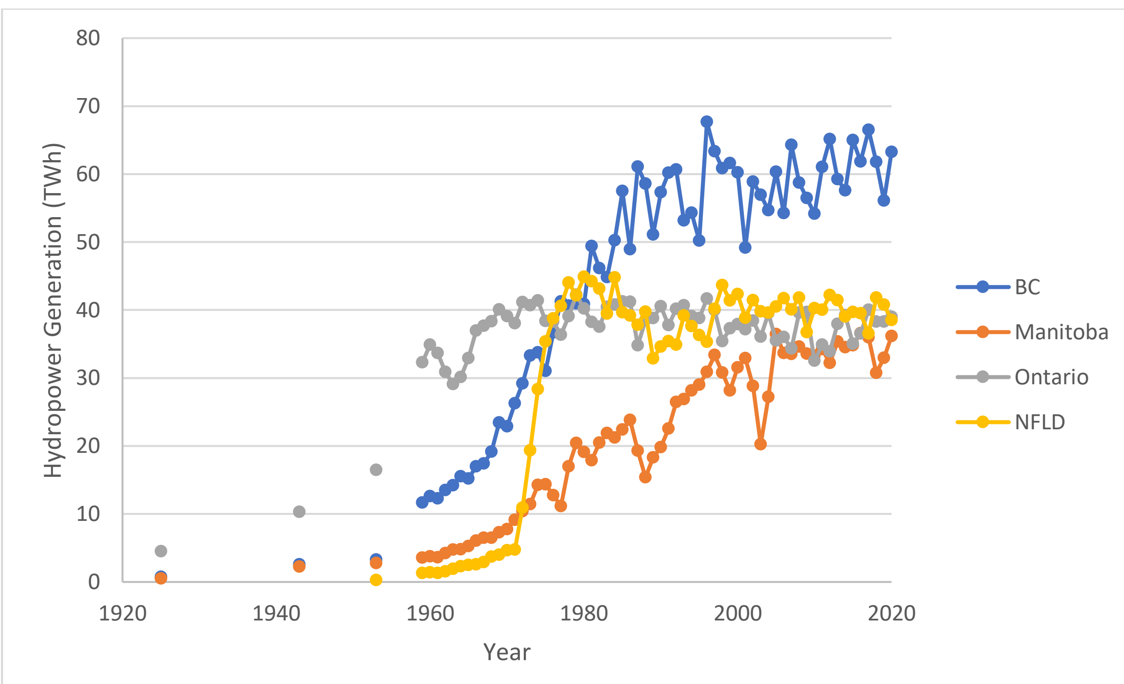

Figure 5.2. Historical hydropower generation (TWh) for BC, Manitoba, Ontario, and NFLD (aggregated StatCan data).

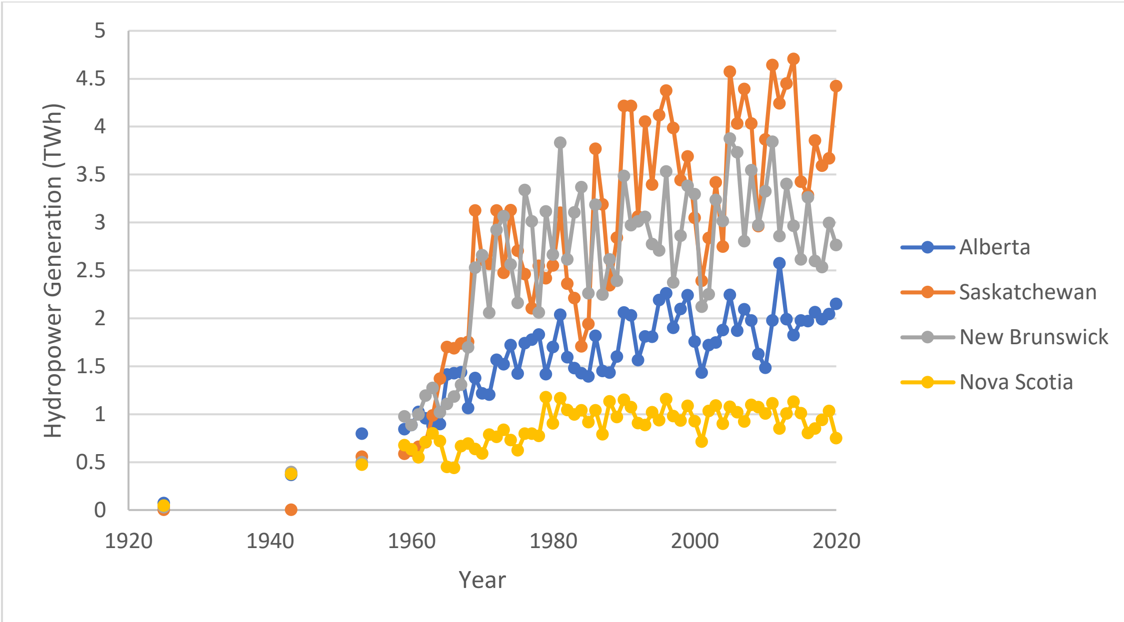

Figure 5.3. Historical hydropower generation (TWh) for Alberta, Saskatchewan, New Brunswick, and Nova Scotia (aggregated StatCan data).

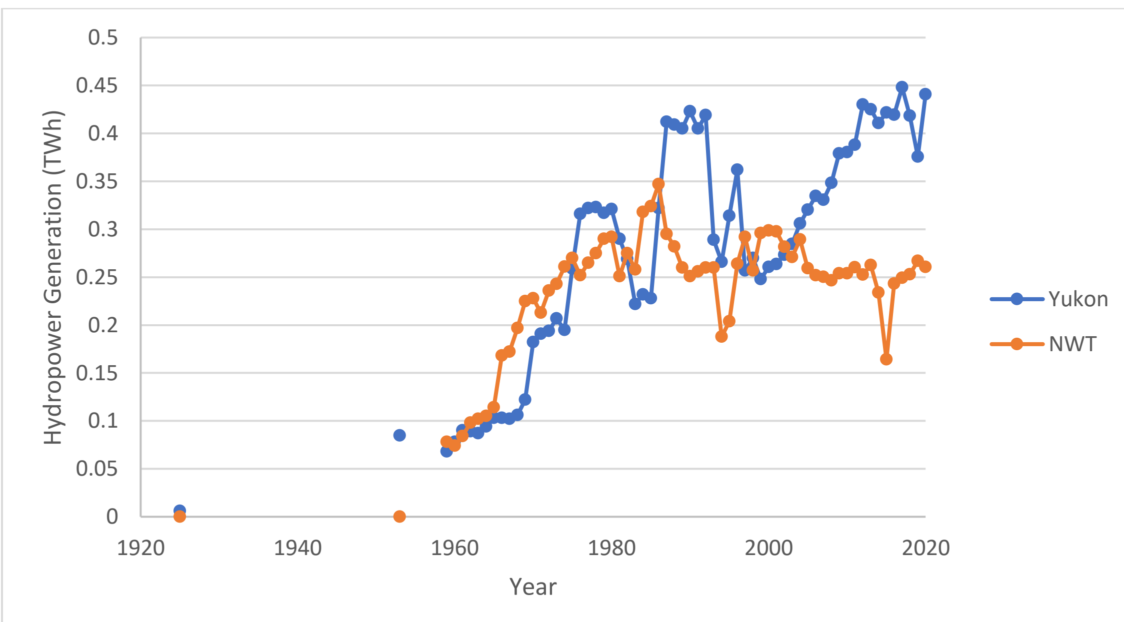

Figure 5.4. Historical hydropower generation (TWh) for the Yukon and the Northwest Territories (aggregated StatCan data).

Table 5.1 presents historical provincial hydropower generation based on the aggregated StatCan data for 5-year increments starting in 1975.

Table 5.1. Historical hydropower generation by province and territory (TWh).

Year	BC	AB	SK	MB	ON	QC	NB	NS	NL	YT	NT	Canada
1975	31.03	1.42	2.70	14.33	38.38	75.72	2.16	0.62	35.35	0.26	0.27	202.24
1980	40.86	1.70	2.55	19.09	40.19	97.56	2.66	0.90	44.86	0.32	0.29	250.99
1985	57.52	1.39	1.94	22.41	41.24	133.28	2.26	1.04	39.65	0.23	0.32	301.16
1990	57.31	2.06	4.22	19.83	40.56	129.94	3.48	1.15	34.59	0.42	0.25	293.81
1995	50.18	2.19	4.12	29.01	38.80	167.42	2.71	0.94	36.29	0.31	0.20	332.17
2000	60.21	1.76	3.05	31.54	37.91	173.01	3.29	0.92	42.31	0.26	0.30	354.55
2005	60.33	2.24	4.57	36.44	35.48	173.36	3.88	1.08	40.50	0.32	0.26	358.45
2010	54.15	1.48	3.87	33.27	32.56	177.41	3.33	1.01	40.28	0.38	0.25	347.98
2015	65.00	1.98	3.43	34.77	35.04	194.37	2.62	1.01	39.69	0.42	0.16	378.48
2020	63.24	2.15	4.42	36.17	39.00	195.08	2.76	0.75	38.52	0.44	0.26	382.79

Figures 5.5-5.8 present total historical hydropower capacity installed for each of the Canadian provinces and territories based on the aggregated StatCan data, with intermittent data starting in 1925, and continuous data from 1959 to 2017 (excluding missing data in 2012). Note that these figures provide capacity units of MW.

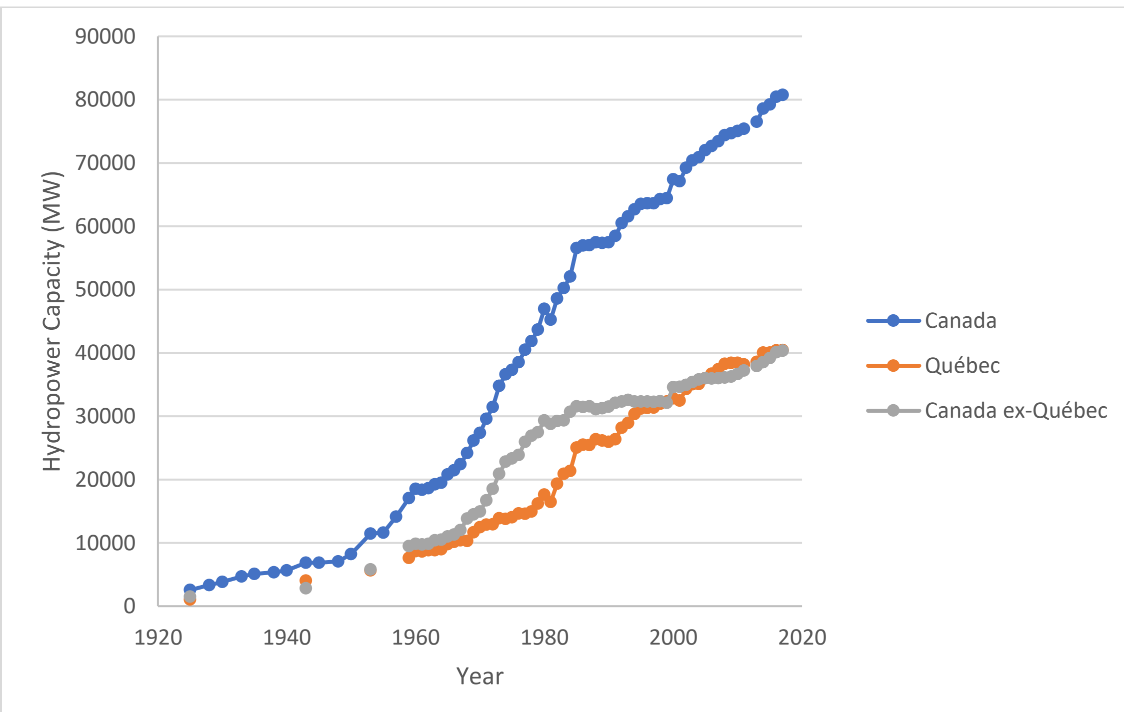

Figure 5.5. Historical hydropower capacity (MW) for Canada, Québec, and Canada without (ex-) Québec (aggregated StatCan data).

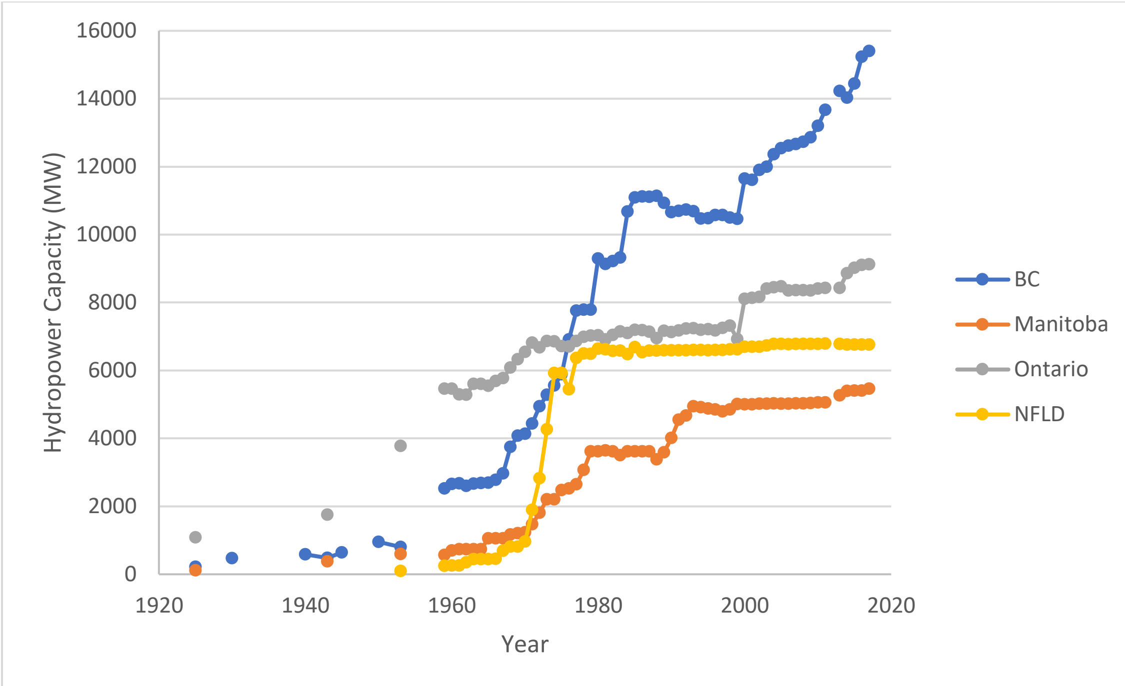

Figure 5.6. Historical hydropower capacity (MW) for BC, Manitoba, Ontario, and NFLD (aggregated StatCan data).

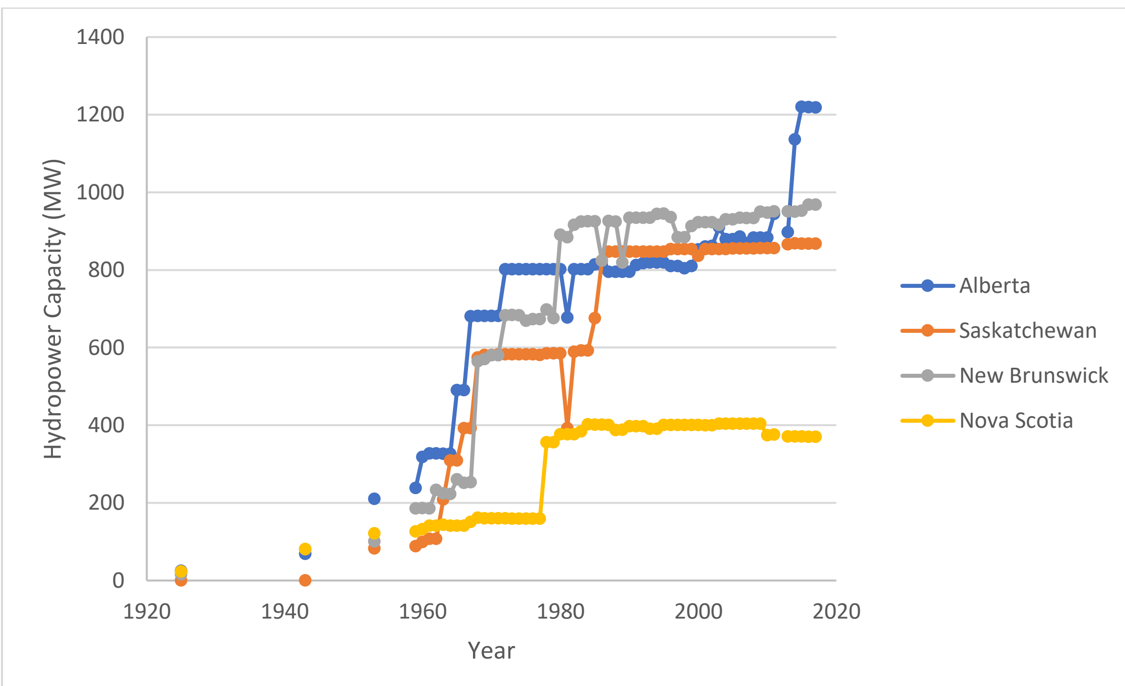

Figure 5.7. Historical hydropower capacity (MW) for Alberta, Saskatchewan, New Brunswick, and Nova Scotia (aggregated StatCan data).

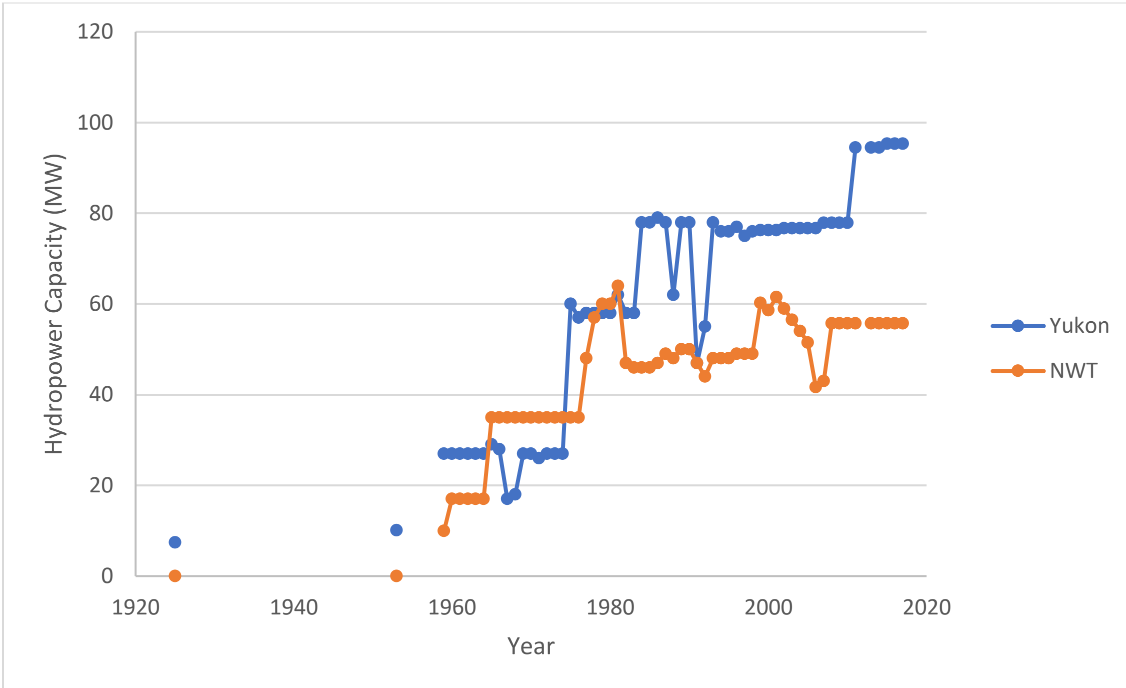

Figure 5.8. Historical hydropower capacity (MW) for the Yukon and the Northwest Territories (aggregated StatCan data).

Note that sudden increases or decreases in the hydropower capacity profiles are often attributable to new generating stations being added and decreases to units being out of service for maintenance or other reasons. The sudden increase in Figure 5.7 for Alberta around 2013 is explained further in the footnote found in Table 5.2. Table 5.2 presents historical provincial hydropower capacity based on the aggregated StatCan data for 5-year increments starting in 1975.

Table 5.2. Historical hydropower capacity by province and territory (MW).

Year	BC	AB	SK	MB	ON	QC	NB	NS	NL	YT	NT	Canada
1975	5,883	801	582	2,477	6,717	14,016	669	159	5,919	60	35	37,318
1980	9,294	801	585	3,620	7,036	17,600	890	376	6,640	58	60	46,960
1985	11,092	814	675	3,620	7,193	25,029	925	401	6,690	78	46	56,563
1990	10,658	795	847	4,017	7,133	25,978	934	397	6,594	78	50	57,481
1995	10,484	819	847	4,881	7,215	31,218	945	400	6,595	76	48	63,528
2000	11,644	853	836	5,004	8,109	32,813	922	400	6,691	76	59	67,408
2005	12,545	879	855	5,024	8,473	35,982	930	404	6,777	77	45	71,990
2010	13,202	883	856	5,054	8,406	38,426	947	374	6,781	78	56	75,062
2015	14,441	1,219[1]	867	5,402	9,023	40,028	952	371	6,760	95	56	79,214

Several trends are observable in Canadian hydropower capacity over time. Notably, growth in Ontario and Québec dominated during the early part of the 20th century. These regions held a large share of established Canadian population during that time period, while population growth in western Canada accelerated in the latter half of the century. Ontario's hydropower generation peaked in 1979 at 42.2 TWh, followed by a period of decline which is only more recently being reversed by newer run-of-river installations that have been added since the start of the 21st century. Alberta and Saskatchewan have added negligible capacity since 1990 (see Table 5.2), but have been able to generally increase generation during that time period, although with large historical and present-day interannual variations. Large developments in northern and eastern Québec and a series of smaller additions in British Columbia have driven hydropower development capacity growth in the early 21st century. Hydropower capacity expansion in the mainland maritime provinces of New Brunswick and Nova Scotia has been negligible since about 1980, a period during which these provinces have experienced low population growth compared to the rest of Canada.

