

# Canada's power system toward zero-emission targets, planning, operation, and flexibility options

By:

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M.Sc., Sharif University of Technology, Tehran, Iran, 2017

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A Dissertation Submitted in Partial Fulfillment of the Requirements for the Degree of  
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University of Victoria

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We acknowledge and respect the lək'wəḡən peoples on whose traditional territory the university stands and the Songhees, Esquimalt, and WSÁNEĆ peoples whose historical relationships with the land continue to this day.

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## Abstract

Canada has targeted to reduce carbon emissions in the power system by 30% until 2030 compared to 2005 levels. Zero-emission is also targeted for 2050. Many transition pathways can be followed to achieve these targets and are being followed by various regulations. One of the main paths is to incorporate variable renewable energy resources as high wind and solar irradiation potentials are proved Canada-wide. At the same time, other sectors are targeting similar targets which are mainly followed through electrification. Variability inherited from large wind and solar capacities and demand growth and change through electrification burdens power systems from both supply and demand sides. Flexibility is a requirement for the power sector to operate reliably to match variable wind and solar capacities with fluctuation and growing demand. Therefore, flexibility should be considered by policymakers when analyzing the transition toward a decarbonized power system.

This thesis proposes linked frameworks to analyze flexibility issues in the outlined generation portfolios and to study a variety of power system flexibility options on the supply and demand sides. Two different frameworks are developed to interlink the power system capacity expansion planning model, production costs model, and building sector energy simulation model. These frameworks are also applied to analyze effectiveness and impact of the different flexibility options impacting various components of the power system, supply side, network, and the demand side.

In the first iteration, flexibility issues stemming from the transmission system and shortage of storage systems are analyzed in an iterative interlinked model. In response, transmission expansion as costs and supply-side storage capacities as minimum constraints are fed to the expansion planning model. Results show that there are several flexibility issues uncovered by the technically detailed operational model. These issues are resolved by adding transmission and storage capacities to the system, posing the system extra expansion costs to reach a certain level of flexibility. The overestimation of the wind capacities is corrected when accounting for the transmission requirements.

In the second iteration, the generation portfolio is outlined by various scenario inputs for electrified and non-electrified demand, and for zero-emission and non-capped emission scenarios. The outputs are analyzed in the operational model using a one-way linked data transfer for flexibility issues. Impacts from demand-side flexibility options, i.e., demand response, are analyzed using an iterative linked loop between the building sector energy simulation model and the operational model. The results show that the demand response programs have a significant impact on flexibility concluding to integrating more generation from wind and solar capacities. It is shown that a realistic representation of the impacts of demand response on the demand curve can cause some limitations in implementing demand response programs. Compared to supply-side options, demand response is discussed to require lower investment requirements to be implemented and even reduce the need for capital-intensive options on the supply side, like transmission and storage.

In the last iteration, the integration of power systems is considered a flexibility option and assessed through the one-way linked framework of expansion planning and operational model. Input scenarios for transmission cap for systems' integration and electrification in the demand are considered to be the most impactful variables in this study. The results show significant savings in costs and electricity prices by integrating the two selected power systems of Alberta and British Columbia. It is also shown that with the better overall flexibility of the integrated systems, more wind and solar generation can be integrated into the generated output. As hydro is discussed to improve flexibility, the analysis shows that climate change effects on the must-run requirements can impact the efficiency of the delivered flexibility.

Investigating various variables in the transition pathways and their impact on the power system during this thesis shows that there are requirements that should be met in the system in order to maintain the reliability and efficiency of the projected paths. Three different flexibility options is analyzed that fulfill these requirements which showed different impacts on expansion planning and operation of the system in terms of costs and their effectiveness to integrate VRE integration. While supply-side options like storage and transmission expansion options impose additional investment costs, power systems can benefit from lower costs of demand-side options as well as reducing supply-side requirements. Integration as the third option has also proved to have a substantial impact on the enacted costs of transition pathways as well as delivering flexibility. These options ranked in terms of implicated costs and their effectiveness as a high-level conclusion as: power systems integration, supply-side options, and demand side options.

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## List of publications

This dissertation is written based on the following manuscripts:

- I. Mohammad Miri, Mohammadali Saffari, Reza Arjmand, Madeleine McPherson, *“Integrated models in action: analyzing flexibility in the Canadian power system toward a zero-emission future”*, Energy, Volume 261, Part A. <https://doi.org/10.1016/j.energy.2022.125181>
- II. Mohammad Miri, Madeleine McPherson, *“Demand response programs: comparing price signals and direct load control”*, Energy, Submitted, revised once (Sep 2, 2023)
- III. Mohammad Miri, Jacob Monroe, Tamara Knittel, Madeleine McPherson, *“Integrated planning and operation of power systems: Flexibility in high penetration of wind and solar”*, Renewable and Sustainable Energy Transition, Submitted (Aug 28, 2023)

My contribution to the above manuscripts includes conceptualizations, methodology, design, and development of the linking frameworks as represented in the chapters, adding required functionalities and constraints to the models (COPPER and SILVER), testing and calibration of the DESTINEE model, verification and validation of all models as represented in the corresponding section, data collection specifically for the demand projection model in the third chapter, visualization frameworks, data curation, formal analysis, and writing the original drafts.

