Decarbonization Pathways for the Western Canadian Electricity System

by

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Bachelor of Science, Queen's University, 2011
Master of Applied Science, Queen's University, 2013

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Supervisory Committee

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Abstract

Decarbonizing the electricity system (*i.e.* eliminating generation from fossil fuels and replacing it with non-emitting sources) is widely considered a necessary step to limiting anthropogenic emissions and minimizing the impacts of climate change. Selecting which non-emitting generators should replace existing fossil fuel sources, and when to build them, is critical to the success of this transition. The optimal pathway to decarbonisation is highly region-specific. It is impacted by both factors such as availability of renewable resources, existing generation resources, and government policy.

This dissertation presents a techno-economic model that is used to assess the decarbonisation of the combined British Columbia and Alberta electricity system. It is found that high levels of decarbonisation are possible through a combination of new wind generation, particularly in Alberta, and increased trade between Alberta, British Columbia, and the United States. Following on this finding, the variability related to high penetrations of renewable generation is introduced to the model and its impact is assessed. These results indicate that variability will be an important constraint in planning decarbonized energy systems. Finally, the representation of British Columbia's existing hydroelectric resources is expanded to determine the ability to buffer variable renewable generation with these resources. This study finds that, while existing hydroelectric resources can support much of the variability in a highly renewable energy system, additional technologies and/or policies are needed to reach a fully zero-carbon system.

The findings in this thesis show that British Columbia and Alberta, with an expanded interconnection between the provinces, can reach high penetrations of variable renewable energy. The majority of this generation consists of wind energy in Alberta, which is abundant and low-cost compared to other generation options. While comparatively little generation is added in British Columbia, the existing hydroelectric resources in the province provide significant flexibility to support the variability of this wind generation.

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Acknowledgments

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Chapter 1 - Introduction

Many electricity systems are undergoing a transformation from relying on a small number of large, centrally controlled generators to systems featuring many smaller renewable sources. This transition is well underway in some parts of the world. Renewable electricity generation has increased by 18% in Canada over the last eight years, largely driven by electricity policy in Ontario [1], [2]. Similar changes are occurring in California [3], Germany [4] and the United Kingdom [5], among others.

The renewable energy revolution is set to impact British Columbia and Alberta as well. In Alberta, there is a target of 30% of energy coming from renewables by 2030 [6]. This renewable energy will partly replace the legislated retirement of all coal-fired generators in the province over the same time frame [6]. In British Columbia, a mandate for 93% of electricity to be sourced from renewables is already being met by hydroelectricity with small amounts of wind and biomass [7]. The challenge for British Columbia is to maintain this level of renewable generation while taking advantage of new market opportunities.

Beyond current policies, renewable generation provides a pathway to a low-carbon economy through the electrification of energy services [8], [9]. Technologies exist today to electrify heating and transportation, two of the largest emissions sources globally. However, in order for electrification to reduce greenhouse gases, the source of electricity must already be low-carbon. It follows that, for this low carbon world to take shape, there must be a shift to entirely zero-carbon electricity.

Decarbonization introduces new challenges in energy systems planning. By nature, almost all sources of renewable energy have variable outputs that follow natural phenomena. This can lead to a mismatch between load and generation, large ramps in generation, and uncertainty of future supply. As a result, systems must rely on less centralized generation capacity to meet a more variable and uncertain net load. In systems with high penetrations of renewables, this can complicate the task of matching supply and demand.

Renewable energy is driven by regionally specific natural phenomena, so the supply mix will vary by region as the availability of natural resources changes. For example, California has an abundant solar resource that peaks in the summer, matching peak demand. In Alberta and British Columbia, there are fewer sunny hours (increasing the unit cost of solar energy) and electricity demand peaks on winter evenings (when solar energy is reduced). This diversity in resource characteristics means that location-specific plans for how to increase renewable penetration are necessary.

Geographic diversity of resources provides incentive to link electricity networks across regions. This can allow lower cost resources to be developed where they are available rather than higher cost resources closer to load centers. A larger area can also increase the diversity of available resources, potentially providing more consistent and reliable generation.

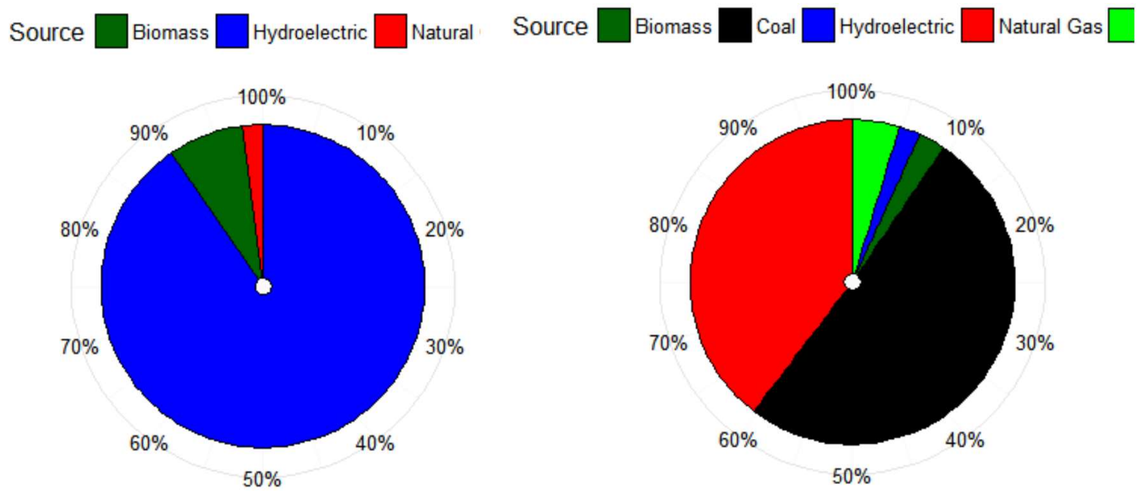
In this dissertation, the potential impacts of increased interconnection capacity between British Columbia and Alberta are examined. There are several potential benefits of linking these two provinces. British Columbia currently has abundant energy and strong connections to energy markets in the United States; this could provide low-cost energy to Alberta in the early years of its transition away from fossil fuels. In the longer term, the complementary generation profiles of British Columbia's summer-peaking hydroelectricity and Alberta's winter-peaking wind resource could provide reliable power year-round. Finally, the large hydroelectric reservoirs in British Columbia could be leveraged to smooth variability from renewable generation. The sum of these benefits could reduce the cost of a decarbonized electricity system in western Canada.

This dissertation uses a “bottom-up” linear programming approach. This type of analysis explicitly models the technical details of the electricity system. The models seek to minimize the net present cost of generation in British Columbia and Alberta combined subject to constraints such as energy balance, capacity adequacy, and resource potential. This modelling approach does not represent the market and political realities of the provinces. Instead, it is focused on technology, policy, and financially agnostic solutions.

The British Columbia and Alberta energy systems are modelled out to year 2060, a period of sufficient length to capture lifetimes of energy technologies. A long time frame is used to represent the full transformation to a low carbon system rather than impacts on the system today. The long period also means that there is significant uncertainty around the costs, demand, and technologies in the later model years. With such a band of uncertainty, the exact outcomes of the model should not be taken as predictions of future electricity systems. However, the general trends within and between scenarios can still provide useful insights.

BC and Alberta Electricity Systems

The electricity systems to be analyzed are the neighboring Canadian provinces, British Columbia (BC) and Alberta. Combined, these provinces account for 23% of Canada’s electricity generation. The supply mix is different in the two provinces: British Columbia sources a majority of its electricity from hydro while Alberta primarily relies on coal and natural gas generation. The energy generation mixes in 2015 for each province are shown in Figure 1-.



(a) (b)

Figure 1-1: Electricity generation mixes in British Columbia (a) and Alberta (b) for 2015 [10]–[12]. British Columbia has an additional 242 MW of wind generation capacity for which the generation is not given in the source data. This generation is omitted from this plot and is estimated to roughly 2% of BC generation [10].

BC's hydroelectric generation is dominated by two large river systems. The Peace River powers the GM Shrum and Peace Canyon generating stations, which combined have a capacity of 3,460 MW and produce 16,600 GWh annually. The Columbia River contains the Mica and Revelstoke generating stations, which have a combined capacity of 5,285 MW and produce 13,500 GWh annually. The reservoirs created by the GM Shrum and Mica dams have volumes of 74 and 25 billion cubic metres, corresponding to 41,300 GWh and 27,700 GWh of storage.

BC's large reservoirs play a vital role in maintaining a year-round balance between supply and demand in the province. In the spring and summer, while demand is low and generation from non-storage generators is high, turbines on the Peace and Columbia operate at a low level while their reservoirs fill. They then draft the reservoir to provide energy during the winter, when demand is high and generation from other sources is low.

Increasing load growth (which peaks during the winter) and expanded non-storage hydroelectricity (which peaks during the summer) will increase the seasonal imbalance between supply and demand in BC. To manage this imbalance, storage reservoirs may have to be drafted more deeply over the winter, leaving the system more vulnerable to supply shortages in drought years. Alternatively, diversifying generation types could provide a more constant supply of energy over the year.

Natural gas generation facilities in BC include the 254 MW Island Cogeneration facility (despite its name the pulp and paper mill which consumed the steam from the Island Cogeneration facility closed in 2010 – it is now an electricity-only generator) and a 73 MW combined cycle facility in Fort Nelson. While located in BC, Fort Nelson is connected to the electricity grid in Alberta [11].

Biomass generation is largely sourced from logging industry waste [11]. This includes waste wood from mill operations as well as black liquor from paper making. These wastes are burned on-site to produce electricity and heat for mill operations. Any excess generation is used to meet demand in the wider BC system.

As of 2019, Alberta’s electricity system is supplied by six coal-fired power plants with a total of 6,300 MW of capacity. An additional 4,629 MW is supplied by natural-gas fired cogeneration facilities. The majority of these units provide electricity and heat to oil extraction and upgrading facilities, with the remainder sold on the Alberta market. Combined, coal and cogeneration facilities serve the bulk of Alberta’s electricity demand [12].

Although Alberta currently generates a majority of its electricity from coal, the government has mandated that all coal generation will be replaced by 2030. As a result, large supply gap in Alberta is expected in the coming years. The government has pledged to provide 30% of electricity from renewables by 2030. This pledge, as well as the changeable nature of government, leaves significant uncertainty surrounding future electricity mixes in Alberta.

The electricity systems of British Columbia, Alberta, and the United States are interconnected, as shown in Figure 1-. The provinces' electricity grids are connected by an intertie with a rated capacity of 1,200 MW. This intertie is currently derated to approximately 750 MW due to constraints in Alberta's interior transmission system [12]. These constraints also mean the 300 MW Montana-Alberta Tie Line (MATL) shares capacity with the BC-Alberta intertie for selling power into Alberta [13]. A potential large expansion to the intertie capacity between the provinces could follow an alternate route to avoid transmission congestion in southern Alberta.

British Columbia exchanges large amounts of electricity each year with the United States. BC is connected through several interconnections with Washington State. These transmission lines have a combined rated capacity of 3500 MW; however, for operational reasons they are often constrained to lower limits. Each year, between 15 and 20 TWh of energy are traded between BC and the United States [14].

Electricity trade between BC and the United States occurs primarily at the Mid-Columbia (Mid-C) trading hub. This hub is the principal clearing house for electricity trade in the Pacific Northwest, including BC, Washington, Oregon, and Idaho. In addition to trades with other utilities participating in the Mid-C market, BC occasionally trades with regions further away, such as California, if there is a sufficient economic incentive.

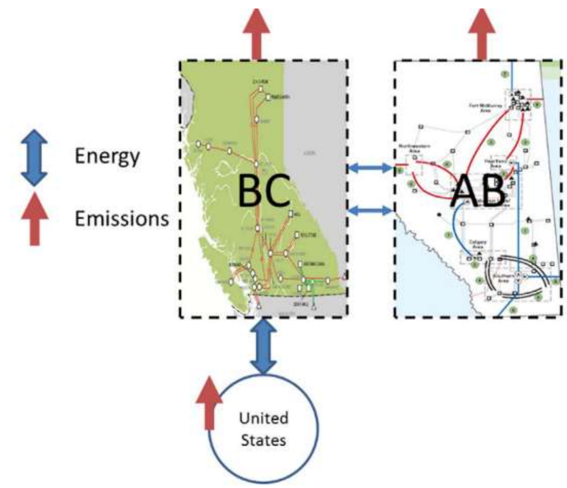


Figure 1-2: Diagram of the relationships between the BC, Alberta, and United States electricity systems.

Historically, much of BC's trade with the United States has centered around purchasing low cost energy, typically in light load hours during the freshet, and selling higher value energy later in the year. This trade pattern allows BC to profit even when its overall trade balance is low or negative (*i.e.* BC imported more power than it exported) [14]. As more non-dispatchable generation is created, such as wind and run-of-river hydroelectric, the ability and incentive for BC to participate in trade may change.

Alberta and BC also have a smaller, but still significant, trade in electricity. BC typically sells between 1 - 3 TWh of energy to Alberta while Alberta exports to BC are very low (less than 500 GWh) [15]. British Columbia is a regulated energy system controlled almost entirely by BC Hydro; by contrast, Alberta has a deregulated system where energy can be traded freely. Under Alberta's market system, importers and exporters must offer or bid an amount of energy to import or export to Alberta each hour before the price is known. It also means that Alberta does not control the amount of electricity it trades with BC. Instead, this trade is controlled by the BC entity, Powerex.

Previous Work

This section provides a broad overview of previous work in techno-economic energy systems modelling and renewable integration. It provides a summary of the types of energy systems models, applications related to hydroelectricity and interconnectivity, and efforts related to improving the representation of variability. A more complete literature review is found in the introductions of Chapters 2, 3, and 4.

Techno-Economic Modelling

Techno-economic energy systems models can be broadly categorized into production cost models and capacity expansion models. Production cost models determine the cost to provide energy based on a fixed generation mix. Some examples of production cost models are AURORA [16], PROMOD [17], and SILVER [18]. Capacity expansion models determine the optimal energy mix for a given scenario. Some examples of capacity expansion models are TIMES [19], [20], MESSAGE [21], and OSEMOSYS [22], [23]. Both types of model are widely used in analyzing future energy systems [24]–[32].

The open source capacity expansion model OSEMOSYS is used as the basis of the studies presented here. OSEMOSYS is a mature, open-source energy systems linear programming model. It provides a standardized set of parameter, variable, and constraint definitions that allow components of an energy system to be easily characterized [22], [23].

The work in this dissertation examines the potential to reduce costs and emissions through integrating the BC and Alberta electricity systems over the long term using a capacity expansion model. Inter-regional connectivity has been shown to costs and curtailment events studies using production cost models [33]–[38], while coordination of hydroelectric and renewable resources has been found to have similar benefits [36], [39]–[41]. In this dissertation, we expand on this work by examining the benefits of regional integration and hydro-renewable coordination on capacity expansion in addition to operational benefits. Regional level capacity studies have previously shown benefits from regional integration [42], [43], but has not considered the combination of regional and technological synergies in the same model.

In order to better model the interactions between regions and system elements the OSeMOSYS model was expanded as part of this thesis. A recent review of energy systems models identified the need to better implement the spatial and temporal renewable variability in planning models [44]. Here we present a planning level model that explicitly includes this variability, including a novel representation of short-term temporal variability. Another review identified the need to include inter-regional trade opportunities, which is also a focus of this work [45]. These additions to OSeMOSYS provide more detailed representations of electricity systems with high penetrations of renewable energy.

Renewable Integration

The variable output from most forms of renewable generation poses problems for widespread adoption of these technologies in the electricity system. A library of literature exists quantifying these problems and their impacts [46]–[54]. From these studies, three prominent issues arise: renewable energy output can ramp very quickly [47], [55]–[60], renewable energy output can be unpredictable [61]–[64], and high levels of renewable generation can lead to overproduction [65], [66].

Several solutions to these issues have been examined in the literature using a variety of models. One possible measure is energy storage, which can be used to balance fluctuations and overproduction from renewable generation [35], [67]–[73]. Inter-regional connectivity has also been proposed as a mitigation measure [38], [74]–[77]. A common feature of these studies is that they focus on relatively short-term analysis using high temporal resolution models and an exogenous generation mix.

In Chapters 3 and 4 of this dissertation we implement representations of the variability caused by renewable generation in a capacity expansion model to examine impact on the BC and Alberta electricity system. In these models the installed capacity mix is allowed to change endogenously over time. This allows us to see how the potential mitigation enabled by hydroelectric coordination and regional connectivity can help increase renewable adoption.

Research Objectives

This dissertation aims to advance the body of knowledge in energy modelling, particularly as it relates to renewable energy integration. It expands on previous energy modelling work by adopting the latest developments in energy systems model and applying them to western Canada. Where needed, it expands findings from short-term energy systems evaluations to evaluate their impact on long-term system evolution. Although the findings are targeted towards British Columbia and Alberta, the findings can be translated to other regions as well.

This thesis seeks to answer several questions regarding the electricity system in British Columbia and Alberta, including:

- Can the cost of decarbonising the electricity system be reduced by increasing intertie capacity between the provinces?
- How can British Columbia's hydroelectric resources be used to support electricity decarbonisation in Alberta? This can include buffering variability in renewable energy generation or simply providing zero-carbon energy.
- What policies and technologies are needed to reach a fully decarbonized electricity system?

Answering these questions leads to other issues that are applicable to energy systems modelling as a whole:

- What effect does higher net load variability caused by increasing levels of variable renewable generation have on the optimal electricity system generation mix?
- How can the variability of renewable generation be incorporated into long-term energy systems models?

Several limitations of OSeMOSYS (and energy planning models in general) were identified as part of this work that limit its effectiveness in answering these questions. This thesis presents new methods of eliminating these limitations:

- Net load variability becomes a limiting factor in energy systems as renewable penetration increases as larger load changes must be balanced by less dispatchable generation. A new representation of variability is necessary in order to reflect this challenge in long-term energy models.
- Electricity markets have volatile prices that change on much shorter timescales than other system costs, such as fuel and maintenance. The objective function of the model must be changed to allow this additional temporal resolution.

- Some elements of energy systems, notably transmission lines, are shared between regions. New constraints are needed to ensure that these assets are consistent across multiple regions in the model.

Outline

This thesis is divided into three main chapters. Each chapter represents a journal publication either in press or under review. A brief summary of each chapter is given below:

- Chapter 2: *Effect of Intertie Capacity on Carbon Policy Effectiveness* investigates the potential cost and emissions reductions that result from an increase in electricity transmission capacity between BC and Alberta. In this chapter, an initial OSeMOSYS-based model of the BC-Alberta electricity system is presented and a variety of carbon policies are evaluated. It determines if increasing intertie capacity can reduce the cost of decarbonisation from a capacity and energy perspective.
- Chapter 3: *Impact of Flexibility Requirements on Electricity System Decarbonization* expands on the study from Chapter 2 by included ramping and regulation constraints in the model. In this chapter, OSeMOSYS is expanded with additional demands related to net load variability. This is a first attempt at determining how British Columbia's hydroelectric facilities can be used to buffer net load.
- Chapter 4: *The Role of Hydroelectricity in Highly Variable Electricity Systems* expands on flexibility needs in a highly variable system and the ability for hydroelectricity to buffer renewable generation. Expanding on the previous chapter, it adds an improved measure of net load variability in the system model.

In this chapter the role of hydroelectricity in future electricity systems is further identified and requirements for new low-carbon technologies are identified.

- Chapter 5: *Conclusions and Recommendations* summarizes the key findings of the previous chapters.

Chapter 2 - Effect of Intertie Capacity on Carbon Policy Effectiveness

Preamble: This chapter investigates the potential cost and emissions reductions that result from an increase in electricity transmission capacity between Canada's two westernmost provinces: Alberta, a fossil fuel dominated jurisdiction, and British Columbia, a predominantly hydroelectric jurisdiction. A bottom-up model is used to find the least cost electricity generation mix in Alberta and British Columbia under different carbon policies. The long-term evolution of the electricity system is determined by minimizing net present cost of electricity generation for the time span of 2010–2060. Different levels of intertie capacity expansion are considered together with a variety of carbon tax and carbon cap scenarios. Results indicate that increased intertie capacity reduces the cost of electricity and emissions under carbon pricing policies. However, the expandable intertie does not encourage greater adoption of variable renewable generation. Instead, it is used to move low-cost energy from the United States to Alberta. The optimal intertie capacity and cost reduction of increased interconnectivity increases with more restrictive carbon policies. This chapter was originally published as a standalone publication in *Energy Policy.*

Introduction

Variable renewable generation such as wind and solar is frequently lauded as a key element of future low-carbon energy systems. However, to enable widespread adoption, the variable output of these technologies must be reconciled with relatively unresponsive energy demand. Increased interregional transmission has been proposed as a method to facilitate greater penetration of variable renewables [57]. This study investigates the impacts of greater integration between a hydroelectricity-dominated jurisdiction (British

Columbia) and a fossil fuel dominated jurisdiction (Alberta) on the cost and emissions of electricity generation.

Hydroelectric reservoirs provide operational flexibility which is becoming an increasingly valuable characteristic of systems where temporal variations in renewable generation need to be managed [78]. In Alberta, the small share of hydroelectric generation limits flexibility; however, there is potential to increase the capacity of the BC-Alberta intertie to enable utilization of BC's reservoir generation to facilitate greater penetration of variable renewable generation in the Alberta system.

Other studies have investigated the use of hydroelectric generation with storage reservoirs to support variable renewable generation in California [40] and the Western Electricity Coordinating Council (WECC) regions [36]. Both of these studies focus on a single year, rather than the long-term evolution of the electricity system, and show that system-wide cost and emissions are reduced by integrating storage hydro power and wind power resources. These studies also find that dispatching hydroelectricity to support renewable generation enables higher penetrations of renewables and reduces the frequency of curtailment events. These findings suggest that BC's existing hydroelectric resources could be used to support new renewable generation in Alberta, lowering the combined emissions of the two provinces.

The current study compares the evolution of electricity generation mixtures in BC and Alberta from 2010 to 2060 under alternative carbon policy scenarios, with and without expanded intertie capacity. The combined electricity system is optimized for lowest net present cost using a technology explicit model for generation in both provinces. The net present cost and cumulative emissions of the combined system are compared to determine the impact of greater integration on the adoption and operation of future low-carbon electricity systems. The study does not consider how the costs and benefits of increased intertie capacity are divided between the two provinces.

The timeframe for this study is much longer than the operational life of most electricity generating technologies. As a result, current generation units, with the exception of hydroelectric facilities, are retired within the model period. This allows modelling of the transition from the current generation mixture to future low-carbon mixtures.

Previous studies have used similar methods to explore the transition to renewable generation in electricity systems under the influence of a range of factors. Among the factors previously examined are environmental performance uncertainty [79], climate and hydrological change [80], grid flexibility requirements [81], fossil fuel price volatility [82], and combined environmental-economic optimization [83]. This study expands on these methods to examine the role of carbon policies and regional integration in decarbonizing electricity generation.

A previous single-year study of BC and Alberta, found that increased intertie capacity with no increase in wind capacity leads to a slight increase in combined annual emissions for the two provinces due to increased thermal generation in Alberta to supply increased exports to BC. These exports, which are primarily from coal-fired generators, offset domestic natural gas-fired generation in BC. However, with expanded wind generation and intertie capacity, emissions decrease as hydroelectric power substitutes for fossil fuel generation to provide grid flexibility in Alberta [35]. A second study by the same group finds that a carbon tax in excess of $100/tonne of carbon dioxide is required to trigger widespread wind power development and, again, that additional wind power development is enabled by increased intertie capacity [34].

A similar study examined the potential of increased transmission capacity to increase the penetration of variable renewables in northern Asia [43]. This study, which models a single year with defined generating capacities, found that increased transmission capacity can reduce emissions from electricity generation by increasing the penetration of variable renewables. Optimal interconnection levels were also determined in [84]. Here the authors use a series of single-year optimizations to find the cost-optimal generation portfolio in individual countries in northern Europe considering only coal, gas, nuclear, and wind power. They found that intertie expansion only occurs when renewable energy targets are applied.

The current study adds to the literature by considering the impacts of increasing intertie capacity between two regions over the long term. Increased interconnectivity has been shown to increase the value of intermittent renewables [85], [38] and to decrease emissions from wind-thermal systems [43], [86] in the short term. The paper examines the extent to which these benefits impact the long-term evolution of the electricity system. The additional value to intermittent renewables afforded by the intertie may reduce the policy incentive required to achieve high penetrations. Additionally, differences in resource characteristics, such as cost and availability, between regions could also lead to large expansion of generation in one jurisdiction for export to another. Although this study focuses on BC and Alberta the conclusions could be applicable to other regions as well.

In the following sections, modelling details are described, including the optimization algorithm, economic and technical assumptions, and carbon policy scenarios. Results are then presented for the least and most carbon intense of the scenarios examined. Finally, trends across scenarios such as carbon mitigation cost and intertie utilization rates are discussed.

Methods

The system structure assumed for this study is shown schematically in Figure 2-1, where BC and Alberta are treated as distinct nodes with no internal resolution of the transmission structure.