[1] This value is presented in the StatCan hydropower capacity dataset, but disputed by others. The StatCan (2020) data suggests a significant jump in Alberta's hydropower capacity beginning in 2014 that is not reflected in other sources. StatCan lists Alberta's capacity as 1,219 MW in 2015, a 333 MW increase over the 2013 figure (897 MW). As of 2023, The Alberta Electric System Operator has listed Alberta's hydroelectric capacity at 894 MW (AESO, 2023), much closer to StatCan's 2013 value. CER's (2020) Energy Futures report also uses 894 MW for 2015. No articles or reports of new hydropower developments or expansions could be found that would explain the sudden increase in StatCan's values for Albertan hydropower capacity after 2013.

5.1.2 Capacity from Modified NRCan Data

The modified NRCan (2018) data yielded a list of 584 hydropower generating stations in Canada. The data were sorted into size categories to yield Table 5.3, which provides statistics on the number and size of existing generating stations by installed capacity.

Table 5.3. Characteristics of existing hydropower generating stations in Canada by installed capacity.

Dam Size Category	Number of generating stations	Capacity (MW)	Percent of total capacity
>1,000 MW	21	43,562.70	53.91%
500–1,000 MW	18	13,304.40	16.47%
250–500 MW	20	7,074.00	8.75%
50–250 MW	104	12,477.38	15.44%
10–50 MW	148	3,226.42	3.99%
<10 MW	273	1,155.15	1.43%
All	584	80,800.05	100.00%

Table 5.3 shows that over half of Canada's installed hydropower capacity is developed at sites that exceed 1,000 MW. Large installed capacities are usually associated with large reservoirs and therefore high capacity factors, so it is likely that a disproportionately larger share of total generation can be attributed to the largest categories of stations. Consequently, some subnational regions with only a few, larger generating stations, like BC-Mackenzie, contribute far more generation than other regions with many smaller installations, like Alberta-Saskatchewan-Nelson.

As described in Section 4.2, the modified NRCan (2018) data were used to supply an alternate, but more spatially detailed estimate of hydropower capacity from the list of existing plants in Canada. Table 5.4 presents the capacities derived for each province using the modified NRCan (2018) data (adjusted for installations as of 2017) compared to the most recent StatCan (2019) values for installed capacity in 2017. The modified NRCan (2018) data may slightly overestimate capacity because they do not account for retirement of generation units or units out of service.

Table 5.4. Installed hydropower capacity (MW) by province or territory for Canada in 2017 for 2 datasets.

Province or Territory	Modified NRCan (2018)	StatCan (2020)
BC	15,565.55	15,406.80
Alberta	907.35	1,217.82[1]
Saskatchewan	864.00	867.40
Manitoba	5,231.00	5,461.38
Ontario	8,782.62	9,122.38
Québec	41,058.21	40,437.53
NB	949.44	967.50
NS	403.40	369.88
NFLD	6,888.91	6,761.92
Yukon	93.30	95.32
NWT	56.27	55.70
Canada	80,800.05	80,763.62

Table 5.4 shows that at a provincial and territorial level, the hydropower capacity aligns quite closely between the 2 datasets for installed capacity. Historical capacity profiles for provinces and territories using the modified NRCan (2018) dataset is not separately presented here at the provincial level, as it generally aligns with the StatCan data (Figures 5.5 to 5.8) with some minor variations. The NRCan (2018) locational dataset did, however, allow for historical capacity estimates at the basin level to be determined. Figures 5.9 and 5.10 provide historical capacity profiles for major basins within British Columbia and Québec, respectively. The figures are accompanied by explanations of these trends to provide context for development in subnational regions.

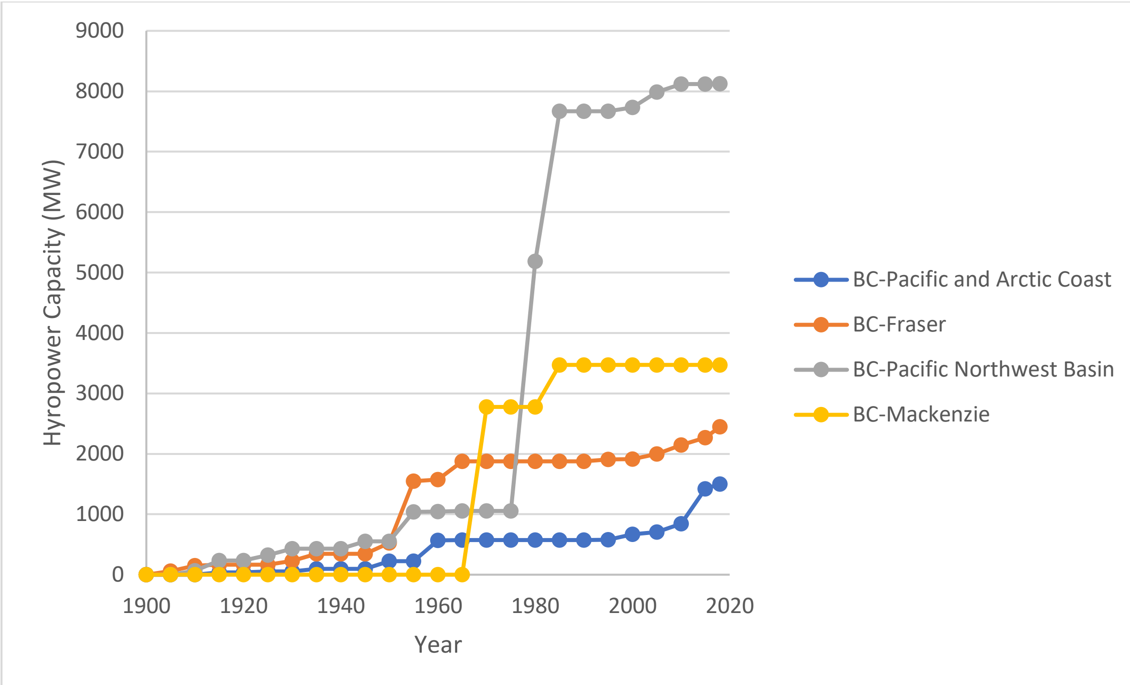

Figure 5.9. Historical hydropower capacity for the major basins of British Columbia (from modified NRCan data, 2018).

BC's hydropower development had a slow start relative to other provinces, owing to its later population growth than eastern Canada. Early growth was focused in areas close to population centres in the southern part of the province. The development of hydropower in BC shifted drastically starting in the 1960s and continuing through the 1980s. An aggressive plan, spearheaded by premier W.A.C. Bennett, created a publicly owned electricity company, BC Hydro, and developed large hydropower installations on two major rivers in the province, the Columbia and the Peace, called the "Two Rivers Policy" (Loo and Stanley, 2011). This led to large growth in capacity in the Mackenzie (Peace River) and Pacific Northwest (Columbia River) basins during that time period. After that, the growth of hydropower stalled while the demand followed the sharply increased supply. This led to industrialization of areas of the province that had previously been minimally developed (Loo and Stanley, 2011), but were now awash in inexpensive electricity that could be used to further develop forestry and forest products and some metals extraction and processing. Only more recently have pressures from population and demand growth incited interest in further development, leading to the present construction of a third facility on the Peace River (Site C).

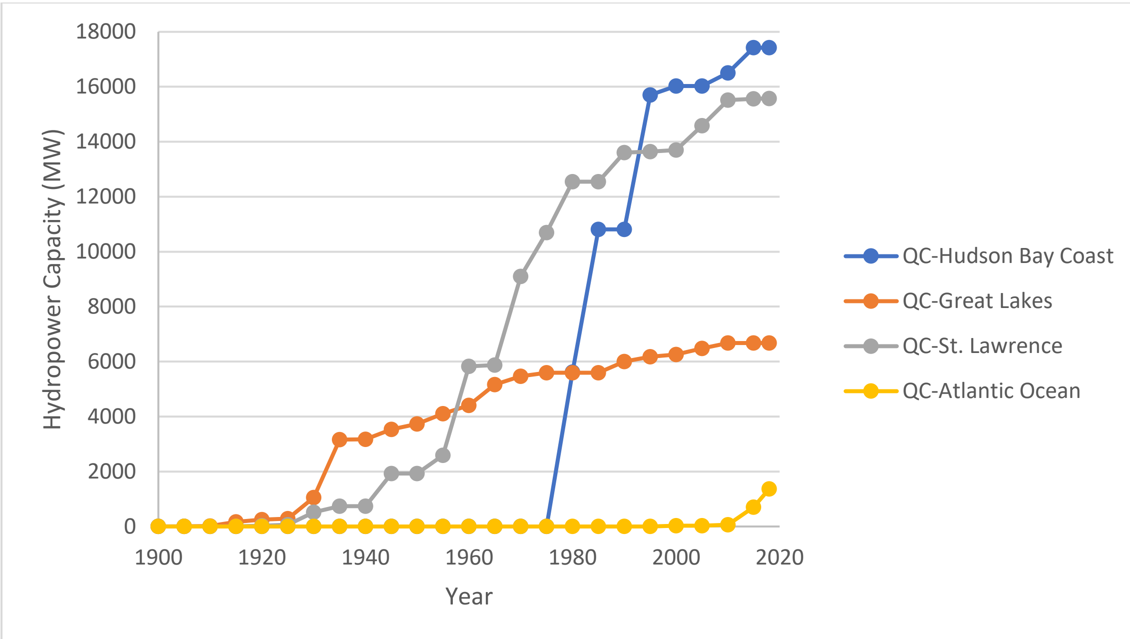

Figure 5.10. Historical hydropower capacity for the major basins of Québec (from modified NRCan, 2018).

In Québec, development of hydropower in the earlier part of the twentieth century occurred closer to population centres clustered in the southern portion of the province in the Great Lakes and St. Lawrence basins. Substantial development of hydropower in Québec followed the sentiment of the "Quiet Revolution" (Chodos and Hamovitch, 1993). Political rallying around the slogan "Maîtres chez nous," translated as "masters of our own home," correlated with a desire for economic and energy independence from other Canadian provinces, and led Québec to focus on development of its abundant hydropower resources. The movement also led to consolidation of electric utilities into the provincially owned Hydro-Québec corporation (Pineau, 2010) and aggressive hydropower development in more remote northern portions of the province. Québec's Atlantic Ocean Seaboard (including the Gaspé Peninsula and eastern Côte-Nord regions) basin saw no hydropower development until the Romaine project was developed in the Côte-Nord region between Labrador and the Gulf of St. Lawrence starting in the 21st century.

5.1.3 Capacity Factors

Table 5.5 presents provincial capacity factors as determined by comparing the StatCan (2022 and 2019) data for hydropower generation and capacity in a 5-year average about 2015.

Table 5.5. Hydropower capacity factors across Canada (5-year average about 2015), for all provinces and territories.

Canada	BC	AB	SK	MB	ON	QC
0.553	0.483	0.200[2]	0.519	0.751	0.484	0.568
NB	**PEI**	**NS**	**NL**	**YT**	**NT**	**NU**
0.354	none	0.295	0.662	0.510	0.472	none

As shown in Table 5.5, capacity factors vary substantially across Canada. Noticeable extremes include Alberta and Manitoba. Alberta's capacity factors are low because its stations are often comanaged to ensure water supply for irrigation (Jean, 2015), allowing water allocations to pass through to downstream provinces (PPWB, 2021), and also for flood mitigation. Further, most of Alberta's dams are located relatively close to the headwaters of watersheds, giving them a higher exposure to variable runoff within and between years. In Alberta, where thermal fuels account for the majority of electricity generation, it is also strategic to employ reservoirs as contingency reserve: hydropower can react very quickly to provide power generation if required due to an unexpected event reducing supply elsewhere in the grid (Gracia et al., 2019). Manitoba's high capacity factor can be attributed to its strategic water management, with many dams in series and a favourable position at the downstream end of the Saskatchewan-Nelson watershed. Manitoba's Nelson River collects water over a very large upstream area, helping to mitigate seasonal fluctuations, and also has several control and diversion structures that can help ensure consistent and reliable river flowrates during any time of year (Déry et al., 2018), with the most significant being the diversion of flow from the Churchill River to the Nelson River. An additional control structure is located on an upstream tributary of the Churchill River in Saskatchewan to regulate flow to the Island Falls hydroelectric generating station (Saskatchewan Environment, 2003). This Churchill River, in the Northwest Territories basin (in northern Saskatchewan and Manitoba), drains to the Hudson Bay and has no relation to the Churchill River in Labrador, a separate basin which drains to the northern Atlantic Ocean, but which also has substantial hydropower operations at Churchill Falls.

[2] Alberta's capacity factor in 2015 would be 0.273 if the installed capacity used to calculate it were 894 MW to agree with AESO and CER. This is still the lowest of any province.

Capacity factors were determined for the basins of BC and Québec according to the procedure described in Section 4.2.3 and are presented in Tables 5.6 and 5.7.

Table 5.6. Estimated capacity factors in the basins of British Columbia.

Subnational Region ID	Province	Basin	Capacity Factor
1	BC	Pacific and Arctic Coast	0.500
2	BC	Fraser	0.702
3	BC	Pacific Northwest	0.406
4	BC	Mackenzie	0.650

Table 5.7. Estimated capacity factors in the basins of Québec.

Subnational Region ID	Province	Basin	Capacity Factor
19	QC	Hudson Bay Coast	0.584
20	QC	Great Lakes	0.668
21	QC	St. Lawrence	0.499
22	QC	New England	None
23	QC	Atlantic Ocean Seaboard	0.662

5.1.4 Historical Generation by Subnational Region

The capacity estimates from the modified NRCan (2018) dataset were converted to generation estimates by applying the appropriate capacity factor to each province and territory and adjusting for historical basin-scale capacity factors in BC and Québec. These figures are consistent with the generation from the aggregated StatCan data. For comparison with subnational capacity (Section 5.1.2), generation figures for BC and Québec are presented in Figures 5.11 and 5.12.

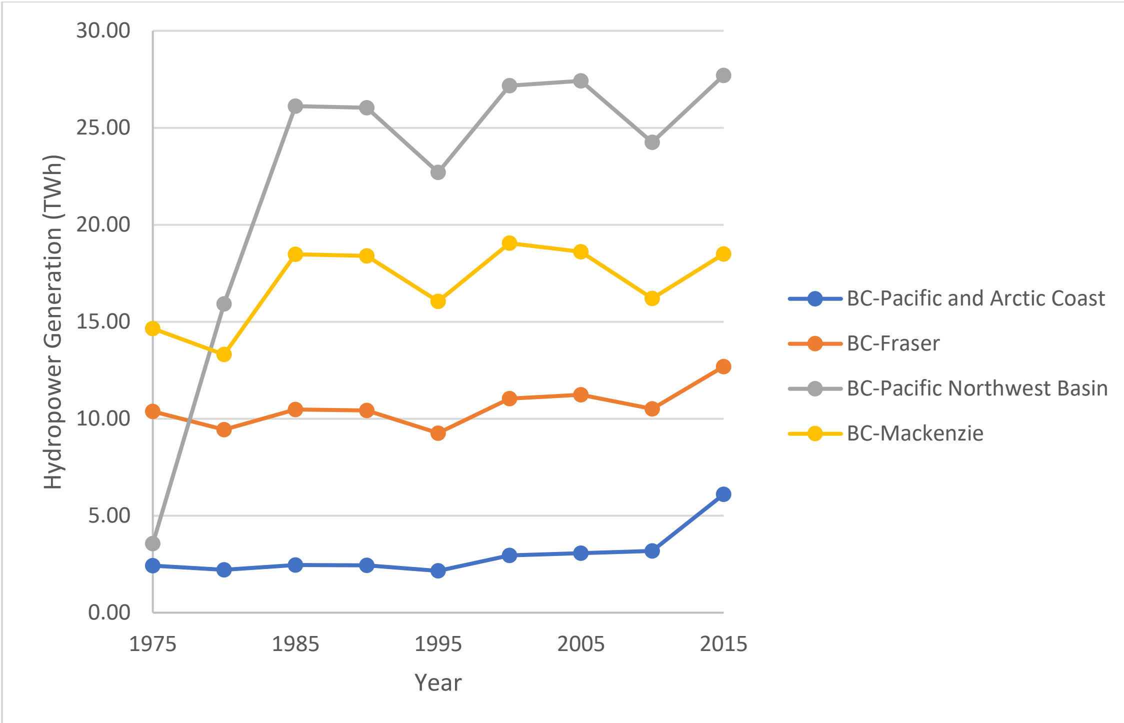

Figure 5.11. Historical hydropower generation for major basins of British Columbia.

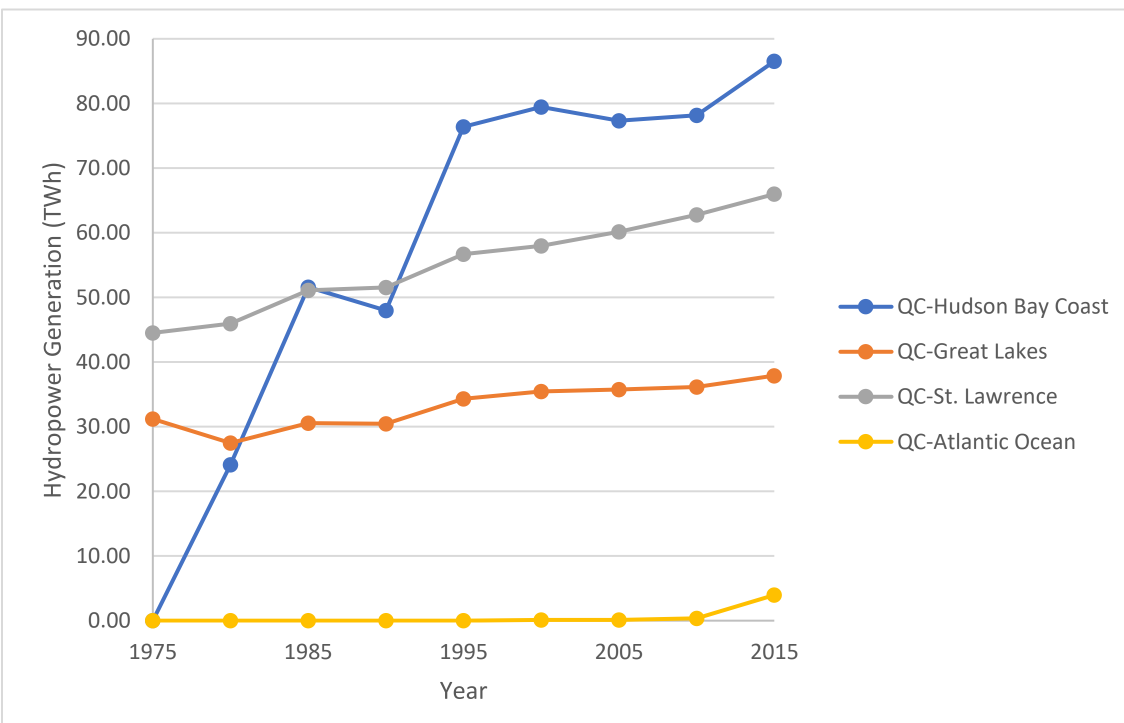

Figure 5.12. Historical hydropower generation for major basins of Québec.

Comparing Figures 5.9 and 5.10 with Figures 5.11 and 5.12, respectively, shows large differences between relative shares of capacity and generation, especially in BC, where the Pacific Northwest Basin achieves low capacity factors and therefore a lower share of generation than would be expected without accounting for local capacity factor trends. Figure 5.11 shows how hydropower generation for anomalous years, such as 1995 and 2010, was distributed across regions within a province, as information about whether any individual or regional factors accounted for anomalies was not considered, effectively spreading the impacts across the river basins. For example, StatCan indicated that BC as a province had relatively low hydropower generation in 1995, which is reflected as reduced generation in all of the basins, although this was not necessarily representative of local conditions and generation patterns in that year.

5.1.5 Historical Subnational Hydropower Generation

Table 5.8 presents a summary of estimated subnational hydropower generation according to subnational region. This is informed by the historical capacity series obtained from the modified NRCan (2018) data and capacity factor corrections described in Section 4.2.3 for BC, Québec, and NFLD.

Table 5.8. Historical hydropower generation contributed by each subnational region, consistent with the aggregated StatCan data (TWh).

Technology	1975	1980	1985	1990	1995	2000	2005	2010	2015
hydro_BC_PA	2.43	2.21	2.45	2.45	2.16	2.96	3.06	3.19	6.10
hydro_BC_F	10.38	9.43	10.47	10.43	9.26	11.03	11.24	10.52	12.69
hydro_BC_PNW	3.56	15.92	26.12	26.03	22.71	27.17	27.42	24.26	27.71
hydro_BC_M	14.66	13.31	18.47	18.40	16.06	19.05	18.61	16.19	18.50
hydro_AB_M	0	0	0	0	0	0	0	0	0
hydro_AB_NT	0	0	0	0	0	0	0	0	0
hydro_AB_SN	1.42	1.70	1.39	2.06	2.19	1.76	2.24	1.48	1.98
hydro_AB_MO	0	0	0	0	0	0	0	0	0
hydro_SK_M	0.06	0.06	0.07	0.11	0.11	0.08	0.12	0.10	0.09
hydro_SK_NT	0.50	0.47	0.35	0.54	0.53	0.39	0.59	0.50	0.44
hydro_SK_SN	2.14	2.02	1.51	3.56	3.48	2.57	3.86	3.27	2.89
hydro_SK_MO	0	0	0	0	0	0	0	0	0
hydro_MB_NT	0.06	0.05	0.06	0.05	0.06	0.06	0.07	0.07	0.07
hydro_MB_SN	14.27	19.04	22.35	19.77	28.95	31.47	36.37	33.20	34.71
hydro_MB_HB	0	0	0	0	0	0	0	0	0
hydro_ON_SN	1.36	1.41	1.44	1.41	1.39	1.35	1.26	1.15	1.21
hydro_ON_HB	3.99	4.13	4.21	4.13	4.01	3.97	3.71	3.38	4.35
hydro_ON_GL	33.03	34.65	35.59	35.01	33.41	32.59	30.51	28.02	29.49
hydro_QC_HB	0	24.11	51.61	47.96	76.40	79.44	77.33	78.16	86.53
hydro_QC_GL	31.20	27.48	30.56	30.45	34.34	35.44	35.77	36.14	37.90
hydro_QC_SL	44.51	45.97	51.12	51.53	56.68	57.99	60.13	62.77	65.97
hydro_QC_NE	0	0	0	0	0	0	0	0	0
hydro_QC_AO	0	0	0	0	0	0.13	0.13	0.34	3.96
hydro_NB_NE	2.14	2.63	2.23	3.44	2.67	3.26	3.83	3.29	2.59
hydro_NB_AO	0.02	0.03	0.03	0.04	0.03	0.04	0.04	0.04	0.03
hydro_PE_AO	0	0	0	0	0	0	0	0	0
hydro_NS_AO	0.62	0.90	0.92	1.15	0.94	0.92	1.08	1.01	1.01
hydro_NL_C	30.77	39.04	33.66	28.68	30.09	34.94	33.24	33.06	32.57
hydro_NL_AO	4.58	5.81	6.00	5.91	6.20	7.37	7.26	7.22	7.11
hydro_YT_PA	0.26	0.32	0.23	0.42	0.31	0.26	0.32	0.38	0.42
hydro_YT_M	0	0	0	0	0	0	0	0	0
hydro_NT_M	0.27	0.29	0.32	0.25	0.20	0.30	0.26	0.25	0.16
hydro_NT_NT	0	0	0	0	0	0	0	0	0
hydro_NT_PA	0	0	0	0	0	0	0	0	0
hydro_NU_NT	0	0	0	0	0	0	0	0	0
Total	202.23	250.98	301.16	293.78	332.18	354.54	358.45	347.99	378.48

5.2 Hydropower Resource Estimates

This section presents estimates of the technical potential and economics of hydropower resource development across Canada on a national, provincial/territorial, and subnational scale. The results presented here may be useful to other Canadian energy system modellers wishing to incorporate hydropower development as an endogenous component.

5.2.1 Developable Resource Potential

Following the methods described in Sections 4.3 and 4.4, the total Canadian hydropower resource is 1,859.4 TWh. Table 5.9 compares the amount of hydropower generated in 2015 with the maximum developable resources for each Canadian province and territory identified by this analysis, along with national totals. Table 5.10 provides the same values tabulated for each of the major river basins in Canada, excluding the portions of those basins outside Canadian borders.

Table 5.9. Existing generation and maximum developable hydropower resources for Canadian provinces and territories.

Province or Territory	Existing Generation (2015, TWh)	Max Developable Resource (TWh)
BC	65.00	369.097
AB	1.98	101.831
SK	3.43	22.439
MB	34.78	89.469
ON	35.01	59.317
QC	194.36	324.169
NB	2.62	17.513
NS	1.02	1.019
NL	39.68	60.039
YT	0.42	81.203
NWT	0.16	705.508
NU	0	27.775
Total	378.46	1,859.381

Table 5.10. Existing generation and maximum developable hydropower resources for major basins within Canada (excluding the portions of those basins outside Canada).

Basin	Existing Generation (2015, TWh)	Max Developable Resource (TWh)
Pacific and Arctic Coast	6.52	109.13
Fraser	12.69	163.47
Pacific Northwest	27.71	38.26
Mackenzie	18.75	937.34
Saskatchewan-Nelson	40.75	96.00
Northwest Territories	0.52	54.30
Missouri	0	0
Hudson Bay Coast	90.88	178.93
Great Lakes	67.39	84.04
St Lawrence	65.97	99.90
New England	2.59	17.48
Atlantic Ocean Seaboard	12.12	34.80
Churchill	32.57	45.74
Total	378.46	1,859.38

5.2.2 Subnational Regions with Restricted Growth

Table 5.11 provides the estimated hydropower generation in regions in which growth is restricted. These regions have a small amount of existing generation, but were not found to have additional resources that could be developed economically in this analysis. Collectively, the restricted growth regions accounted for only about 2.7 TWh of generation in 2015, or slightly less than 1% of Canada's total hydropower generation (the rest of which occurs in regions which are assigned smooth resource curves).

Table 5.11. Hydropower generation of restricted growth regions in 2015.

Subnational Region ID	Province or Territory	Basin	Generation (TWh)
10	SK	Northwest Territories	0.445
16	ON	Saskatchewan-Nelson	1.173
25	NB	Atlantic Ocean Seaboard	0.030
27	NS	Atlantic Ocean Seaboard	1.019

Some subnational regions have been found to have negligible hydropower resources based on a lack of identified resource potential and historical lack of development. The subnational regions which are assumed to have no developable hydropower resources in any model period are regions 6, 8, 12, 15, 22, 26, 33, and 34, which are AB-Northwest Territories, AB-Missouri, SK-Missouri, MB-Hudson Bay Coast, QC-New England, PEI-Atlantic Ocean Seaboard, NWT-Northwest Territories, and NWT-Pacific and Arctic Coast.

5.2.3 Subnational Hydropower Resource Supply Curves

For regions with sufficient data for development of resource supply curves, Table 5.12 provides the results associated with the smooth resource curve formula (Eq. 4.1 in Section 4.4.2). The values in the column for "R max resource" represent the maximum hydropower resources that could be developed in each region if all available sites were exploited. Along with these values, the estimated generation for each subnational region in 2015 is presented. Comparing existing generation to the maximum resource for each region indicates the fraction of each region that is already developed. For example, most of the BC-Pacific Northwest region's hydropower resources have already been developed, while the northern territories have substantial amounts of remaining, theoretically developable hydropower.

Table 5.12. Summary of curve parameters for subnational regions assigned smooth resource curves.

Subnational Region ID	Province or Territory	Basin	Existing Generation (2015)	R max Resource	m_P midPrice	C Curve exponent
1	BC	Pacific and Arctic Coast	6.10	54.858	1.196	1.900
2	BC	Fraser	12.69	163.472	0.041	0.608
3	BC	Pacific Northwest	27.71	38.264	0.144	0.440
4	BC	Mackenzie	18.50	112.503	0.212	0.712
5	AB	Mackenzie	0	89.842	0.675	1.364
7	AB	Saskatchewan-Nelson	1.98	11.989	1.183	1.706
9	SK	Mackenzie	0.09	2.547	0.433	4.928
11	SK	Saskatchewan-Nelson	2.89	19.447	0.131	0.924
13	MB	Northwest Territories	0.07	26.081	1.146	1.799
14	MB	Saskatchewan-Nelson	34.71	63.389	0.837	1.212
17	ON	Hudson Bay Coast	4.35	22.411	0.525	1.382
18	ON	Great Lakes	29.49	35.733	0.212	1.036
19	QC	Hudson Bay Coast	86.53	156.514	1.249	3.785
20	QC	Great Lakes	37.90	48.308	0.201	0.737
21	QC	St Lawrence	65.97	99.897	0.209	0.796
23	QC	Atlantic Ocean Seaboard	3.96	19.450	0.541	1.524
24	NB	New England	2.59	17.483	0.148	0.828
28	NL	Churchill	32.57	45.742	0.117	2.403
29	NL	Atlantic Ocean Seaboard	7.11	14.297	0.125	0.983
30	YT	Pacific and Arctic Coast	0.42	54.267	1.140	2.264
31	YT	Mackenzie	0	26.936	2.886	2.805
32	NT	Mackenzie	0.16	705.508	0.378	2.944
35	NU	Northwest Territories	0	27.775	2.141	5.954

Table 5.12 displays the heterogeneity of hydropower resources across Canada. Region 32, Northwest Territories-Mackenzie, accounts for nearly 38% of nationally identified resources, but has very modest existing generation concentrated in local tributaries closer to demand centres. Despite its very large size, only about 45,000 people live in the Northwest Territories, making demand only a very small fraction of potential resources. The Northwest Territories-Mackenzie region features very large flowrates that concentrate toward the Mackenzie River, but substantial hydropower development of this major river is unlikely

given the very long distance to any large population centres and extreme local climate conditions with very harsh winters. Further, the entire length of the Mackenzie River is an important shipping route for resupplying remote Arctic communities with no access to roads by barge from Hay River, NWT, during ice cover-free summer months (Engler and Pelot, 2013). This shipping route also supports a relatively modest amount of oil and gas development near Norman Wells, NWT, and has the potential to be used for increased international exports of products from elsewhere in Canada (Engler and Pelot, 2013).

The BC-Fraser region displays a resource supply curve with a very low midPrice; this occurs because the majority of this region's resources are identified in just a few grid cells which were assigned similarly low costs. Three grid cells along the lower Fraser basin from upstream of Boston Bar to the Vancouver metropolitan area account for about 130 TWh of the 163.5 TWh identified and were each assigned similarly inexpensive resource development costs by Zhou et al. (2015). In this case, the highest-density urban area of Vancouver was largely excluded from consideration, but the lower-density suburbs and agricultural lands to the east were identified as potential options for development in the Zhou et al. (2015) dataset. Full development of hydropower in these grids would imply significant impacts to large populations that would likely make them effectively unexploitable. Besides, BC Hydro's long-term capacity plans suggest a variety of other measures will be exhausted in the coming decades before even considering new large-scale hydropower development as an option (BC Hydro, 2021a). See Figure 5.13 for a map showing the three grid cells with the majority of the identified resource in the BC-Fraser basin.

Development of hydropower on the mainstem Fraser River in this area would imply displacement of tens of thousands of people in outer Vancouver suburbs. Further, it would flood the particularly high-value agricultural region of the Fraser Valley, which has a biogeography unique to Canada with favourable precipitation, temperature, and soil conditions. This relatively small region had estimated gross farm receipts of $1.6 billion in 2005, exceeding the rest of British Columbia combined (FVRD, 2012), despite hosting only a small fraction of the province's agricultural lands. Additionally, transportation infrastructure in the area is critical. This bottleneck controls most capacity for land routes from mainland Canada into the Lower Mainland of BC for transportation and goods movement, making any possible hydropower development that could affect the highways or railways untenable. This reliance on the lower Fraser Valley's infrastructure for transportation was highlighted by a series of flood events in November 2021, which cut off access to the routes, effectively isolating metropolitan Vancouver from interior BC and the rest of Canada by land routes, and placing immense strain on the movement of goods and people through the region (CBC News, 2021). The immediate response to re-establish these connections as a vital link demonstrates that inundation of the lower Fraser River for hydropower would not be tolerated in any way that impedes access to this narrow transportation corridor. However, the hydropower potential in this region remains in the proposed estimates in the interest of maintaining consistent methodology between regions.

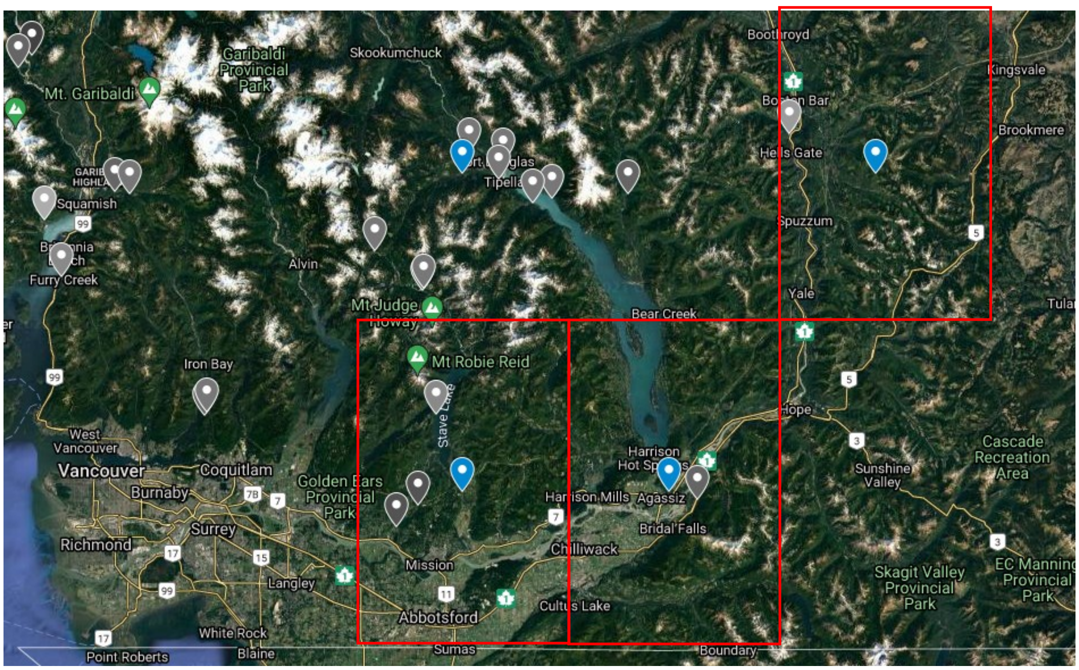

Figure 5.13. Map of the lower Fraser River basin. Resource potential is indicated by the centres of red-bordered grids with blue markers. The indicated grid cells contain most of the resources identified for the entire BC-Fraser basin. Existing hydropower generating stations are indicated by gray markers.

The hydropower supply resource curves are shown for each of the subnational regions in Figures 5.14 through 5.19. These curves should be interpreted along with existing generation values when assessing the competitiveness of remaining hydropower resources based on costs and previously developed resources.

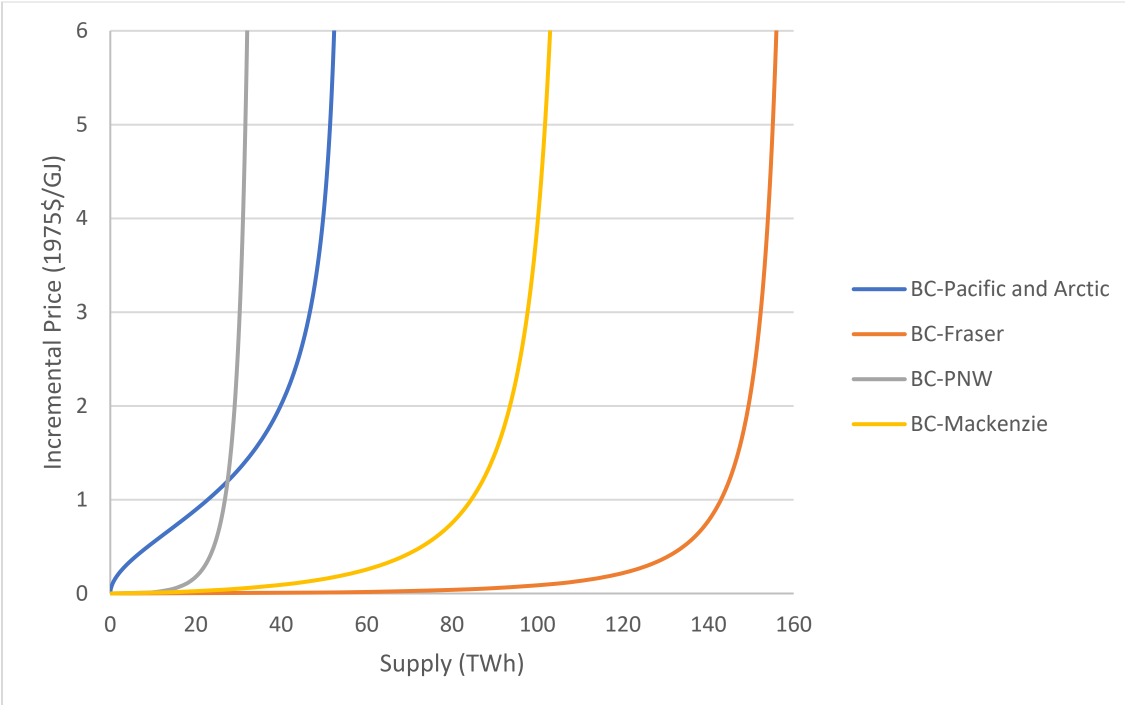

Figure 5.14. Hydropower resource supply curves for British Columbia by major basin.

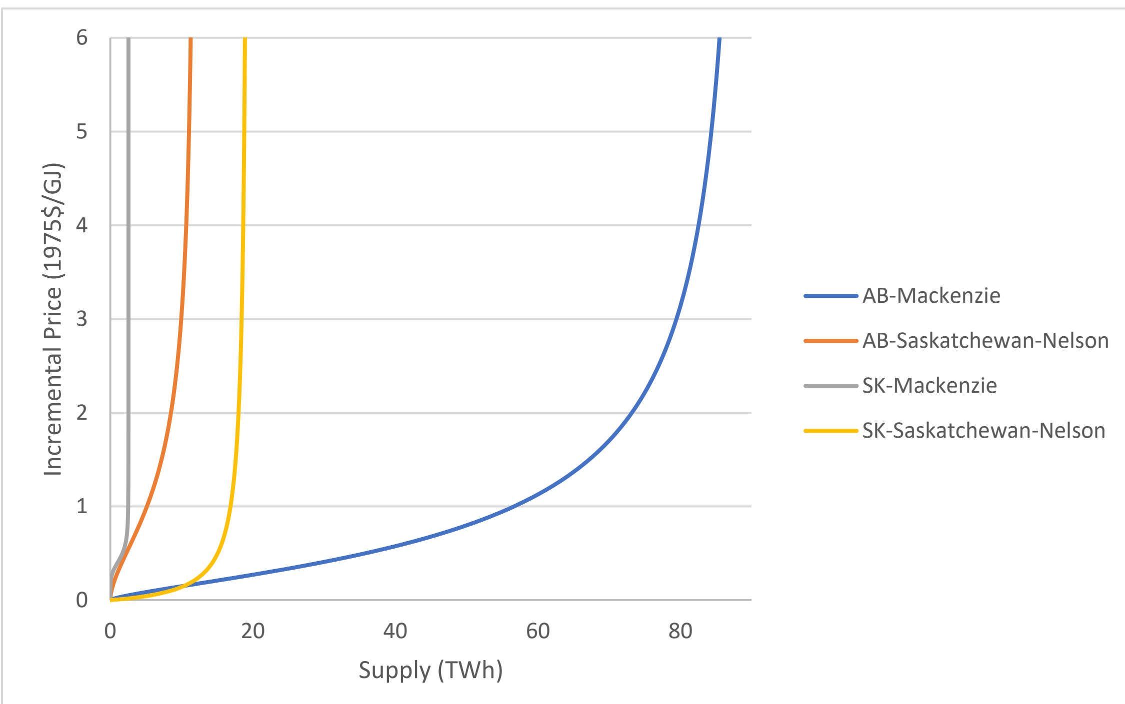

Figure 5.15. Hydropower resource supply curves for Alberta and Saskatchewan by major basin.

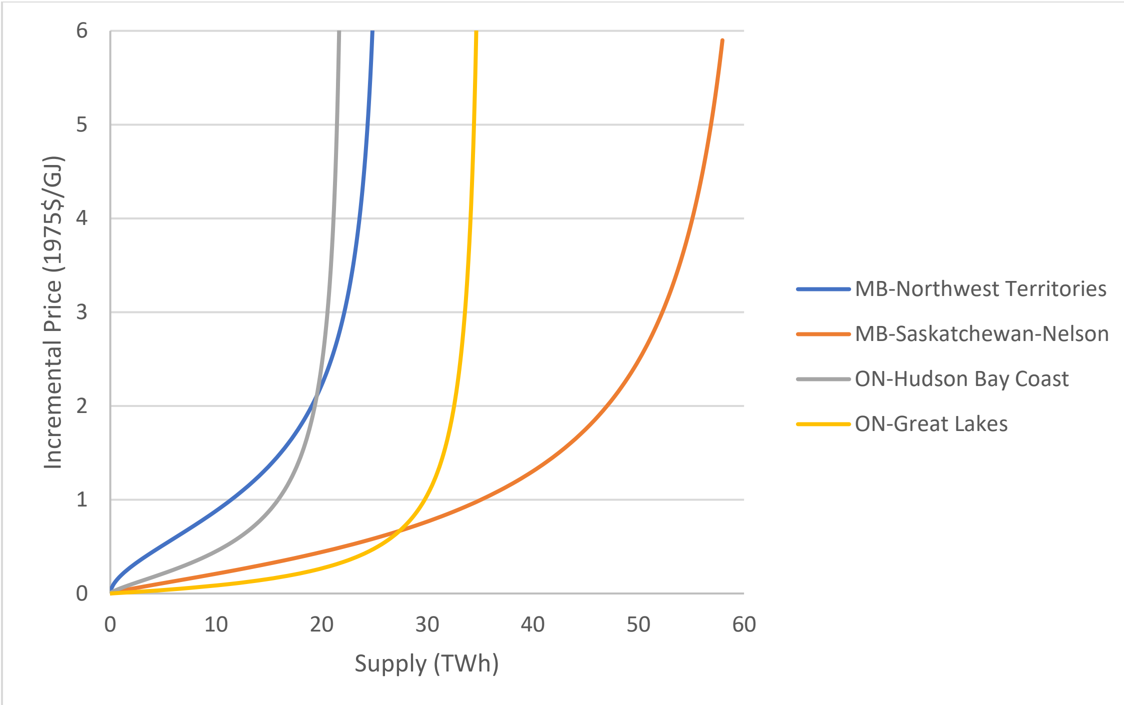

Figure 5.16. Hydropower resource supply curves for Manitoba and Ontario by major basin.