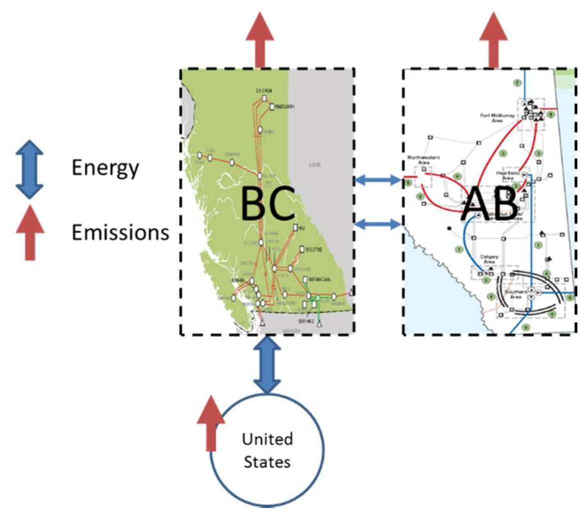
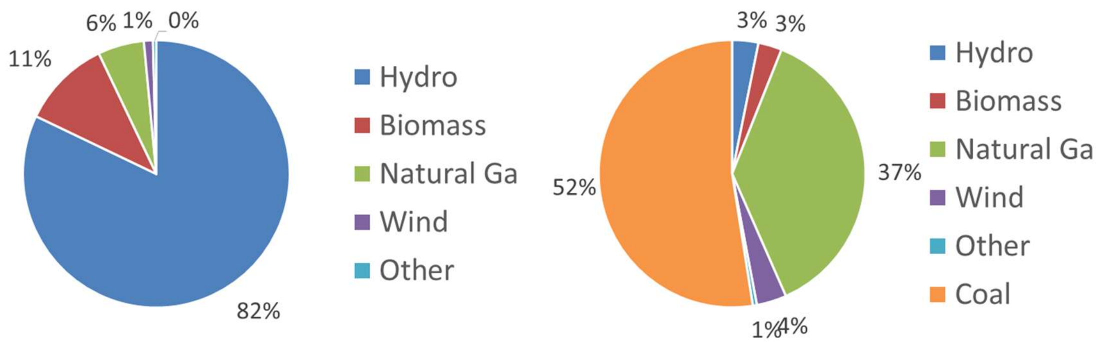


Figure 2-1: Diagram of the modelled area and connections between regions. Energy can flow between BC and both Alberta and the United States. Emissions are accounted for in all three regions.

Combined, British Columbia and Alberta host 22% of Canada's electricity generation [87]. British Columbia's electrical system is dominated by hydroelectric generation, with small contributions from biomass, and natural gas (Figure 2-2(a)). In contrast, Alberta's generation mix is dominated by large shares of coal and natural gas with small shares of wind, hydro, and biomass (Figure 2-2(b)).



(a) (b)

Figure 2-2: Electrical energy generation mixes in British Columbia (a) and Alberta (b) for 2012 [88], [89].

The initial (*i.e.* 2010) supply mixtures for BC and Alberta are defined to represent the existing infrastructure, the capacities of each technology are listed in Table A-3. The United States is represented by the Mid-Columbia (Mid-C) electricity market, which has a 3.5 GW interconnection with BC. The intertie at Mid-C is constrained to its current capacity which is assumed constant for the duration of the study. The physical constraint that is central to this study is the link between BC and Alberta, which is represented as a single intertie. Electricity trade is driven by cost minimization for the combined BC and Alberta jurisdictions. Supply scenarios for BC and Alberta reflect current estimates of available quantities and costs.

Initial generation capacities are taken from the 2013 Electricity Supply and Demand report of the North American Electricity Reliability Corporation [11]. Retirement dates are based on the assumed operational life of each generator. The initial generation capacity in 2010 and the operational life of each generating type are listed in Appendix A.

Demand Growth

Electricity consumption is projected to increase over the next twenty years in both Alberta and British Columbia [90], [91]. This contrasts with other industrialized jurisdictions, such as California and Germany, that are anticipating little or negative demand growth [92], [93]. Meeting this growing demand will require a combination of increased generating capacity, demand side management, and imports from neighbouring jurisdictions [94][29]. The majority of additional capacity for Alberta is forecast to be combined cycle gas turbines and cogeneration facilities [91]. Projected additions for British Columbia (BC) include a 1.1 GW hydroelectric dam (i.e. the Site C Clean Energy Project on the Peace River) and capacity upgrades to existing hydroelectric facilities [95].

Electricity demand in BC is forecast to grow from 57.1 TWh in 2013 to 79.5 TWh in 2032 [90] while demand in Alberta is projected to increase from 75.5 TWh in 2012 to 131.3 TWh in 2033 [91]. In the model, these projected annual growth rates of 1.3% (for BC) and 1.7% (for Alberta) from 2023-2033 are extended to 2060. This approach implicitly assumes that the current high rates of industrial growth continue to 2060, even in scenarios with carbon-constraining policies. The impacts of this demand growth are examined with alternative scenarios where the growth rate is halved in both provinces.

Electricity demand is aggregated across provinces and is divided into twelve seasons corresponding to the months of the year. Each month is comprised of a representative day. The day is divided into three portions corresponding to the peak, mid-peak, and off-peak demand periods based on hourly demand. This results in an annual demand profile comprised of 36 time intervals or *timeslices* per year. The output from variable renewable generation is defined for each timeslice as well. The methodology for creating these time intervals is detailed in Appendix A.

Electricity Generation Model

The BC and Alberta electricity systems are modeled using the Open Source Energy Modelling SYStem (OSeMOSYS). OSeMOSYS is technologically-explicit energy modelling software for long-term energy planning [22], [23]. The objective function is to minimize the net present cost of electricity generation over the model period subject to constraints on energy production, demand, capacity adequacy, and resource availability.

Numerous generation technologies are available to each province, as shown in Figure 2-3. These scenarios include five common fossil-fuel generation technologies, each with unlimited potential capacity, and five renewable energy technologies, each with province-specific implementation limits.

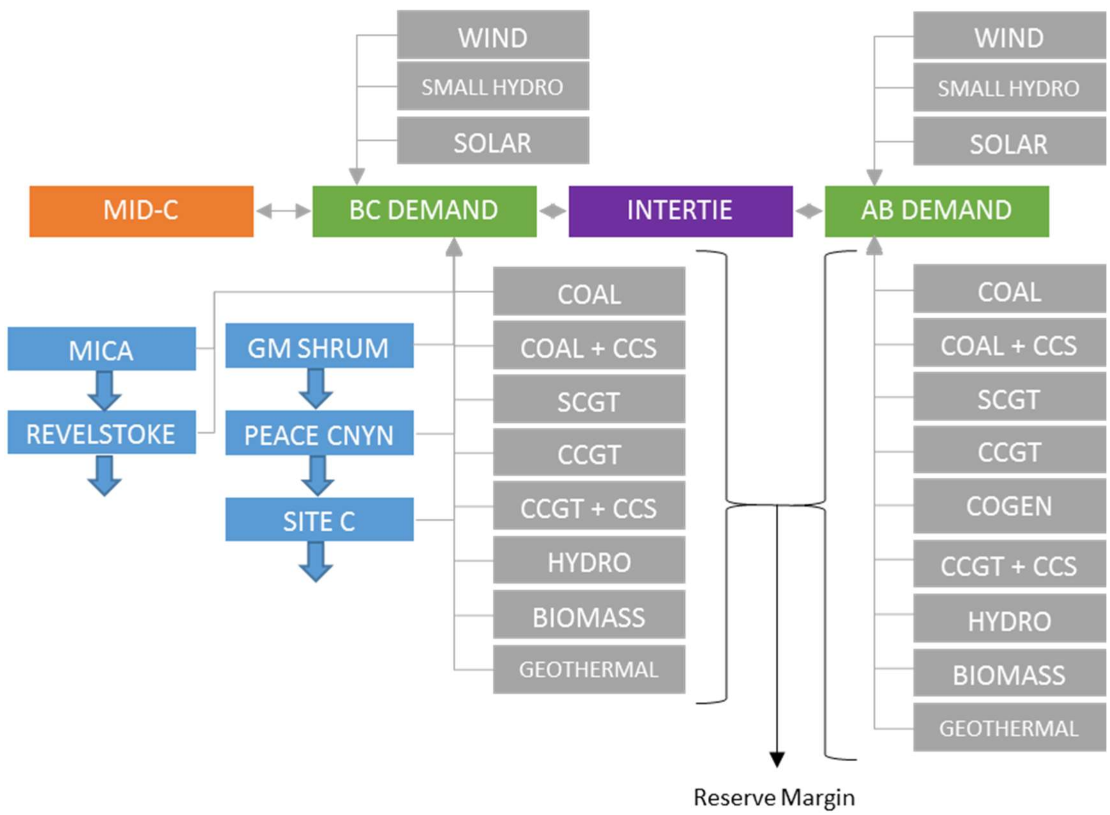


Figure 2-3: Diagram of the modelled electricity system. Electricity demand is shown in green, conventional generating units shown in grey, and cascaded hydro generators shown in blue. Grey arrows indicate power flows. Blue arrows indicate water flows.

A reserve margin of 18% above peak demand is prescribed for each province to be supplied by dispatchable generators only. Dispatchable generators are those which can be deployed as needed to meet demand, including all fossil-fuel fired generators as well as large hydroelectric and biomass generators. The reserve margin constraint ensures sufficient capacity of dispatchable power generation to meet demand. The reserve margin is based on the forecast instantaneous peak demand for BC [90] and Alberta [91] rather than the model-predicted peak demand. The latter is calculated as the average demand during the on-peak interval described previously; this average demand is lower than the instantaneous peak demand. This difference between the model-predicted peak demand and actual peak demand is added to the modelled reserve margin to account for this difference and ensure adequate capacity to meet forecast power demands.

Variable generation types such as wind are modelled using capacity factors for each of the 36 time intervals. For BC-based wind and small hydro generators, this capacity factor is based on BC Hydro's 2013 Resource Scenarios Report [96]. Alberta wind and hydro generator capacity factors are based on historical hourly generation from eight wind farms and three hydroelectric facilities in Alberta [97]. Solar capacity factors were calculated for each province using PVWatts [98] with data from Calgary, AB and Summerland, BC. Capacity factors are constant over the day (i.e. for the off-peak, mid-peak, and peak intervals) for each generator type with the exception of solar, which varies by time of day as well as by month.

The storage hydro facilities in BC that are modeled on an individual basis are identified in Figure 2-3. These include the Peace River generators (*i.e.* G.M. Shrum, Peace Canyon, and the planned Site C) and Columbia River facilities (*i.e.* Mica and Revelstoke).

Combined, these generators serve approximately 62% of electricity demand in BC [99]. These facilities have multi-year storage capability and, as a result, are potentially a resource for balancing demand and generation from widespread variable renewable generation. For each of these five hydroelectric facilities, the flow of water into and out of the reservoir is monitored. Each reservoir receives an exogenously defined inflow for each time step as well as an endogenous inflow from its upstream reservoir, if present. Rather than a defined capacity factor, generation from these facilities is constrained by water availability, maximum flow rates, and reservoir storage capacities. A full description of the storage hydro model used in this study can be found in [100].

Annual inflow data for the uppermost reservoirs (*i.e.* Mica and G.M. Shrum) are taken from a previous study [101] which predicts the average inflow at each reservoir for 2041 to 2070. Accordingly, inflows to GM Shrum and Mica increase by 9% and 10%, respectively, over the model period. Exogenous inflows to the lower dams on both systems are assumed constant. These inflows are based on current levels from the Peace River and Columbia River Water Use Plans [102], [103]. The remainder of the hydroelectric facilities in British Columbia are combined and modelled as a single generation source with a seasonal capacity factor defined by their aggregated inflows.

The intertie between BC and Mid-C can import or export up to 3.5 GW from or to the US. The flow of power on the intertie is determined endogenously using the annual temporal distribution of energy prices at the Mid-C market from 2010 to 2013 [104]. For a given month, the price during the daily off-peak interval is set to the average of the lowest daily prices for that month. The price during the daily mid-peak interval is set to the monthly average of the daily mean price. The price during the daily on-peak interval is set to the monthly average daily high price. Mid-C energy prices are prescribed to increase 2.4% per year [105]. Alternate scenarios with prices growing at 3.4% are used to examine the effect of higher Mid-C prices.

Economic Assumptions

Each generation technology is assigned three costs: capital cost, which is the cost of constructing new generating capacity; fixed cost, which is the cost of maintaining a generator over a year; operating cost, which is the cost per unit of energy produced including both variable maintenance and fuel costs. Capital, fixed, and variable maintenance costs are from the EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants [106]. Fuel costs are from the EIA Annual Energy Outlook 2014 [107]. Additionally, wind and solar capital costs are assumed to decrease linearly over the model period as these technologies mature [108]. Wind capital cost is assumed to decrease by $5/kW annually and solar capital cost is assumed to decrease by $49/kW annually. All capital, fuel, operating, and fixed costs are tabulated in Table A-2. An annual discount rate of 6% is assumed, with all costs given in real dollars.

Scenarios

Multiple carbon policy scenarios are evaluated both with the capacity of the BC-Alberta intertie constrained to current levels and with intertie expansion allowed, as shown in Tables 1-1 and 1-2. Current policies in BC include a 93% renewable portfolio standard [7], a mandate to meet annual provincial energy demand with in-province generation (*i.e.* zero net imports) [7] and a $30/tonne carbon tax [109]. Alberta has an intensity-based carbon tax on emissions from industrial sources which can be met through a combination of emissions reductions, carbon offsets, and payments into a technology fund used to develop renewable generation [110]. This policy is not included in this analysis because of its complexity and low effective cost of carbon. Both provinces are bound by Canadian federal regulations which limit the carbon intensity of new generating units to less than 420 tCO_2/GWh [111]. This regulation effectively prohibits the construction of coal-fired generators without carbon capture and storage (CCS).

Two types of carbon policy are analyzed: carbon caps and carbon taxes. Two carbon cap scenarios are modelled: (1) a 30% decrease from 2005 levels by 2030 which mirrors the proposed US Clean Power Plan [112] and (2) an 80% decrease from 2007 levels by 2050, as stipulated in the BC Greenhouse Gas Reduction Target Act [113]. For the carbon cap scenarios, the cap is modelled as a linear decrease from 2010 to the target year, after which the cap is constant. Two carbon tax scenarios are investigated, an equalization of carbon taxes in BC and Alberta at $30/tonne and a stepped increase in both provinces of $10/tonne every 5 years. These policies are in addition to the $30/tonne tax in BC, which is included or raised in each policy scenario. Each carbon policy applies only to emissions in BC and Alberta. Emissions from the US are included in cumulative emissions figures but are not affected by carbon policies. Tables 2-1 and 2-2 summarise the scenarios used in this study.

Table 2-1: Carbon taxes and caps in British Columbia and Alberta for each carbon policy scenarios. Carbon policies include both the taxes and caps in each province in the corresponding row

Carbon Policy	**British Columbia**		**Alberta**	
Option	Carbon Tax	Carbon Cap	Carbon Tax	Carbon Cap
Current policies	\$30/tonne	N/A	N/A	N/A
30% by 2030	\$30/tonne	70% of 2005 emissions after 2030	N/A	70% of 2005 emissions after 2030
80% by 2050	\$30/tonne	20% of 2007 emissions after 2050	N/A	20% of 2007 emissions after 2050
Equalized carbon tax	\$30/tonne	N/A	Increasing by \$10/tonne every 5 years to \$30/tonne in 2025	N/A
High carbon tax	Increasing by \$10/tonne every 5 years beginning in 2025	N/A	Increasing by \$10/tonne every 5 years	N/A

Each carbon policy is analyzed under two transmission scenarios: the BC-Alberta intertie capacity constrained to the current intertie rating (*i.e.* 1200 MW) and with a model-determined optimal intertie expansion. For the expandable intertie scenarios, additional intertie capacity can be constructed at a cost of \$820/kW. This cost is based on recent large-scale transmission projects in BC and Alberta [114], [115], [116]. The resulting ten *scenarios* and their corresponding designations are given in Table 2-2 in the form "*x-y*" where *x* is a carbon policy listed in Table 2-1 and *y* is a transmission scenario (fixed at existing capacity, *C*, or, optimally determined, *E*.)

Table 2-2: Outline of the *scenarios* used in this study. Each scenario is a combination of a carbon policy scenario and a transmission expansion scenarios. Scenarios are referred to by their designation in the results and discussion.

		BC-AB Intertie Capacity	
		Current	Expandable
Carbon Policy	*Current Policies*	CP-C	CP-E
	30% by 2030	30%-C	30%-E
	80% by 2050	80%-C	80%-E
	Equalized carbon tax	ECT-C	ECT-E
	High carbon tax	HCT-C	HCT-E

In addition to these ten scenarios, there are an additional ten *sensitivity scenarios* that examine the effects of changing key assumptions of the study. Each sensitivity scenario is based on a corresponding carbon scenario with a modified cost or demand assumption. These scenarios and their designations are presented in Table 2-3:

Table 2-3: Outline of the *sensitivity scenarios* used in this study. Each sensitivity scenario is based on a corresponding carbon scenario. Each scenario is referred to by its designation in the results and discussion.

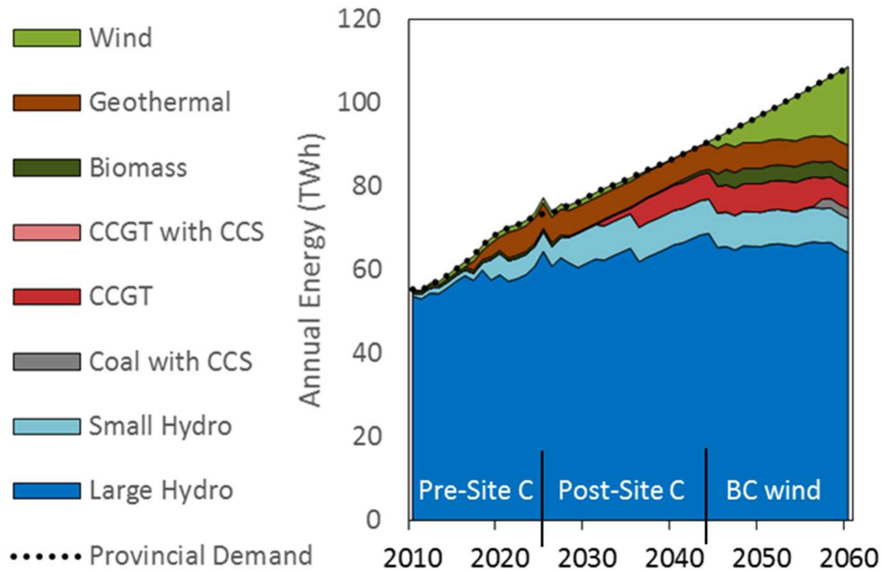
Sensitivity Scenario	Modified Assumption	Carbon Scenario	Designation
Low renewables cost	Lower capital cost for wind and solar generation. Costs of generators are given in Table A-2.	CP-C	CP-C(LR)
		CP-E	CP-E(LR)
		80%-C	80%-C(LR)
		80%-E	80%-E(LR)
Low demand growth	Electricity demand grows at 50% of the reference case rate for 2030-2060. New demand growth rates are 0.65% for BC and 0.85% for Alberta.	CP-C	CP-C(LG)
		CP-E	CP-E(LG)
		80%-C	80%-C(LG)
		80%-E	80%-E(LG)
High Mid-C prices	Mid-C prices increase at a greater rate than the reference case. New Mid-C price increase rate is 3.4%	80%-C	80%-C(HP)
		80%-E	80%-E(HP)

Results

Annual energy production and trade flows are first presented for the current policies scenarios (CP-C and CP-E) and then for the 80% by 2050 policies scenarios (80%-C and 80%-E). These scenarios are presented because they result in the most and least carbon-intensive systems of all scenarios, respectively. The results for the other six scenarios fall between the results for these two scenarios and are presented in the supplementary materials. The results from all scenarios are then compared with respect to cumulative costs and emissions, carbon abatement costs, sensitivity of key assumptions, and intertie capacity factors.

Current Policies Scenarios

Under the current policies scenarios, the least cost solution results in no expansion of intertie capacity in the expandable intertie scenario. As a result, the outcomes of the CP-C and CP-E scenarios are identical. Figure 2-4 shows the energy generated by source in BC (top) and Alberta (bottom) on an annual basis from 2010 to 2060 in these scenarios. The dotted line represents the annual energy demand of the province. Energy above this line is exported.



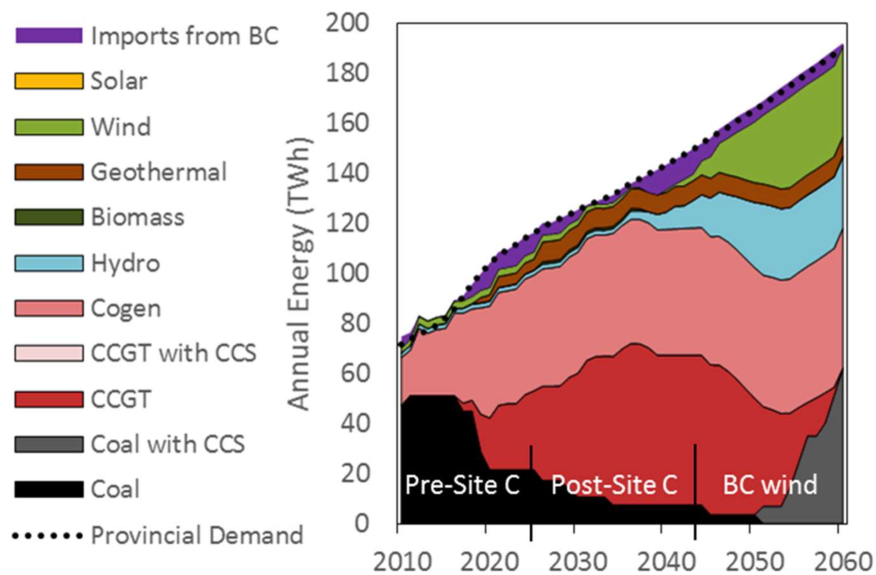


Figure 2-4: Stacked area plot of electricity generation in Alberta (top) and British Columbia (bottom) from 2010 to 2060 in the current policies scenario (CP-C and CP-E). The three *eras* are delineated in each graph. The dotted line indicates annual demand in the province; generation above this line is exported. Energy which is imported and resold is not included in this figure.

Three *eras* are defined by these results, each of which is distinguished by a particular pattern or trend in the generation mixture. The first era, spanning from 2010 to 2024, is the *pre-Site C era*. During this time, BC relies on geothermal and small hydro generation to meet demand growth and Alberta expands natural gas generation to replace retiring coal facilities. The second era, lasting from 2024 to 2043 in this scenario, is the *post-Site C era*. It is defined by growth in hydro and wind generation in Alberta while demand in BC is met by increasing output from hydro storage reservoirs with a small contribution from natural gas. Electricity trade from Mid-C, wheeled through BC, to Alberta increases during this time period. Following the post-Site C era is the *BC wind era*, which lasts from 2043 to 2060 in this scenario. During this time, BC has reached its hydro capacity limit and expands both biomass and wind generation. Meanwhile, Alberta begins to switch from natural gas to coal with CCS.

The shift from natural gas to coal with CCS during the BC wind era is driven by escalation in fuel price and the federal regulation prohibiting new coal development without CCS mentioned previously. The price of natural gas is forecast to rise at 2.9% annually, which is greater than the forecast rise in the price of coal at 1.1% [107]. As a result, power generation from coal with CCS is less expensive than from combined-cycle natural gas turbines beginning in 2051. Cogeneration is not displaced because a portion of the fuel consumed is attributed to heat demand and not included in this study, resulting in a higher effective efficiency and therefore lower exposure to rising fuel costs.

In the current policies scenario, BC has gross exports of 434 TWh with net exports of 6 TWh over the model period. Figure 2-5 shows the destination of these exports on an annual basis. Years with both imports and exports to the same region indicate either locational or temporal arbitrage. Location-dependent arbitrage occurs when one jurisdiction buys power from an outside source to sell to another jurisdiction at a higher cost. Time-dependent arbitrage occurs when a jurisdiction imports power at times of low price to meet demand

and sells power in times of high price to generate revenue. In 2030, BC purchases 5.5 TWh from the US during low-cost times (*i.e.* off-peak hours in March, April, and May). 1.5 TWh of this power is sold back to the US during high-cost times (temporal arbitrage) and 4.0 TWh is sold to Alberta (locational arbitrage).

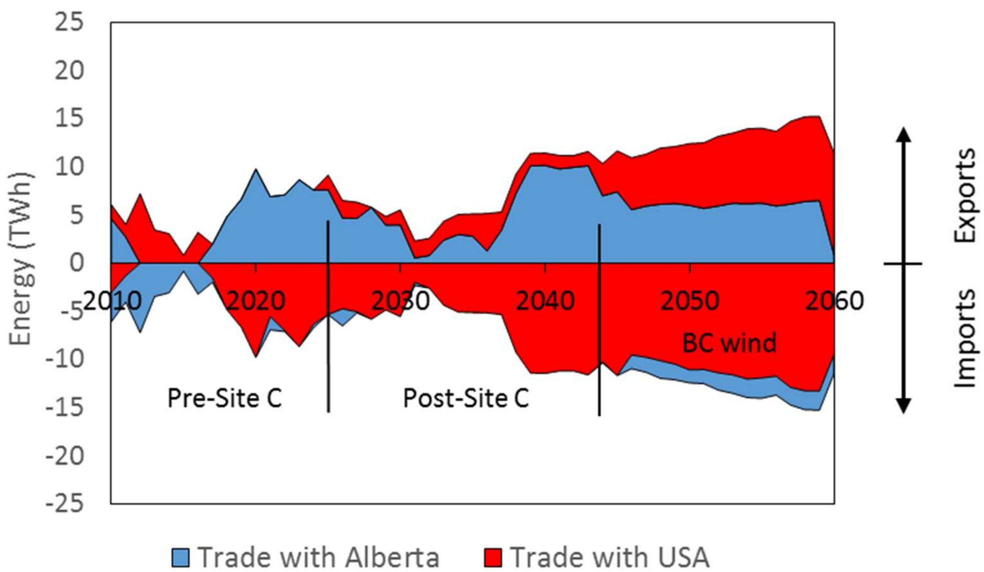


Figure 2-5: Stacked area plot of gross electricity trade between British Columbia with Alberta and the United States in the current policies scenario (CP-C and CP-E). Imports into BC are negative, exports from BC are positive. Total import volume to BC is 428 TWh. Total export volume from BC is 434 TWh.