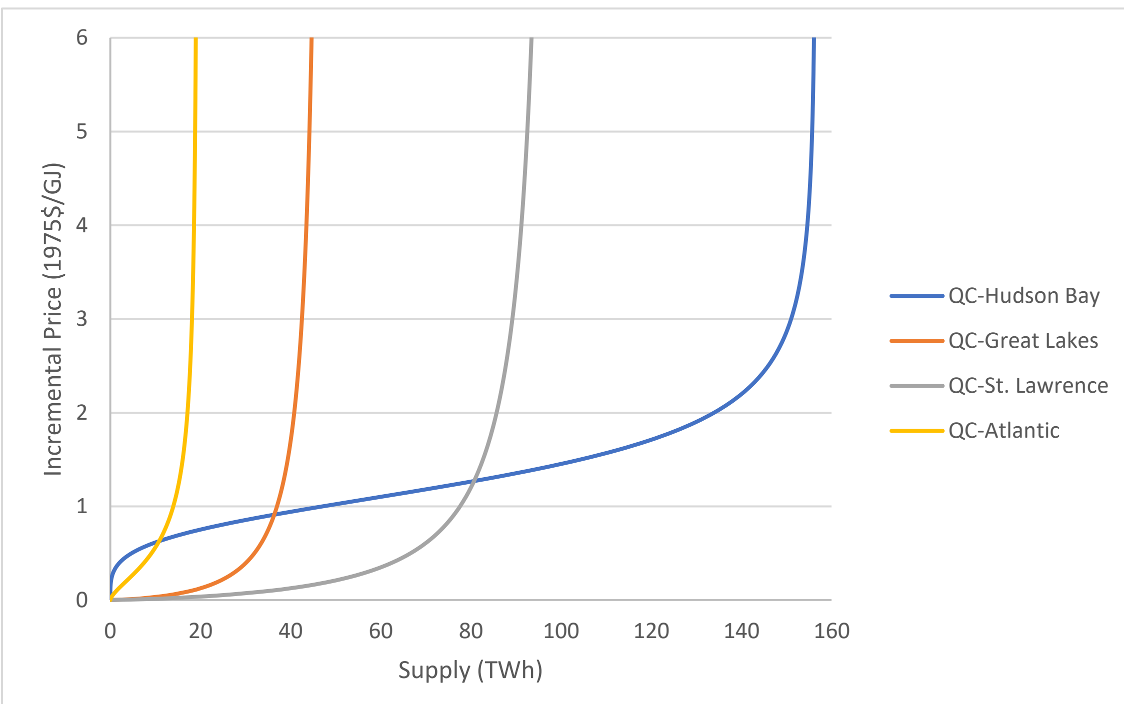

Figure 5.17. Hydropower resource supply curves for Québec by major basin.

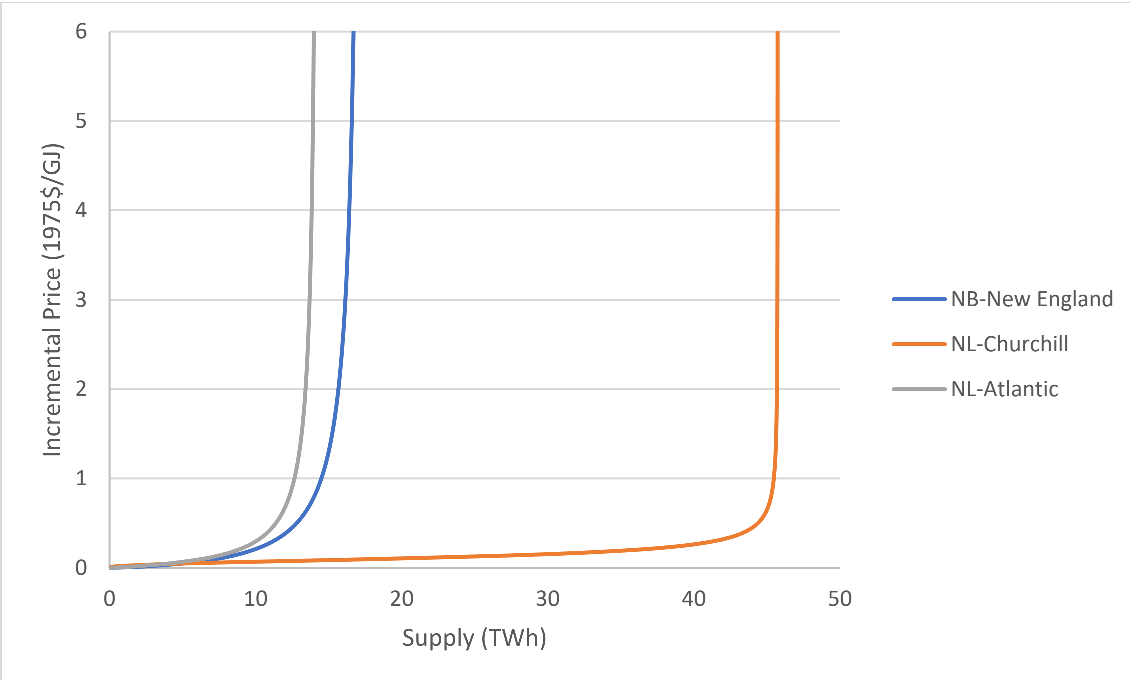

Figure 5.18. Hydropower resource supply curves for New Brunswick and Newfoundland and Labrador by major basin.

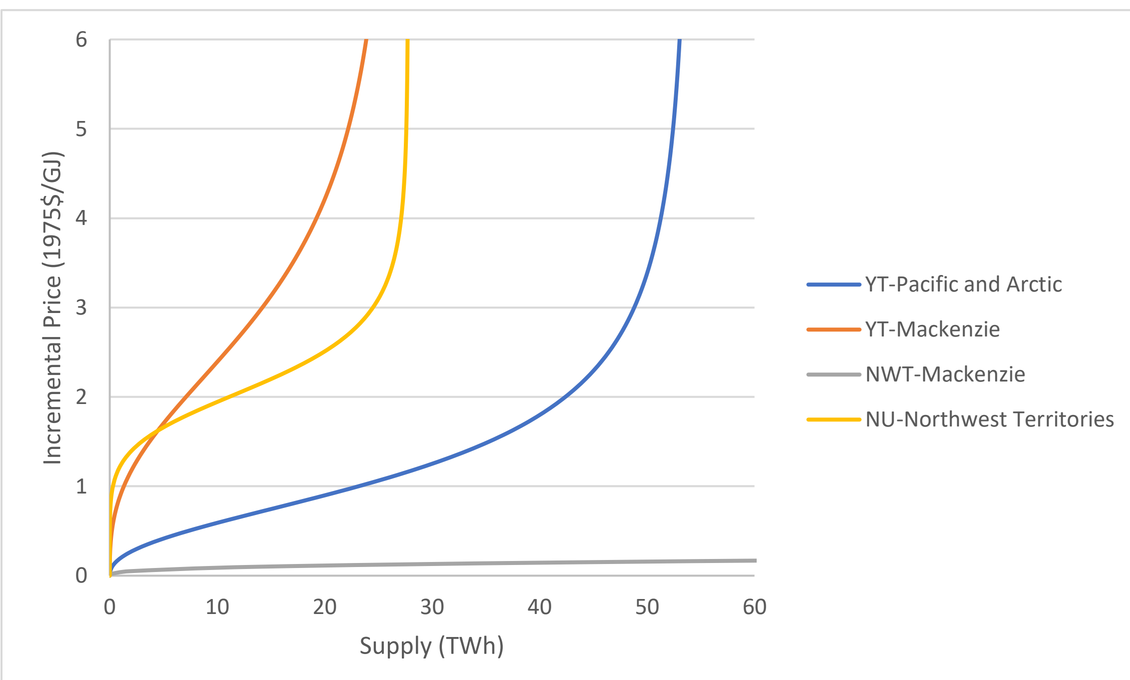

Figure 5.19. Hydropower resource supply curves for the northern territories by major basin (NWT-Mackenzie extends off the right of the graph to a maximum supply of 705.5 TWh).

5.2.4 Comparison of Resource Estimates with Literature

This section compares developable hydropower resources determined in this thesis with those from literature. Table 5.13 provides comparisons on the basis of nationally developable resources.

Table 5.13. Comparison of estimates for national Canadian hydropower resource potential (average annual basis).

Source	Developable National Hydropower Resources (TWh)
This thesis	1,859.4
Barrington-Leigh and Ouliaris (2017)	1,015.0
Canadian Academy of Engineering (2009)	1,243.6
World Energy Council (2016)	1,180.7

While Arbuckle et al. (2021) proposed a national developable resource estimate, we did not correct hydropower resource potential to account for existing generation in that article. Instead, we adjusted the hydropower resources found in Zhou et al. (2015) to a total national assumption of 800 TWh of reasonably developable hydropower. This meant that it was necessary to constrain the available resources to obtain more reasonable results because the data included remote resources that are in practice unlikely to be developed, without otherwise accounting for regional constraints. While this thesis provides a more optimistic value for nationally developable hydropower, much of this resource is located in regions that present logistical challenges which make substantial development infeasible. Including the subnational regions in this analysis removes the need to adjust resource estimates for the purpose of calibration of GCAM-Canada, because logistically challenging regions will attain very low shareweights, constraining future development to effectively account for other factors like population size, transmission distances, or easier access to resources in a particular region.

The study conducted by Barrington-Leigh and Ouliaris (2017) estimated values for developable hydropower potential (along with other renewable sources) for each Canadian province, without assigning values individually for the territories. Their national total deviates significantly from this study, but many values for provinces agree quite closely. They determined total hydropower resource potential and adjusted for developed generation, based on estimates from a 2006 study conducted for a hydropower advocacy group now known as Water Power Canada (Barrington-Leigh and Ouliaris, 2017). The sum of values from Barrington-Leigh and Ouliaris (2017) among provinces does not equal their national value, so the difference between these values likely lies in the 3 northern territories combined. As shown in Table 5.14, one of the most significant deviations between the datasets for a province is for British Columbia, which in this study contains a significant amount of what is likely unexploitable potential in the lower Fraser valley, resulting in a much more optimistic value. Resources identified for the provinces of New Brunswick and Nova Scotia also deviate significantly between these studies, with each resource estimate bearing higher optimism for only one of these provinces. Provincial comparisons to Zhou et al. (2015) and Gernaat et al. (2017) are not included because Zhou et al. (2015) largely coincides with this thesis, except for adjustments for existing generation and potential in northern Manitoba, and Gernaat et al. (2017) excluded the northern territories and Arctic basin watersheds.

Table 5.14. Comparison of provincial estimates for total developable hydropower generation (TWh, average annual basis).

Province/ Territory	This thesis	Barrington-Leigh and Ouliaris (2017)
BC	369.097	159
AB	101.831	101
SK	22.439	24
MB	89.469	56
ON	59.317	65
QC	324.169	308
NB	17.513	5
NS	1.019	27
NL	60.039	61
YT	81.203	-
NWT	705.508	-
NU	27.775	-
Total	1,859.379	1,015

The annual developable hydropower generation values are converted to an estimated capacity basis in Table 5.14. For the estimates from this thesis, generation from each province is converted to capacity using the 5-year averaged provincial capacity factors given in Table 5.5 (without adjustments for basin-level capacity factors). The estimated developable capacity for Nunavut was converted assuming the capacity factor for the NWT. The Barrington-Leigh and Ouliaris (2017) values were converted using a capacity factor of 0.60, as was assumed by that study in the formulation of their estimates for all regions. Values for developable capacity between the datasets deviate more than they did for generation. For example, while Alberta had similar developable generation in Table 5.14, the Barrington-Leigh and Ouliaris (2017) estimate for capacity is much lower because they assumed a higher capacity factor based on the national estimate.

Table 5.14. Comparison of provincial estimates for total developable hydropower capacity (MW).

Province/ Territory	This study	Barrington-Leigh and Ouliaris (2017)
BC	87,175	30,230
AB	58,083	19,203
SK	4,932	4,563
MB	13,590	10,647
ON	13,981	12,358
QC	65,106	58,560
NB	5,644	951
NS	394	5,133
NL	10,346	11,598
YT	18,164	-
NWT	170,513	-
NU	6,713	-
Total	454,641	192,980

Chapter 6 Modelling and Output

This chapter presents model output. Considerations for GCAM-Canada model calibration and validation are presented in Section 6.1, along with some comparisons to baselines from other studies. Based on the intermediate historical and resource cost-supply results (Chapter 5), output from simulations with GCAM-Canada to support the research questions is presented in Section 6.2.

6.1 Model Calibration and Validation

This section presents information about the calibration and validation of GCAM-Canada, including details of its capabilities to model subnational hydropower endogenously. This is shown by quantifying historical calibration (with shareweights) and by comparing reference case model output with CER Energy Future (2020) simulations.

6.1.1 Calibrated Hydropower Shareweights

As part of modelling endogenous hydropower in the revised GCAM-Canada, hydropower shareweights for each historical period are determined for each province and territory. The values determined in the model for 2015 are given in Table 5.18. The largest producer of hydropower, Québec, is assigned a constant value of 1, and all other regions are calibrated relative to that value. For each of the provinces, these shareweights are held constant beyond 2015, but the shareweights for the territories increase linearly from 2015 to a maximum value of 0.01 in 2100 to allow room for some modest growth; otherwise, Nunavut would not develop hydropower due to a historical lack of development. Comparing these calibrated values gives information from which some insight can be drawn: for example, that resources in Alberta have already been exploited quite heavily given the characteristics of its resources (especially its very low capacity factors), and that the northern territories are being heavily constrained from development, which can be attributed to low local demand and lack of access to larger markets, and other practical constraints on development in remote areas. Therefore, the historical shareweights are a representation of the influence of factors on hydropower development other than those which are explicitly accounted for in the model.

Table 6.1. Hydropower shareweights determined for 2015 for each province and territory.

BC	AB	SK	MB	ON	QC	
0.470	1.658	0.007	0.049	0.335	1	
NB	**PEI**	**NS**	**NL**	**YT**	**NT**	**NU**
0.060	none	none	0.027	0.001	0.001	none

Due to the nested structure of hydropower in the model, shareweights were separately determined for each basin within each province and territory. These values are presented for 2015 in Table 5.19. Based on the nested structure used, each province or territory's largest hydropower-contributing basin is assigned a shareweight of 1 for that jurisdiction and others are calibrated around that value. The shareweights within each province can then be compared against each other in the same manner as at the provincial level. Many of the more remote or northern basins within provinces are assigned lower shareweights, but lower shareweights are also observed for the BC-Fraser and southern Québec regions as well. These shareweights are assumed constant from 2015 through future periods, except in regions which had no historical generation, which are allowed a modest linear increase in shareweight through future periods so that they are not completely excluded from consideration.

Table 6.2. Hydropower shareweights determined for 2015 for each subnational region.

Subnational Region ID	Province/ Territory	Basin	Shareweight
1	BC	Pacific and Arctic Coast	0.081
2	BC	Fraser	0.101
3	BC	Pacific Northwest	1
4	BC	Mackenzie	0.152
5	AB	Mackenzie	0
7	AB	Saskatchewan-Nelson	1
9	SK	Mackenzie	0.042
11	SK	Saskatchewan-Nelson	1
13	MB	Northwest Territories	3.54E-04
14	MB	Saskatchewan-Nelson	1
17	ON	Hudson Bay Coast	0.059
18	ON	Great Lakes	1
19	QC	Hudson Bay Coast	1
20	QC	Great Lakes	0.192
21	QC	St Lawrence	0.571
23	QC	Atlantic Ocean Seaboard	0.005
24	NB	New England	1
28	NL	Churchill	1
29	NL	Atlantic Ocean Seaboard	0.201
30	YT	Pacific and Arctic Coast	1
31	YT	Mackenzie	0
32	NT	Mackenzie	1
35	NU	Northwest Territories	0

6.1.2 Reference Case Electricity Generation

As part of the calibration of the electricity sector (Section 4.7), the electricity generation results by technology for the ContPol50 scenario are compared to simulations from the CER Energy Future (2020) Reference case, which has similar policy assumptions. Electricity generation by technology for ContPol50 is shown in Figures 6.1-6.4, along with the data from the CER (2020) reference case for comparison. Iterating through model runs and visualizing with this data helped to determine the model calibration for GCAM-Canada's electricity generation system that was described in Section 4.6. Biomass and geothermal generation are combined in these results because the CER (2020) reports them together. Note that the GCAM-Canada scenario treats 2020 as a future period, so that values between these datasets begin to diverge after 2015. The CER (2020) dataset provides values starting in 2005 and makes active projections to the year 2050 on a yearly basis. Differences in methodology between CER (2020) and the GCAM-Canada scenarios are significant and therefore the CER (2020) data was used as a loose guide for relative and near-term calibration rather than for direct calibration. For example, total electricity demand deviates between the datasets based on divergences in finer-scale sectoral divergences that cannot often be compared directly due to differences in technological boundaries. The CER (2020) active projections also result in some behaviours that GCAM does not mimic, because it does not include future expectations. This is especially notable in Figure 6.2, where CER (2020) nuclear output shows reductions in near-term future periods because of planned outages for maintenance, while the GCAM-Canada ContPol50 scenario shows slower growth and then decline over the same period. The ContPol50 output is caused by a preference for other electricity technologies to develop in that scenario in the longer term, with later reductions due to assumed retirement of capacity without replacement.

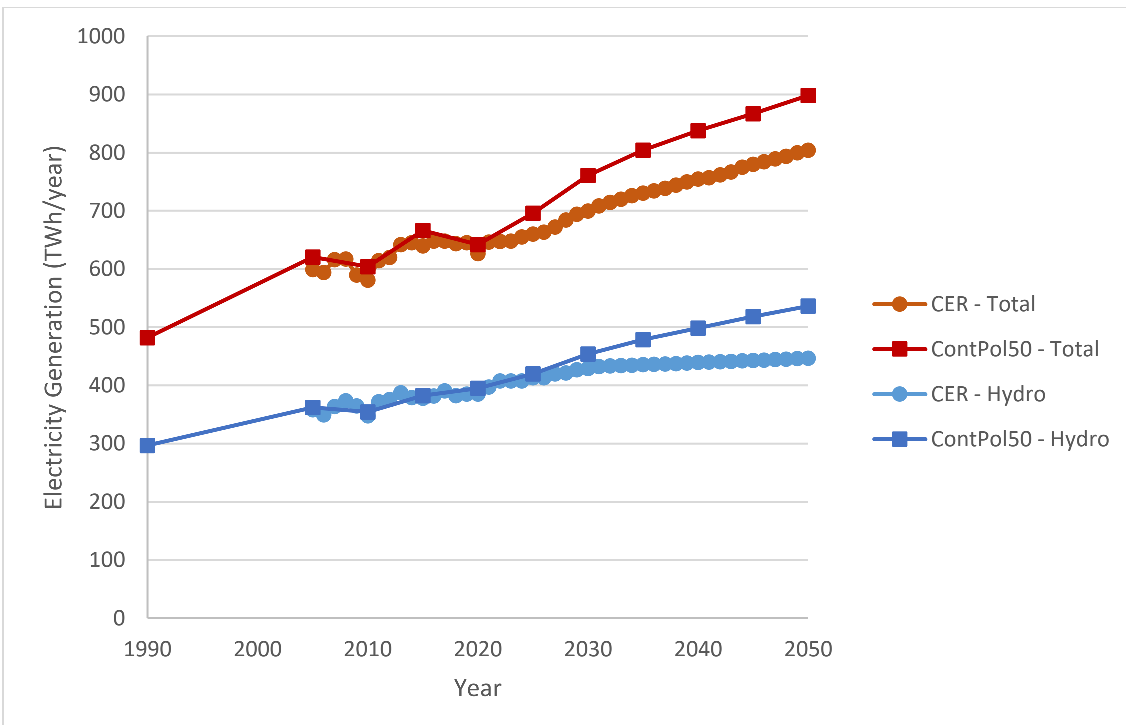

Figure 6.1. Total and hydropower electricity generation for Canada, CER (2020) Energy Future compared to ContPol50 scenario.

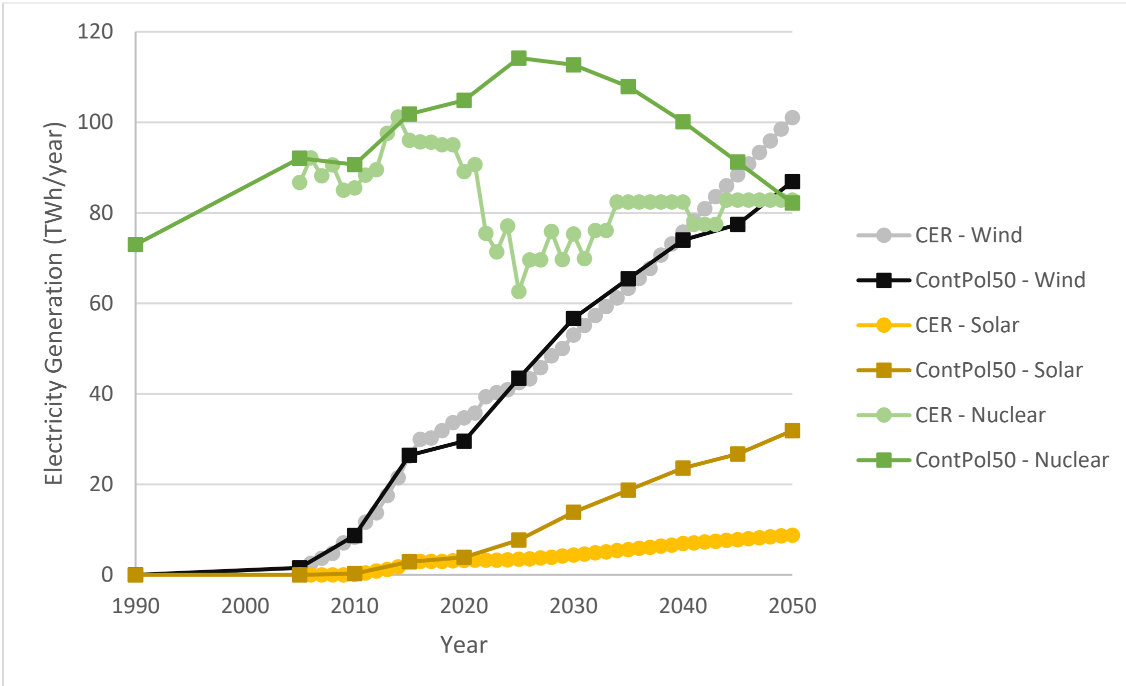

Figure 6.2. Wind, solar, and nuclear electricity generation for Canada, CER (2020) Energy Future compared to ContPol50 scenario.

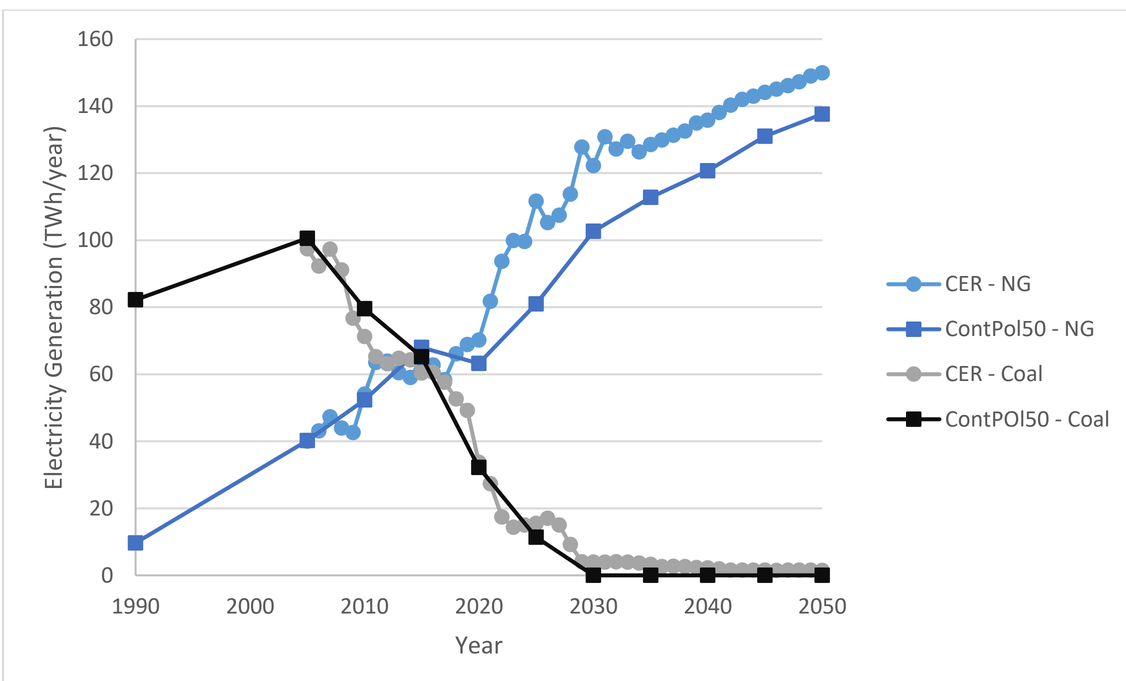

Figure 6.3. Natural gas (NG) and coal electricity generation for Canada, CER (2020) Energy Future compared to ContPol50 scenario.

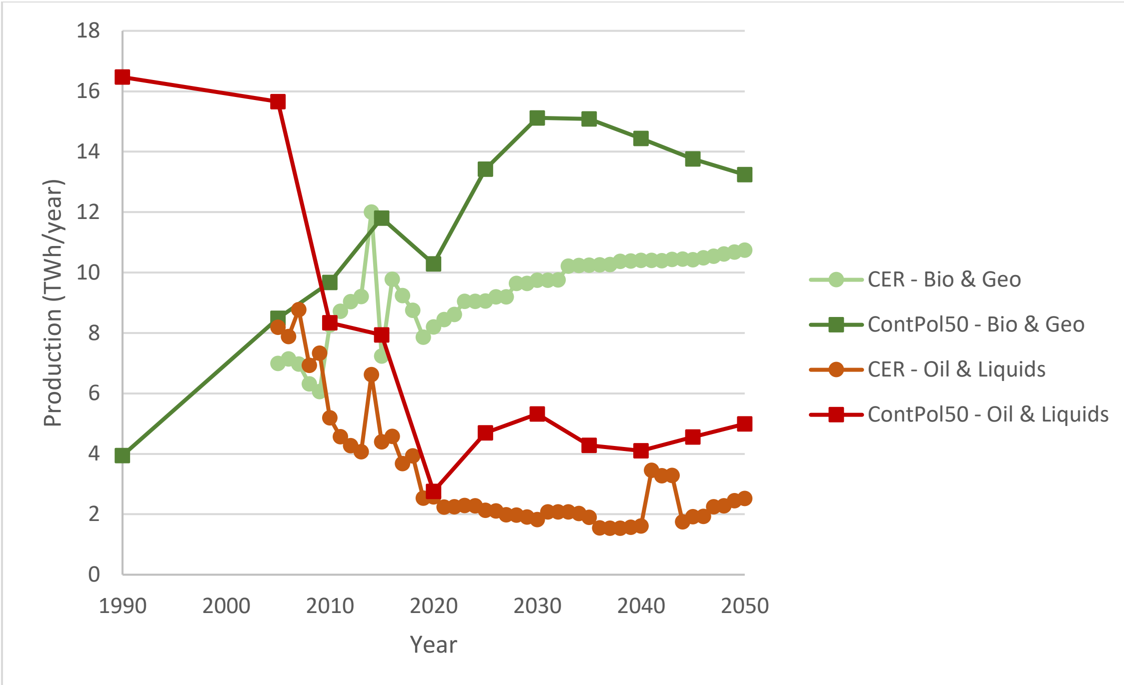

Figure 6.4. Combined biomass and geothermal and oil and refined liquids electricity generation for Canada, CER (2020) Energy Future compared to ContPol50 scenario.

6.1.3 Reference Case Hydropower Generation by Province and Territory

Figure 6.5 shows the reference case CER (2020) Energy Future hydropower generation compared to the GCAM-Canada ContPol50 scenario for all provinces and territories with hydropower generation. Note that the y-axis scale changes from panel to panel, whose order proceeds west to east among provinces, followed by the territories. Comparisons to other modelling work cannot be shown with finer detail than at the provincial scale for hydropower generation because no other energy-economy or integrated assessment model provides comparable results. The provincial results show that the GCAM-Canada ContPol50 results are not substantially different than the active projections from CER (2020). The GCAM-Canada ContPol50 scenario yields somewhat more optimistic results for most provinces. The results in Section 6.2 provide the first basin-level estimates for hydropower evolution using an integrated assessment model for Canada.

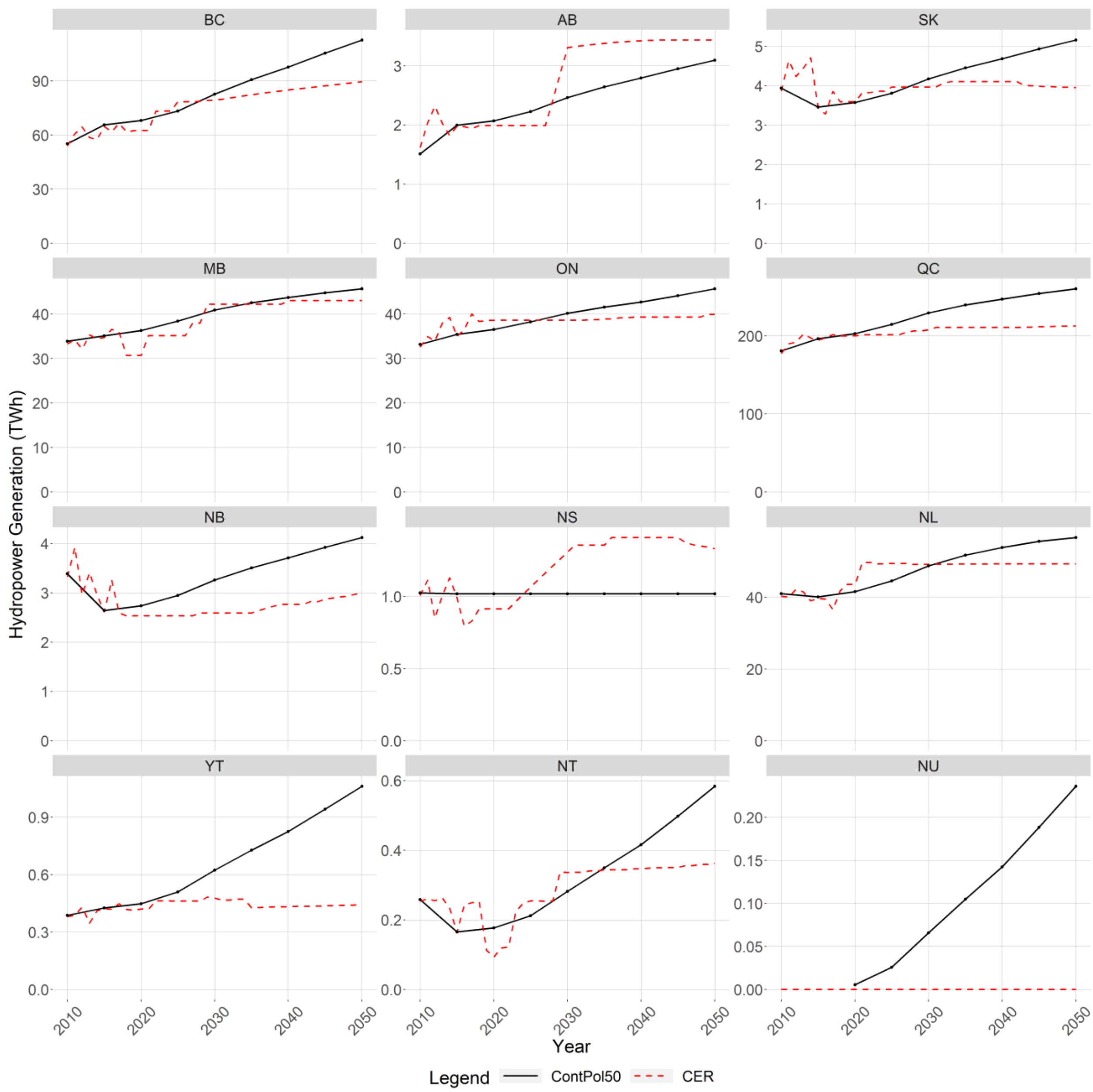

Figure 6.5. Hydropower generation for the ContPol50 scenario and CER (2020) Energy Future reference scenario.

6.2 GCAM-Canada Scenario Results

This section presents scenario output from the completed GCAM-Canada model with endogenous and subnational hydropower. Section 6.2.1 shows model generation of hydropower in the subnational regions of interest by climate policy scenario. Sections 6.2.2 and 6.2.3 then present climate scenario results for the electricity system and emissions for

Canada. Finally, Section 6.2.4 demonstrates other insights available from GCAM for climate policy analysis.

6.2.1 Hydropower Generation Results

Figure 6.6 shows hydropower generation by scenario for all provinces and territories with simulated hydropower generation. Note that the y-axis scales change from panel to panel. For each province, hydropower generation increases from NoPol to Paris2021 in order of climate action ambition. Refer to Section 3.4 for descriptions of the scenario design, inputs, and assumptions. The degree to which provinces develop hydropower in future years depends not only on electricity demand and carbon prices, but also on the economics of remaining resources. The results therefore show that provinces like BC and Québec, with substantial remaining resources, may be able to expand their hydropower development significantly, and take an even larger share of the national growth in more ambitious climate scenarios. Conversely, remaining resources in Newfoundland and Labrador and Manitoba are exploited fairly rapidly in all scenarios, resulting in more subdued long-term growth in those regions in all scenarios. In provinces with more modest existing generation (such as Alberta, Saskatchewan, and New Brunswick) and the northern territories, simulations show expansion of hydropower generation that is significant compared to present local values, but which form a relatively minor component of total generation on the national scale.

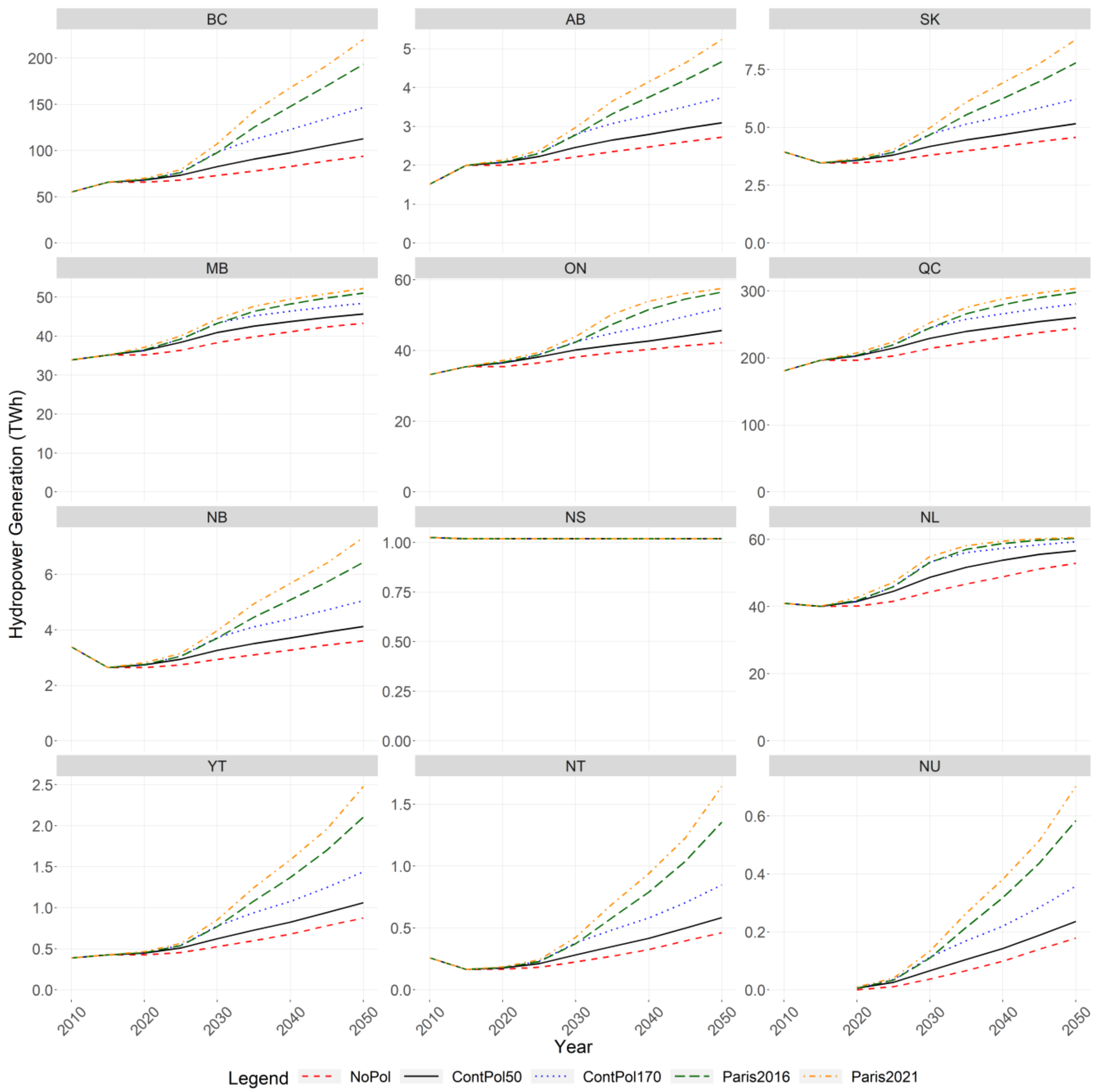

Figure 6.6. Hydropower generation by scenario for all provinces and territories.

Figure 6.7 shows hydropower generation by scenario for all modelled subnational regions at the basin level, ordered from maximum hydropower generation in any scenario in the top-left to the least in the bottom-right. Note that the y-axis scales are consistent across each row, but the maximum values are reduced from top to bottom. This figure helps to identify specific subnational regions that may undergo significant hydropower development. For example, this figure shows that BC's Pacific Northwest Basin is unlikely to see much growth, while the other regions in BC could see much more substantial new growth. The regions in which hydropower generation was considered fixed beyond 2015 for modelling purposes are identifiable by flat outputs that are coterminous for all scenarios, such as in Nova Scotia-Atlantic Ocean Seaboard. In several cases, the model simulates more significant new hydropower generation in relatively remote northern regions with significant pre-existing development, such as BC-Mackenzie and the Hudson Bay Coast regions of both Ontario and Québec. Abbreviations for regions are those included in Table 4.1. Subnational regions in which no resources have been developed or identified were excluded from Figure 6.7.

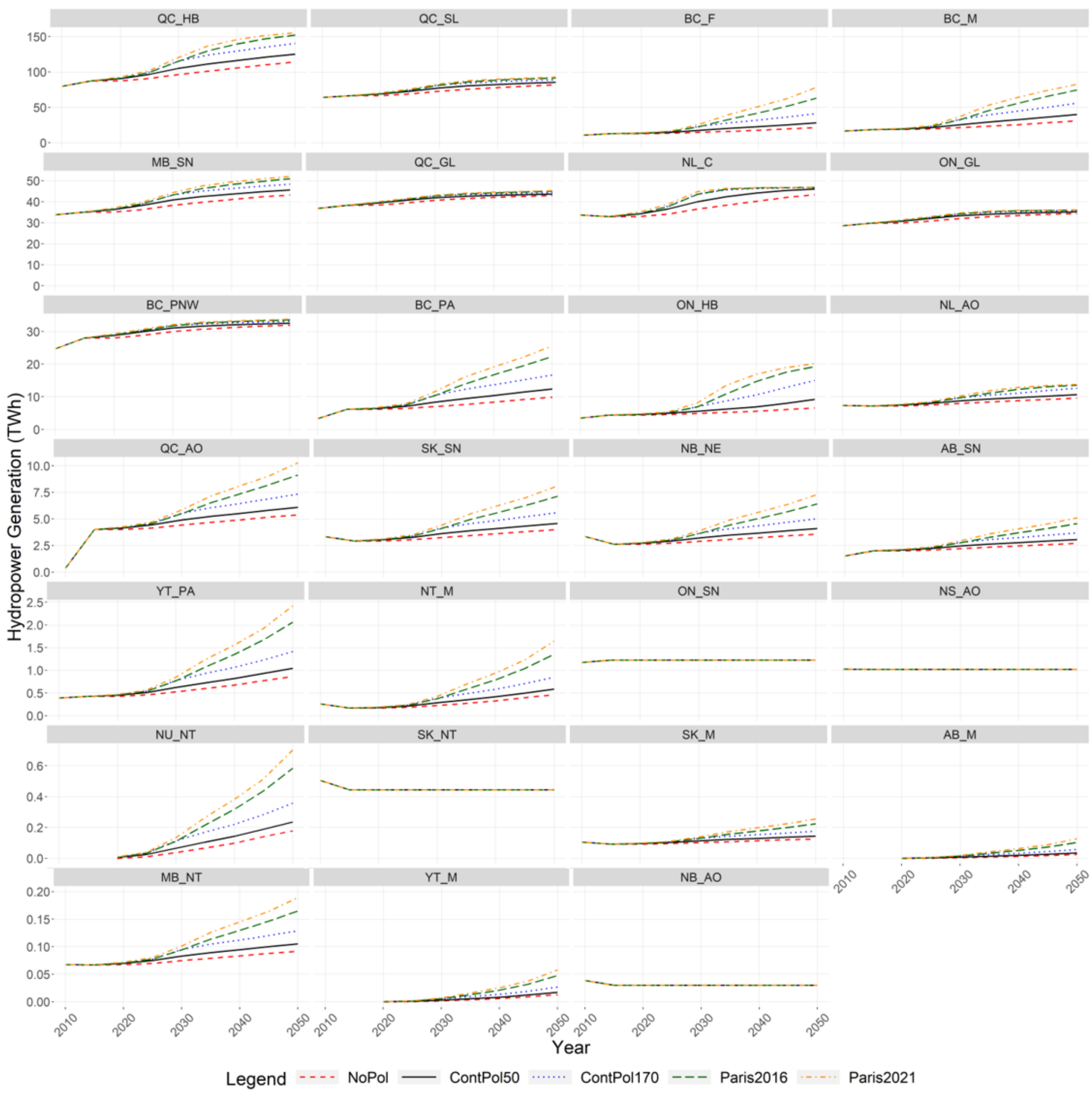

Figure 6.7. Hydropower generation by scenario for all modelled subnational regions.

For each basin region and model period, GCAM-Canada solved for the cost of hydropower electricity production, which provides some insight into model behaviour. Figure 6.8 shows the cost of hydropower electricity generation by subnational region in GCAM-Canada, for select regions in which development is determined endogenously. Many regions are omitted from the figure for easier readability. The Paris2021 scenario provides the most exaggerated cost differences between regions in future periods. The time profiles of these cost curves range from very flat to steep increases. The flattest and lowest cost is observed for the Manitoba-NT region, which is a result of the region's high resource availability, but very low technology shareweight, which strongly constrains development in the region, therefore preventing the cost escalation that would occur with more aggressive development toward resource limits within a region. The steepest price escalation occurs in the Ontario-Great Lakes basin, which has a strong technology shareweight as the largest historical producer in Ontario, where generation was already close to the maximum identified resource, causing costs to climb steeply along the asymptote of the smooth resource curve due to limited remaining availability. Similar rapid price escalations occur in the BC-Pacific Northwest (not shown) and NL-Churchill basins. Higher hydropower costs in historical years correlate with regions which have been assigned low capacity factors, as more capacity must be installed to achieve generation similar to regions with higher capacity factors. Thus, there is a strong and competitive price advantage in model simulations for regions with higher capacity factors.

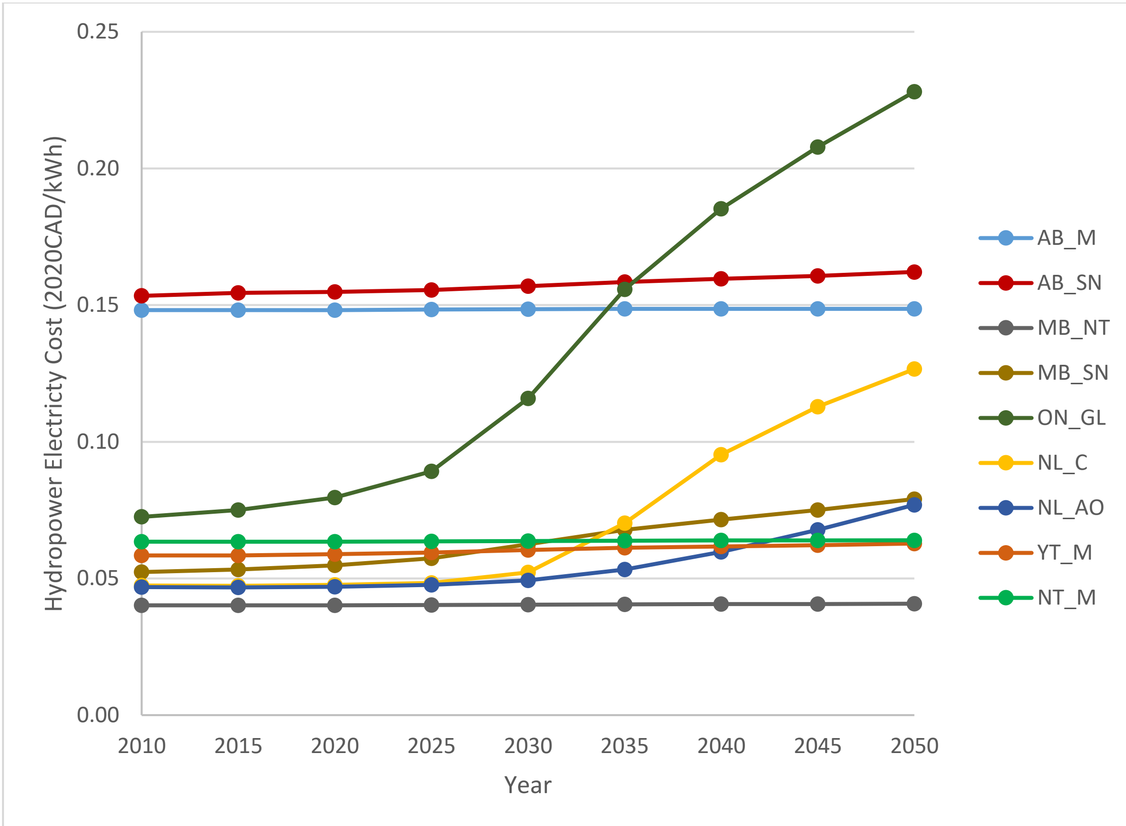

Figure 6.8. Cost profile of hydropower electricity generation for select subnational regions, Paris2021 scenario.