80% by 2050 Scenarios

Current Transmission Capacity Scenario (80%-C)

The 80%-C scenario represents the most restrictive carbon policy scenarios combined with current intertie capacity. Figure 2-6 shows annual energy generation for Alberta and BC from 2010 to 2060 in the 80%-C scenario:

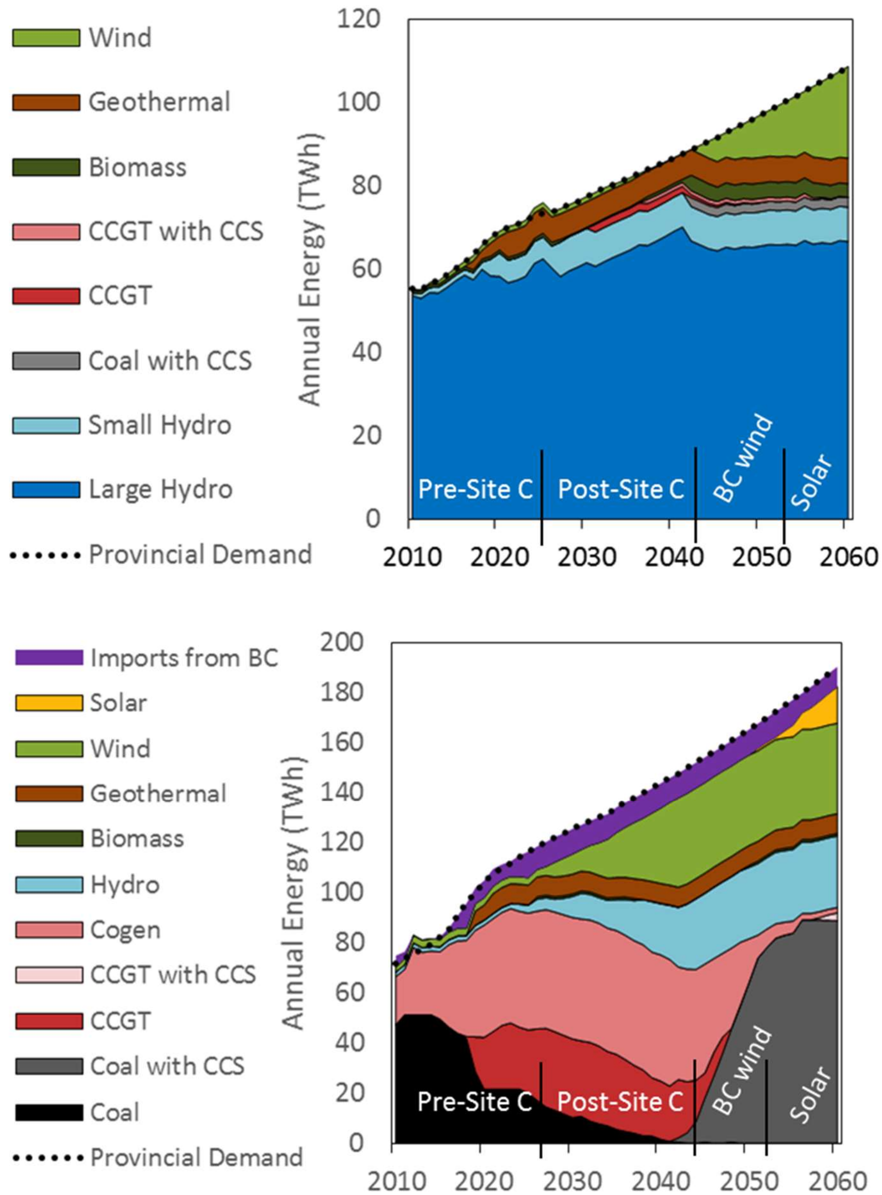


Figure 2-6: Stacked area plot of electricity generation in Alberta (top) and British Columbia (bottom) from 2010 to 2060 in the 80% by 2050 scenario with current transmission capacity (80%-C). The dotted line indicates annual demand in the province; generation above this line is exported. Energy which is imported and resold is not included in this figure.

This scenario demonstrates the same three eras as the current policies scenario and an additional fourth era, the *solar era,* during which Alberta begins installing solar generation. In this scenario, the pre-Site C era lasts from 2010 to 2025, the post-Site C era from 2024 to 2043, the BC wind era from 2043 to 2051, and the solar era from 2051 to 2060.

Compared to the current policies scenario, BC has a smaller portion of natural gas generation in the post-Site C and later eras, with a transition from gas to coal with CCS in the BC wind era as a result of the carbon cap. The carbon cap in Alberta reduces generation from natural gas in the post-Site C era in favour of wind, hydro, and imports. The cap also forces a switch from CCGT and cogeneration to coal with CCS in the BC wind era and drives the adoption of solar generation in Alberta.

Electricity trade in the 80%-C scenario is shown in Figure 2-7 where export volumes from BC increase from 434 TWh in the current policies scenarios (CP-C/CP-E) to 515 TWh in the 80%-C scenario with net exports decreasing from 6 TWh to 5 TWh. The destinations of BC exports are shown in Figure 2-7. The proportional shift in exports from BC to Alberta rather than the US is a result of higher generation costs in Alberta caused by the carbon cap.

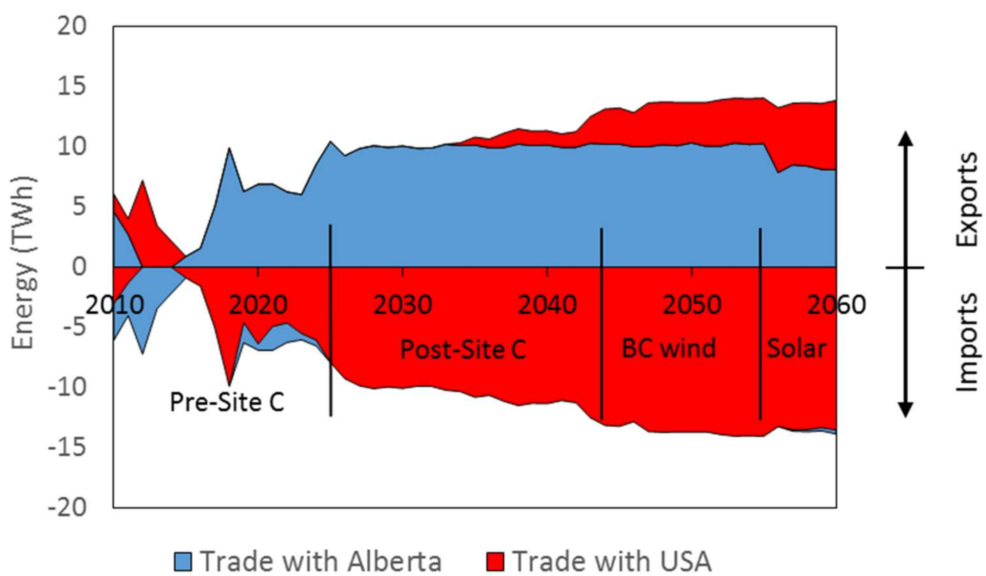


Figure 2-7: Stacked area plot of gross electricity trade between British Columbia and Alberta and the United States in the 80% by 2050 scenario with current transmission capacity (80%-C). Imports into BC are negative, exports from BC are positive. Total import volume to BC is 510 TWh. Total export volume from BC is 515 TWh.

In this scenario, exports from BC to Alberta reach near constant levels beginning in 2024 with the introduction of Site C. This trade then decreases in the solar era as imports to Alberta during the summer peak are replaced by solar generation. With the exception of net positive exports in 2024 and 2025, BC maintains a net zero energy trade balance over this time. This indicates that the additional energy from Site C is not directly exported to Alberta. Instead, the additional flexible generation allows BC to take advantage of low market prices in the Mid-C market to purchase power which is later used to meet peak demand in Alberta.

Expandable Transmission Capacity Scenario (80%-E)

The 80%-E scenario uses the same carbon policy as the 80%-C scenario but allows intertie expansion. Figure 2-8 shows annual generation for Alberta and BC from 2010 to 2060 in the 80%-E scenario:

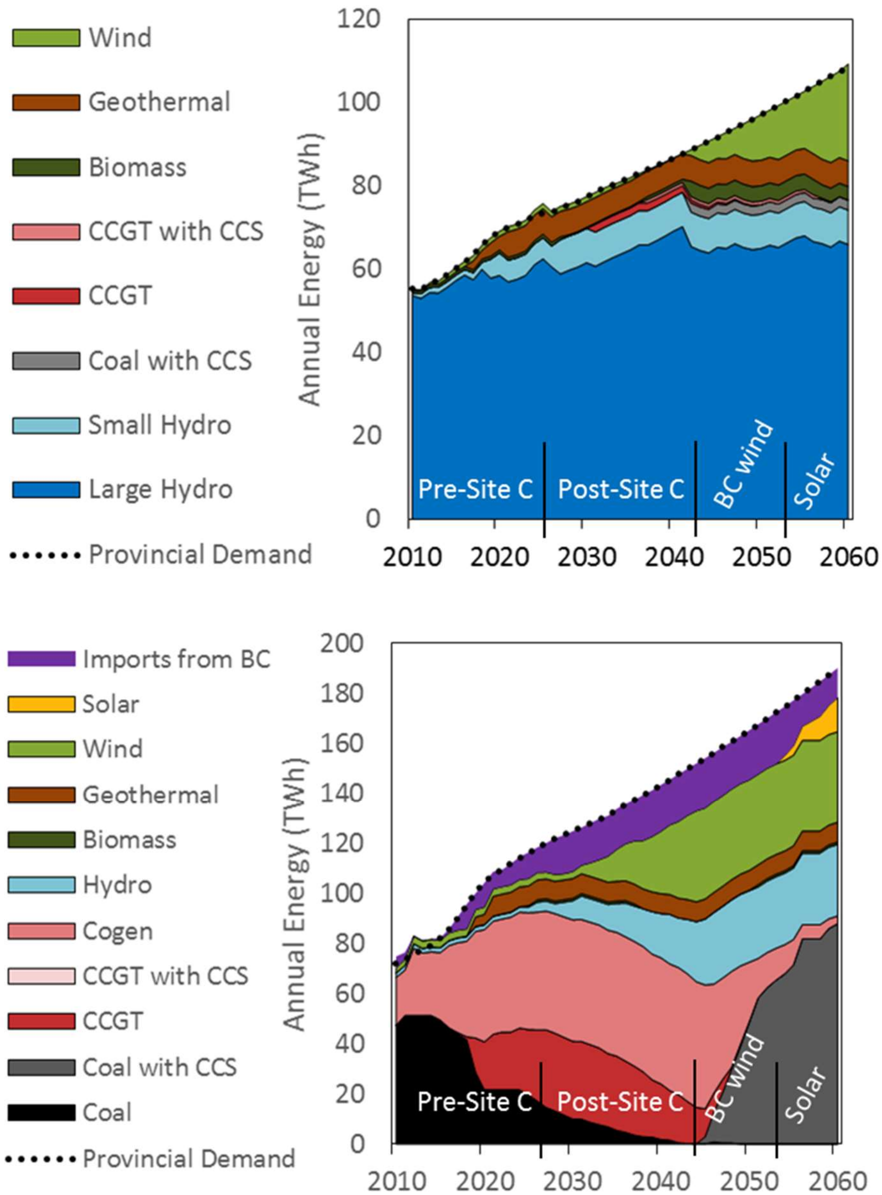


Figure 2-8: Stacked area plot of electricity generation in Alberta (top) and BC (bottom) from 2010 to 2060 in the 80% by 2050 scenario with expandable transmission capacity (80%-E). The dotted line indicates annual demand in the province; generation above this line is exported. Energy which is imported and resold is not included in this figure.

Compared to the 80%-C scenario shown in Figure 2-6, in the 80%-E scenario Alberta develops its renewable resources, namely wind, hydroelectricity, and coal with CCS several years later. This effect can be seen by comparing the energy generated from these sources in these two scenarios, as shown in Figure 2-9.

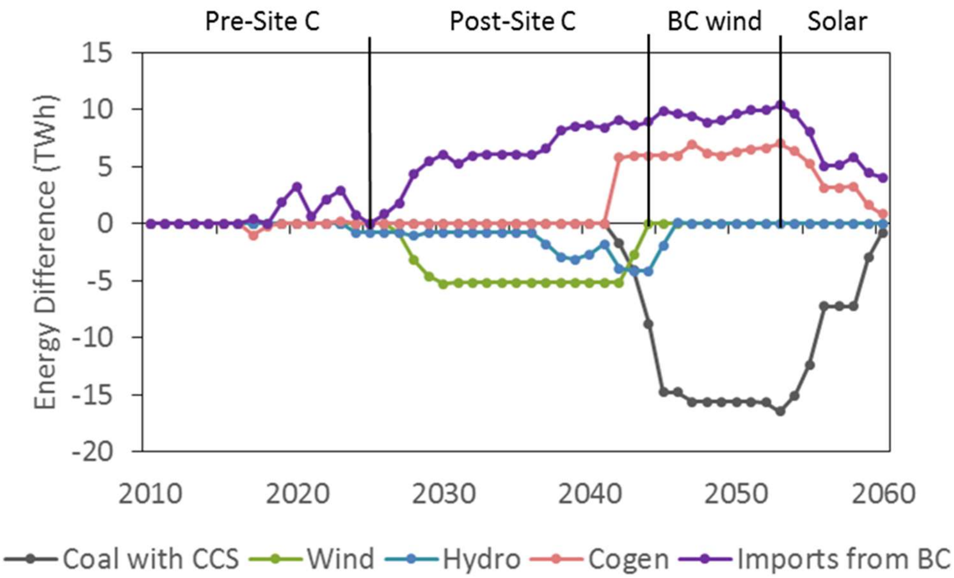


Figure 2-9: Difference in annual energy generation in Alberta between the 80% by 2050 carbon policy scenario with current transmission capacity (80%-C) and expandable transmission capacity (80%-E). Generation by coal with CCS, wind, hydro, cogeneration and imports from BC are shown. Positive values indicate higher generation in the expandable transmission capacity scenario.

In the 80%-E scenario, the larger intertie allows more low-cost energy to be exported from BC to Alberta. This results in reduced wind and hydro generation in Alberta during the post-Site C era. In the BC wind era, Alberta's wind and hydro resources are fully developed. However, the increased import capacity of the intertie reduces Alberta's reliance on thermal generation. This allows some coal with CCS generation to be replaced by cogeneration, which has higher specific emissions, while still meeting the emissions cap.

Gross exports from BC increase from 515 TWh in 80%-C to 706 TWh in the 80%-E scenario with net exports remaining at 5TWh. As shown in Figure 2-10 by the symmetry between imports and exports, BC effectively wheels power from the US to AB. This trade increases throughout the post-Site C and BC wind eras. As seen in the 80%-C scenario

(Figures 2-6 and 2-7), imports into Alberta decrease as solar generation expands and removes the need for imports during summer months.

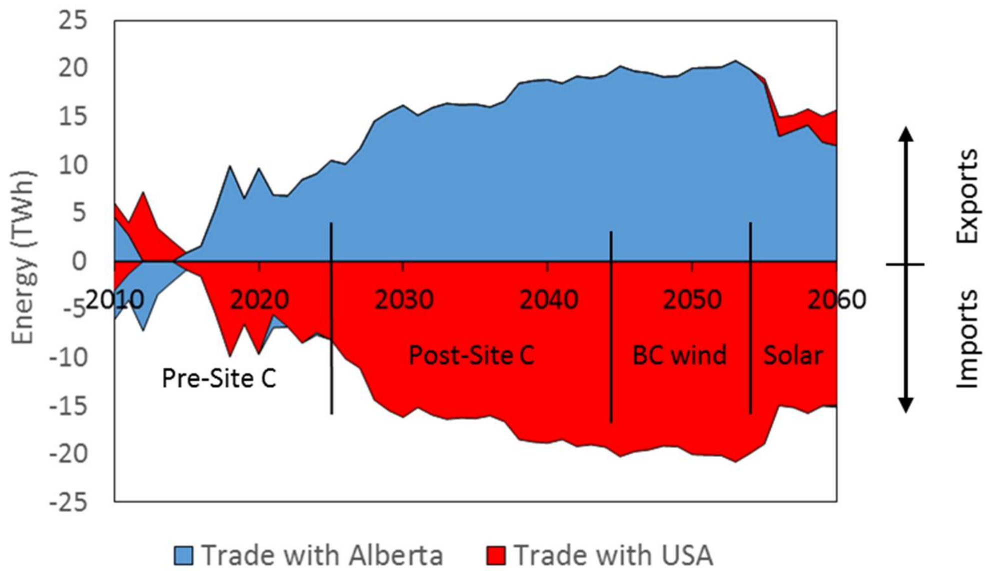


Figure 2-10: Stacked area plot of gross electricity exports from British Columbia to Alberta and the United States in the 80% by 2050 scenario with expandable transmission capacity (80%-E). Imports into BC are negative, exports from BC are positive. Total import volume to BC is 701 TWh. Total export volume from BC is 706 TWh.

Transmission Expansion

Intertie expansion occurs in all expandable scenarios except for CP-E and 30%-E, which are the least carbon restrictive policy scenarios considered. This indicates that the generation cost difference between the provinces is insufficient to offset the capital cost of the intertie. More restrictive carbon policies result in larger intertie expansions. Figure 2-11 shows intertie capacity over time in each expandable transmission scenario.

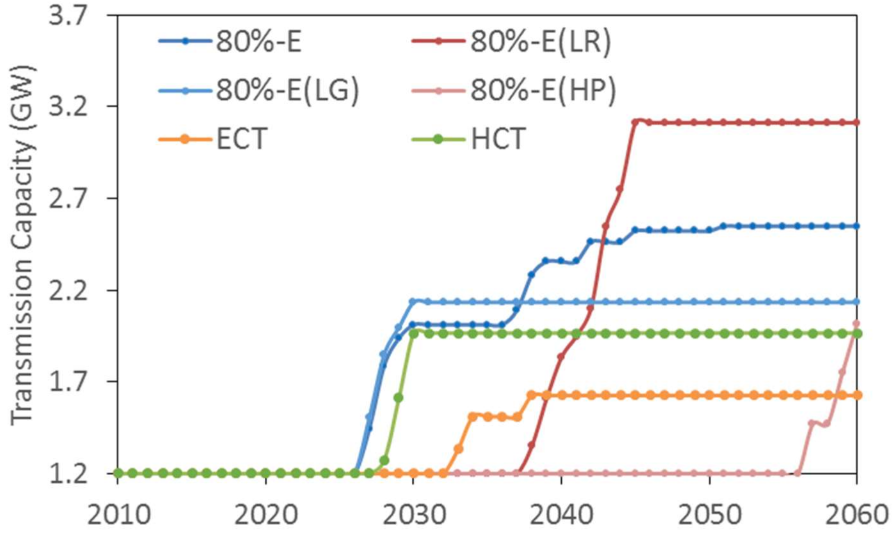


Figure 2-11: Optimal annual BC-Alberta intertie capacity for scenarios with expandable transmission. Intertie expansion does not occur in any scenario until the post-Site C era at the earliest. In the 80%-E(LR) scenario intertie expansion occurs in the BC wind era. In the 80%-E(HP) scenario intertie expansion occurs in the solar era.

In all cases, intertie expansion occurs after completion of Site C in 2025. Site C provides additional flexible generation capacity at low marginal cost in BC, allowing more energy generated in BC to be exported to Alberta during high price times. In the 80%-E(LR) scenario, intertie expansion is delayed until the BC wind era because the low cost of wind power results in the installation of more wind capacity in Alberta, reducing the need for imports. Intertie capacity is then greatest in this scenario to accommodate the high variability of BC wind generation relative to Mid-C imports.

In the 80%-E (HP) scenario intertie capacity is delayed until the solar era. In this scenario, the cost differential between Alberta and Mid-C is not large enough to offset the cost of intertie expansion during the post-Site C and BC wind era. In the solar era the intertie is expanded and used to export energy from Alberta through BC to the US. This export occurs during timeslices with high solar generation, during which the marginal cost of generation in Alberta is low.

Scenario Comparison

Scenarios are compared to highlight the effects of both the carbon policy and the effect of intertie expansion for each policy. Comparisons are made of the cumulative emissions and net present cost for each scenario as shown in Figure 2-12. Non-tax costs (*i.e.* capital, fuel, and O&M) and carbon tax costs are separated to provide distinction between the cost changes caused by these two factors.

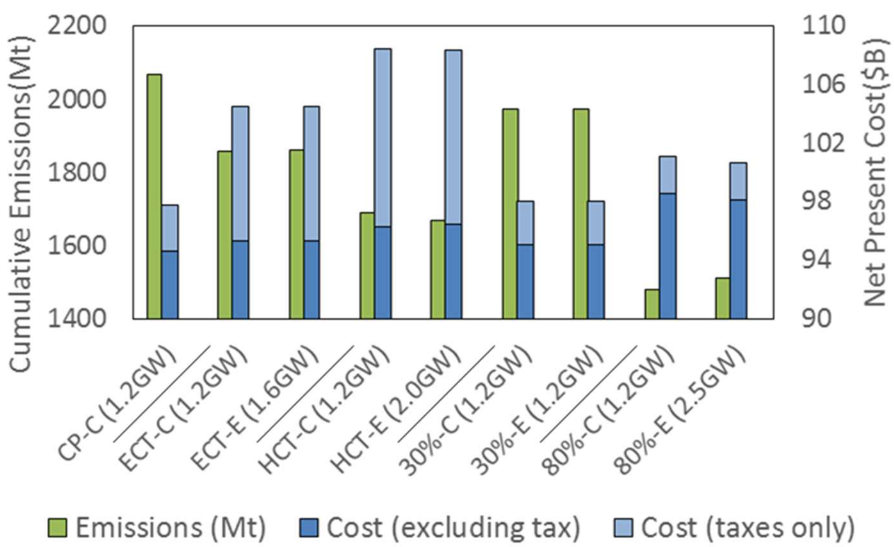


Figure 2-12: Net present cost and emissions for each scenario. Costs values are stacked non-tax (*i.e.* capital, fuel, and O&M) and tax costs. Labels indicate comparisons between values made in the text.

Current carbon policies (CP-C/E) result in the highest carbon emissions and lowest cost of all the carbon policy scenarios considered. More restrictive carbon policy scenarios (*e.g.* 80%-C/E and HCT-C/E) result in higher system costs. The 30% by 2030 carbon policy scenarios (30%-C/E) has the least effect; it results in a 4.6% decrease in cumulative emissions with a 0.2% increase in net present cost. The greatest emissions decrease is in the 80%-C scenario, in which cumulative emissions decrease by 27% and net present cost increases by 4.6%.

Comparing expandable and current intertie scenarios with the same carbon policy scenarios (*e.g.* 80%-C and 80%-E, label *a*) shows that there is only a small change in the emissions from allowing intertie expansion compared to the effect of the carbon policy (label *b*). The largest difference between current and expandable intertie scenarios occurs in the 80% by 2050 policy scenarios in which there is a 0.4% decrease in cost and a 2.1% increase in emissions in the –E scenario relative to the –C scenario (label *a*).

Counter-intuitively, in ECT-E and 80%-E scenarios there are greater emissions than in the corresponding –C scenarios (labels *a* and *c*). This is a result of emissions from power imported from the US, which, in the model, are exempt from carbon policies. In the 80%-E scenario, which features the most imports from the US, these emissions total 82 Mt which negate the corresponding 51 Mt decrease in BC and Alberta emissions.

The cost (excluding carbon tax) increases under more restrictive carbon policies as a result of increased high-cost/low-carbon generation such as wind and coal with CCS in place of low-cost/high-carbon sources such as combined cycle gas turbines. This effect is more prevalent in Alberta, as shown in Figures 2-3, 2-5, and 2-7, because of the higher carbon intensity of its generation mix, which is more affected by carbon policies than BC's hydroelectricity-dominated generating fleet.

For higher carbon tax policy scenarios (*i.e.* ECT-C/E and HCT-C/E) the tax cost increases because of the higher explicit price on carbon (labels *d* and *e*). For carbon cap scenarios (*i.e.* 30%-C/E and 80%-C/E), the tax cost decreases (labels *d* and *f*) because the tax per tonne is unchanged while emissions decrease, lowering carbon tax costs.

Although more restrictive carbon policies result in higher net present cost, the cost increase can be slightly reduced by expanding the intertie between the two provinces, as shown by comparing –E and –C scenarios in Figure 2-11. Expanding the intertie allows more power to flow from areas of low-cost supply to areas of high cost supply, avoiding the need to develop higher cost generation. An example of this is shown in Figure 2-8, where wind and then coal with CCS in Alberta are displaced by lower cost imports from BC. The Alberta system also benefits from the storage potential of BCs large hydroelectric facilities. Rather than using hydro to enable greater penetration of wind generation, these facilities are used to store energy imported at low cost from Mid-C and to generate during peak times in BC and Alberta. These factors lead to differences in net present cost and cumulative emissions for the same carbon policy scenarios with current and expandable intertie capacity.

Carbon Abatement Costs

All of the more restrictive carbon policies studied increase the net present cost and decrease the emissions of the combined BC-Alberta electricity system compared to current policies. The ratio of this cost increase to the associated emissions reduction can be expressed as an abatement cost in dollars per tonne of carbon dioxide. Table 2-4 shows the cumulative emissions from BC and Alberta for each carbon scenario and the abatement cost relative to the current policies scenario:

Table 2-4: Cumulative emissions and carbon abatement costs in each scenario. Cumulative emissions include emissions from Mid-C imports. Abatement costs are calculated as the difference in net present cost divided by the difference in emissions relative to the current policies scenario. Asterisks indicate model-determined optimal transmission capacity for expandable transmission scenarios.

Policy	**Transmission Capacity (GW)**	**Cumulative Emissions (Mt)**	**Abatement Cost ($/t)**	**Abatement Cost Excluding Taxes ($/t)**
Current policies	1.2	2066	---	---
30% by 2030	1.2	1971	2.51	4.38
80% by 2050	1.2	1478	5.62	6.68
	2.5*	1509	5.18	6.31
Equalized carbon tax	1.2	1858	32.36	3.38
	1.6*	1860	32.56	3.30
High carbon tax	1.2	1689	28.39	4.33
	2.0*	1668	26.59	4.65

For the two carbon tax scenarios (*i.e.* equalized carbon tax and high carbon tax), the abatement cost is much higher than for the carbon cap scenarios (*i.e.* 30% by 2030 and 80% by 2050) as a result of the carbon taxes themselves. Removing the carbon tax costs allows comparison of the abatement cost of these carbon policies based on the cost of electricity generation. For carbon cap scenarios, the abatement cost excluding carbon taxes is higher than the abatement cost with taxes. This is because some of the cost increase due to greater use of high-cost/low-carbon technologies (to meet the carbon cap) is offset by decreased carbon tax costs.