6.2.2 Electricity System Results

Figure 6.9 provides the modelled electricity generation by technology for Canada, with hydropower values superimposed onto the columns. Total electricity demand increases from NoPol to Paris2021, correlating with increased fuel switching from fossil fuel end-use demands. Even in the NoPol scenario, little growth in coal occurs as natural gas and hydropower absorb most demand growth. The GHG constraint scenarios stimulate significant adoption of hydropower generation, along with much more non-hydropower renewable growth and adoption of CCS.

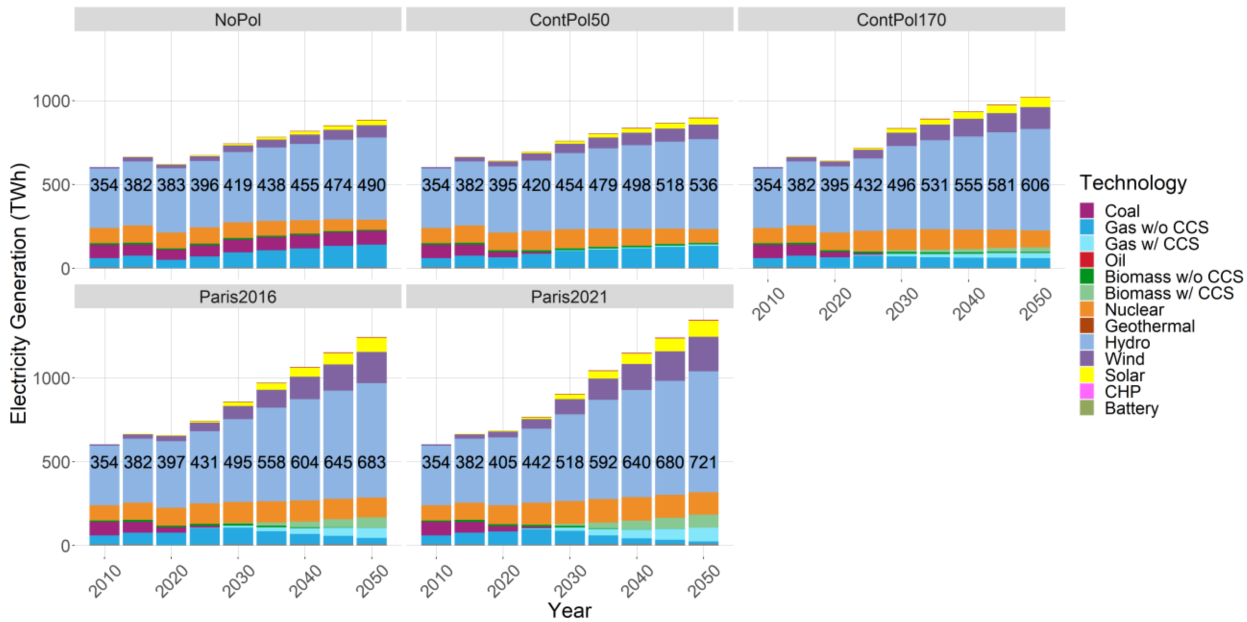

Figure 6.9. Total electricity generation by technology for Canada, by scenario. Superimposed values are national hydropower generation (TWh).

Figure 6.10 provides the bilateral electricity trade net export from Canada to the United States for each scenario. Note that the net electricity trade is calibrated based on historical values but does not specifically account for important trade infrastructure or policy parameters like transmission capacity or long-term power purchase agreements, which influence trade flows significantly in the real world. In the Continuing Policy scenarios, Canada’s net exports of electricity to the United States fall because of rising relative electricity prices, as these scenarios do not apply climate policies for the United States, allowing electricity prices in the United States to become more favourable for domestic use. Canadian exports of electricity increase in the GHG constraint scenarios because the United States’ decarbonization policies incentivize purchase of more Canadian electricity to replace existing fossil fuel sources.

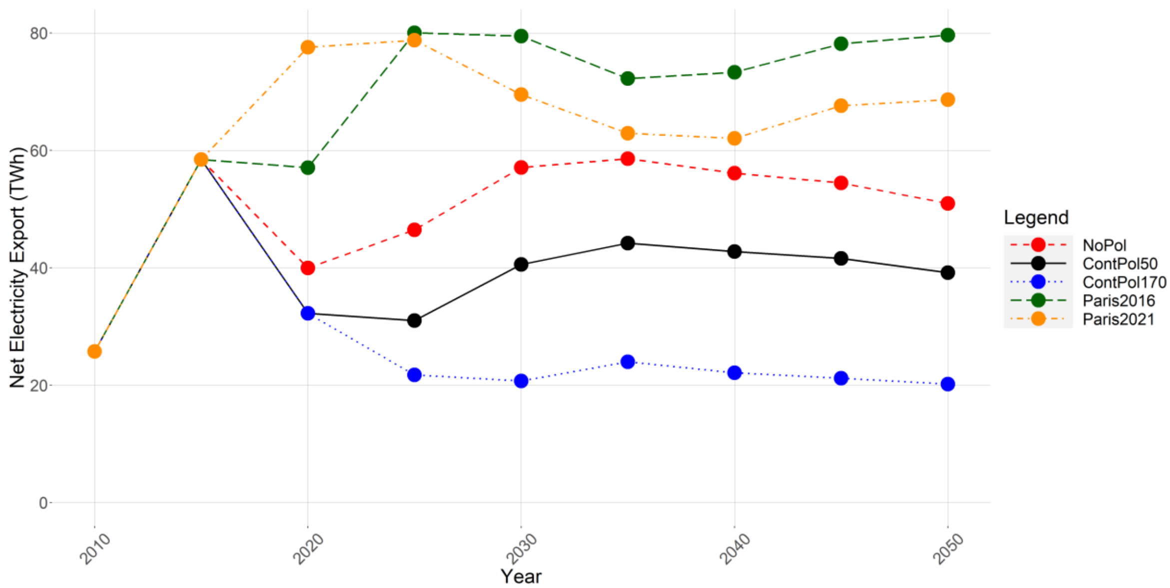

Figure 6.10. Net export of electricity from Canada to the United States by scenario.

Figure 6.11 shows the average national electricity prices for Canada as indexed relative to 2015 prices at a value of 1. Electricity prices for more ambitious scenarios are similarly grouped at about 10-15% higher prices than for NoPol. In general, the electricity price outcomes shown here for more ambitious climate scenarios suggest that such scenarios are not likely to make electricity prices substantially more expensive, despite large differences in carbon prices, owing to the largely decarbonized nature of Canada's electricity generation. The electricity prices represented here reflect only those inputs which are represented in GCAM, and therefore do not directly simulate prices that would be charged to consumers, which can be further influenced by government policy (especially in regions where significant power production is owned by the government), seasonal price fluctuations, or changes to fee structures for distribution, administration, or franchising.

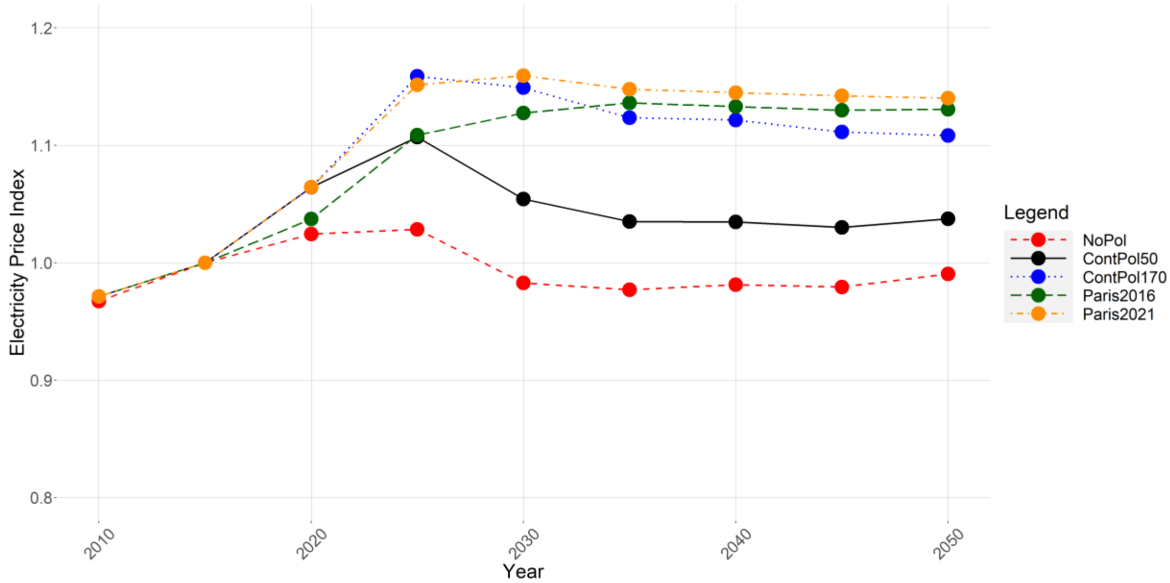

Figure 6.11. Electricity price indices for Canada by scenario (relative to the 2015 historical price).

GCAM-Canada results are generally consistent with a result from Beiter et al. (2017) that higher bilateral electricity trade between Canada and the USA results in somewhat higher electricity system costs (and therefore prices) in Canada, but with even smaller impacts on overall system costs in the USA due to its much larger electricity grid. While the United States could benefit from increased import of relatively inexpensive, non-emitting electricity from Canada, this would require more rapid Canadian electricity generation development into marginal resources, causing domestic Canadian electricity prices to increase. In the Continuing Policy scenarios, Canadian emissions reductions are achieved partially by reducing electricity exports to the United States. Therefore, the interplay between these two countries' climate action policies is an important component for electricity generation modelling, but is more important for Canada than for the USA. An asymmetrical trade dynamic could discourage some Canadian jurisdictions from increasing cross-border transmission capacities so that local benefits from lower electricity prices, including industry competitiveness, are maintained.

Figure 6.12 provides simulated electricity consumption by major sector in Canada, along with the net electricity export from Canada to the USA. Note that the total electricity consumption is slightly smaller than generation for each scenario and year, as consumption excludes "net own use" of electricity, which comprises between 3 and 4% of the electricity generation as input to the electricity sector itself (powering infrastructure). Losses during transmission and distribution are included as part of consumption. This figure highlights that most of the difference in electrification of end use sectors in the modelled scenarios is attributable to industry, the building sector to a lesser extent, and the electricity consumption of the transportation sector remains nearly constant between all modelled scenarios.

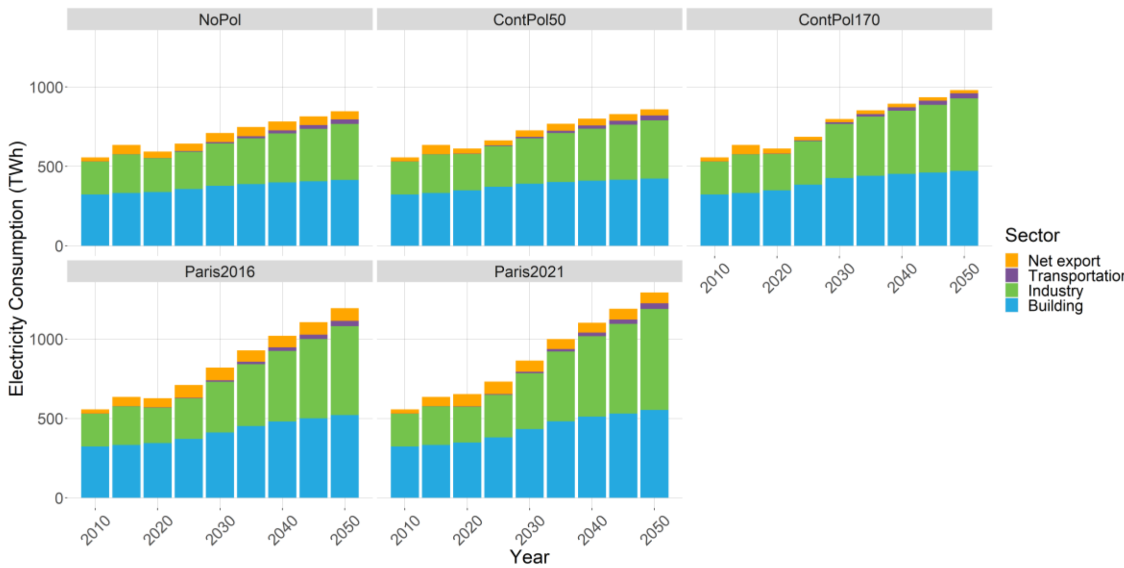

Figure 6.12. Total electricity consumption by sector for Canada, by scenario.

In all GCAM-Canada scenarios, increases to aggregate industrial electricity demand are led by increases to the industrial energy use sector, which excludes refining, cement production, and hydrogen production, but is otherwise not very detailed in this version of GCAM. Electrification of the building sector in more ambitious climate policy scenarios is led largely by fuel switching to electricity for heating and operations of commercial and residential buildings. Electricity demands for cooling buildings are not sensitive to climate policy scenario, grow very little from 2015 to future periods, and comprise only about 5% of the modelled electricity demands of heating in 2015 for Canada. Meanwhile, electricity demand for heating buildings increases especially significantly in GHG constraint scenarios due to fuel switching from natural gas, accounting for most of the electricity consumption growth in the buildings sector.

In Figure 6.12, the electricity consumed by Canada's transportation sector in 2050 was found to be 29.18 TWh for the NoPol scenario and 35.11 TWh for the Paris2021 scenario, with other scenarios intermediate between these values. The electricity consumed for transportation in 2015 was 0.97 TWh, indicating that each scenario yields a significant increase in electricity demand for transportation in future periods, but model results in this sector are not very sensitive to the climate policy scenarios applied. In contrast, the net zero scenario from EPRI (2021) shows the transportation sector's electricity demand rising to about 167 TWh by 2050, indicating much larger growth than any GCAM-Canada scenario. EPRI's (2021) assumptions regarding future costs of lower-emission transportation technologies are much more optimistic than the more conservative assumptions in core GCAM used here. For more accurate modelling in this area, it may be important to specify and update policy and cost expectations for electric transportation options directly to observe a more robust model response.

6.2.3 Emissions Results

GHG emissions results from the model show how the model scenarios perform against each other with regard to emissions reduction and the pathways taken to achieve those outcomes. The Continuing Policy scenarios have exogenous carbon prices and endogenous emissions results, while the GHG constraint scenarios have exogenous net GHG emissions and endogenous carbon prices. Figure 6.13 shows the carbon prices for each of the scenarios, represented in 2020 CAD/tCO2e. This shows that the ContPol170 scenario sets a similar carbon price profile to 2030 as the Paris2021 scenario requires to that model period.

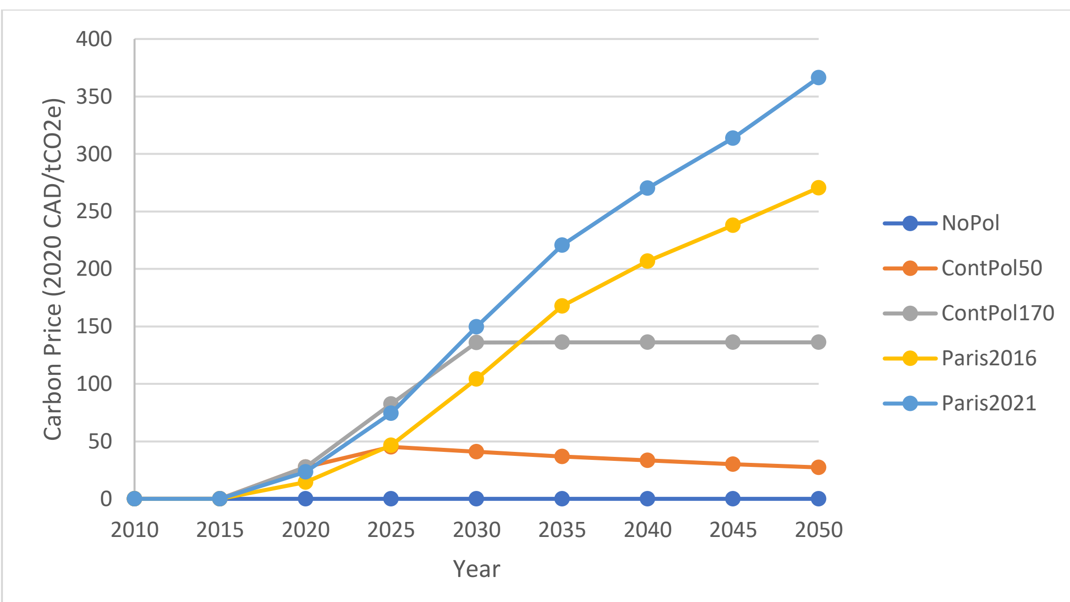

Figure 6.13. Canada national carbon price by scenario.

For all scenarios except Paris2016 and Paris2021, carbon prices in all regions other than Canada are set at 0 in all model periods. In the GHG constraint scenarios, non-Canadian carbon prices increase in future model periods in order to achieve intended greenhouse gas emissions reductions. The USA's carbon prices by 2050 for the Paris2016 and Paris2021 scenarios are, respectively, \$294.82 CAD/tCO_2e and \$339.73 CAD/tCO_2e. This implies that the USA would need a slightly higher carbon price than Canada for the Paris2016 scenario and slightly lower carbon price than Canada for the Paris2021 scenario. For the Paris2021 scenario, carbon prices for China, Brazil, and the European Union, would be \$139.81, \$226.05, and \$301.47 CAD/tCO_2e. Considering all model regions for these scenarios, the highest carbon prices are assigned to Canada and the USA, coinciding with exogenously specified ambitions for net zero, while other regions remain set to maintain NDCs from 2016, which are not as aggressive as net zero by 2050 for developing countries.

Figure 6.14 provides the simulated total equivalent GHG emissions for each scenario. This figure shows some of the starkest differences among model outcomes between scenarios. Outcomes range from slow, continued growth of GHG emissions in the NoPol scenario to near net zero equivalent GHG emissions for Paris2021. These results suggest that the continuing policy scenario climate policies are not sufficient to drive emissions to net zero.

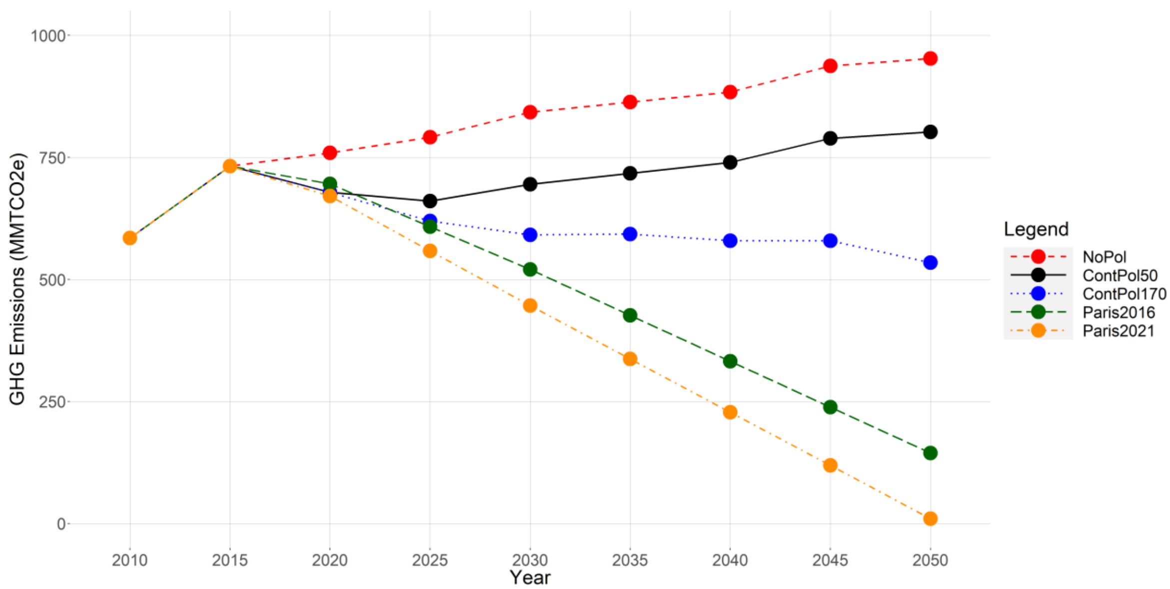

Figure 6.14. Total equivalent GHG emissions by scenario.

Figure 6.15 presents the makeup of GHG emissions by species for each scenario. In the figure, emissions from LUC ex-tundra represent a combination of multiple species that contribute to land-use change emissions, as carbon dioxide equivalent. The species most sensitive to the policy scenarios is carbon dioxide, which is reduced largely through increased share of renewable electricity generation and electrification of industrial and building sectors. The second-most GHG emissions-contributing species, methane, holds at relatively consistent levels regardless of scenario. As methane emissions are reduced per unit of energy produced in the oil and gas sectors, oil and gas production can increase somewhat without total equivalent GHG emissions increasing. Agriculture contributes about 22-30% of total methane emissions for any modelled scenario and period. Emissions from this sector are especially persistent in model results, with a lack of ready alternatives to shift to lower-emitting activities for production. The methane released from thawing of permafrost ecosystems, which could accelerate with further warming and Arctic amplification, could be a more significant factor than accounted for in these results (Elder et al., 2021). In the 2015 historical period, the agricultural sector contributed 64% of Canada's third-most potent GHG, nitrous oxide (N_2O). Depending on model scenario, the share of total N_2O emissions derived from the agriculture sector is simulated to grow to 75-80% by 2050, but for total levels to grow slowly between 2015 and 2050 (30.2% growth for NoPol and 11.4% growth for Paris2021, with other values being intermediate).