For most scenarios, abatement costs increase as carbon policies become more restrictive. This is because as carbon emissions are forced to lower levels, more expensive mitigation options must be used, increasing the average cost of the emissions reduction. Exceptions to this trend are the 30% by 2030 carbon policy scenarios, which have a higher abatement cost, excluding taxes, than the carbon tax equalization scenarios, despite having greater emissions. This is because the 30% by 2030 policy implements a firm cap on emissions. For some years meeting this cap requires expensive abatement actions (*i.e.* replacing CCGT generation with wind), while in other years even relatively low-cost abatement actions (*i.e.* replacing CCGT with coal with CCS) are not needed to meet the cap and do not occur. Both of these conditions increase the average abatement cost. By contrast, the equalized carbon tax policy provides a consistent incentive for decarbonization.

The high carbon tax scenario with expandable transmission (HCT-E) has a 6.3% decrease in abatement cost compared to current transmission capacity (HCT-C) but a 7.4% increase in abatement cost when carbon taxes are excluded. This is because the larger intertie allows more energy from the US to be used in Alberta, displacing CCGT generation and reducing emissions while increasing costs. This increases the cost of electricity but decreases the cost of the carbon tax, resulting in overall savings. By contrast, under the equalized carbon tax policy, the price of carbon is too low to displace CCGT generation. Instead, the increased imports from the US replaces wind generation, increasing emissions and decreasing costs. This results in a higher abatement cost when carbon tax is included and a lower abatement cost when carbon tax is excluded.

Sensitivity Scenarios

Eight sensitivity scenarios are used to examine the effects of renewables cost, load growth, and Mid-C price on the outcomes of this study. Table 2-5 shows the cumulative emissions and net present costs for BC and Alberta in these scenarios. Stacked area plots of the generation mixes and trade patterns in these scenarios are available in the supplementary materials.

Table 2-5: Cumulative emissions and net present of the combined BC-Alberta electricity system in the eight sensitivity scenarios. Net present cost is based on a 6% discount rate. Emissions from Mid-C imports are included in cumulative emissions.

Scenario	**Transmission Capacity (GW)**	**Cumulative Emissions (Mt)**	**Net Present Cost ($B)**
CP-C/E	1.2	2066	97.7
80%-C	1.2	1478	101.1
80%-E	2.5	1509	100.6
CP-C/E(LR)	1.2	1833	95.7
80%-C(LR)	1.2	1461	97.7
80%-E(LR)	3.1	1484	97.4
CP-C/E(LG)	1.2	1962	92.2
80%-C(LG)	1.2	1477	94.6
80%-E(LG)	2.1	1500	94.3
80%-C(HP)	1.2	1412	100.6
80%-E(HP)	2.2	1411	100.5

The low cost renewables scenarios have lower emissions than the corresponding reference scenarios. The savings in the CP-C/E(LR) scenarios are a result of the earlier switch from natural gas to renewables, particularly in Alberta. In the 80%-C/E(LR) scenarios the additional emissions reduction from the low renewables cost is much less because some Mid-C imports are replaced by domestic wind generation in BC. The optimal intertie capacity is larger in this scenario than in the 80%-E scenario to support the variability of this wind generation with power from BC.

Each of the low growth scenarios has slightly lower emissions than the corresponding reference scenario. This difference is greatest in the CP-C/E(LG) scenarios in which production and, therefore, emissions from fossil-fuel sources decrease to match the lower demand. For these scenarios, adoption of renewable technologies does not differ greatly in timing or selection from the CP-C/E scenarios. This reduction in emissions is negated under the 80% by 2050 carbon policy, under which provincial emissions meet the same cap regardless of load growth. The slight decrease in emissions in the 80%-C/E(LG) scenario compared to the 80%-C/E scenario is a result of decreased imports from Mid-C.

In the 80%-C(HP) and 80%-E(HP) scenarios emissions decrease by of 4.5% and 6.5%, respectively, compared to the corresponding default scenario. In these scenarios, the high price of Mid-C power reverses the trade pattern with the US. Instead of importing power from the US into Alberta, whose emissions are not counted towards the cap, energy is instead exported from Alberta and BC to the US. This energy displaces higher-carbon production in the US, resulting in an overall decrease in emissions.

Intertie Utilization

Intertie expansion incurs capital cost and fixed costs but does not contribute directly to meeting demand. As a result, for the intertie to be economically optimal it must reduce the cost of meeting demand by allowing more low cost generation to be used. If there are persistent cost differences between regions, the expanded intertie will have a high capacity factor. If instead there are shorter duration but larger price differences the expanded intertie will have a low capacity factor. Figure 2-13 shows the intertie capacity and capacity factors over the entire model period for the BC-Alberta intertie in each scenario:

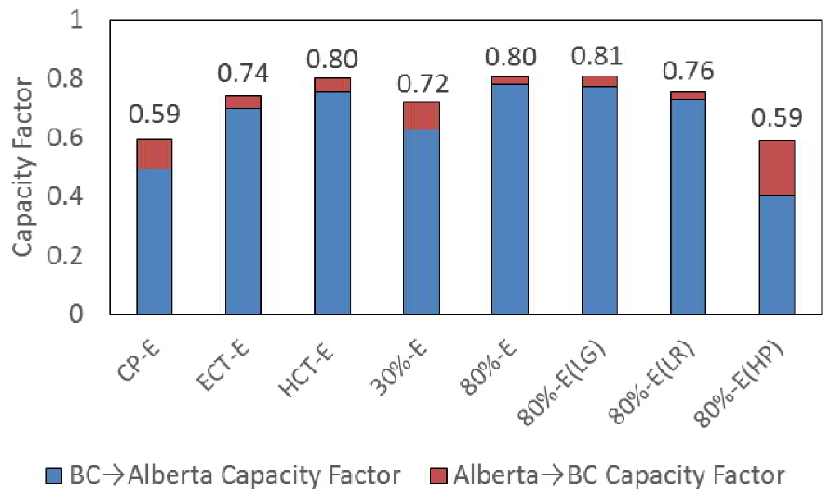


Figure 2-13: Stacked plot of the BC-Alberta intertie capacity factors in each scenario. The combined height is the total capacity factor of the intertie over the model period.

The capacity factors shown in Figure 2-13 indicate that there is consistently a higher price in Alberta in most scenarios. This is a result of an abundance of low-cost power in the Mid-C market which cannot be consumed in BC as a consequence of its no-net-imports mandate. Instead, the power is wheeled through BC and resold into Alberta. This indicates that the increased intertie is used to provide more energy from the US, via BC, to Alberta rather than to accommodate short-term power imbalances caused by renewable generation.

This pattern changes in the high Mid-C price sensitivity scenario (80%-E(HP)). In this scenario, there is much less low-cost power available, resulting in a lower BC to Alberta capacity factor. This is partially countered by a reversed trade flow. Due to the high escalation rate of Mid-C electricity it is economically viable to export energy from Alberta to the US, which results in a higher Alberta-BC trade flow.

Discussion

Emissions Reduction

The results of this study indicate that significant emissions reductions can be driven by policy changes alone or by policy changes in conjunction with intertie expansion. In scenarios with intertie expansion, the change in emissions enabled by allowing intertie expansion is an order of magnitude smaller than the change caused by the carbon policy. In some scenarios, global (*i.e.* BC, Alberta, and the US) emissions increase with an expanded intertie because of the increased ability to import power from the US, which is not affected by the carbon policies. This highlights to need to have consistent carbon policies across regions with high interconnectivity to ensure that emissions are prevented rather than relocated.

Over the modeled period, carbon policies result in significant emissions reduction. These reductions result from the evolution of the generation mixture toward low carbon technologies. This evolution is characterized by four distinct eras: the pre-Site C era, post-Site C era, BC wind era, and solar era. The pre-Site C era features a continuing dependence on hydroelectricity in BC and a switch from coal to natural gas in Alberta. BC remains primarily hydroelectrically powered through the post-Site C era while Alberta begins adopting wind and hydro. Beginning in the BC wind era both BC and Alberta rapidly expand wind generation and coal with CCS becomes prevalent in Alberta. Finally, in the solar era Alberta, but not BC, begins adopting solar generation. While coal with CCS features heavily in the model, it could be replaced with any scalable, dispatchable, and low carbon technology such as enhanced geothermal or solar with storage. Changing carbon policies and adjusting sensitivity parameters changes the timing and duration of these eras but does not change their order.

The net present cost of these abatement actions, shown by the difference in both tax and non-tax costs between each scenario and the CP-C in Figure 2-11, ranges from 0.2% of the total system cost under the 30% by 2030 carbon policy option to 4.6% of the total system cost for the 80% by 2050 policy option. The nominal cost of these actions is obfuscated in these results by discounting, particularly in later portion of the model, during which the carbon policy options have the greatest effect. Keeping this in mind, the results of this study suggest that a high level of decarbonization is possible for a modest increase in system cost.

Intertie Benefits

Under current carbon policies, the benefit from expanding the BC-Alberta intertie is less than its cost. With more restrictive carbon policies the least cost power generation mix includes an expanded intertie. For most scenarios, this expansion occurs at the start of the post-Site C era. The larger intertie allows more energy from the US to be used in Alberta, displacing domestic generation sources. More energy is imported by Alberta under more restrictive carbon policies as the difference in cost between domestic generation and imports increases.

In some cases intertie expansion results in later adoption of variable renewable generation, particularly wind in Alberta. As a result, global emissions increase slightly. This pattern is reversed in the high Mid-C price sensitivity scenarios, in which carbon-free energy from wind and solar is exported from Alberta to the United States, reducing both global emissions and system cost.

Model Limitations

At the beginning of the modelled period, generation mixes differ slightly from current actual mixes. In particular, natural gas and biomass have much smaller shares in the model for BC across all scenarios than present levels (Figure 2-1). Current biomass generators operate at pulp-and-paper sites to provide heat and power from the abundant waste feedstock, a by-product of normal operations. Although the cost of biomass-fueled power generation is greater than that of hydroelectricity, a portion of this cost is recovered by the mill owner in reduced heating needs and waste disposal. As a result, the effective cost of biomass generation is lower than other forms of generation. This generation is not included in the model because accurate estimates of its cost and availability are not available.

Natural gas also has a greater generation share at the start of the model period than modelled as a result of generation in some transmission-constrained areas of BC. This effect is not captured in the model, which does not consider the internal transmission structure of the provinces.

In all scenarios, a significant portion of carbon savings are from the replacement of Alberta coal generation with cleaner energy from the Mid-Columbia market. Historical data suggests this pattern already occurs, as BC has maintained a negative international and positive interprovincial energy trade balance for five of the past six years prior to 2013 [117]. The larger transmission link between the provinces allows more of this power – up to 84 GWh/day in the 80%-E scenario – to reach Alberta. In 2013, the daily average trading volume between BC and the Mid-C market was 41 GWh/day [117]. The model does not include the effect of price elasticity in the Mid-C market. The feasibility of the low-carbon scenarios presented in the paper is dependent on the price and carbon intensity of Mid-C power remaining low despite this increase in trading volume.

In addition to the availability of Mid-C power, its price structure is assumed to remain constant over the model period. However, technological, political, and climatic developments could change this power pattern significantly. For example, high levels of solar photovoltaic generation in the western US could mid-day power prices, or declining water levels could reduce the impact of the freshet on spring power price. These changes, and their impact on the cost and availability, could significantly change the findings of this study. Possible future scenarios for Mid-C power prices and availability will be the subject of future work.

The timeslice method used in this study does not capture short-term variations in demand and generation, as discussed in Appendix A. A reserve margin requirement is, therefore, used to ensure that sufficient dispatchable generation capacity is available to meet demand. However, there is no requirement in the model to provide ramping capacity to meet regulation needs.

Conclusions and Policy Implications

This study investigates the potential benefits of increasing transmission capacity between BC and Alberta under a range of carbon policies. It expands on previous studies by including trade between BC and the US and by extending the time period modelled [29], [35]. Under current carbon policies, the least cost solution does not include additional intertie capacity. However, under more stringent carbon policies, greater intertie capacity lowers both costs and emissions.

Four carbon policies are considered. The cumulative emissions reductions from these policies range from 4.3% to 27% with cost increases from 0.2% to 4.6%. Abatement costs are between \$2.51/t and \$32.56/t including carbon tax costs, or \$3.30/t to \$6.68/t if carbon tax costs are excluded. This abatement cost can be lowered by expanding intertie capacity between the two provinces. Overall, a low-carbon electricity system for BC and Alberta is possible with only a minor increase in cost.

The emission reductions obtained through intertie expansion in the model are largely a result of increased imports from the Mid-C market, which are exported to Alberta. This energy displaces domestic generation in Alberta, primarily consisting of coal and natural gas generation, resulting in lower greenhouse gas emissions. This imported power also displaces wind generation in Alberta, which is contrary to the expectation that greater interconnection will lead to more wind power development. This pattern relies on the low cost and high availability of low-carbon energy in the Mid-C market. These findings indicate the potential for carbon leakage in the electricity sector. This phenomenon, and methods to combat it, are the subject of recent research [118], [119], [120].

The evolution of the generation system can be described by four distinct eras: the pre-Site C era, post-Site C era, BC wind era, and solar era. BC remains hydroelectrically dominated through the pre-Site C and post-Site C eras before adopting wind in the BC wind era. Alberta switches from coal to natural gas in the pre-Site C era, expands wind and hydro generation in the post-Site C era, adopts coal with CCS in the BC wind era, and finally begins using solar power in the solar era. Carbon policies and intertie expansion change the dates and duration of these eras but not their order of occurrence.

Chapter 3 - Impact of Flexibility Requirements on Electricity System Decarbonization

Preamble: Decarbonizing electricity generation through deployment of renewable technologies such as wind and solar is a key component of many climate change mitigation efforts. With increasing penetrations, the need to manage variability in renewable generation becomes critical. However, renewable variability is often poorly represented in energy planning studies which focus on energy and capacity adequacy. In this study, we used a hybrid capacity expansion and dispatch model with explicit inclusion of ramping and regulation services to examine balancing requirements in a decarbonizing electricity system. We find that ramping and regulation services needed for management of variable renewables alter the optimal mix of generation and transmission capacity relative to simpler planning models. In particular, we find enhanced value in expanding transmission capacity to access flexibility. This chapter was originally published as a standalone publication in *Renewable Energy.*

Introduction

The transition from emissions-intense sources of electricity to renewables, and the substitution of fossil fuels with clean electricity are key components of many climate change policies. However, renewable resources like wind and solar, and new electrical loads such as electric vehicles, can be highly variable and uncertain. As their penetration increases, so, too, does the need for flexibility in the electrical system [121]. With constraints on the type of generators that can be used in a fleet, providing the flexibility to manage variability can increase the total cost of electricity [122]. Because flexibility is typically related to short-term operational requirements, it is a challenging issue to include in long-term capacity expansion and dispatch studies. Thus, with increasing emphasis on the use of variable renewable supplies, there is a growing need for planning studies that capture effects of variability and the impact on adequacy and reliability. More broadly, quantifying system costs of net load variability is needed to inform policies aimed at decarbonizing electrical systems.

Previous studies have examined the effect of increasing levels of capacity from variable renewable (VR) generators on the variability of net load (*i.e.* load that must be met by conventional generators). Olausen et al. [77] examined the change in net load variability in the Nordic power system with increasing amounts of VR energy. It was found that replacing thermal and nuclear generation with VR energy increased the standard deviation of net load, particularly in the medium-term (2 days to 4 months) and that the peak net load and hourly ramp rates rise as well [77]. In a study of California, it was determined that high levels of VR generation require additional ramping from dispatchable generation and that the VR capacity required to reach high energy penetrations results in times of surplus supply, lowering the value of VR energy [123]. These effects can be mitigated, to some degree, by deploying a complementary mix of wind and solar generation to reduce the frequency and duration of concurrent generation events [124], by dispatching hydroelectric generators in times of low-VR production [40].

Energy storage has been evaluated as a means to increase the grid's ability to manage the variability in net load. Recent studies have found that a near-fully renewable powered electricity system is feasible with very high VR penetrations provided that large storage capacities are available [73], [125], [126]. Storage has also been shown to increase the value of VR energy; however, due to the high cost of storage technologies, widespread grid-level energy storage is currently uneconomical [67], [127], [128].

Interregional transmission can provide access to capacity and flexibility and allow high penetrations of VR energy at lower cost than in isolated systems. A one-year study in Northeast Asia found that both the cost and emissions of electricity generation are reduced by increasing transmission between regions [43]. In a study of the European electricity system, Rodriguez et al. found that the portion of annual energy that must be served by balancing generators is reduced when interregional transmission is increased [76]. Other studies have found that increased transmission can reduce curtailment in high penetration VR scenarios [33], [56], [127], thereby increasing the portion of system energy served by VR, and reducing the cost of meeting renewable energy targets [129].

Fully renewable electricity systems with increased interregional transmission have been studied for Europe [125] and the Nordic power system [77]. In the latter study, net load variability can be met by existing hydroelectric facilities with no need for new storage capacity. Both of these studies consider systems with defined VR mixes optimized to reduce VR production variability over a period of one year. These studies do not present a least cost VR mix, nor do they examine the transition from today's electricity system to one that is fully renewable.

Interregional transmission can provide access to energy and ancillary services. To realize these technical benefits, there must also be appropriate coordination of regional assets. Understanding how technical benefits couple with markets and regulatory frameworks are important issues in the transition of electrical systems to high penetrations of VR. In particular, the assessment of long-term system structures which include short term demands such as regulation and ramping capacity is needed. In this study, we examine the impact of flexibility requirements on interregional transmission and generation fleets in a two-region electricity system with high penetrations of VR generation. These regions are jointly optimized using a long-term hybrid expansion and dispatch model. This work builds on a previous study by including short-term flexibility constraints in a long-term electricity system optimization [130]. Expanding on this previous study, we explore the impacts of these flexibility requirements on the expansion and dispatch of the electrical system and the value of interregional transmission in an optimized low-carbon system.

In the following sections we first describe the modelling methodology, followed by the results showing capacity and dispatch to year 2060, and finally the implication of these results for regional coordination through service sharing.

Methods

Designing electrical systems for the future often relies on cost minimized capacity expansion and dispatch models [131]. The issue of increasing need for flexibility due to variability in supply and demand has spurred new methods for system planning [81]. In this study, a long-term model is used that directly accounts for the variability of net load in the expansion and operation of the electricity system. We focus specifically on the impacts of net-load variability due to large-scale penetrations of VR. Two balancing regions are modeled connected by a single expandable intertie. The growth in intertie capacity and the use of the transmission lines is determined endogenously.

The model minimizes cost to deliver four specific services: baseload energy, peaking, ramping, and regulation capacity. Flexibility requirements due to load and VR are defined. The following section describes the different generation technologies, their respective ability to provide each service type of service, and their capital, fixed and variable costs. Costs incurred by dispatchable generators due to ramping are explained thereafter. The study uses the western Canadian provinces of British Columbia (BC) and Alberta (AB) as a representative case of interconnected jurisdictions with very different attributes. One, (BC), is low-carbon and flexible due to the use of large reservoir hydro, and the other (AB) is a system dominated by fossil fuel with goals for decarbonisation. The regional characteristics are described along with policies defining carbon costs and renewable credits.

Capacity Expansion and Dispatch

Long-term capacity expansion and dispatch optimization from the year 2015 to 2060 is performed under technological, economic, and policy constraints. The optimization model is based on OSeMOSYS, an open source energy model previously described in [22], [23]. A key addition to OSeMOSYS functionality used in this study is explicit modelling of cascaded hydroelectric systems [130]. The model optimizes water use by generators on defined river systems with constraints on minimum and maximum flow rates and reservoir volumes. This level of detail is desirable for jurisdictions dominated by reservoir hydro as it allows the long-term storage potential of these reservoirs to be co-optimized with shorter term dispatch and expansion of non-hydroelectric generators.

In the past, including in energy dispatched by generators and the associated capacity required for peak days and reserve margin would be the key outputs of a planning study. Uncertainty and variability emphasize the need for dispatchability and responsiveness. Hence, in addition to energy dispatch and capacity, this work uses another extension that captures short-term constraints on the electrical system such as minimum generation level, maximum output changes between time steps (ramping), and capacity allocated to regulation. This OSeMOSYS extension is published in [132] with further validation in [81]. This allows flexibility commitment to be modelled explicitly. In the present study, we expand on this method by requiring additional flexibility to support VR generation; this is described in detail in the following sections

Time Steps

A model year is divided into 32 time steps where each time step represents a group of hours. A *day* is represented by four groups of hours: (1) night - from 9pm to 4am, (2) morning - from 4am to 9am, (3) mid-day - from 9am to 3pm, and (4) evening - from 3pm to 9pm. In addition, two types of days (*regula*r and *high-load*) are defined for each of the four *seasons*: winter, spring, summer, and autumn. Regular and high-load days are defined by daily energy demand where high-load days represent the 13 highest demand days in a season (one per week) and regular-load days represent the remaining days in that season. Seasons and daily time periods are categorized chronologically to track storage use. Four seasons, with two day-types, and each day with four demand periods results in 32 time steps in a year. Annual load profiles and demand growth are exogenously defined based on regional projections from the system balancing authorities.

Services

Four services are defined that must be provided during every time step: *baseload, peaking, ramping* and *regulation*. Two services, *baseload* and *peaking*, are energy services. *Ramping* and *regulation* are flexibility services which ensure sufficient dispatchable generation to match short-term load fluctuations. Flexibility services meet changes in demand that occur on hourly (ramping) and sub-hourly (regulation) time scales. Flexibility requirements are assumed to be the same in high-load and regular days. For each time step, the optimization must meet the requirement for each of these four services in both BC and Alberta.

A sample daily profile with baseload and peaking services is shown in Figure 3- where the black line shows the aggregated hourly demand in a region. The hourly baseload energy demand is approximated by the dark blue region where the plateaus correspond to the time-steps. The light blue regions represent the peaking energy requirements for each time step in excess of the baseload demand.

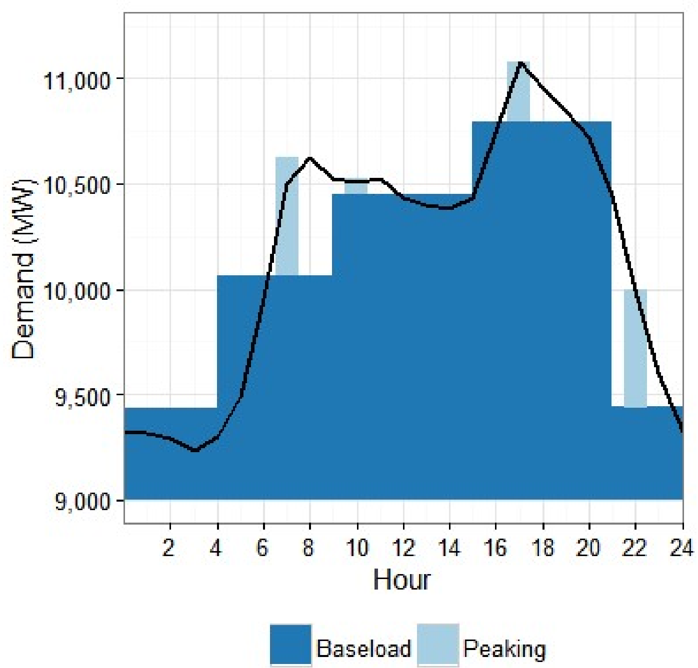


Figure 3-1: Sample daily demand profile (solid line). The dark blue areas represent baseload in daily time-steps and light blue areas represent peaking demand within each time-step.

The peaking energy demand, E^{PK}, for each time step, i, is the difference between the average energy demand and the highest hourly demand for a time step as defined by Equation 1,

$$E_i^{PK} = \max_{1 \le h \le N_i}(\mathrm{L_{h,i}}) - \frac{\sum_h^N L_{h,i}}{N_i} \qquad \forall\, \mathrm{i}\, \in TS \qquad (1)$$

where *L* represents hourly load in MW, *N* is the number of hours in a time step, subscript *h* represents time in hours, and *TS* is the set of unique time steps. In many other energy models, peak capacity requirements are represented by a reserve margin constraint that captures the capacity need, but not the energy component of this peak demand [23], [82].

Baseload demand, E^{BL}, is the cumulative energy demand over a time step, less the peaking energy, as defined in Equation 2.

$$E_i^{BL} = \sum_h^{N_i} L_{h,i} - E_i^{PK} \qquad \forall\, \mathrm{i}\, \in TS \qquad (2)$$

Ramping flexibility meets hourly changes in load as shown in Figure 3-. Requirements for ramping capacity, F^{RP}, for each time step are then determined by the largest one-hour change in load in each time step as defined by Equation 3.

$$F_i^{RP} = \max_{1 \le h \le N_i}\left(\left(L_{h,i}\right) - \left(L_{h-1,i}\right)\right) \qquad \forall\, \mathrm{i}\, \in TS \qquad (3)$$

Ramping requirements must be met by dispatchable generators.

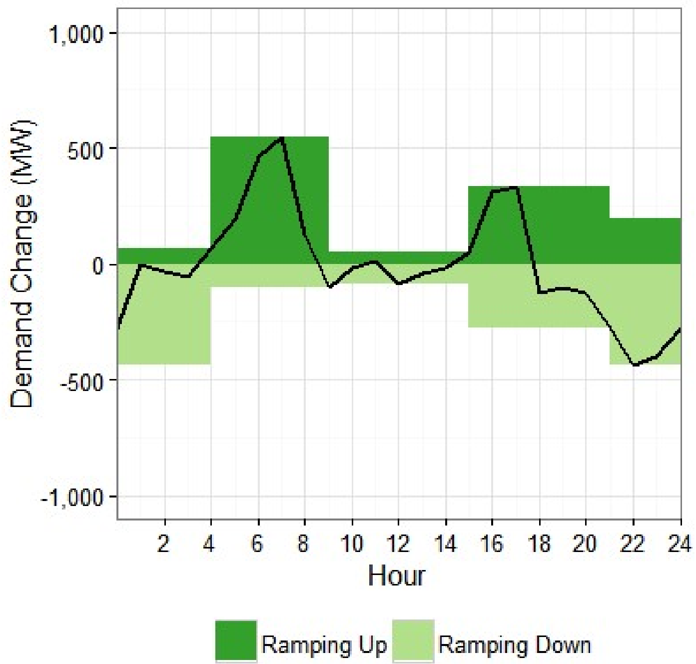


Figure 3-2: Hourly changes in demand (black line) and ramping demand for each time slice (green areas). Positive changes reflect ramp up requirements while negative changes are ramp down demand. Ramping demands for each time step is determined by the maximum up and down requirements.

Regulation requirements refer to short-term balancing - in this work, any changes in demand occurring at less than one hour. Regulation requirements are defined by historical regulating reserve dispatch in Alberta, typically set between 1% and 2% of load [12]. The regulation capacity, F^{RG}, for each time step is defined as the highest hourly dispatched reserve during that time step, as defined in Equation 4.

$$F_i^{RG} = \max_{1 \leq h \leq N_i} (\mathrm{DR_{h,i}}) \qquad \forall\, i\, \in TS \qquad (4)$$

where *DR* is the dispatched regulating reserve (*i.e.* generation dedicated to meeting short-term load fluctuations) and N_i is the number of hours in the time step *i*. The regulation requirement for the sample day is shown in Figure 3- where the dispatched regulation reserve (black line) is the actual value for the sample day. For future years, the regulation requirement for each time step is assumed to scale linearly with increase in demand (i.e. remaining at 1-2% of demand as for the initial year 2015.)

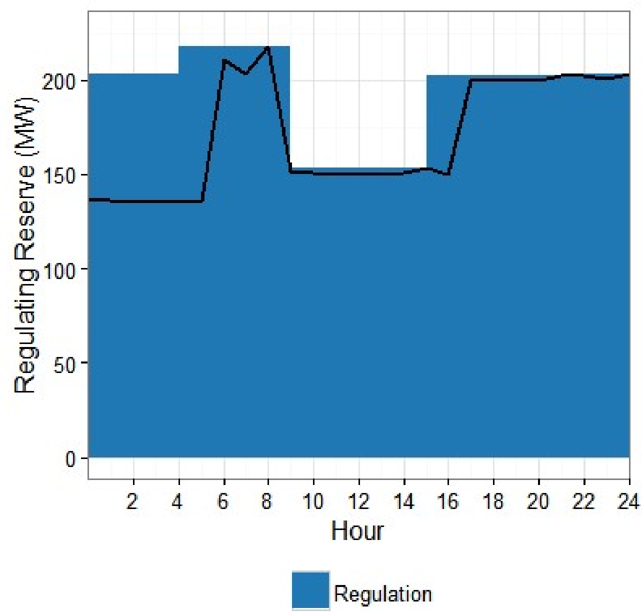


Figure 3-3: Demand for regulating reserve for a sample day (black line) and regulation demand for each time slice (dark blue areas)

When generators providing a flexibility service (referred to in this paper as being *committed* to this service) are called upon to meet load changes they produce energy as the generator output ramps to follow demand. As a result, some of the flexibility committed generation capacity will produce energy during the time step. Historically, the average energy output of flexibility-committed generators is 18% of ramping-committed capacity and 47% of regulation-committed capacity, based on the 2015 load profiles of BC and Alberta [133], [134].

This energy production from flexibility commitment is accounted for in the model and allocated to meeting the baseload energy demand in an associated time slice. The energy provided by flexibility-committed generators, E^{flex}, is determined by the energy content of hourly load changes as defined by Equation 5.

$$E^{flex} = \sum_{h=2}^{8760} \frac{|L_h - L_{h-1}|(1\ hour)}{2} \qquad (5)$$

The variability of wind and solar generation requires additional ramping and reserve flexibility above that required by load variability. A recent review examined a range of simulation and statistical studies of the flexibility requirements in high-VR systems [135]. This review found that estimates of flexibility requirements vary among regions, VR energy penetrations, and evaluation methods. Brouwer at al. estimate the required flexible capacity as a fraction of VR capacity, f, to be

$$F^{VR} = f \times G^{VR} \qquad (6)$$

where G^{VR} is the capacity of a VR resource and f, is 7% for ramping and 1% for regulation.

In this study, total ramping and regulation requirements provided by dispatchable generators are defined by a component related to demand variability, F^{load}, (as described previously in Section 2.1) and a component related to VR penetration. Here, the ramping and regulating capacity needed in each time step to support VR is determined by the average energy produced by VR. In this way, a resource such as solar, which is not generating during the night will not incur additional flexibility costs night time steps. The capacity scaling proposed by Brouwer can be related to energy production using the annual capacity factor, CF, of a resource, i.e.

$$E^{VR} = \mathrm{CF} \times G^{VR} \qquad (7)$$

where E^{VR} is annual energy production and CF is the annual capacity factor. Using Equation 7 in Equation 6, flexible capacity is a function of annual energy production and capacity factor,

$$F^{VR} = f/CF \times E^{VR} \qquad (8)$$

This relationship is assumed to hold for each time step where average annual energy production, E^{VR}, is replaced by the average production in a time step, P^{VR}.

Thus, the total capacity requirement for each type of flexibility, F, is due to load variations, F^{load}, (defined by Equations 3 and 4) and average VR energy generation in a time step, i.

$$F_i^j = F_i^{j,load} + f_i^j/CF \times P_i^{VR} \quad (9)$$

Equation 9 is used to define both ramping and regulation requirement in each time step (superscript j represents ramping or regulating). For this study, $f_{i,}$, for ramping and regulation requirements are assumed to be 7% and 1% of VR capacity, respectively, based on the results of [135]. Using these values and yields *f/CF* for ramping of 0.21 for wind and 0.42 for solar; and, for regulation, *f/CF* is 0.03 for wind and 0.06 for solar. The high value for solar is a result of its low annual capacity factor and the constant ratio of flexibility requirement to VR capacity. Each value F_i^j represents a constraint for the optimization model.

Generation Characteristics

Each generation type is constrained in its ability to provide the four services. These constraints include: ramp rates, minimum generation, the ability of a generator to provide peaking service, and availability factor. For dispatchable generators, availability limits the total commitment across all four services in a year including the need to account for typical maintenance. Availability factor for VR supplies is equal to capacity factor. Highly flexible generators, such as natural gas fired units, are assumed to ramp up to 80% of their rated capacity in an hour while traditional baseload generators, such as coal, are assumed to ramp up to 20% of rated capacity. Maximum regulation commitment is constrained to 0.167 (*i.e.* 1/6) of the maximum ramping commitment consistent with the 10 minute time frame of regulation used by many balancing authorities [12]. Table 3- summarizes the assumed limits of each generation technology.

Table 3-1: Limits on the production from each generator type. Annual availability factor is the maximum energy output over the year. Minimum generation is the minimum percentage of installed capacity that must be dispatched if a generator is being used in a time step. Maximum ramping and regulation commitments are the percentages of installed capacity that can be committed to providing ramping and regulation in a time step.

Technology	Annual Availability or Capacity Factor (%)	Minimum Generation (% capacity)	Maximum Ramping Commitment (% capacity)	Maximum Regulation Commitment (% capacity)	Maximum Peaking Commitment (% capacity)
Coal	85	70	20	3	100
Coal with CCS	85	70	20	3	100
SCGT	92	20	80	13	100
CCGT	87	50	80	13	100
CCGT with CCS	87	50	80	13	100
*Storage hydro**	Varies	10	80	13	100
*Hydro***	20/47	10/70	80/30	13/6	100
*Wind***	33/27	0	0	0	0
*Solar***	17/20	0	0	0	0
Geothermal	92	40	20	3	100
Biomass	83	70	20	3	100

* - Storage hydro is treated differently than other generators.

** - Values differ between provinces. The first value is for Alberta, the second for BC.

Costs

Costs for all generators as well as coal and natural gas prices are taken from the US Energy Information Administration (EIA) 2015 Annual Energy Outlook [136]. The capital cost for an expanded BC-Alberta intertie is assumed to be $820/kW based on the cost of recent high-voltage transmission lines in the region [130].

Cost reductions over time are included for maturing technologies (*i.e.* CCS, wind, and solar). The model assumes that production from VR can be curtailed at no cost. Ramping operation and maintenance cost (Ramping O&M) is the cost to provide flexibility services and is defined as a function of the capacity committed to flexibility service. The capital, fixed O&M, variable O&M, and ramping O&M cost for each generator type are given in Table 3-.

Table 3-2. Cost of different generator types. All costs are from the US EIA [136] except for ramping O&M which is from [137].

Technology	**Capital Cost 2015 ($/kW)**	**Capital Cost 2050 ($/kW)**	**Fixed O&M ($/kW-yr)**	**Variable O&M ($/MWh)**	**Heat Rate (MJ/kWh)**	**Ramping O&M ($/MWh)**
Coal	N/A	N/A	29.62	4.47	8,800	2.45
Coal with CCS	6102	5442	63.11	8.44	10,700	2.45
SCGT	631	631	6.69	10.37	10,800	1.59
CCGT	956	956	14.60	3.27	7,050	0.64
CCGT with CCS	1947	1713	30.20	6.44	7,530	0.64
Hydro	2492	2492	13.42	0	0	0.59
Storage hydro	N/A	N/A	13.42	0	0	0.59
Geothermal	2301	2301	95.00	0	0	3.34
Biomass	3540	3540	100.35	27.9	0	3.34
Solar	1541	1389	23.46	-	-	-
Wind	1861	1770	37.57	0	0	-

In addition to ramping O&M, generators committed for flexibility services incur costs on the energy produced. As a result, energy provided by ramping and regulating generators is more expensive than for the same generator providing baseload. The total variable O&M cost (excluding fuel cost), $C_s^{T\ O\&M}$, for each generator in each time step is given in Equation 10:

$$C_s^{T\ O\&M} = C_R^{O\&M} + \alpha_s^{VR} C_{BL}^{O\&M} \qquad (10)$$

Where $C_R^{O\&M}$ is the ramping O&M cost, $C_{BL}^{O\&M}$ is the variable O&M cost for baseload production, and subscript *s* is the service provided (ramping or regulation). α_s^{VR} is the ratio of energy provided by a flexibility-committed generator to the capacity-hours committed; it is 0.18 for ramping and 0.47 for regulation.

Regional Electrical Systems

The model optimizes the capacity expansion and dispatch of the integrated BC-AB electricity systems and the intertie connecting them. The regional generation mixtures are initialized for year 2015 based on the existing generators and intertie capacity. A schematic representation of the model is given in Figure 3- where the technology options for the BC and AB regions are on the left and right respectively. Besides the intertie connecting BC and AB there is also an intertie between BC and the neighboring US market known as MidC.

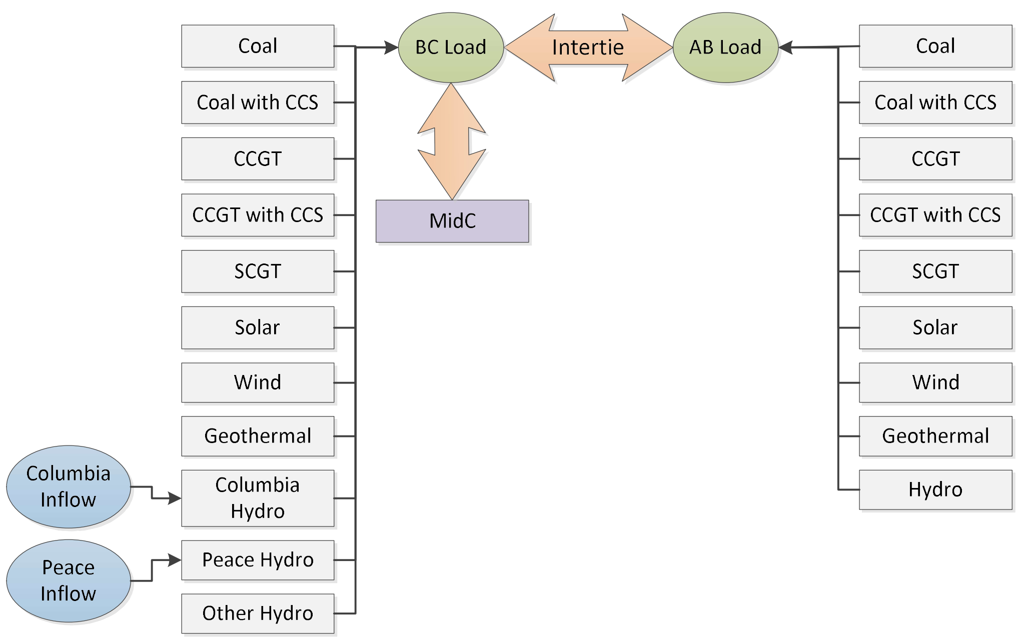


Figure 3-4: Schematic drawing of the BC-Alberta electricity system model. CCGT refers to combine cycle gas turbines, SCGT refers to simple cycle gas turbines

Two cascaded hydroelectric systems are modelled in the BC region: (1) the Peace River, containing the G.M. Shrum, Peace Canyon and, beginning in 2024, Site C generating stations[1]; and, (2) the upper Columbia River, containing the Mica and Revelstoke generating stations. The combined capacity of these generators is 3.46 GW for the Peace River, increasing to 4.56 GW with the addition of Site C, and 5.17 GW for the Columbia River. As of 2014, the Peace and Columbia systems together serve approximately 50% of the BC energy demand. This share varies from year to year depending on natural inflow, energy demand, and market conditions in neighbouring jurisdictions [10]. The remaining hydroelectric generators in BC, referred to as non-storage hydroelectricity, do not have significant seasonal storage capacity. These generators can provide a limited amount of flexibility but are otherwise non-dispatchable. Reservoirs for these generators are not explicitly modelled. Instead, their output is specified seasonally following historical output patterns in the same manner as used in [130].

The BC system is connected to the Mid-Columbia (MidC) electricity market through a 3.5 GW interconnection. The MidC market is the principal electricity trading hub for the Pacific Northwest, which includes BC and the states of Washington and Oregon. The MidC market is further connected to other trading hubs around the western US and northern Mexico. The MidC market and adjoining regions are modelled as a trading node where BC can buy and sell energy at a predetermined price. This price is based on historical patterns of the MidC market, as described in Section 2.4.

Table 3- presents the installed capacity of generators by type in British Columbia and Alberta for the initial year 2015. With the exception of storage hydroelectricity and BC-US intertie, new generators of any type can be built.

[1] The Site C dam is current under construction with an expected in-service date of 2024.

Table 3-3. Installed capacity by generator type in British Columbia and Alberta as of 2015.

Technology	British Columbia [GW]	Alberta [GW]
Storage hydro	8.63	0
Non-storage hydro	5.06	0.89
Wind	0.55	1.45
SCGT	0	1.00
CCGT	0	1.70
Cogeneration	0	4.63
Coal	0	6.29
Biomass	0.45	0.40
BC-US Intertie	3.5	0
BC-Alberta Intertie	0.76	

The natural gas price forecast from the Annual Energy Outlook is used to inform the MidC price forecast. Historic monthly economic heat rates for MidC are determined by comparing average daily MidC prices [138] to AECO C natural gas prices [139]. The relationship between these two prices has been consistent over the past five years, with some year-to-year fluctuation related to hydroelectric energy availability. It was also found that the MidC economic heat rate increases in July of each year (i.e. after the peak freshet). The model uses an economic heat rate of 8,650 MJ/kWh from January to June and 11,200 MJ/kWh from July to December for MidC electricity.

Forecasts for hourly demand are taken from BC Hydro's most recent load forecast [90] and the Alberta Electricity System Operator's long-term outlook [133]. This data is extended to 2060 assuming constant growth rates based on the final ten years of the forecasts. Flexibility service requirements (*i.e.* ramping and regulation) are based on the load profiles of BC and Alberta in 2015. Peaking, ramping, and regulation are assumed to increase at the same rates as energy demand in the two jurisdictions respectively.

Carbon policies implemented in the model represent those currently in effect in BC and Alberta, both of which currently have carbon taxes of $30/tonne. In addition, Alberta is assumed to provide Renewable Energy Credits (RECs) for wind and solar generation with a constant value of $25/MWh. This value is based on a previous study that assessed the subsidy needed to incent widespread renewable energy capacity expansion [140]. Finally, the use of coal for electricity generation in Alberta is forbidden from 2030 onward [6]. Alternate carbon policies and technological development pathways are not explored.

The model presented here is able to represent the effects of increasing VR generation on the electricity system over the long term. These effects will impact both the buildout and operation of the electricity system. In this following section, we describe the effects of flexibility requirements as they pertain to the BC-Alberta electricity system.

Results

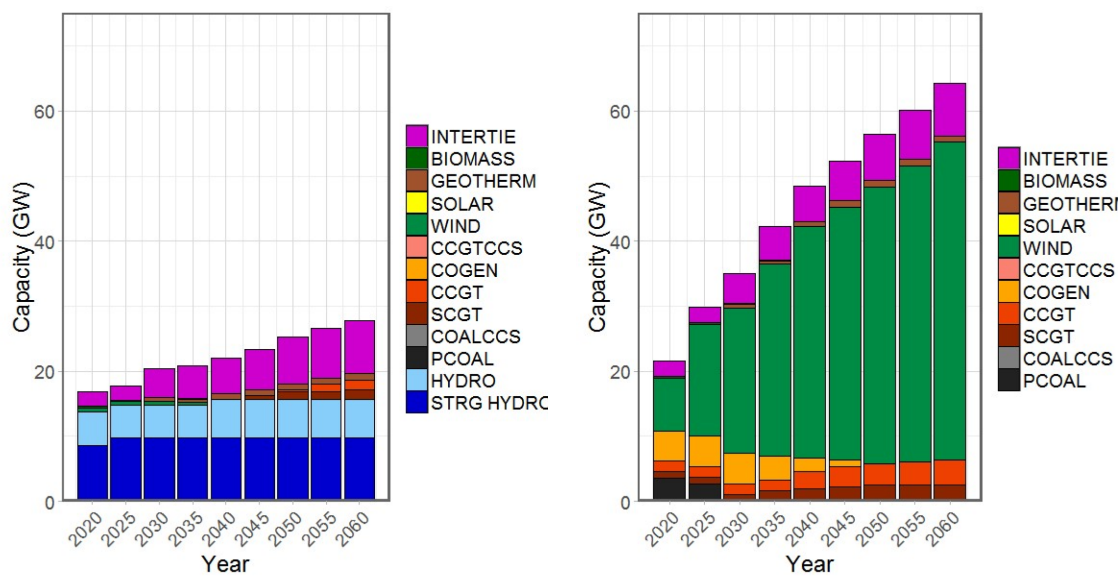
The combined regions of BC and AB are optimized over the period 2015 to 2060. Results are presented to show the cost-optimal transition from today's electricity system to a future low-carbon system, driven by current carbon policies. Installed capacities by generation type are shown in Section 3.1. The energy production and flexibility commitments by generator type are shown in Section 3.2. The commitment of the intertie and BC's storage hydroelectric generators is shown in Section 3.3.

Installed Capacity

The generation mix in BC, shown in Figure 3-5(a), does not change significantly over the model period. The two major additions are Site C, which is included in storage hydro, and the intertie expansion. Later in the model period, there are small additions of geothermal and combined cycle gas turbine capacity.

Alberta's generation mix, shown in Figure 3-5(b), has a major expansion of wind capacity over the model period, reaching 48.1 GW by 2060. Despite this growth in VR generation, Alberta's fossil fuel generation capacity decreases only slightly. Coal is eliminated by 2030, as mandated by the provincial government (Province of Alberta 2016). Cogeneration is slowly phased out and is eliminated by 2050. Coal and cogeneration are replaced by combined cycle gas turbines and a smaller amount of simple cycle gas turbines. Although natural gas fired generators have high operating costs, this is offset by their flexibility and low capital cost.

Intertie capacity between the two provinces increases from 0.75 GW in 2015 to 7.93 GW in 2060. Intertie capacity, as a fraction of annual average load, reaches 30% in 2046 and remains constant thereafter. This expansion is driven by the cost reductions enabled by trading services between the provinces.



(a) (b)

Figure 3-2: Installed capacity by type in (a) British Columbia and (b) Alberta from 2020 to 2060

3.2 Production by Source

Figure 3-74 shows energy production by generation type to provide each baseload and peaking energy from 2020 to 2060 for BC and Alberta. Figure 3-7 shows the unit commit by type to provide ramping and regulation over the same period. Note that the y-axes in Figure 3-74 are different than those in Figure 3-7 Energy service graphs show the energy generated in TWh. Flexibility service graphs show the capacity committed to providing these services in units of TW-h. The difference between these two units is subtle: energy refers to the actual energy generated, while commitment refers to the amount and duration of the commitment, not necessarily to actual production from a generator.

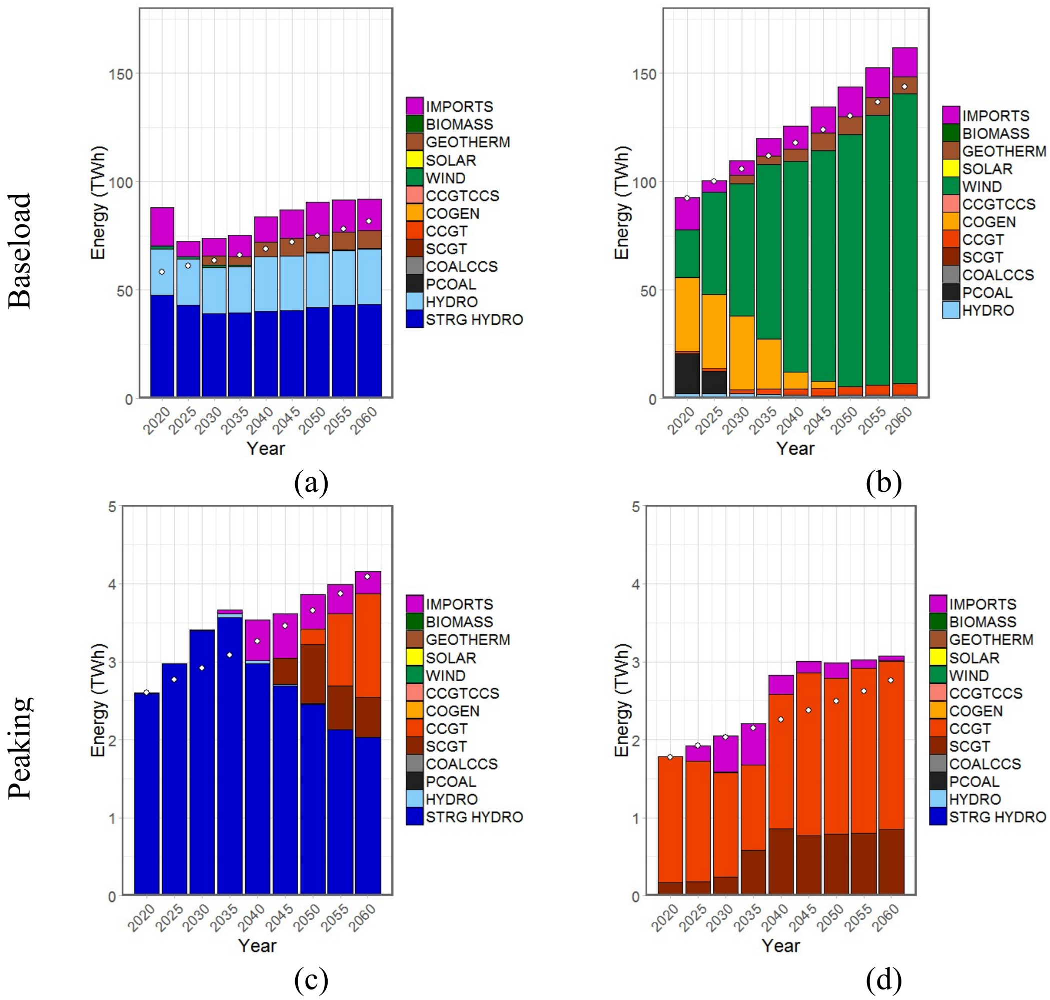


Figure 3-63: Energy production by generator for each demand in BC (left) and Alberta (right). Dots indicate service requirements based on load not including flexibility requirements from VR generation. Generators are stacked following the order in the legend.

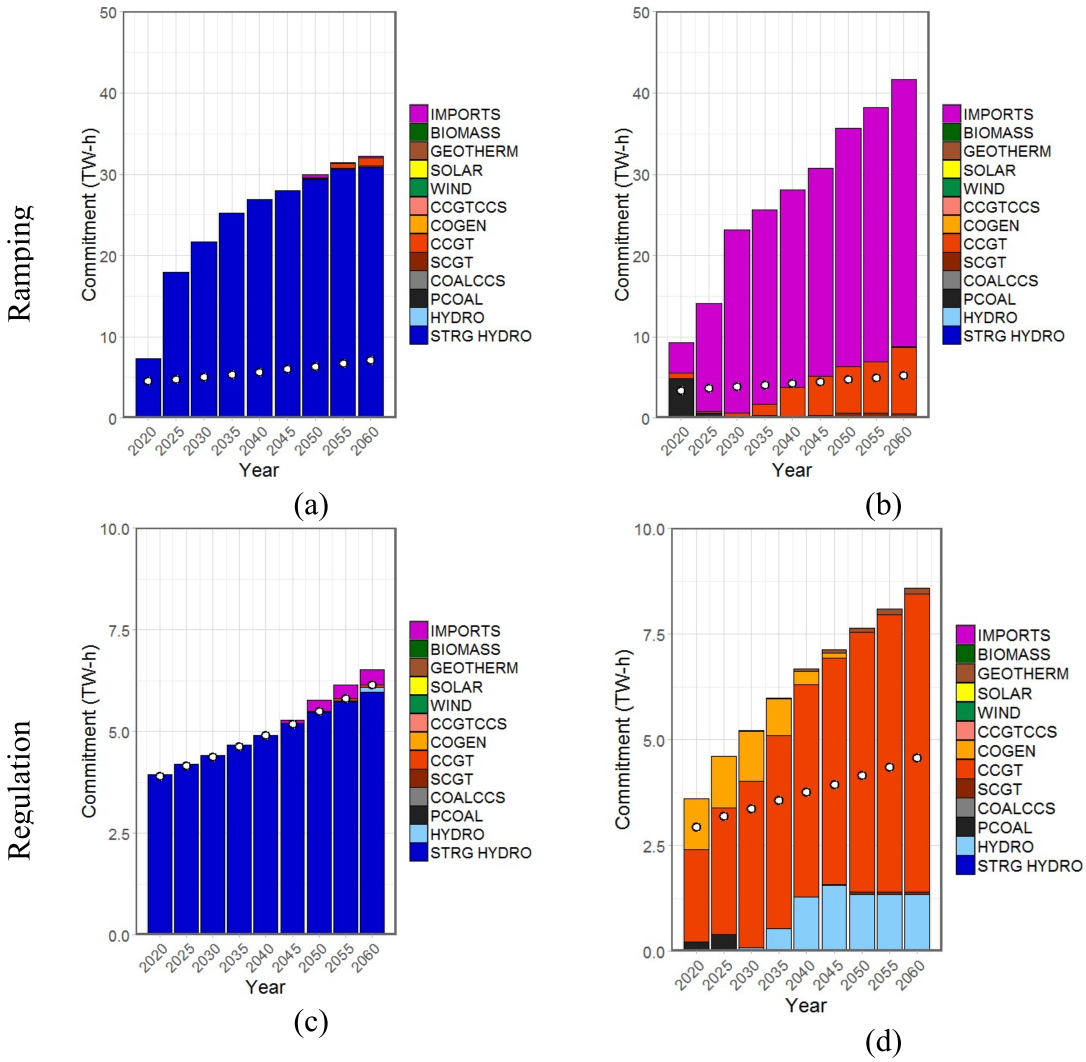


Figure 3-74: Unit commitment for flexibility service by generator for each demand in BC (left) and Alberta (right). Dots indicate service requirements based on load not including flexibility requirements from VR generation. Generators are stacked following the order in the legend.