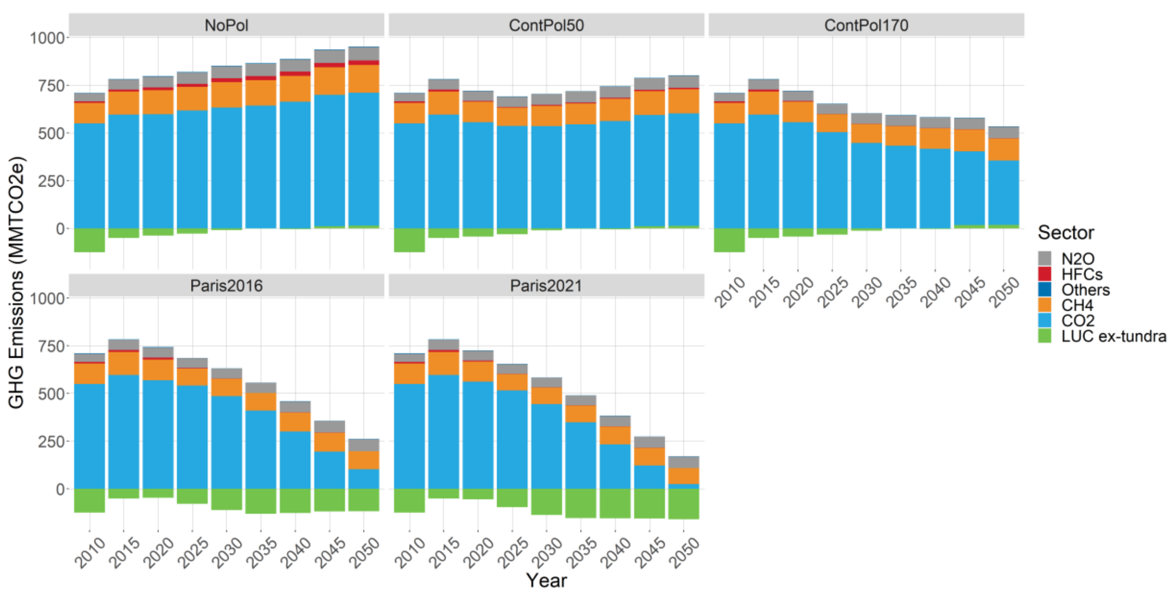

Figure 6.15. Total equivalent GHG emissions by species.

In this analysis, emissions exclude land use change emissions from Canada's tundra region, which were exogenously specified in core GCAM. Emissions from Canada's tundra regions in the model were specified at 179 MMTCO2e in 2015, but fall rapidly to just 7 MMTCO2e by

2050. Since this is an exogenous core model assumption that has not been influenced by new model developments in this work, the tundra emissions profile is identical for all modelled scenarios. Despite GCAM's early assumptions of substantial GHG emissions from tundra, the National Inventory of greenhouse gases that Canada uses for submissions to the UNFCCC (ECCC, 2021d) accounts for emissions from tundra only as a portion of grasslands, which themselves account for nearly net zero emissions in that report. The purpose of the GHG constraint scenarios is to provide scenarios for emissions paths that could be followed by Canada, according to the accounting system used to do so. Therefore, it was decided to neglect the influence of tundra land use change emissions for the purposes of this modelling work. While establishing the policy addon files for the GHG constraint scenarios, corrections were applied to ensure that net emissions profiles follow the intended paths after ignoring contributions from tundra regions in the model. As a result of the scenario design and emissions accounting used in this paper, potential greenhouse gas emissions from permafrost thaw, which could be significant in the coming decades (Turetsky et al., 2020), are largely neglected in this thesis, or are effectively deemed a potential carbon emission source that would not be accounted for or abated by the scenarios.

In policies with higher carbon prices, CCS becomes increasingly appealing. In the Paris2021 scenario, Canada stores 238.5 $MMTCO_2$ per year by 2050, allowing net non-LUC anthropogenic CO_2 emissions to approach nearly 0 for that scenario. The NoPol scenario simulates no carbon storage due to a lack of incentive for doing so, the ContPol50 scenario sees very limited adoption because the costs of storing carbon are not competitive at such price levels, while ContPol170 and Paris 2016 yield intermediate values.

For assessment of climate policy effectiveness on a global scale using the GCAM-Canada scenarios, model output of annually averaged atmospheric CO_2 concentrations are provided in Table 6.2. Note that GCAM's calibrated atmospheric CO_2 concentration values in historical periods appear to be lower than most measurements, with 383.02 ppm in 2015, in which NOAA (2021) measured atmospheric concentrations at 400 ppm at the Mauna Loa Observatory. Historical CO_2 concentrations in Hector, the climate model employed by GCAM (Hartin et al., 2015), are below NOAA Mauna Loa observations by 15 to 17 ppm, but this does not imply poor fitting of temperature anomaly or radiative forcing trends through future model periods. The trends shown in Table 6.3 reveal that climate policy actions in Canada alone ("ContPol-") have little effect on global CO_2 concentrations compared to the NoPol scenario, while applying the global emissions constraints in the "Paris-" scenarios leads to a significant slowing of growth in CO_2 concentrations.

Table 6.3. Global atmospheric CO_2 concentrations by scenario.

Scenario	2030	2050
NoPol	415.15	469.43
ContPol50	415.07	469.97
ContPol170	415.04	468.88
Paris2016	412.27	436.03
Paris2021	411.62	433.26

Each scenario other than NoPol includes a methane emissions reduction policy for the natural gas and oil production sectors, which reduces the emissions intensity of those sectors in a linear fashion from 2015 to 2025. Figure 6.16 shows this for natural gas production, with emissions reported in Tg of direct methane emissions (not CO2e) per EJ of natural gas produced. The emissions reduction intensity of oil production is analogous to that for natural gas for each scenario. As the methane emissions intensity is reduced by marginal abatement cost curves defined by carbon prices, the scenarios with higher carbon prices achieve slightly better methane emissions intensity reduction. Assumptions in core GCAM accounted for a gradual reduction in methane emissions intensity (see the NoPol case), although it is less ambitious than the current Canadian targets, which are better represented by the lower near-term methane emissions intensity shown in all other scenarios.

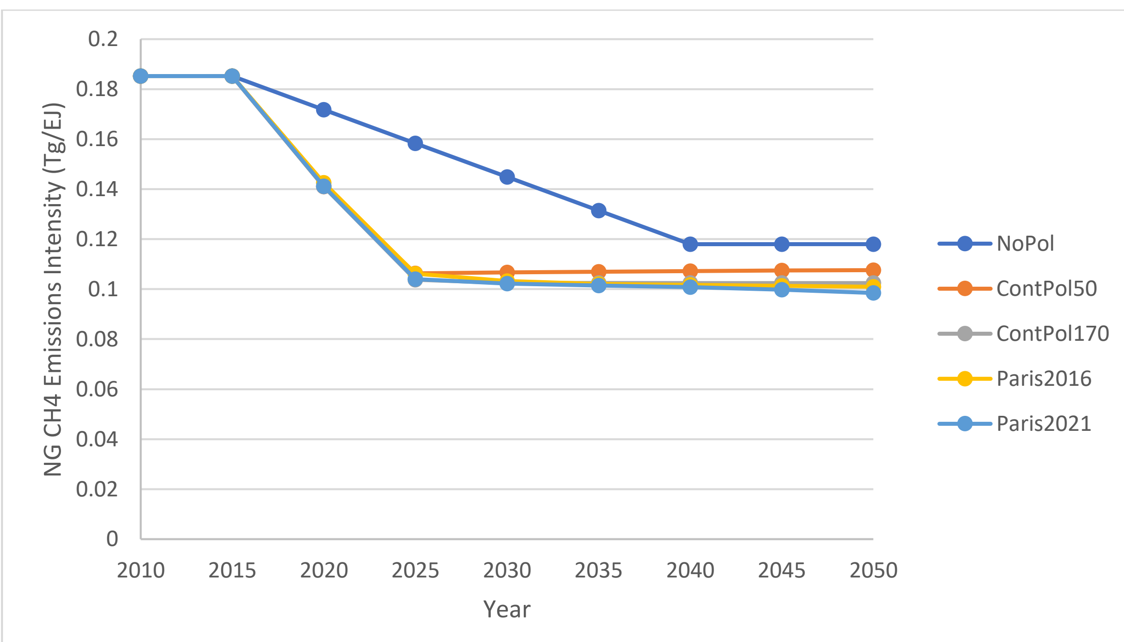

Figure 6.16. Natural gas methane emissions intensity by scenario.

The near-term reduction of methane emissions intensity from oil and gas production in the model allows some leeway for production to continue without being immediately and substantially reduced by carbon prices. Much of the oil and gas sector is not in practice subject to the same carbon pricing system for other sectors, so it could be useful, if more details regarding the oil and gas sector are desired, to more accurately specify such policies as model input.

6.2.4 Other Model Results: Potential Explorations Possible with IAMs

Integrated assessment modelling allows exploration of multiple impacts and feedbacks beyond the primary goals of this study. Model scenarios can be compared among seemingly distant sectors of interrelated human-earth systems. Beyond electricity systems, the author has not validated the results, so these extensions should be interpreted with caution. Nevertheless, such results can provide preliminary insight for wider systems impacts.

As an example of the type of additional scenario comparison that can be conducted with further model output exploration, this subsection analyzes energy consumption. Figure 6.17 provides primary energy consumption for Canada by scenario. In 2015, Canada's primary energy consumption was 73.1% derived from fossil fuels. In the ContPol50 scenario, that fraction falls slightly to 69.2% by 2050, but in the Paris2021 scenario, it falls much more dramatically, to 37.0%. Despite reductions in the share of primary energy derived from oil and natural gas in Canada for the more ambitious climate scenarios, this does not immediately correlate with reduction in raw resource production in those fields. In the Paris2021 scenario, natural gas production continues increasing until 2040, although there are slight reductions to unconventional oil production starting in 2020, but this is stabilized somewhat by gradual increases to conventional crude oil production, leading to only slow decreases to total national oil production. Therefore, simulated reduction in domestic demand for fossil fuels in more ambitious climate scenarios results in increased international exports rather than reduction of resource production.

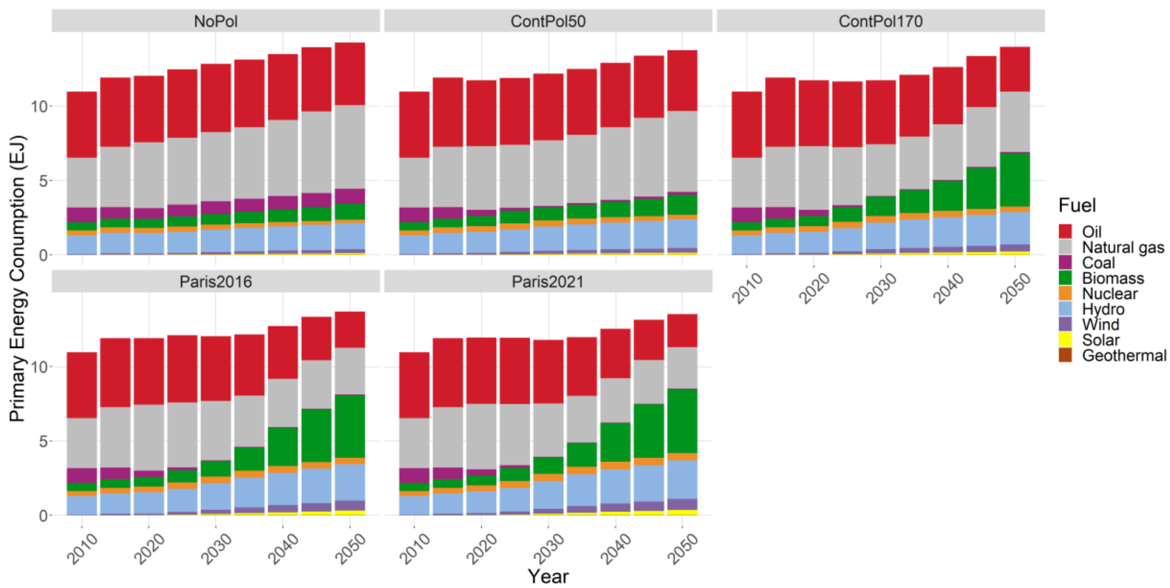

Figure 6.17. Primary energy consumption by fuel and scenario.

Changes in the production and consumption of biofuels under the climate scenarios provide an interesting opportunity to look at how some model responses may provide insight:

- The more aggressive climate action scenarios from ContPol170 to Paris2021 each achieve slightly negative fuel prices for delivered biomass in future periods when carbon prices are sufficiently high. This suggests that consumers of biomass as a final energy are effectively paid to use the fuel due to credits obtained when using biomass as fuel with CCS at higher carbon prices.
- In scenarios which lead to higher purpose-grown biomass production (more ambitious scenarios), land presently used for production of animal feed or food crops would be redeployed for biomass production, and therefore could lead to increases in livestock production costs and in food prices in general. While the agricultural sector may be able to take advantage of more high value activities, consumer price signals could lead to some limited substitution of the food products people consume. The Paris2021 scenario shows meat and crop consumption about 3.5% and 1.3% lower than the NoPol scenario, despite population being prescribed exogenously.

Chapter 7 Discussion

This chapter presents a brief discussion of the results and analyses provided in Chapters 5 and 6.

7.1 Historical Generation and Remaining Resource Availability

Section 5.1 presented data that allows for a regional look at the development of hydropower in Canada. Table 5.8 showed historical growth of hydropower generation in Canada for smaller subnational regions and revealed that a majority of existing hydropower generation occurs in only a few regions. Canada as a whole is a very water resource-rich nation, but the picture is more complicated upon closer inspection of local realities, where some regions experience water stress (Younis and Davies, 2023). In the period from 1975 to 2015, many subnational regions saw very little change in hydropower generation, except for notable development efforts in British Columbia-Pacific Northwest Basin (in the Columbia River system), incremental growth elsewhere in BC, and growth in Manitoba and Québec. The more northern and remote regions are able to supply much of the hydropower and generally have the most advantageous capacity factors, but higher development costs limit their implementation. Moving forward, Canada's northern hydropower facilities may be able to insulate the assets somewhat against the climate change, seasonality, and other aspects like water stress (Hamududu and Killingtveit, 2016) that are currently depleting large hydropower reservoirs in the United States (Wheeler et al., 2022).

Section 5.2 provided the first spatially comprehensive dataset of hydropower resource estimates with costs for Canada. A review of the results in Table 5.12 shows that, unsurprisingly, the Great Lakes regions in Ontario and Québec have already been significantly exploited, generating 83% and 78% of the maximum resource potential identified. There is a correlation between hydropower resource potential and population density within each subnational region, except where northern or more remote basins within the hydropower dominant provinces are heavily exploited and connected with population centres through very lengthy transmission lines, such as from Québec-Hudson Bay and Manitoba-Saskatchewan-Nelson. Some of the resource curves in Section 5.2 are constructed from relatively few, resource-rich grid cells. For example, Newfoundland and Labrador-Churchill has only 3 grid cells that showed major development potential, which coincide with the location of Muskrat Falls and nearby sites on the mainstem of the Churchill River. This resulted in a resource curve shape that shows a large amount of cheap power before it rapidly becomes much more expensive. The scale on which hydropower resource estimates are produced is an important factor discussed further in the limitations (Section 8.2).

7.2 Comparisons to Other Modelling Work

The results from the subnational GCAM-Canada hydropower modelling were compared in Section 6.2 to the CER (2020) Energy Future projections. GCAM-Canada and CER rely on differing sets and types of assumptions. The CER projections included forward-looking assumptions regarding various factors that can affect results, like currency exchange rates, and consider developments that are currently under construction or planned. For instance, CER (2020) projections for 2021 showed increases in hydropower capacity that correspond approximately to full openings of the Muskrat Falls and Keeyask projects, which were then in their early stages of commissioning. CER (2020) also assumed that existing coal power plants could be retrofitted to natural gas for a lesser cost than building new plants, which was not considered in GCAM-Canada.

The EPRI (2021) Canadian National Electrification Assessment and the Canadian Energy Outlook 2021 — Horizon 2060 (Langlois-Bertrand et al., 2021) provided relevant energy system modelling for Canada. Both provided greater detail on provincial and regional energy demands and finer time-scale resolutions than are considered by the GCAM-Canada modelling work. EPRI (2021) used an energy-economic model for Canada and the United States called REGEN, which has substantial detail about end-use energy demand, investment, dispatch, and transmission, but has fewer connections to other systems than IAMs. The Langlois-Bertrand et al. (2021) modelling was based on integrated assessment modelling using TIMES (Vaillancourt et al., 2017), and was intended to explore cost-optimal pathways. Both of these reports considered input data more recent than 2015, of the base year for this version of GCAM-Canada. The scope, input assumptions, and intent of these reports diverge from GCAM-Canada; however, there are some observations to draw from comparisons between these reports.

- They did not simulate substantial hydropower growth in Canada, owing to the lack of available data regarding resource potential that this work aims to help solve.
- They simulated more growth of nuclear power than GCAM-Canada, employing small modular reactors for most of this growth, despite the nascence of this technology today.

- They more explicitly valued electricity storage and grid reliability. As such, firm capacity provided by hydropower, nuclear, and natural gas (including with CCS) is relied upon more steadily on an hourly basis. Growth of nuclear and natural gas with CCS is therefore an important part of their net zero scenarios.
- They simulated significant reductions in final energy consumption for Canadian net zero scenarios from present levels, while GCAM-Canada showed a slight increase.
- They did not simulate as much uptake of biomass for energy as GCAM-Canada in the GHG emissions constraint scenarios (even with the biomass "ceiling" in place for the Paris2021 scenario).
- Langlois-Bertrand et al. (2021) considered approximately 2 EJ of biomass consumption to be the limit for Canadian uptake, but acknowledged considerable uncertainty in availability. This was approximately half of the amount of biomass consumed in the Paris2016 and Paris2021 GCAM-Canada scenarios.
- EPRI (2021) simulated the largest net export of electricity from Canada to the USA. Their net zero scenario suggested domestic demand of only about 700 TWh and total generation of about 1,050 TWh in the year 2050, implying net export to the USA of about 350 TWh. The Paris2021 net export with the USA was only 68.6 TWh in 2050. Langlois-Bertrand et al. (2021) simulated net trade of only about 21.4 TWh in the net zero 2050 scenario.
- Electricity consumption in the net zero 2050 scenario of Langlois-Bertrand et al. (2021) was 1,128 TWh. Electricity generation for the Paris2021 scenario was 1,344 TWh.

Graphical comparisons of some electricity and energy system model outcomes for reference (ContPol50) and net zero (Paris2021) scenarios from the EPRI (2021) report, the GCAM-Canada results from this thesis, and several other reports with comparable analyses are presented in Figures 7.1 and 7.2. These figures have been adapted from EPRI (2021) – note that their assumptions are explained in more detail in their report. Scenario assumptions within a category (reference, deep decarbonization, and net zero) are not identical between modelling studies, but these figures help to clarify how results from the electricity system modelling work with GCAM-Canada fit in with other recent Canadian model analyses. Figure 7.1 plots percentage growth in electricity demand and carbon emissions reduction between 2010 and 2050 for several scenarios and models. GCAM-Canada's scenarios experienced somewhat higher growth in electricity demand than other models have simulated, especially for the net zero case. The black circle

(Paris2021) and triangle (NoPol) in the figure show electricity demand increase to 2050 versus CO_2 emissions reduction for this thesis. Compared to the other net zero scenarios (circles), this work appears to achieve closer to 100% economy CO_2 emissions reductions. The NoPol scenario also shows a higher increase in electricity demand to 2050 than the other model reference scenarios (triangles) compared in the figure.

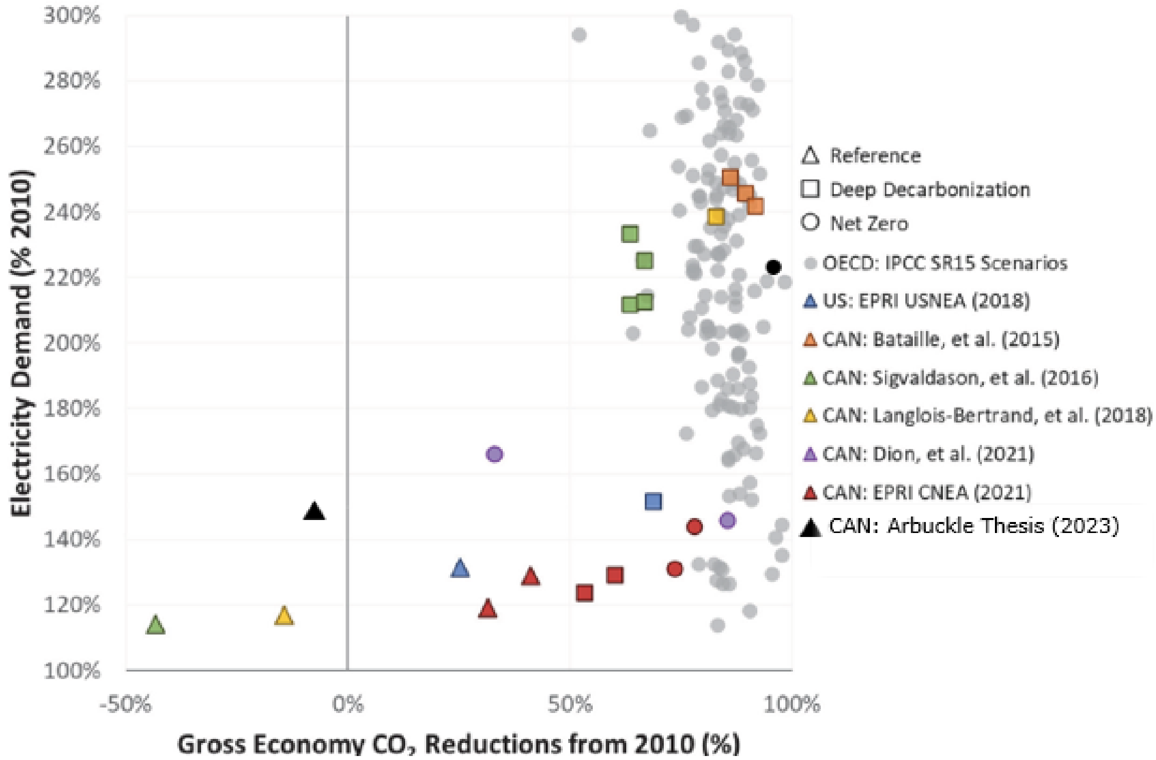

Figure 7.1. Comparison of electricity demand growth and emissions reductions between 2010 and 2050 for scenarios from a variety of modelling studies. Adapted from EPRI Canadian National Electrification Assessment (2021) with values from this study.