Baseload in BC, shown in Figure 3-74(a), is met primarily by hydroelectricity throughout the model period with the introduction of small amounts of geothermal generation at the end of this period. In Alberta, shown in Figure 3-74(b), there is a switch from the current energy mix, led by large amounts of coal generation, to one dominated by wind with a smaller amount of cogeneration. Energy is traded between BC and Alberta at different times of the year, as indicated by baseload imports in both provinces. BC remains close to net-trade neutral over the model period, with a slight trend towards net exports. Alberta begins as a net importer and transitions to net exports, beginning in 2050.

Peaking service in BC, shown in Figure 3-74(c), is met by storage hydro with some contribution from gas turbines and imports after 2040. Peaking service in Alberta, shown in Figure 3-74(d), is primarily met by both combined- and simple-cycle gas turbines. Both provinces also trade peaking generation at different times, with the most notable occurrence being Alberta's import period from 2025 to 2040.

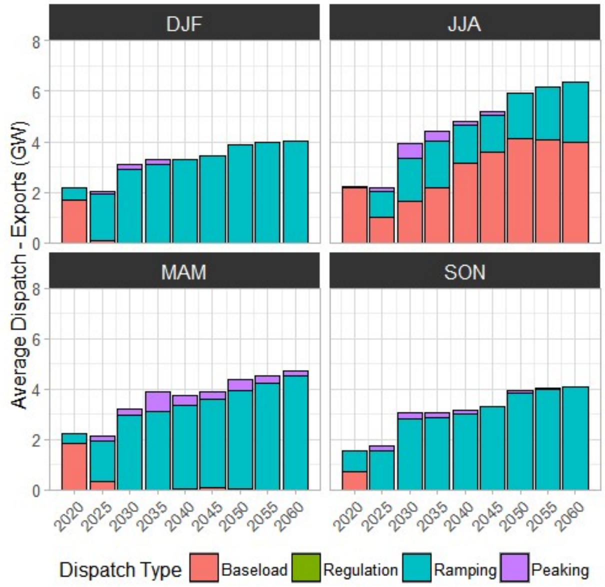
Ramping commitment in BC, shown in Figure 3-7(a), exceeds domestic needs with surplus commitment transmitted to Alberta. A fraction of these imports is used to meet the ramping requirement from load, while the remainder is consumed supporting wind variability. In 2060, 77% of ramping commitment supports variable renewables. This requires an extra 42 TW-h of ramping commitment, corresponding to 4.6 TWh of baseload energy.

Regulation commitment has a similar but less drastic growth. BC provides this service with storage hydro while Alberta primarily uses CCGT and cogeneration with small contributions from coal and in-province hydroelectricity. Unlike the other services, regulation is not significantly traded between the provinces. This implies that the economic and opportunity costs of trading regulation service are greater than those of trading peaking and ramping. Alberta's 8.6 TW-h of regulation commitment corresponds to 4.1 TWh of baseload energy. In total, 6% of Alberta's baseload energy in 2060 is provided by flexibility-committed units.

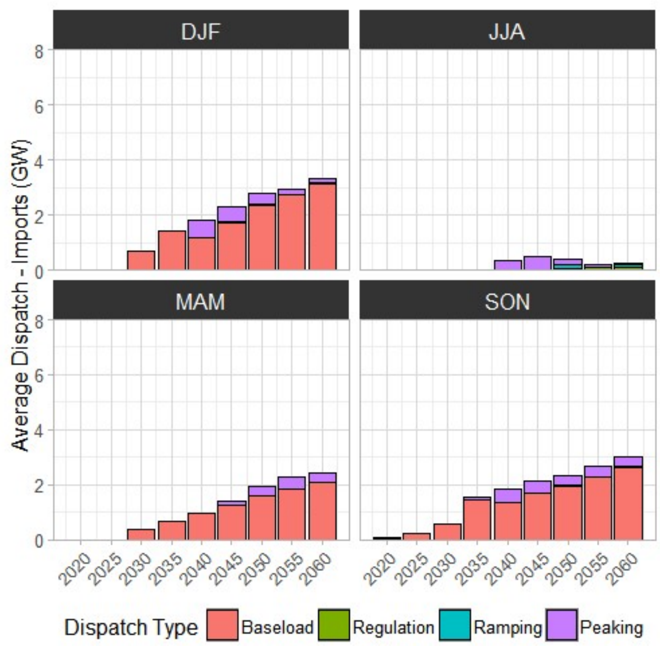
In the near-term, the modelled results for baseload and peaking agree closely with historical data from BC and Alberta [12]. Less data is available for ramping, which is not a traded energy service, and regulation, for which AESO publishes annual data. For regulation – the model commits gas-fired generators as opposed to the actual hydroelectric commitment [12]. This difference is because Alberta's hydroelectric facilities are not modelled as storage hydro facilities. This means that providing flexibility service would lower the amount of energy these units could produce annually. Instead, the model commits more expensive natural gas generation, which has excess capacity.

Intertie Commitment Pattern

Commitment of the intertie varies significantly among seasons. Figure 3-8 shows the average commitment of the BC-Alberta intertie by service type from BC to Alberta and from Alberta to BC in each season. Note that this plot shows intertie commitment, not energy.



(a) Exports

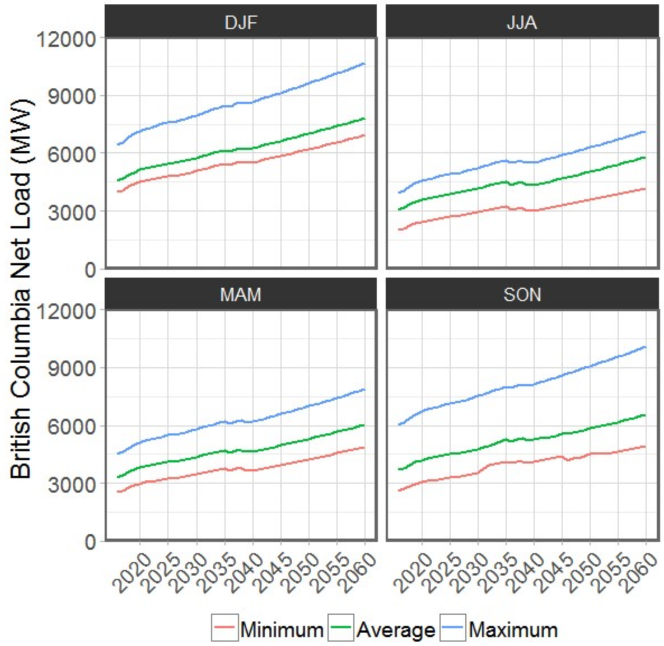


(b) Imports

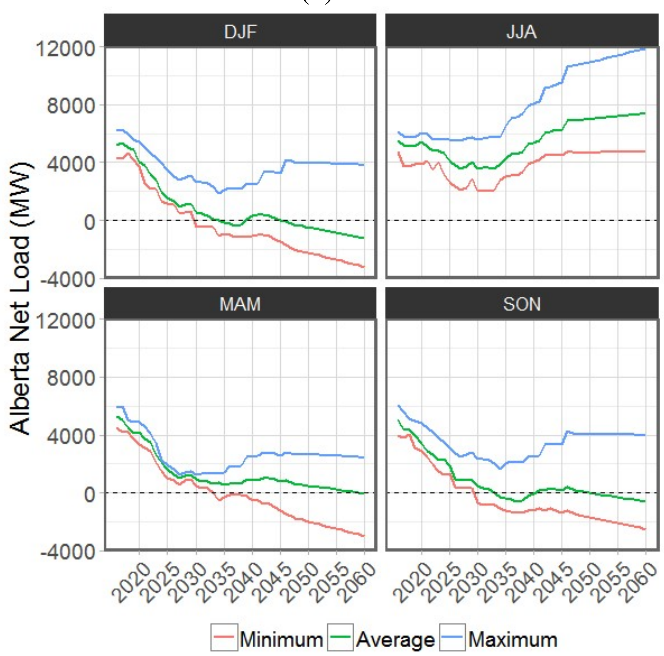
Figure 3-8: Commitment pattern of intertie flows from (a) BC to Alberta and (b) Alberta to BC. Commitment is shown for winter (DJF), spring (MAM), summer (JJA) and fall (SON).

BC exports, shown in Figure 3-8(a), consist of ramping commitment during the fall, winter, and spring and a mix of baseload and ramping during the summer. In return, Alberta exports baseload energy to BC during the spring, fall, and winter. Net intertie commitment remains heavily skewed towards BC exports over the model period. However, because only a fraction of this commitment is used for energy, Alberta exports more baseload energy than it imports beginning in 2050.

This intertie use pattern is a result of the changing annual net load. We define net load for a region as the demand less must-take supplies. For BC, net load is domestic baseload requirement less production from non-storage hydroelectricity; for AB net load is the domestic baseload requirement less production from cogeneration and VR (in this case, wind.) Minimum, average, and maximum seasonal net loads are shown in Figure 3-9 (a) for BC (b) for AB.



(a)



(b)

Figure 3-9: Seasonal net load patterns in (a) BC and (b) Alberta. Lines indicate the minimum, average, and maximum net load. Net load is shown for winter (DJF), spring (MAM), summer (JJA) and fall (SON).

Alberta net load becomes negative during the fall, winter, and spring seasons beginning in 2030 and remains negative for the rest of the model period. This change is caused by winter peaking of wind generation and low electricity demand in the spring and fall. BC imports excess energy from Alberta where wind capacity factors are high, and does not experience negative net loads. BC's lowest net load occurs in the summer when hydroelectric generation is at its peak and load is at its minimum.

The intertie commitment pattern is driven by these seasonal net load patterns. Initially, BC exports both energy and ramping to meet Alberta's needs. As Alberta expands wind generation, the flow of energy reverses with BC importing energy from Alberta during times of low or negative net load. In return, BC exports ramping capacity to Alberta to meet ramping requirement from load and VR production. BC also exports baseload to Alberta during the summer, when BC's net load is at its lowest and Alberta's is at its highest.

Discussion

Renewable Penetration

The results of this study indicate that high penetrations of renewable generation are attainable with current technology and current carbon policies through regional integration. For the model scenario, with a combined region, the market share of wind generation for energy production (both baseload and peaking) reaches 56% in 2060, with 31% of energy provided by hydroelectricity and 7% by geothermal.

This expansion of renewable generation results in a decrease in emissions from 49.3 Mt/yr in 2015 to 5.0 Mt/yr in 2060. While this reduction is significant, it does not meet the reductions outlined in Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, which targets emissions from electricity generation between 0 and

6 Mt/yr nationally by 2050 [8]. This finding suggests that further policy and/or technological changes are necessary to reach a zero-carbon electricity sector.

This buildout of VR capacity requires system flexibility. In this case, flexibility is provided by existing storage hydroelectricity in BC and an expansion of the BC-Alberta intertie. In 2060, storage hydroelectricity provides 79% of ramping commitment and 41% of regulation commitment in the two provinces combined. Storage hydroelectricity is particularly well suited to this role because its energy production is typically limited by water availability rather than installed capacity. This means that the reduced energy production caused by providing flexibility rather than baseload can be offset by higher production at other times. By contrast, a thermal generator has a higher opportunity cost when providing flexibility, as it necessarily lowers the generator's annual energy output.

The large-scale buildout of renewable generation causes a shift in the makeup of system costs as outlined in Table 3-. In 2015, capital costs are zero because the cost of existing generators are sunk. In 2020, non-variable (*i.e.* capital and fixed) costs account for over half the total system cost. This is predominantly driven by the large buildout of wind in Alberta. By 2060 fixed O&M and capital costs combine for 81% of all system costs. This suggests that, although the higher variability in generation will increase maintenance costs, as discussed by Ueckerdt et al. [122], most of the cost of decarbonizing the electricity system will be in building and maintaining clean energy sources. The shift from variable to fixed costs could necessitate shift away from energy-only markets to encourage investment in flexible generators, as discussed in [54], [141], [142].

Table 3-4: Cost breakdown of electricity generation in 2015 and 2060. Capital costs are amortized over the life of the generator.

Year	Cost Component (% of Annual System Cost)				
	Fuel	**Variable O&M**	**Carbon Tax**	**Fixed O&M**	**Capital**
2015	54%	28%	3%	14%	0%
2025	23%	12%	11%	20%	35%
2060	11%	7%	2%	25%	56%

Net Load Changes

The high penetration of wind generation in Alberta lowers net load significantly over the model period. Beginning in 2030, Alberta experiences time steps with negative net load, as previously shown inFigure 3-. During these times, Alberta exports its excess baseload energy to BC, displacing baseload generation from storage hydroelectric generators.

Although, by 2060, wind provides 58% of combined baseload energy in BC and Alberta, and non-storage hydroelectricity provides another 11%, there is no time step in which production from these non-dispatchable generators exceeds the combined baseload requirement of both provinces. This is due to the complementary seasonal profiles of these two resources: hydroelectricity peaks in the summer and wind peaks in the winter. If these two resources were to peak simultaneously their combined output would exceed the load in the two provinces, necessitating curtailment.

The annual pattern of net load in BC and Alberta, shown in Figure 3-, follows the same patterns as hydroelectric and wind production. BC's net load is lowest in the summer (JJA) driven by concurrent high hydroelectric production and low load. Alberta's net load is lowest in the winter (DJF) when its wind capacity is producing at its peak. These seasonal differences provide value to the intertie between the provinces.

Comparison to Previous Studies

This study expands on previous work that has studied the decarbonisation of Alberta's electricity sytem alone [143] or alongside British Columbia [130]. Both of these previous works found that low carbon baseload generation, represented by coal with carbon capture and storage, is ultimately selected to provide large amounts of energy. By contrast, in the present study we find that this baseload component can be provided by wind at lower cost, even after accounting for flexibility requirements.

Implications for Other Jurisdictions

While this study focuses on the BC-Alberta power system, the methods and findings has implications for other jurisdictions as well. One such implication is that, in systems with very high VR penetrations, dispatchable generation must exist not only meet a fixed reserve margin but also to provide sufficient flexibility. Flexibility requirements can be readily met by natural gas or hydroelectric generators, but less so by traditional baseload generators like coal and nuclear plants. In this study, cogeneration, which is more efficient but less flexible than CCGT, is phased out in favour of more flexible but costly generation. This is in contrast to recent energy-and-capacity-only studies that find low-carbon baseload generators (*e.g.* nuclear or coal with carbon capture) are prevalent in decarbonized energy systems [130], [144]–[147].

While zero carbon energy is economical under today's carbon policies and technologies, a lack of zero carbon flexible capacity prevents full decarbonisation of electricity generation. In 2060, peaking, ramping, and regulation commitment are equal to 18%, 32%, and 7%, respectively, of average baseload production. However, in energy terms these services account for only 3%, 3%, and 4% of production. Carbon free technologies that are economical under low capacity factor operation and that can manage frequent, steep ramps in output are necessary to fully decarbonize electricity generation. These technologies may include hydroelectricity, as shown in this study; energy storage, as explored in [67], [72], [73], [148]; by adopting zero-carbon fuel sources for fast-ramping generators [149]; through the use of demand response [150], [151], or by equipping conventional generators with carbon capture [152].

In this study, the intertie between BC and Alberta is used primarily to transmit ramping commitment, as shown in Figure 3-. This trade of ramping commitment is enabled by BC's large hydroelectric storage capacity. Another use of the intertie, which is applicable to jurisdictions without storage hydroelectricity, is to transmit surplus VR energy between the provinces. This interconnection enables the development VR sources with complementary seasonal profiles as there is a wider pool of resources from which to choose. This resource diversity reduces net load variations, particularly at long time scales, as explored in [77], [124]. For BC and Alberta these resources are hydroelectricity and wind. Other regions may have similar resource complementarity such as complementary wind profiles or solar and wind production.

Despite its decreasing cost, solar generation is not installed during the model period. This is, in part, a result of solar's high daily output range. Solar generation changes from full capacity to zero output over the day while wind generation is more evenly spread over the day. Solar generation thus requires more capacity in backup generation than the same amount of wind generation. While previous studies have found that hydroelectricity can provide this backup capability, the results of this study suggest that the flexibility of existing hydroelectric generators is better used to provide flexibility for wind rather than solar. This may change in regions with better solar or worse wind resources where the lower cost of energy offsets the higher backup capacity requirement. More significant reductions in solar capital cost may change the specific mixture evolution; however, it is unlikely to impact the main findings regarding the need for flexibility.

Model Limitations

In the later stages of the model period, Alberta frequently exports baseload energy to BC at the same time as BC is exporting ramping flexibility to Alberta. In the model, this requires intertie capacity equal to the sum of these components. As a consequence, the actual required intertie capacity and, by extension, the intertie cost would be less than is indicated in the model because the same intertie capacity would provide both services. However, the capital cost of the intertie is a small fraction of total model costs (<1%), so this effect likely does not significantly affect the results.

As modelled, wind generation in Alberta is less expensive than wind generation in BC. This is a reflection of the operation of current wind generators; generators in Alberta typically have a higher capacity factor than those in BC. However, given the large buildout of wind in the model results, it is likely that some of the wind generation installed in Alberta would be more economically placed in BC. Moving a portion of this generation into BC would reduce the disparity in net load and flexibility requirements between provinces, although total requirements would remain unchanged. This would result in reduced need for intertie capacity. Addressing this question would require a spatially resolved supply stack for wind, a topic of future work.

This study is based on a single forecast for the price of fuels and technologies over the model period. Changes to these forecasts could impact the outcomes of the optimization. For example, if the price of solar panels falls more than expected, solar may begin to displace or supplement wind generation. Widespread adoption of solar PV in the US could also change the price of electricity at the MidC market. These changes could impact the ultimate generation mix of the electricity system.

In the model the flexibility requirement for VR production is defined as a constant fraction of VR energy. As more VR generation is adopted, geographic diversity may result in a flatter generation profile, thereby lowering flexibility requirements, as shown in [153] and [154]. However, because the flexibility requirement of VR generators depends heavily on the VR production profile in a region, this ratio is very location-specific and could be higher than estimated in studies from other regions. Increasing this requirement would increase the capacity required to provide these services, and therefor increase the role of natural gas generators. Similarly, a lower requirement would reduce the amount of natural gas generation required.

The time steps used in the model lose some of the short time scale variations in load and generation. One important implication of this is that overgeneration is often smoothed away. For example, even if VR generation exceeds load for many of the 274 hours that make up an average time step, the model does not curtail VR generation unless the average VR generation is greater than the average load. Accurately modelling curtailment is an important addition to be added in future studies.

Despite these limitations, the model used in this study provides an improved representation of the long-term expansion and operation of an electricity system compared to energy-and-capacity-only studies. The four services approach used here provides more resolution of the electricity system than treating electricity as a single service. A key implication of this improved representation is that the complementarity of hydroelectric and VR production, which has been previously shown in short-term studies only [40], is sufficient to incent transmission expansion to link these resources. Additionally, the four-service model used here captures the value of flexibility. As a result, instead of low-carbon baseload generators being a major driver of decarbonisation, as presented in [130], [144]–[147], the results of this study indicate that a combination of VR and flexible generation is optimal.

Conclusion

This study investigates the cost-optimal transition of a thermal-dominated electricity system to a renewable-dominated system through carbon policies and increased interregional transmission. Recent studies have shown that interregional transmission can be used to mitigate some of the negative effects of VR generation, particularly net load variability. Using a long-term optimization model we show the potential for transmission between BC and Alberta to enable high levels of wind generation under current carbon policies.

The model used in this study includes flexibility requirements in addition to the traditional energy and capacity constraints found in many energy systems models. This inclusion allows the benefits of fast ramping generation, and the limits of VR generation, to impact investment and dispatch decisions. As the system switches to a VR-dominated generation mix these factors have increasingly large effects. In the long-term, the need for flexibility results in more efficient but less flexible generators being replaced by those that are less efficient but more flexible.

Although the results show deep decarbonization occurring over the model period, the system never reaches a zero-carbon level. This is a result of the need for flexible generation to offset the variability in VR production. While hydroelectricity provides some of this flexibility, there is insufficient hydroelectric capacity to meet the needs of a high-VR system. Existing hydroelectric generators are supplemented by a combination of SCGTs and CCGTs providing peaking, ramping, and regulation services. In order to completely decarbonize the electricity sector, technologies to provide flexibility services and the policy and market environment to support these technologies are necessary.

The expanded intertie allows flexible generators in one province to provide flexibility services in both provinces. This allows lower cost flexible generators, such as hydroelectricity, in one region to offset the need for more expensive flexibility in the neighbouring region. At the same time, the intertie allows renewable resources with complementary profiles, such as summer-peaking hydroelectricity and winter-peaking wind generation, to be traded between regions, allowing higher penetrations of renewables than would otherwise be possible. These two value components, flexibility and resource complementarity, mean that interregional transmission can, in some cases, provide more services at lower cost than local options such as fast-ramping generators and resource diversification.

Chapter 4 - The Role of Hydroelectricity in Highly Variable Electricity Systems

Variable renewal electricity sources such as a wind and solar require flexibility from conventional generators to respond to fluctuates in their output to maintain energy balance. The flexibility will become increasingly important as the level of variable renewable generation increases to meet climate targets. The degree to which flexibility will impact electricity system expansion and operations will depend on the characteristics of local load and available renewable resources. In this study we develop a model to parameterize the variability caused by variable renewable generation and include it as a factor in a long-term capacity expansion and dispatch model. This allows the variability of renewable energy sources to be more accurately incorporated into long-term system plans. Using this method, we demonstrate that high levels of wind penetration are attainable in the BC-Alberta electricity system by leveraging existing hydroelectric resources. Even so, to reach a fully-decarbonized electricity system, additional zero-carbon flexibility resources will be required. This chapter will be submitted as a standalone publication in a journal to be determined.

Introduction

Switching from fossil fuels to variable renewable (VR) energy in the electricity sector is a key step towards meeting climate change mitigation targets. However, the seasonal, diurnal, and hourly fluctuations of VR generation present a significant and growing challenge as systems migrate toward higher VR energy penetrations. Managing these fluctuations is critical to achieving deep decarbonisation of the electricity sector.

Perversely, as traditional dispatchable generation is replaced by VR generation, the capacity available to manage these fluctuations is reduced. In the literature, energy storage is the often proposed as a solution this problem. In one study of California, it was found that storage capacity equivalent to nearly a quarter of the average daily energy demand and 115 GW of renewable generation capacity is needed to reach an 85% penetration of renewable generation [73]. Another study of western North America found that storage effectively levels the diurnal pattern of solar generation in decarbonisation scenarios that incentivize high levels of solar penetration [155]. However, storage is not necessarily economically beneficial in an energy system, as at least one study found that its benefits do not outweigh its costs when used to provide flexibility [128].

Previous studies have examined the variability of 100% renewable electricity systems in which hydroelectricity is available to provide flexibility. For example, Olauson et al. optimize the generation mix in the Nordic power system for minimum net load variability [77]. By deploying an optimal mix of geographically separated wind, solar, wave, and tidal generation, net load variability in the Nordic countries is reduced such that it can be balanced by existing hydroelectric generators. However, increasing the amount of VR generation can also lead to more frequent oversupply events and financial losses in systems with high levels of hydroelectricity [64].

Hydroelectricity has also been studied as means to provide flexibility in support of VR energy in California [40]. This study divides California's hydroelectric resources into must-run, daily, and seasonal components; each component having the ability to shape generation on a different time scale. The dispatch of hydroelectricity is then adjusted by the model to minimize the occurrence of VR curtailment. The study finds that optimally dispatched hydroelectricity can reduce VR curtailment significantly in a high VR system. Other studies present similar results for the eastern United States [41], South Africa [37], and Europe [39]. In these studies, hydroelectric generation is optimized to maximize the revenue of hydroelectric generators or to minimize curtailment of renewables.

The studies discussed above [37], [39], [77], [156] use short-term models to show that hydroelectricity can play an important role in providing flexibility in a decarbonized electricity system. However, in long-term economic optimization models, such as in [43], [153], [157]–[159], hydroelectricity is often treated as a generator with a fixed dispatch schedule. In this representation, hydroelectricity is a pre-defined block of energy that cannot be optimized. This assumption can lead to underestimation of the flexibility of systems with hydroelectric generators and, by extension, overestimation of the need for fast-ramping generation or storage. No studies have been identified in which hydroelectric resources are co-optimized with the dispatch and expansion of the electricity system so as to meet the flexibility needs of high-VR systems.

In this work, we examine the use of existing hydroelectric resources to provide both energy and flexibility over the duration of a long-term system expansion. We use a long-term cost-optimization model to determine both the dispatch of hydroelectricity and the addition of new resources. We identify the roles to which hydroelectricity is best suited in a decarbonizing electricity grid and, by extension, identify roles that are better served by other technologies, such as energy storage.

For this study, we developed a linked simulation-optimization model that represents the variability of VR generation and the ability of hydroelectricity to manage this variability. The model works in two steps. In the first step, the net load profile of the electricity system is simulated and, from this, curtailment and system flexibility requirements are determined. These requirements are then input to a long-term optimization model. The optimization model determines the optimal expansion and dispatch of the electricity system over a period of 45 years.

We examine the evolution of an electricity grid from a current hydro-thermal mix to a future hydro-renewable mix from 2015 to 2060. The neighbouring Canadian provinces of British Columbia (BC) and Alberta are used as a case study. Interconnection expansion between the provinces is allowed, as previously explored by English et al. [130]. The transition to renewables is driven by current carbon policies, *i.e.*, a carbon tax of $50/tonne and a renewable energy credit of $25/MWh applied to wind and solar generation [6].

Our study expands on the work in Chapter 3 that implements flexibility constraints in the OSeMOSYS energy systems model. This previous study finds that BC's hydroelectric resources can provide services in support of Alberta's flexibility requirements, in a deep decarbonisation scenario featuring massive expansion wind generation in Alberta. Here we build on this work by improving the representation of flexibility requirements and expanding the hydroelectric representation to include facilities without large storage capacities. In contrast to Chapter 3, which used published figures to estimate ramping requirements, in this study we calculate the flexibility required to match both typical and extreme ramping events. In the following sections we describe the linked simulation-optimization model, present the optimal expansion and dispatch results and discuss the implications of these results.

Methods

Electricity Services Representation

In this study, we represent the load on the electricity system in terms of two *energy* services and four *flexibility* services. The demand for each of these six services is defined for each of 32 *time steps* in a year. The method for including flexibility constraints in the optimization model is based on the methods developed in [81] and used in Chapter 3. This approach captures the variable nature of electricity demand and VR generation while avoiding the computational demands of high temporal resolution in the optimization model. The six services used are described below.

The two energy services are: *baseload*, which is the average energy per hour during a time step, and *peaking*, which is the energy in the highest load hour of the time step, less the baseload level. Peaking energy represents short-term energy needs that are typically met by capacity reserves [22] while baseload represents the average energy requirement of the system.

In addition to baseload and peaking energy services, four *flexibility services* are defined, each of which meets a particular category of *ramping events*. Ramping events are defined as hourly changes in net load, i.e. demand less production from non-dispatchable sources. The magnitudes of all up-ramping events in Alberta during the winter of 2015 are shown in Figure 4-1, plotted in order of increasing magnitude. Also shown in the figure are the 50th and 95th percentile up-ramping events, P_{50}^{UP} and P_{95}^{UP}, respectively. P_{95-50}^{UP} is defined as the difference in between the magnitudes of the 95th and the 50th percentile ramping events.

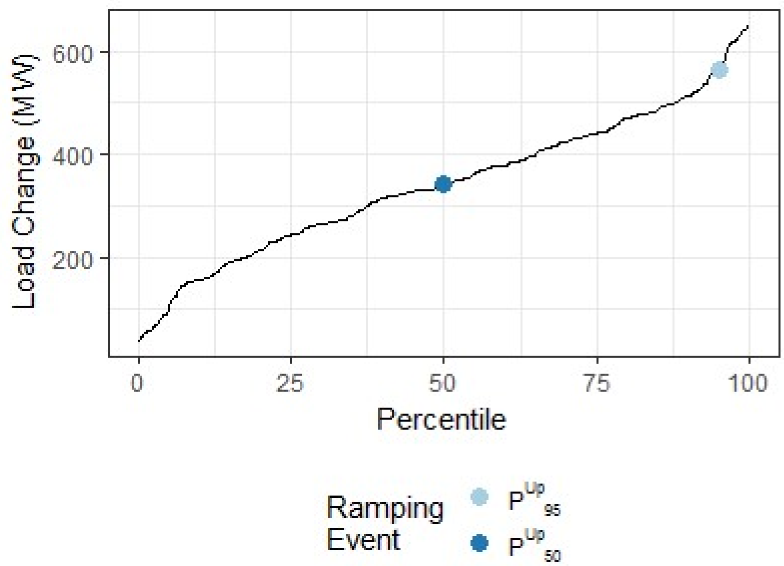


Figure 4-1: Hourly net load changes are sorted by magnitude. The 50th percentile of net load increases represents the $\boldsymbol{P_{50}^{UP}}$ demand. The difference between in 50th and 95th percentile represents the $\boldsymbol{P_{95-50}^{UP}}$ demand

Flexibility services are defined in terms of the magnitudes of the 50^{th} and 95^{th} percentile up and down ramping events, as show in Table 4-1.

Table 4-1: Flexibility service requirements definitions

Designation	**Definition**
$\boldsymbol{P_{50}^{UP}}$	Magnitude of 50^{th} percentile of up-ramp
$\boldsymbol{P_{50}^{DOWN}}$	Magnitude of 50^{th} percentile of down-ramp
$\boldsymbol{P_{95-50}^{UP}}$	Magnitude of 95^{th} percentile up-ramp minus magnitude of 50^{th} percentile up-ramp
$\boldsymbol{P_{95-50}^{DOWN}}$	Magnitude of 95th percentile of down ramp minus the magnitude of 50th percentile of down ramp

In the optimization model, variable renewable generators require an input of flexibility to produce energy. In this way, variable renewable generators and fuel-fired generators each consume a resource, fuel and flexibility respectively, to produce electrical energy. Flexibility service requirements are based on hourly changes in net load in each timestep.

The demand for flexibility service, $P_N^{UP/DOWN}$, is the *N*th percentile of either up or down ramps of provincial electricity demand less generation from variable renewable generators.

The definition of flexibility service requirements as a function of VR generation serves two purposes. First, it ensures that flexibility is provided only when VR generators are producing energy (i.e. solar generators do have a flexibility service requirement at night). Second, this definition enables the optimization model to capture the effect of changing VR capacity. For example, the optimization model can choose to reduce the amount of VR generation to reduce ramping requirements.

For the purposes of the model, variable renewable generation is linked to flexibility service requirements, $F_{P(F,T)}$, defined as the ratio of the flexibility service requirement to VR generation, as shown in Equation 2. $F_{P(F,T)}$ is defined for each of the flexibility services, *F*, and generation technology, *T*, shown in Table 4-1.

$$F_{P(F,T)} = \frac{P_N^{UP/DOWN}(\Delta L_{Net_T}) - P_N^{UP/DOWN}(\Delta L_{Gross_T})}{E_T} \qquad (2)$$

Here, the net load, L_{Net_T}, is calculated as the gross load, L_{Gross}, minus renewable generation from generation technology *T*. Changes in load, $\Delta L_{Ne\ T}$ and ΔL_{Gross}, are calculated for each hour in the year. E_T is the average VR generation over the year in MW for each generation type *T*. The flexibility requirement of each VR generation type is represented by the flexibility coefficient, $F_{P(F,T)}$.

When no energy is produced in a time step (*e.g.* from solar during the night), the flexibility service requirement is zero. If there is no VR capacity in a year, the flexibility service requirement is calculated as though there were 1 MW of capacity to avoid dividing by zero.

The flexibility service requirement is dependent on the correlation between ramps in VR generation and ramps in load. If VR generation ramps down while load is increasing, the magnitude of the net load change increases. Conversely, if VR generation ramps up while load is increasing, the magnitude of net load change decreases. Additionally, different levels of VR penetration can lead to different flexibility service requirements. For example, if a small wind farm increases production as load is increasing, net load variability is reduced; a large wind farm with the same generation profile could result in a reversal of net load change from increasing to decreasing, thereby increasing net load variability. This is demonstrated in Figure 4-2.

Figure 4-2: Net load profile for a sample day in Alberta with no wind (gross load), 3 GW of installed wind, and 10 GW of installed wind. With 3 GW of installed wind capacity, the load increase during the evening ramp-up is eliminated. Using the same wind profile but increasing the installed capacity to 10 GW, the evening ramp-up is replaced by a larger magnitude ramp-down.

The optimization model is constrained to meet all four flexibility service requirements in each time step. To do this, the model must balance the additions and dispatch of variable renewable and conventional generators. This modelling strategy allows representation of many of the complex trade-offs that are characteristic of systems with high penetrations of renewable energy.

The optimization model is initially run using a single value for each flexibility coefficient, based on Brouwer et al. 2014. The net load profile based on the resulting capacity mix is calculated for each year. The simulation model determines updated flexibility coefficients, $F_{P(N)}$, for each flexibility service requirement and generation type for each year. The optimization model is then re-run using the updated flexibility coefficients. VR generation and flexibility coefficients are recalculated until the results converge. Convergence is defined as less than a 1% difference in net present costs between successive runs. This process is illustrated in Figure 4-3.

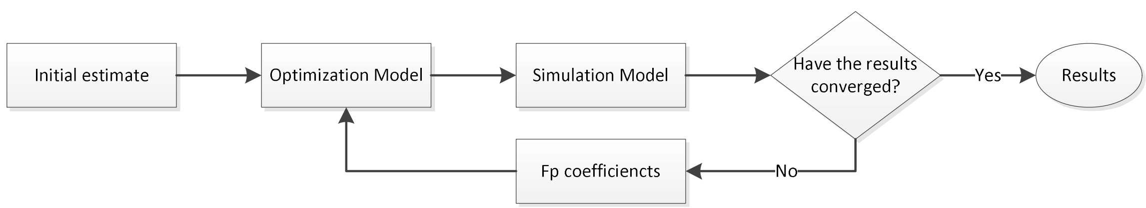


Figure 4-3: Flow chart of the optimization and simulation method used in this chapter

For this study, flexibility service requirements are determined using the hourly load and wind generation profiles from 2015, solar generation profile from an average meteorological year, and hydroelectric generation from an average hydrological year.

Hydroelectric Representation

In the optimization model, each river is modelled separately as a series of reservoirs and generators. Each reservoir receives natural inflows in addition to inflows from upstream dams. The energy available from these inflows is proportional to the height of the dam. Hydroelectric operations are constrained by minimum and maximum reservoir levels, minimum and maximum flow rates, and maximum capacities of hydroelectric generators.

Three rivers are modelled explicitly, the Peace, Columbia, and Pend d'Oreille. These rivers have the largest developed hydroelectric resources in western Canada, together accounting for 58% of the electricity generating capacity and 66% of the annual production in British Columbia. The reservoir volumes and generation capacities on each of these rivers are shown in Table 4-2. Reservoir volume is defined as the volume difference between the highest and lowest allowable reservoir levels.

Table 4-2: Characteristics of modelled hydroelectric generators [102], [103], [160]

		Reservoir Size (Mm^3)	**Specific Energy (GWh/Mm^3) at 80% efficiency**	**Capacity (GW)**	**Annual Local Inflow (Mm^3)**
Peace	*GM Shrum*	39,472	0.41	2,914	33,543
	Peace Canyon	286	0.11	736	0
	*Site C**	166	0.13	1,100	2,592
Columbia	*Mica*	14,800	0.52	2,805	18,204
	Revelstoke	173	0.38	2,980	7,309
Pend d'Oreille	*Seven Mile*	46	0.14	848	21,972
	Waneta	0	0.17	785	0

**The Site C dam is under construction with expected completion in 2024.*

The Peace and Columbia hydroelectric systems both have reservoirs that can store several months of inflow. These reservoirs provide significant operational flexibility to downstream generators. Inflows, which peak during the spring and summer, can be stored until the winter when inflows are low and load is high.

By contrast, the Pend d'Oreille reservoir can store inflows for no more than approximately 16 hours. This small storage volume means that any inflow must be used on the same day that it arrives. However, the reservoir does provide the ability to shift inflows from the night to the day, or to match generation to hourly or sub-hourly variations in load and VR generation.

In addition to these seven facilities, there are smaller generators throughout BC and Alberta. These generators are limited by constraints such as minimum river flows, limited storage capacity, and conflicting water demands (*e.g.* recreation). Rather than modelling each generator individually, these small hydroelectric facilities are aggregated by province. These aggregated generators have a fixed dispatch schedule defined by historical average generation. The dispatch schedule for these generators is provided in the supplementary materials.

Generation Characteristics

Each generation type can be dispatched to provide one or more services in each timestep. In this paper we refer to the capacity from generators providing a service as being *committed* to this service. For example, a P_{50}^{UP}*-committed* generator is dedicated to providing P_{50}^{UP} service, while a *peaking-committed* generator is dedicated to providing peaking service. Total annual commitment of each generator type is limited by annual availability factor. Generators are further constrained in each time step by maximum capacities that can be committed to each of the flexibility services. These constraints are summarized in Table 4-3.

Table 4-3: Constraints on generator dispatch by generation type. CCGT refers to combined cycle gas turbines, SCGT refers to simple cycle gas turbines, and CCS refers to carbon capture and sequestration

Technology	Annual Availability Factor (%)	Maximum Ramp Up Commitment (% capacity)	Maximum Ramp Down Commitment (% capacity)	Maximum Peaking Commitment (% capacity)
Coal	85	20	20	100
Coal with CCS	85	20	20	100
SCGT	92	80	80	100
CCGT	87	80	80	100
CCGT with CCS	87	80	80	100
Storage hydro	--	80	80	100
Hydro	20/47	80/30	80/30	0
Wind	33/27	0	0	0
Solar	17/20	0	0	0
Geothermal	92	20	20	100
Biomass	83	20	20	100

Non-VR generators can operate in one of six *modes*. Each mode corresponds to one of the six electricity services defined above. Each generator type can be fractionally committed across multiple modes in each time step (*i.e.* a generator can commit 50% of its capacity to baseload and 50% of its capacity to P_{95-50}^{UP}). When operating in a mode corresponding to one of the four flexibility services, a generator also provides baseload energy. This is because a flexibility-committed generator also to provides energy to meet ramps in load. For example, a P_{50}^{UP}-committed generator will be called upon to provide energy whenever net load is increasing. The energy generated to meet increasing net load is classified in the optimization model as baseload energy.

The simulation model also calculates the net load in both provinces as the gross load minus generation from VR generators, as shown in Equation 2. For hours in which net load is negative (*i.e.* VR generation is greater than load), the simulation model has the option to export surplus energy to the neighbouring province. BC also has the option to export energy to the United States. If excess generation cannot be exported, either because of insufficient intertie capacity of lack of load in the neighbouring province, it is curtailed. In hours when curtailment is necessary, the three VR generation types are curtailed in proportion to their available generation in that hour.

In the optimization model, VR generator output is limited by a maximum capacity factor in each time step. This capacity factor is calculated in the simulation model alongside flexibility service requirements. The maximum capacity factor is defined by the historical capacity factors of VR generation in 2015. VR generators can curtail at no cost in each time step.

For each generator type, capital, fixed, variable, and fuel costs are shown in Table 4-4. Variable costs depend on the commitment of the generator with flexibility commitment being more expensive than baseload. Capital cost reductions between 2015 and 2050 are included for maturing generation types such as wind and solar. Capital, fixed and operation costs are taken from [136] and flexibility O&M is taken from [137].

Table 4-4: Generation costs by generation in Chapter 4

Technology	Capital Cost – 2015 ($/kW)	Capital Cost – 2050 ($/kW)	Fixed O&M (&/kWyr)	Variable O&M ($/MWh)	Heat Rate (MJ/kWh)	Flexibility O&M ($/MW)
Coal	N/A	N/A	29.62	4.47	8,800	2.45
Coal with CCS	6102	5442	63.11	8.44	10,700	2.45
SCGT	631	631	6.69	10.37	10,800	1.59
CCGT	956	956	14.60	3.27	7,050	0.64
CCGT with CCS	1947	1713	30.20	6.44	7,530	0.64
Hydro	2492	2492	13.42	0	0	0.59
Storage hydro	N/A	N/A	13.42	0	0	0.59
Geothermal	2301	2301	95.00	0	0	3.34
Biomass	3540	6540	100.35	27.9	0	3.34
Wind	1686	1604	37.57	-25	0	-
Solar	2277	2052	23.46	-25	0	-

Results

Capacity Additions

The generation mix in BC remains relatively unchanged over the model period while significant amounts of new generation are installed in Alberta, as shown in Figure 4-4: Installed capacity by type in British Columbia (left) and Alberta (right). Intertie refers to the BC-Alberta intertie. Imports refers to the capacity of the BC-US intertie..

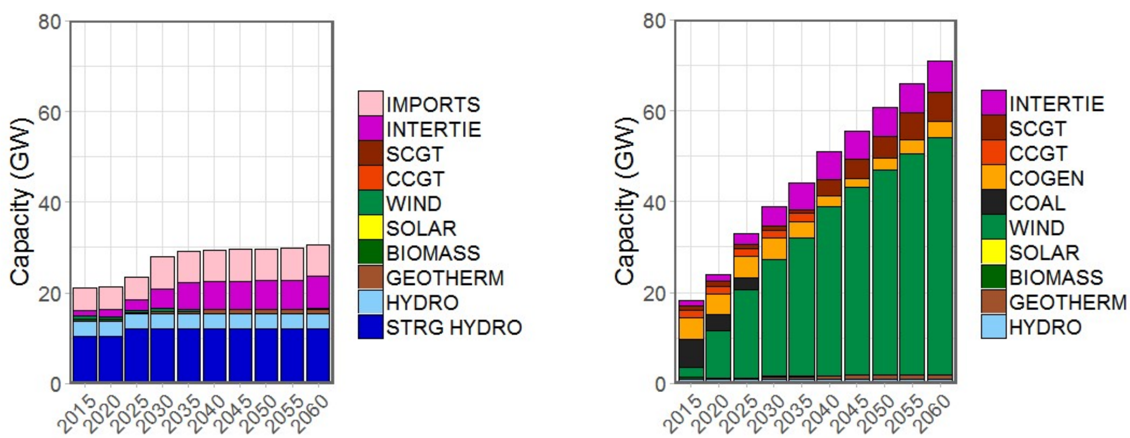


Figure 4-4: Installed capacity by type in British Columbia (left) and Alberta (right). Intertie refers to the BC-Alberta intertie. Imports refers to the capacity of the BC-US intertie.

Over the model period, wind capacity in Alberta grows from 2 GW in 2015 to 57 GW in 2060. This expansion is driven by the decreasing cost of wind energy and policy support for renewable generation (*i.e.* carbon taxes and renewable energy credits). Wind capacity initially expands quickly to replace generation from retiring coal facilities. This expansion then slows to follow load growth.

The BC-Alberta intertie expands from 0.75 GW in 2015 to 6.5 GW in 2037, with a further expansion to 7.5 GW by 2060. This expansion serves multiple purposes. It allows excess wind generation in Alberta to be sold to BC and allows flexibility from hydroelectric generators in BC to meet load changes in Alberta.

Natural gas capacity in Alberta increases slightly from 7.3 GW (1 GW of SCGT, 1.7 GW of combined CCGT, and 4.6 GW of cogeneration) to 8.3 GW (6.9 GW of SCGT and 1.4 GW of cogeneration) between 2015 and 2060. The elimination of CCGT is a result of the low cost of wind (for energy) and SCGT (for flexibility). Today, CCGT provides both baseload energy and a small amount of flexibility. As existing generators are replaced, wind replaces CCGT for baseload energy requirements and a combination of SCGT and hydroelectricity replaces CCGT for flexibility service requirements.

System Flexibility

The increase in wind capacity in Alberta leads to a net load profile in 2060 with larger ramps than in 2015, as shown in **Error! Reference source not found.**5. This figure shows histograms of hourly changes in the BC-Alberta combined net load in 2015 and 2060.

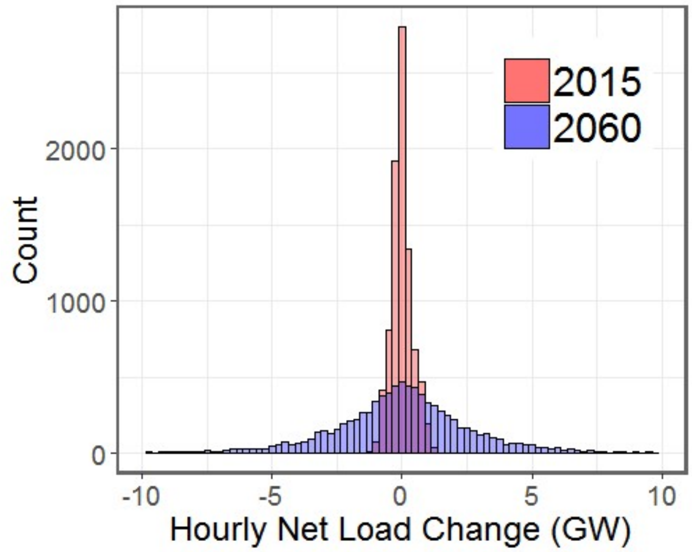


Figure 4-5: Histograms of hourly changes in the combined BC-Alberta net load in 2015 (red) and 2060 (blue). Net load refers to the hourly demand less generation from wind, solar, and small hydro.

As shown in **Error! Reference source not found.**-5, large net load changes are much more frequent in 2060 than in 2015. On an annual basis, the P_{50}^{UP} and P_{50}^{DOWN} increase from 239 MW and 206 MW to 1,439 MW and 1,474 MW, respectively, between 2015 and 2060. By contrast, P_{95-50}^{UP} increases from 905 MW to 5,919 MW and P_{95-5}^{DOWN} increases from 747 MW to 6,123 MW over the same time period. These extreme ramping events are significant constraints on the dispatch of both wind and dispatchable generators.

In the optimization model, the model can choose to curtail wind generation to limit the number of P_{95-50}^{DOWN} events when wind generation ramps up. In this mode of operation, wind is curtailed during rapid increases in output to eliminate the need for P_{95-5}^{DOWN} flexibility. This curtailment reduces the energy output of wind generators as well as the down ramping requirement. Although curtailing wind generation during extreme ramps reduces flexibility service requirements significantly, the infrequency of these ramps means that little energy production is lost. In 2060, curtailment lowers the P_{95-50}^{DOWN} requirement by 33.1 TW-h and wind energy produced by 2.2 TWh. This suggests that curtailing wind generation to limit net load variability can provide a large reduction in flexibility service requirements for relatively modest energy losses.

The annual requirement for each flexibility service is shown in Figure 4-6. This shows the total commitment needed to match variations in net load in each year.

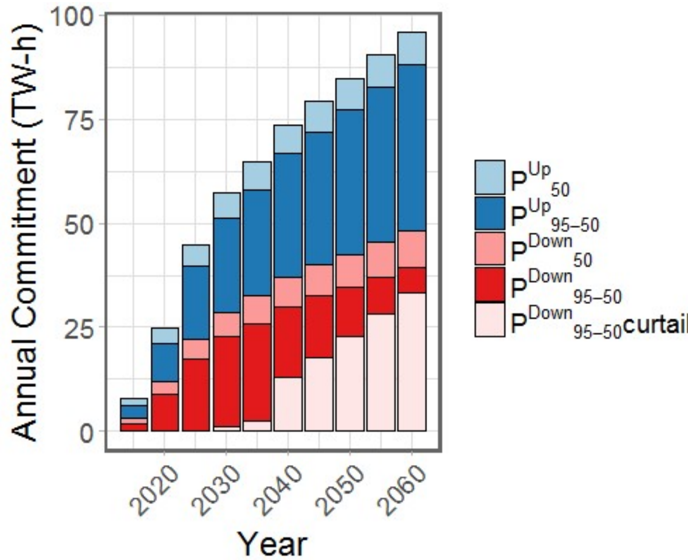


Figure 4-6: Annual commitment requirement for flexibility services in BC and Alberta by flexibility type.

Coincident with the increase in flexibility commitment, there is an increase in energy from flexibility-committed generators relative to current levels, as shown in **Error! Reference source not found.**4-7. As with flexibility commitment, energy from flexibility-committed generators increases rapidly at the start of the model period. After 2035, the decline in P_{95-5}^{DOWN} commitment, shown in Figure 4-6, causes total flexibility-committed energy production to decease, as shown in Figure 4-7. This is because P_{95-5}^{DOWN}-committed generators dispatch off only for extreme ramping events, so their energy generation is high per unit of commitment. By contrast, despite its high commitment requirement, P_{95}^{UP} -committed generators produce comparatively little energy.

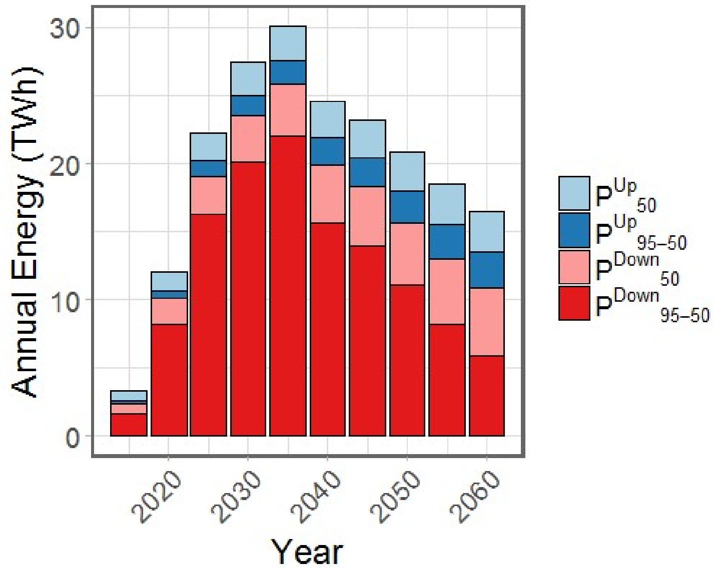


Figure 4-7: Annual energy from flexibility-committed generators in BC and Alberta by flexibility type.

As a fraction of total energy, energy from generators providing flexibility services increases from 4% in 2015 to a peak of 26% in 2035 before decreasing to 14% in 2060. This energy is a significant portion of the annual total with unique constraints on its production. These constraints are not captured by energy and capacity metrics alone, highlighting the value of including ramping constraints in long-term studies.