Figure 7.2 provides a plot of final energy per capita and electricity's share of final energy for several studies and scenarios. The GCAM-Canada results for the reference and net zero scenarios showed substantially higher energy intensity per capita than in EPRI (2021), although the GCAM-Canada reference case was similar to the energy intensity determined by Sigvaldason et al. (2016) and Langlois-Bertrand et al. (2018). Notably, the red coloured "x" mark in Figure 7.2 shows that, in 2010, Canada's energy consumption per capita was over 300 GJ/person, and all scenarios from all models show substantial energy intensity reduction by 2050, with EPRI (2021) being the most optimistic.

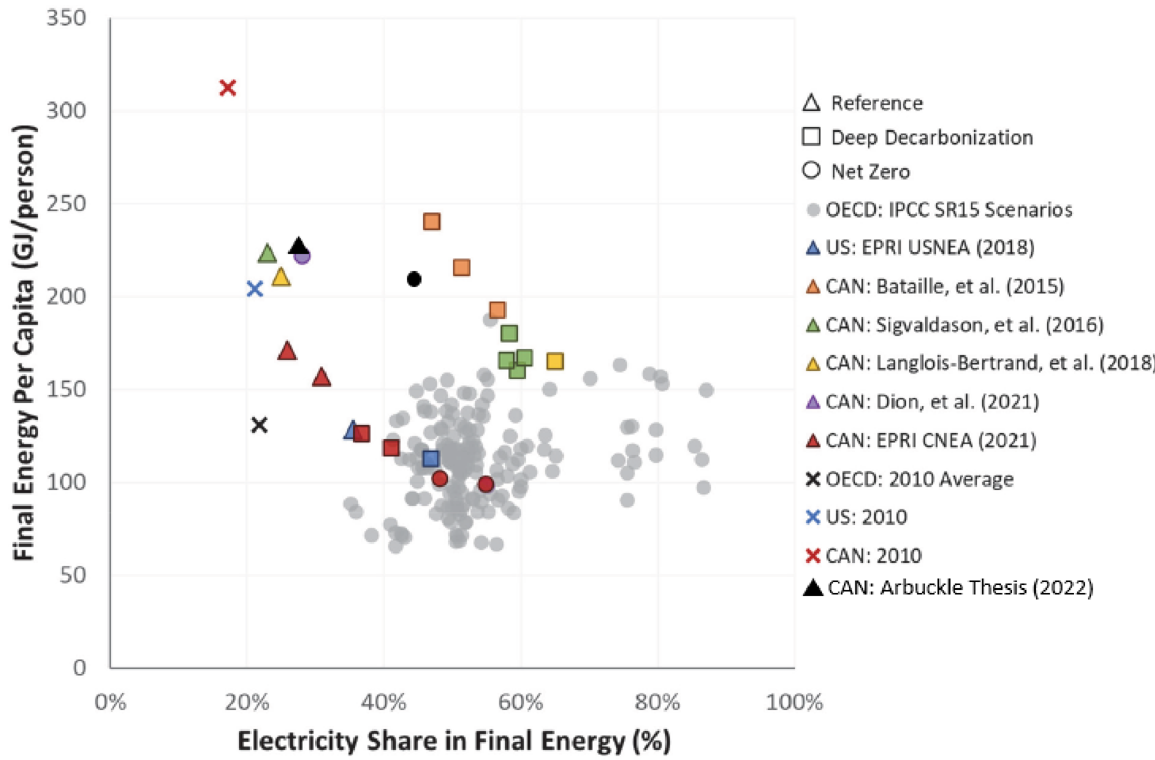

Figure 7.2. Comparison of final per capita energy demand and electricity's share of final energy in 2050 for scenarios from a variety of modelling studies. Adapted from EPRI Canadian National Electrification Assessment (2021) with values from this study.

7.3 Interpretation of Model Results for Remote Locations

The newly developed GCAM-Canada presented simulations with hydropower generation for some regions that have very small populations and very challenging climates in extremely remote areas, such as portions of the northern territories. Also effectively operating on their own power grids are many small First Nations villages in particularly remote locations, such as along BC's northern Coast, in Ontario's far north, or along the coast of Labrador. In practice, model results in these regions should be interpreted with caution, because the datasets are so small that even the construction of a small hydropower generating station could represent a significant deviation from model results. There may be significant hydropower generation in Labrador, but most of that power is diverted to Québec and Newfoundland, while the Inuit community of Nain remains separated from this grid, dependent on diesel and some solar power (Atter, 2022).

Electricity generation by diesel is a relatively small portion of Canada’s total, and is predominantly conducted in remote communities. Therefore, persistence of some diesel generation, even with constraints to reduce carbon emissions, is a reasonable model result. Switching remote communities from diesel to other sources of electricity is a topic of ongoing discussion (Senate of Canada, 2015), and these transitions are likely to occur in some areas over the next decades. Decisions to conduct transitions in most of these remote communities depend strongly on a set of political desire, complicated logistics, and other non-economic influences that would be very challenging to capture with GCAM. Electricity generation by refined liquids in GCAM-Canada should be interpreted with this context.

7.4 Land Use Change Emissions Feedbacks

The ContPol170 and Paris2021 scenarios shared very similar carbon prices up to 2030, but total GHG emissions diverged significantly. In 2030, about 86% of this divergence can be explained by differences in land use change emissions between the scenarios. The Paris2021 scenario applied NDCs globally, which changes Canada’s imports and exports considerably compared to ContPol170, where Canada’s climate policy actions are not reciprocated by other regions, although, based on shareweight calibrations, some existing climate actions as of 2015 in other model regions are effectively accounted for to some extent. This highlights the importance of considering feedbacks from land use change emissions on emissions accounting in energy system models.

Canada’s carbon emissions accounting systems and National Inventory do not presently quantify carbon emissions from land use change associated with peatlands, which store much more carbon than other types of unmanaged forests (Harris et al., 2021). In the context of conversion of land for biomass production modelled by GCAM, it is likely better to avoid land use change in peatland areas, as any potential benefits associated with biomass production would likely be undone by release of stored carbon and carbon-storing capabilities. This highlights that the land conversions simulated by GCAM may be in some cases operating with a scale that is too coarse for some applications, because peatlands are not represented as a specific type of land use in the model.

7.5 Prospects for Hydropower Development in Canada

Model results support the possibility of modest growth of hydropower development in Canada. Some comments on the near-term prospects of development based on current planning follow. New hydropower generally takes a long time to build; therefore, educated guesses can be made about changes to hydropower capacity by 2025 or even 2030. Such near- to medium-term guesses would add the capacity of Keeyask, Muskrat Falls, Site C, and Romaine-4 to 2025 totals, as well as perhaps a handful of small projects, but no other new large projects are expected by 2030. As of 2023, Muskrat Falls has been commissioned, but is experiencing turbine issues that threaten to necessitate costly repairs (Butler, 2023). Even with Site C being commissioned by 2025, BC Hydro is preparing to issue a “call for power” to have independent producers develop new capacity, with early indications showing a preference for “clean” and renewable energy, and to partner directly with First Nations (Government of BC, 2023b). In other words, BC has no plans to build any new large hydropower and is more open than it has been in the past to develop renewable sources other than hydropower. In this call for power, BC is planning to discourage new run-of-river hydro projects (Government of BC, 2023b), because they often provide the bulk of their power during spring freshet, which coincides with a season in which its already hydropower-dominant grid provides a surplus, and milder temperatures yield lower demand for electricity. While run-of-river hydropower is not necessarily discouraged in other regions, few small hydropower stations are currently under development. Hydro-Québec’s most recent strategic plan specifically calls for development of mostly new wind power, and to add capacity to existing hydropower stations where possible, with new hydropower less preferable (Hydro-Québec, 2022).

Chapter 8 Conclusions

This chapter provides conclusions, a summary of model limitations, and opportunities for future work.

8.1 Conclusions

This thesis documents the development of the GCAM-Canada model to include, for the first time, endogenous hydropower resources at a subnational scale. This work follows Arbuckle et al. (2021), where we first established endogenous hydropower on a national basis for Canada within GCAM, which had not previously been included for any country. As part of this work, the most detailed history of hydropower development in Canada has been aggregated and presented, which provides a dataset available for other energy system modellers. In many ways, the history of hydropower is intertwined with the history of post-colonial Canada, so this dataset may be of use to historians, geographers, and others interested in understanding the development of hydropower in Canada. Also presented was a dataset that provides hydropower resource and cost estimates on a provincial/territorial, and subnational basis, which may provide a basis for other energy system modellers to include Canada's hydropower resources endogenously within their work.

The regionalized historical hydropower generation and resource cost-supply data were applied to a newly developed GCAM-Canada model capable of simulating hydropower growth for subnational regions within provinces as part of its rich energy-economic modelling framework. After model calibration and validation, scenarios were applied to this model to investigate potential pathways for hydropower resource development in Canada to the year 2050.

The model results in Chapter 6 provided a basis to answer the questions proposed in Chapter 1. The first set of questions was:

- How and where might Canada's hydropower sector develop to 2050? How does this development relate to broader electricity generation networks, energy systems, and climate outcomes?

A review of the figures in Section 6.2.1 shows that some provinces may be able to grow hydropower significantly relative to existing values, including British Columbia, Québec, Alberta, New Brunswick, and the Territories, while some of the more established provinces of Manitoba and Newfoundland and Labrador may level off as the relatively few remaining developable locations are exploited. Allocation of hydropower development between subnational regions was highly sensitive to both current position and price on the resource-supply curves and shareweights as determined by historical calibration. In the most ambitious scenario in which electrification occurred the most rapidly, hydropower generation grew by 89% from 382 TWh in 2015 to 721 TWh in 2050. To achieve this substantial growth, regions which previously have not contributed much hydropower are exploited more heavily, and the largest absolute growth of any province would occur in British Columbia.

Model results shed light on some interesting aspects related to hydropower's role in electricity trade between Canada and the United States. In scenarios where Canada takes stronger climate action than the United States, increased electricity demand in Canada made electricity prices relatively more expensive, so that Canada would be incentivized to reduce exports. This reduced pressure to develop new electricity or hydropower stations as quickly. However, in the scenario where Canada and the United States both seek net zero by 2050, part of Canada's more rapid electricity demand growth was spurred by the United States' need to import decarbonized electricity, which led to more marginal hydropower resources in Canada being developed. This appeared to increase electricity prices for domestic Canadian electricity to a maximum of about 15% above 2015 prices, after adjusting for inflation, as the gap between electricity prices in Canada and the United States would tighten as Canada chases less optimal resources.

The second question was:

- What role can hydropower be expected to play in Canadian electricity generation development and emissions reduction, considering current and proposed federal energy and climate policies?

Among the model scenarios, the net zero GHG emission (Paris 2021) pathway is the one in which hydropower commanded the least market share of the electricity system by 2050, falling from 60% in 2015 to 42% in 2050. This occurs as the increasingly cost-effective solar and wind power grew more substantially. However, the benefit of hydropower in Canada for balancing these intermittent loads should not be underappreciated for making electricity grids that are more diverse, but still reliable, possible.

The implementation of hydropower at a subnational scale enriched model analysis of energy and climate policies, since it allowed for better representation of the ability for hydropower to contribute to an energy system in transition. This brought hydropower more in line with existing GCAM capabilities to do the same for other electricity technologies. Model scenarios in this study showed several permutations of climate policy ambition, with hydropower generation increasing in the most ambitious scenarios. Resources remain for Canada to develop hydropower, and it provides a continued opportunity to reduce emissions. Model simulations seeking emissions reduction without inclusion of endogenous hydropower would need to be more innovative (or desperate) with other available technologies, and would see additional price increases and tradeoffs to the results included in Chapter 6.

The purpose of this research, more than to develop GCAM-Canada for a certain end goal, was to develop input data and features that improve model response and allow for richer understandings of system interactions. The overall development of electricity sector features and endogenous hydropower are included in the upcoming more complete GCAM-Canada being worked on by this research group, which ECCC and JGCRI hope to use for future policy analysis. The model results in Chapter 6 are not meant to be interpreted as expectations of how energy systems will evolve, but rather as a basis for understanding complex system interactions, and to assess whether policy scenarios might have unintended consequences or whether they can be expected to make progress toward their goals. If a GCAM-Canada modelling study uses the developments presented here and applies that for policy analysis to aid in planning by more fully accounting for the nuances of hydropower development and providing insight today about potential outcomes, that is a success on its own, whether model results are found in 2050 to have accurately matched future outcomes is not the intention.

8.2 Utility of Results for Audiences

The model developments and results of this work may be of interest for three types of audiences: the IAM and energy systems modelling communities, hydropower utilities and planners, and broader energy policy analysts and decision makers.

From this work, the IAM and energy systems modelling communities are supplied with datasets that may be helpful for incorporating hydropower endogenously in their models. Many modelling studies employ the shared socioeconomic pathways (SSPs) for model simulation, which have very divergent pathways. If hydropower is exogenously prescribed in these models, despite expectations that the more extreme SSPs should diverge, there may be very little difference in scenario outcomes regarding electricity generation, particularly in regions where hydropower already forms a majority of generation. This work showed that endogenous hydropower representation can be achieved in these models and provides for more robust responses that allow for better analysis of electricity systems.

Canadian hydropower utilities and planners may benefit from the regional hydropower cost-supply estimates provided as part of this work, as well as the historical hydropower development data. The same methods used to develop cost-supply estimates for Canada can be employed using the methodologies of this thesis to develop the same for other nations or subnational regions. However, when choosing physical locations for dams, more site-specific studies with detailed topographical, hydrological, and geological survey are required.

Energy policy analysts and decision makers may learn from longer-term electricity system responses to the scenarios analyzed in Chapter 6, but likely have more specific questions to answer. GCAM-Canada is open source and was designed flexibly to allow exploration of a variety of policy options which could be applied using this model, or a more completely regionalized GCAM-Canada. There are learning curves to being able to apply the model, but future public releases that include endogenous hydropower are likely to become available.

8.3 Limitations

Datasets provided in this report for hydropower history and resource potentials represent attempts to aggregate the best and most complete information available into one place, but should still be labelled as estimates. The historical data aggregation likely overlooked some very small generating stations, simplified some aspects such as capacity refurbishments, and relied on assumptions regarding applicability of capacity factors throughout basins. The hydropower resource estimates were influenced by the limitations of the parent dataset in Zhou et al. (2015), as well as some additional assumptions such as how to share resource potential between grid cells that straddle jurisdictions. It may be possible to consider hydropower resource availability on a more site-specific basis, but the universality of the gridded data available in Zhou et al. (2015) and its compatibility with GCAM data structures were the reasons for its inclusion in this exercise, as the processes used in this thesis could be extended for other countries using the same methods described in Section 4.3.

GCAM includes exogenous economic assumptions that provide context for interpretation of results. Importantly, gross domestic product (GDP) is an exogenous variable in GCAM and therefore any changes to GDP as a result of any policy or carbon price implementation are not reflected in model output. This means that model results effectively cut any feedback loops that would lead to increased or reduced total economic output. Conversely, the economic assumptions are not endogenously related to climate outcomes: the model would not capture effects of climate change (and avoidance or exacerbation thereof) on economic output. According to estimates by Canada's Parliamentary Budget Officer, carbon pricing to 2022 may have reduced Canada's GDP a total of 0.35% (PBO, 2018), however the total impact from climate change itself may already be a reduction of 0.8% (PBO, 2022).

A limitation of modelling hydropower with GCAM-Canada is that calibration was based on historical observations, which are not necessarily a predictor of future outcomes. As discussed in Chapter 7, the province of British Columbia has decided against construction of new run-of-river hydropower because it would benefit from a more diversified grid without concentrating production only at the time of year the flows are highest. This marks a significant change in strategy, for which the model cannot account unless policy input scenarios to specifically simulate such drastic policy changes are created and analyzed.

Results from GCAM-Canada are output on a less refined time scale than many energy-economic system modellers might wish. The "smooth" results of GCAM-Canada model output are often simplifications of longer-term trends, but as a result are not capable of simulating large discrete events, such as the opening of a very large hydropower plant in a specific year. This can seem ignorant of some important system characteristics that make especially large impacts when refining to smaller scales. The 5-year time scale of GCAM-Canada is both a blessing and a curse for modelling at regional scales: the smaller a region becomes, the less data is available to calibrate the model, and the more relatively small changes make outsized impacts. While the addition of subnational regions to the model allows more nuanced study of model results, it also adds a layer of complexity that requires more careful calibration and attention.

The provinces and river basin-based subnational regions considered in this modelling study are based on geographical and physical features that make the model developments presented more easily integrated into future versions of GCAM-Canada that may include more advanced water markets or trading structures. However, in choosing these regions, there are large discrepancies in size and population, making comparisons between such disparate regions seemingly arbitrary. For instance, the Québec-New England subnational region represents just a small sliver of the province, while Québec-Hudson Bay Coast represents roughly half of the province's land mass. However, given the concentration of population in Canada's south, Québec-New England may have a similar population to the entirety of Québec-Hudson Bay Coast. When modelling to a more refined geographical basis, model analysts can choose whether to focus on the finer details, or to gain more insight from the wider results, such as on a national basis. The model analyst must understand where additional regional refinement has contributed to more informed model responses, and where there may be additional data limitations.

Although the hydropower sector was modelled according to the major river basins to match GCAM's water modelling, the sector was not integrated directly with the regional water markets themselves. Water consumption occurring in hydropower reservoirs (through evaporation) has proven difficult to estimate (Macknick et al., 2012), with a wide range of estimates spanning up to an order of magnitude above all other electricity generation technologies. The matter is further complicated by reservoir operation strategies, which often involve making changes to reservoir levels based not just on power production, but also on constraints imposed by irrigation, flood management, and recreation. Therefore, it is very challenging to compute how much of the water consumption that occurs at a hydropower reservoir is attributable to power generation (Macknick et al., 2012), which complicates efforts to more fully integrate these model developments with regional water markets.

GCAM-Canada is not well suited for more accurate representations of Canada's remote off-grid communities. It may be better to consider these communities separately from the types of questions which GCAM-Canada may typically be employed to provide insight, such as for energy and climate policy. While emission contributions from remote places may be significant on a per capita basis, the question of what may provide cost-optimal emissions reductions in other places is not generalizable to these locations. Besides, these communities, being separated from larger grids, need their electricity grids developed with a particular focus on improving reliability and reducing vulnerabilities, which usually means that diversification to multiple electricity technologies can provide considerable benefits.

8.4 Future Work

The author is pleased that methodological work that was conducted for Arbuckle et al. (2021) and this thesis is already being applied to new research. The author's colleagues have recently published a study applying endogenous hydropower on a global scale in GCAM

(Zhang et al., 2022), which follows some of the methodologies developed here and in Arbuckle et al. (2021). These new capabilities may also be extended to other regional versions of GCAM, like GCAM-USA. Other IAMs that do not yet have endogenous hydropower may find this work helpful for beginning that process, although methodologies will differ according to model frameworks and requirements for different assumptions and input data.

More complete integration of hydropower with GCAM's water sector would make water availability and use much more robust. In its highest form, this would place value on the storage of water at reservoirs and connect more strongly with climate input. Such detailed model connections might allow for analysis of optimization of water use in regions such as southern Alberta, where water is relatively scarce. There, dams are co-managed for irrigation, municipal use, and power production. This kind of study with an improved GCAM-Canada might be able to explore whether certain water users derive more benefit from water than others, and perhaps whether different schemes for water allocation or markets would be able to improve outcomes.

Versions of GCAM-Canada and GCAM could be developed that more explicitly account for the value of hydropower for storage in allowing more intermittent renewables to be established. The reliability of a grid is probably something that can be quantified, and hydropower generally excels at reliable, long-term production. However, as seen in Ontario in this study's historical hydropower data, generating stations can lose efficiency over their long lifespans as a result of sedimentation and as equipment ages (Zhang et al., 2022). Further, more complete life cycle accounting should be conducted in modelling to truly understand all the lifecycle emissions of energy sources being used, as hydropower can be a significant source of emissions during construction and in reservoir filling. Pye et al. (2020) propose that good energy modelling, for net-zero analysis especially, can be improved in several ways: especially by ensuring adequate representation of emerging technologies as mitigation options and better consideration of policy effectiveness in real-world applications.

8.5 Reflections

This work attempted to improve understanding of how hydropower development in Canada could facilitate energy transitions that focused on emissions reductions. While model results show that hydropower can continue to be developed in some parts of Canada, they in no way prescribe that hydropower should occur at any site or not. While researching this work, the author has developed a more nuanced understanding of the benefits and drawbacks of hydropower. The history of hydropower generation in Canada is complex: it allowed early adoption of affordable energy which empowered the nation to tackle many large problems and has provided substantial economic benefit, but came with a history of serious unmitigated environmental impacts and displacement of people, especially First Nations, who were treated unjustly in many of these projects. The context of development is not so different today, except that processes for environmental assessment and public engagement are much more substantial. These processes, while they may seem lengthy and expensive, are an important part of developing electricity systems responsibly, and should be undertaken with due consideration. The results of GCAM-Canada, while able to effectively account for some socioeconomic inputs, should be considered and evaluated with social outcomes in mind, so that "cost-optimal" pathways are not preferred at the expense of others that may be more tenable to the communities they impact.

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