Hydroelectric Commitment

As described in Methods, we model seven hydroelectric facilities on three rivers. Figure 4-8 shows the annual commitment of these facilities in three groups based on their storage capacity. GM Shrum, Mica, and Peace Canyon are classified as *large* generators. While Peace Canyon does not have significant storage of its own, its proximity to GM Shrum means it benefits from upstream storage such that it behaves like a large storage facility. Seven Mile and Waneta, with very little storage capacity, are classified as *small* generators. Between these extremes are the *hybrid* generators, Revelstoke and Site C. Hybrid generators are downstream from large storage facilities but, unlike Peace Canyon, have local inflows that differentiate their dispatch from upstream dams.

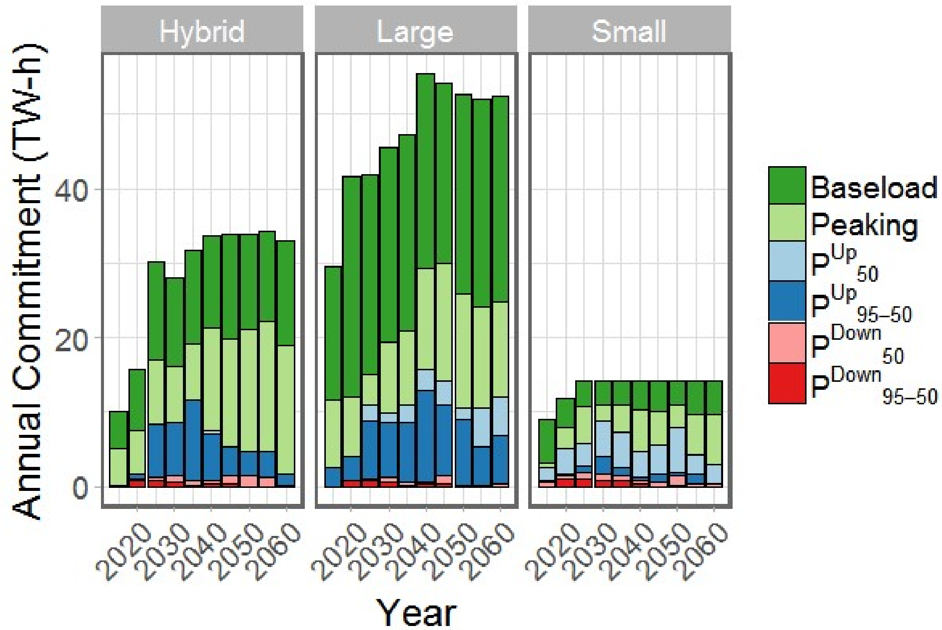


Figure 4-8: Annual commitment by type for storage hydroelectric generators in British Columbia. Generators are aggregated by storage type - large (GM Shrum, Peace Canyon, Mica), small (Seven Mile, Waneta), and hybrid (Site C, Revelstoke)

Hydroelectric facilities optimize the value of commitment in each time step across the six different services. Two factors change the optimal commitment mix over time. First, reservoir inflows increase as a result of climate change, requiring that more water is passed in each successive year. Second, increasing wind penetration increases the need for flexibility services.

In the early years of the modeled period, hydroelectric dams provide all of the P_{50}^{UP} and P_{95-50}^{UP} needs of the system. The majority of P_{95-5}^{UP} commitment comes from the large storage reservoirs, which are capable of storing inflows for use months or years later. This *shaping* allows the dams to store water during the summer, when inflows are high, and use it to provide flexibility in the winter, when wind production is high. Small generators, with less storage capability, focus on P_{50}^{UP} service because this service allows more frequent generation.

Later in the model period, the commitment from hydroelectric generators switches partially from up-flexibility (*i.e.* P_{50}^{UP} and P_{95-50}^{UP}) to peaking, shown in Figure 4-8. This is a consequence of the increasing flexibility service requirement caused by increasing levels of VR generation. Eventually, new generation capacity must be added to provide flexibility commitment. The lowest cost option is to build additional SCGT capacity to provide P_{95-5}^{UP} service. This frees up hydroelectric capacity to serve peaking requirements.

Relative to large and small generators, hybrid generators provide comparatively little flexibility, as shown in Figure 4-8. Instead, these generators primarily provide a combination of baseload and peaking energy. These generators do not have the ability to store water seasonally when providing P_{95-50}^{UP} flexibility, nor do they have a high minimum production level that is characteristic of small generators. Operating between these extremes by providing peaking energy provides the greatest value for the commitment of these dams.

A common feature in the dispatch of all types of hydroelectric generator is the preference for capacity-heavy services, such as peaking and up-flexibility, rather than providing down-flexibility, which has a higher water requirement. This is because, unlike fossil-fuel fired generators, hydroelectric generators have energy-limited production. By focusing on services with low delivered energy, hydroelectric generators are able to get the most value from their capacity.

Discussion

Benefits of Flexibility Modelling

The modelling method in this study improves the representation of variable renewables in long-term energy models. This has recently been highlighted as an area for improvement in energy modelling [31], [161]. This study improves this representation by linking a simple hourly simulation model to an expanded long-term model. This is an evolution of the study presented in Chapter 3, which used a similar flexibility term in a long-term model but did not include a simulation step to determine flexibility service requirements. This previous study also found that hydroelectricity can provide a significant portion of the flexibility needs of the BC-Alberta electricity system. In the present study we examine this finding in more detail, determining the nature of flexibility hydroelectricity is best suited to meet and including hydroelectric generators with lower storage volumes.

At high penetrations of VR generation, a significant portion of the electricity system must be devoted to managing variability. In this study, flexibility service requirements increase significantly at both the P_{50} and $P_{95\text{-}50}$ levels. Other regions with different load profiles and variable renewable resource options may have different flexibility service requirements. The inclusion of the hourly simulation model to determine ramping coefficients ensures that this method is applicable to these regions as well.

The inclusion of variability in the model impacts the expansion plan in Alberta. One example of this is the switch from CCGTs to SCGTs in Alberta. Currently, CCGTs are built because their high efficiency leads to lower energy costs over the life of the plant. However, over time, wind generation replaces CCGTs as a source of energy. While there is still a need for dispatchable generators, the amount energy served by these generators drops. With less need for energy from dispatchable generators, SCGTs are built instead because their lower capital cost is not offset by reduced fuel consumption.

In this study we consider only one hour ramps when determining flexibility service requirements. This could be expanded to also consider longer ramping periods. For example, jurisdictions with high capacities of solar energy may experience several consecutive hours of high ramp events, a phenomenon known as the duck curve. These events could be included in the optimization model as a separate flexibility service.

The flexibility services approach used in this study could also be expanded to account for uncertainty in addition to variability. In this case, the simulation model could be appended to determine the difference between forecast and VR generation levels. Dispatchable generators must be committed to meeting this gap if, for example, expected wind generation does not materialized. Similarly, a generator must be able to reduce its output if wind generation is above forecast levels. These factors further increase the flexibility needs of the electricity system.

Role of Hydroelectricity

Hydroelectricity has previously been explored as a source of flexibility in electricity systems [39]–[41]. The results of this study support this previous research by showing how hydroelectric dispatch can be altered to provide flexibility in highly variable electricity systems. The results expand on these previous studies by showing that including this flexibility in capacity expansion studies can alter the optimal buildout of the system, thereby reducing costs above what could be achieved through dispatch only.

The impact of variability is evident in the commitment pattern of hydroelectric generators. Initially, BC's hydroelectric generators meet 100% of the P_{50}^{UP} and P_{95-50}^{UP}

requirement in both provinces, in addition to 60% of the peaking energy requirement and 33% of P_{50}^{DOWN} requirement. Over time the amount of flexibility service required increases as more wind comes online; this requires some of these demands to be met by other generators. As both the reserve requirements and the other generators in the system change so does the commitment of the hydroelectric facilities. Ultimately, storage hydroelectric generators provide 100% of P_{50}^{UP} commitment, 85% of peaking, 20% of P_{95-50}^{UP}, and 10% of P_{50}^{DOWN}.

The commitment pattern is different for different types of hydroelectric facilities. This is a consequence of the varying energy, and by extension, water use of each service. For example, a generator providing P_{95-5}^{UP} service is only called upon to provide energy rarely, and therefor uses little water. A generator providing P_{95-5}^{DOWN} service is called upon to provide energy in all but the most extreme cases and will use much more water. Facilities with large reservoirs, which are capable of storing months of inflows, provide low-energy services (*i.e.* P_{95-50}^{UP} and peaking energy). Generators with small reservoirs must focus on higher-energy services (*i.e.* P_{50}^{UP}) to maintain water balance. These results highlight the value of even a small amount of storage for providing system flexibility.

Implications for Other Jurisdictions

Although this study presents results for BC and Alberta, the methods and general findings of this study are widely applicable. One such application is the use of flexibility metrics defined by the net load profile in a combined dispatch-expansion model. In this study we focus on the ability of hydroelectricity to meet these requirements. However, other studies could focus on technologies such as energy storage and demand side management; policies, such as incentivising generation with desirable or flexible generation profiles; or strategies, such as diversifying the mix of renewable resources.

The results presented here show that hydroelectricity is capable of providing system flexibility, even for generators with small storage volumes. For example, the two modelled generators on the Pend d'Oreille River (shown as *small* generations in **Error! Reference source not found.**4-8) provide more than 50% of P_{50}^{UP} commitment. This means that this finding is not limited to jurisdictions with large hydroelectric resources like BC but can be applied to those with smaller generators as well.

In this study, wind generation is the primary source of new renewable energy while solar generation is never installed. There are several factors that cause this. Solar generation is summer-peaking, which is anti-coincident with BC and Alberta's winter-peaking loads. Solar also generates larger ramps, which require higher flexibility inputs. This is particularly evident at the P_{50} level because solar ramps occur regularly (*i.e.* daily) whereas wind ramps are less frequent. Finally, solar generation is much more temporally concentrated, which leads to more curtailment events. Combined, these effects mean that a wind-solar mix is more expensive than wind alone given the parameters of the study.

Conclusions

This study introduces flexibility constraints in long-term energy planning through the coupling of a simulation model, which defines how much flexibility is required, with an optimization model, which determines how to best meet flexibility constraints in the context of the entire energy system. This approach allows decision makers to integrate flexibility needs into their long-term planning process. In this study, we use this method to investigate how hydroelectricity can meet flexibility needs in highly variable energy systems.

The methods used provide a base for examining other short-term phenomena in long-term energy models. For example, uncertainty in VR generation can be modelled in the same manner as variability. Including both uncertainty and variability of VR generation will increase the need for dispatchable capacity, potentially impacting system expansion. The method introduced can help quantify how new strategies and technologies for handling flexibility can be implemented as part of the full energy system.

The results show that flexibility service requirements in the BC-Alberta electricity system will increase significantly as more VR generation is added. This is a function of the variable output of wind generation. Flexibility service requirements are partially served by optimally allocating of hydroelectric resources. The ability of hydroelectric generators to provide flexibility is constrained by the capacity, storage size, and inflow pattern of the generator.

In the case of the BC-Alberta electricity system, hydroelectric generators primarily provide flexibility services with a medium energy demand (*i.e.* services where the unit is not providing energy too frequently or too infrequently). These flexibility services correspond to frequent, low magnitude ramping. Thermal generators and curtailment are called upon to provide flexibility in extreme magnitude ramping events. In order to reach a zero-carbon target, new technologies and policies must be in place to provide these services as well.

Chapter 5 – Conclusions and Recommendations

This thesis is comprised of three studies addressing the role of increasing interregional coordination on enabling decarbonization in the electricity sector. Each study uses a long-term energy systems model to analyze the decarbonization pathways of the British Columbia – Alberta electricity system up to 2060, providing both the optimal low-carbon generation mix, and the transition to this generation mix from the status quo.

The first study, presented in Chapter 2, introduces a model of the electricity system based on the OSeMOSYS modelling system. This model is used to analyze the system under a variety of carbon policies, with and without intertie expansion. In Chapter 3, this model is expanded to include constraints on ramping and regulation in addition to energy and capacity. This chapter provides a first understanding of how variability will influence future electricity systems. Finally, Chapter 4 further expands on this theme by including a model to calculate flexibility requirements and incorporating these requirements directly into the optimization. This provides a platform to further understand how to incorporate high levels of variable renewable energy.

Each chapter presents several methodological changes from the previous study. In Chapter 3, in addition to the addition of ramping and regulation demands, there are incremental updates to the costs of new generation, market prices, time steps, and limits of renewable energy capacity. In Chapter 4, additional changes are made to the resolution of the hydroelectric model and the price forecasts for fuel and generators are updated. These updates mean that each study used the most relevant information available at the time; however, it also means that comparisons across chapters are more difficult. One notable example of this is the elimination of wheeling from the US to Alberta between Chapter 2 and Chapter 3, which could be a result of the changing market prices or competition with flexibility services for intertie capacity.

The cumulative effect of the changes between chapters, particularly between Chapter 2 and Chapter 3, result in large changes to the results. Still, the findings of earlier chapters provide useful insights. The potential for carbon leakage identified in Chapter 2 highlight the ability for low-cost generation in the US to be sold into Alberta. In the future, widespread adoption of solar generation in the United States could lead to lower than expected market prices, in which case this generation pattern may occur.

The studies presented here have several common structural uncertainties. Because there is only a single, deterministic forecast of prices, there is potential for these results to change significantly if these inputs change. For example, if the cost of solar is much lower than expected it could replace large amounts of wind generation in Alberta, with impacts on the seasonal and daily variability in net load. The single forecast of wind and water availability also impacts how the system behaves. In years with different inflow and wind characteristics the ability for hydroelectric generation to buffer variability in wind generation may be affected. Finally, the reliance on wind and hydroelectric generation, both of which can vary significantly between years, could result in years of undersupply. Additional work should be conducted to ensure that the system is robust against this possibility.

This thesis presents a study into the ability to decarbonize the electricity system in British Columbia and Alberta; however, electricity is only a portion of the overall energy system. In order to reach a completely low-carbon society it is also necessary to decarbonize other areas such as transportation, the built environment, and industry. Each of these sectors is coupled to the electricity sector such that changes in one area will impact the others. Future models can include the crossover between these industries to investigate the pathways to broader decarbonization.

Contributions

This thesis provides several new insights on how the electricity system can transition to a low-carbon generation mix. As it is focused on the British Columbia and Alberta electricity systems, some of the findings are specifically applicable to this region. These findings include:

- Increasing intertie capacity can reduce the cost of reaching a low-carbon generation mix by allowing lower-cost renewable generation, particularly wind generation in Alberta, to displace higher-cost generation in other regions. This finding is consistent across the studies in Chapter 2, 3, and 4.
- British Columbia's existing hydroelectric resources, when combined with an expanded intertie can be deployed to partially offset the net load variability caused by increasing penetrations of variable renewable generation in Alberta. This is first identified in Chapter 4, with additional details in Chapter 5.
- Reaching a fully decarbonized electricity system will require additional policies and/or technologies to provide additional flexibility beyond what is available from hydroelectric facilities. This could include energy storage, demand response, dispatchable renewable generation, or some combination of these. This finding is explored in Chapter 5.

In addition, this thesis presents novel findings that are applicable to energy systems more broadly:

- Net load variability will be a significant constraint in future energy systems that are dominated by variable renewable generation. As a result, the value of dispatchable generators will shift from their ability to provide energy and capacity to their ability to respond to changes in net load. This is a key finding in Chpater 4 and Chapter 5.

Finally, throughout this thesis new techniques are presented which allow long-term energy systems models to better represent variable renewable generation:

- A new approach for representing the variability of net load under high penetrations of variable renewable energy. This approach was introduced in Chapter 3 and further refined in Chapter 4.
- An improved representation of the price volatility in electricity markets. This was achieved by improving the temporal resolution of the previous cost function. This change allows the value of both dispatchable and non-dispatchable energy to be better represented. This representation is introduced in Chapter 2 and carried through the thesis.
- A way to link entities across regions. Here this is presented as a method to ensure consistent behavior of transmission lines between regions. In future studies, it could be adapted to also represent, for example, weather patterns that move across regions. This was implemented beginning in the study in Chapter 2.

Recommendations

While this thesis enhances the OSeMOSYS energy model to include constraints related to variability of renewable energy generation, there remains room to improve it further. One potential improvement is to adjust the time steps used in the model. For example, the method presented in [162] could be adapted so that representative days, not average days, are used in the long-term optimization. In implementing this method, representative days could be selected based on their load, available renewable generation, and occurrence of ramping events.

Another improvement of the model would be to include uncertainty in variable renewable generation in addition to variability when setting flexibility demands. As currently presented, it is implicitly assumed that any changes in renewable generation output are known well in advance so that the system can be prepared. Adding an uncertainty term would require additional capacity be kept in reserve and, conversely, more energy be sourced from generators with down-ramping capability.

Also valuable would be to add new technologies, such as energy storage and dispatchable loads, that can provide flexibility service. As mentioned in Chapter 4, these technologies could provide services to which the existing hydroelectric system is not well suited. In combination with the improved time slicing and uncertainty representation, this would provide a very strong model for decision makers to evaluate future changes to the electricity system.

In this thesis the intertie is presented as either limited to its current status or expandable *ad infinitum*. In reality, expanding the intertie will involve one or more discrete projects. Each of these discrete projects should be evaluated considering its specific costs and system impacts. It is likely that supporting high levels of interconnection will also require additional transmission expansion within the provinces themselves. A model with greater regional detail could represent these costs.

Additionally, this thesis makes no distinction as to the location of new renewable resources and the transmission required to support it on a provincial level. Representing a diversity of generation locations, along with transmission availability and expansion options, would improve the accuracy of the model. This additional geographic resolution would also allow the effects of resource diversity on the variability and uncertainty of variable renewable generators to be modelled, which could impact the optimal mix of renewables.

Finally, there are factors that impact electricity planning that are not accounted for in the model. One example is the structure of the electricity market. Contrary to the model used in this thesis, which minimizes the total discounted cost of the system, in a deregulated electricity market such as Alberta the least-cost pathway is likely to be sub-optimal for some individual stakeholders. This could be accounted for either by novel additions to the model presented, or by adopting an agent-based model which better represents the electricity market and its participants.

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Appendix

Appendix A – Supplementary Information for Chapter 2

Timeslices

Each modelled year is divided into thirty-six timeslices based on the month of the year and power demand. The *daily off-peak interval* occurs when demand is lower than the monthly median demand, less one-half standard deviation. For the months of June to August and December to February, in which the evening demand peak seen in Figure A-1 is largest, the *daily on-peak interval* occurs when demand is greater the monthly median plus one-half a standard deviation. For the other months, in which the evening demand peak is less defined, the *daily on-peak interval* occurs when demand is greater the monthly median plus one-quarter standard deviation. The *daily mid-peak interval* occurs when demand is greater than that of the daily off-peak interval but less than that of the daily on-peak interval. As an example, A1-1 shows the actual monthly average and modelled daily demand distribution in BC for two months in 2012 [163], [164]. Five annual demand profiles were generated using historical data from 2009 to 2013. These profiles are repeated in order for the entire model period.

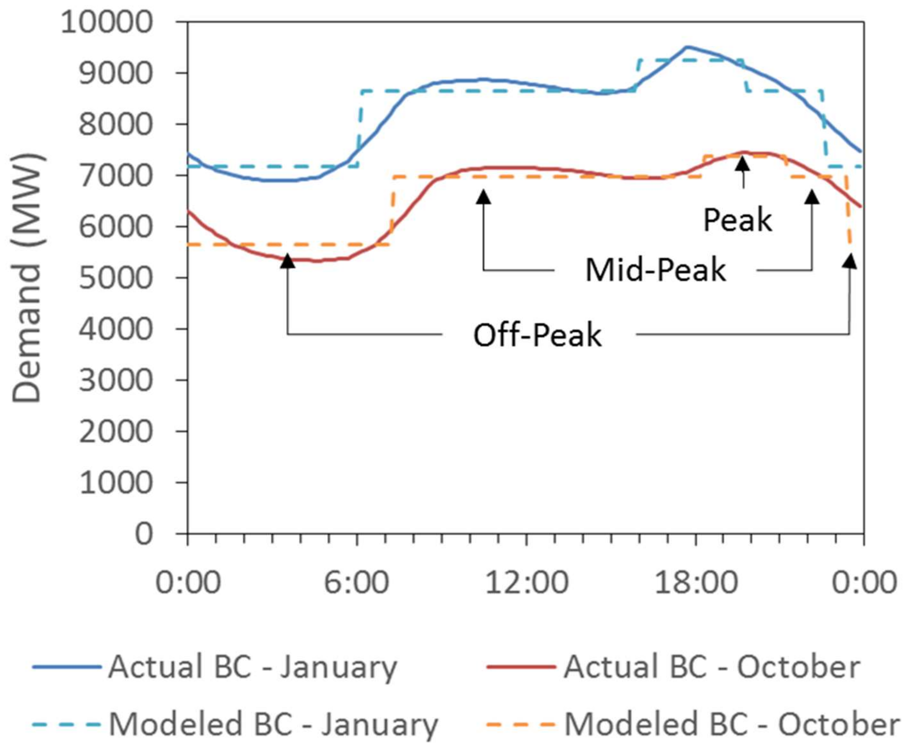

Figure A-1: Actual and modelled electricity demand in British Columbia for a single day in January 2012 and October 2012

Renewable Availability

Limits on the availability of renewable resources are based on estimates by industry groups. These are often focused on short-term capacity expansion and as a result may discount resources with high costs or that are located in remote regions. Renewables can be limited by either their capacity or by their annual energy output.

Table A-1: Maximum capacities and energies of renewable generation technologies

Resource	**Alberta**		**British Columbia**	
	Maximum Capacity (GW)	Maximum Energy (TWh)	Maximum Capacity (GW)	Maximum Energy (TWh)
Small hydro	0	--	1.92[1]	--
Large hydro	--	28.5[2]	14.58[3]	--
Wind	13.2[4]	--	13.2[1]	--
Geothermal	2[5]	--	0.78[1]	--
Solar	--	--	--	--
Biomass	--	2.05[6]	--	9.77[6]

[1] – Sites with a levelized cost of energy less than $150/MWh [165]
[2] – Equal to 50% the technically feasible hydroelectric potential in Alberta [166]
[3] – Assumes no further large hydro developments. Includes the cascaded hydro facilities indicated in Figure 2-4. Energy output from cascaded hydro facilities is based on reservoir volume and water availability.
[4] – Assumes equal capacity potential as British Columbia
[5] – Assumes 2.5% recovery on resources at 2.5km depth [167]
[6] – Based on BC Hydro energy estimates and the relative quantity of forestry byproducts [168]

Generation Characteristics

Costs for generating technologies are based on estimates from the US Energy Information Administration where available. For mature technologies (i.e. all combustion technologies, geothermal, hydro, and biomass) capital costs are fixed over the model period. For wind and solar generation capital costs decrease linearly over the model period at a rate based on estimates from the International Energy Agency [108]. This represents the decreasing cost of these technologies are their technology improves.

Table A-2: Capital, fixed, and operating (including fuel) costs for each generator type. Operating costs shown are for 2010 fuel costs.

Technology	**Capital Cost ($/kW)**	**Fixed Cost ($/kW*yr)**	**Operating Cost ($/MWh)**	**Operating Cost Escalation (%/yr)**	**Capital Cost Decrease ($/kW*yr)**
Coal	2815	29.62	20.35	1.1	0
Coal with CCS	4488	63.11	30.19	1.1	0
SCGT	661	6.69	58.82	2.9	0
CCGT	982	14.60	32.11	2.9	0
CCGT with CCS	1970	30.20	40.38	2.9	0
Cogeneration	1203	14.60	24.89	2.9	0
Large Hydro[1]	2789	13.42	5.96	0	0
Small Hydro[1]	2789	13.42	1.06	0	0
Wind	2207	37.57	0	--	5
Solar	3643	23.46	0	--	49
Geothermal	4144	95.00	0	--	0
Biomass[2]	3908	14.60	26.70 – 110.28	0	0
Mid-C Intertie	--	--	29.84 – 43.65	2.4	0
BC-AB Intertie	820	0	0	--	--

[1] – Variable cost for hydro plants are based on British Columbia water rental rates. This operating cost applies to hydroelectric facilities in BC only.
[2] – Variable cost for biomass plants are based on the BC Hydro Resource Options Report [96]. Fuel cost varies depending on feedstock.

Carbon emissions are accounted for based on the heat rate of thermal generators and the average carbon intensity of their fuels. Only emissions from combustion are considered. Carbon policies are not applied to these emissions. Instead, it is assumed that the cost of power includes the effect of any emissions policy.

Table A-3: Emissions intensity of generator types. Generators not listed here are assumed to have no emissions.

Technology	**Emissions Intensity (t/MWh)**
Coal	0.804
Coal with CCS	0.109
SCGT	0.506
CCGT	0.334
CCGT with CCS	0.040
Cogeneration	0.252
Mid-C Intertie	0.126[1]

[1] – Based on the average emissions intensity of generation in Washington and Oregon [169]. Emissions from Mid-C imports do not count against carbon taxes or caps but are accounted for in scenario comparisons.

Initial Generation Mix

Table A-4: Initial capacity and operating life of generator types.

Technology	**BC Capacity (GW)**	**AB Capacity (GW)**	**Operating Life (years)**
Coal	0	6.29	40
Coal with CCS	0	0	40
SCGT	0	0.96	30
CCGT	0	0	30
CCGT with CCS	0	0	30
Cogeneration	0	3.60	30
Large Hydro[1]	13.38	0.89	100
Small Hydro	0.32	0	100
Wind	0.55	1.09	25
Solar	0	0	25
Geothermal	0	0	40
Biomass	0.45	0.40	20
BC-Alberta Intertie	1.2	1.2	100
BC-US Intertie	3.50	0[2]	100

[1] – Large hydro includes the cascaded hydro facilities included in Figure 2-3

[2] – The 300 MW Montana-Alberta Tie-Line (MATL) is not included in the study because of its small capacity and interaction with the BC-Alberta intertie [170]