Dr. Madeleine McPherson did the original conceptualization by writing the application for the research grant. She mentored during the thesis in all chapters and supported the work by supervising, acquiring funding, answering my questions all the way, editing my research writings, and submitting the papers.

Other researchers contributed to this work as their names appear on the authors for each of the papers. Their contribution to the chapters is covered as follows.

- In chapter two, Mohammadali Saffari (PhD graduate of Civil Engineering at UVic) helped to develop the inputs for the national model used in the translation module in the linked framework in this study.
- In chapter two, Reza Arjmand (PhD graduate of Civil Engineering at UVic) helped to incorporate two features into the expansion planning model as the feedback in the iterative loop introduced in this chapter. The first feature is a constraint for the minimum storage capacity. The second feature is a cost adjustment formulation for each VRE location. Running the model, testing it, and validating the features are done further by me in the thesis.
- In chapter four, Tamara Knittel (PhD candidate of Civil Engineering at UVic) helped to formulate the hydro must-run constraints for different hydropower technologies. She also helped in writing a part of the third chapter which describes the methodology. I implemented the constraint into the model and tested and validated the results.
- In chapter four, Jacob Monroe (Post-doc at UVic), helped develop scenarios and run the base planning model for those scenarios. He also helped in editing the manuscript from this chapter.

Other collaborative works:

- IV. Madeleine McPherson, Jacob Monroe, Jakub Jurasz, Andrew Rowe, Richard Hendriks, Lauren Stanislaw, Muhammad Awais, Madeleine Seattle, Robert Xu, Timothy Crownshaw, Mohammad Miri, Dustin Aldana, Moe Esfahlani, Reza Arjmand, Mohammadali Saffari, Tristan Cusi, Kanwarpreet Singh Toor, Joel Grieco, *“Open-source modelling infrastructure: Building decarbonization capacity in Canada”*, Energy Strategy Reviews, Volume 44, 2022

I contributed to this manuscript by providing linkage-related software, a visualization dashboard, writing, and reviewing.

# 1 Introduction

Canada has targeted to reduce carbon emissions in the power system by 30% until 2030 compared to 2005 levels. Zero-emission is also targeted for 2050 [1], [2]. Many transition pathways can be followed to achieve these targets and are being followed by various regulations. One of the main paths is to incorporate variable renewable energy resources as high wind and irradiation potentials are proven Canada-wide.

At the same time, other sectors are targeting similar targets which are mainly followed through electrification. Variability inherited from large wind and solar capacities and demand growth and change through electrification burdens power systems from both supply and demand sides. Flexibility is a requirement for the power sector to operate reliably to match variable wind and solar capacities with fluctuation and growing demand. Flexibility is becoming more important when more variable renewable resources are integrated into the system, as they are dependent on weather conditions and solar irradiation or wind availability.

This thesis aims to explore the different aspects of flexibility, their impacts and issues the lack of flexibility imposes, their sources, and the options that make Canada's power system more flexible so it can adjust quickly to the changes in supply and demand.

This section provides the background, motivation, terms, and scope of this thesis. Other basic terms used in this section and the course of the thesis are explained in detail in Appendix B: Supplementary terms and definitions.

## 1.1 Background and Motivation

Power systems have a crucial role in transitioning toward emission reduction goals from two different perspectives: reducing their emissions and providing clean energy for other sectors. Greenhouse gas emissions in Canada are coming from various sources in different sectors. The electricity sector is ranked 6<sup>th</sup> for having 9% of the share of greenhouse gas emissions [3]. This share is lower compared to the global emissions from electricity generation with the help of hydropower plants which generate more than 60% of electricity for Canadians [4]. Despite the lower emissions, the power sector is targeted to reduce emissions by 50% compared to 2005 levels by 2030 and to become net-zero emissions by 2050 [1], [2].

Various options can be mentioned to be followed to reach decarbonization goals for the power system including but not limited to variable renewable energy, carbon capture, utilization, and storage, nuclear power plants, and energy efficiency. This thesis focuses on variable renewable energy resources as the main option for transitioning Canada's power system toward decarbonization targets because, first, Canada has extensive resources of wind and solar through its vast land. Both technologies have been implemented around the globe and have shown their effectiveness when there is available potential. Several studies have validated the high potential for both wind and solar capacities in a wide range of locations throughout Canada [5]. Other power system planning studies and

Canada's Energy Future also emphasized the role of wind and solar capacities in reaching emission mitigation goals in Canada [4], [6], [7]. In addition, while the environmental impacts of these technologies are discussed in the literature, wind, and solar are proven to have the lowest life cycle impact compared to other options [8].

Second, carbon capture, utilization, and storage technologies are controversial in the literature due to their current limitation of capturing only 90~95% of the emissions and further improvements need extensive energy with current technologies and further research investment [9]. At the same time, utilizing the captured gas can conflict with the goal of this technology. To improve the economic outcome, captured carbon is used in enhancing oil extractions in some cases, which would further fuel other emitting capacities [10]–[12].

Third, nuclear energy comes with safety risks, high costs, and other pollutants, which is also a controversy both in the literature and policies and legislation. There are emerging technologies like small modular reactors, which are yet to become available to mitigate the risks of conventional nuclear plants. However, this technology is not yet commercially utilized, and its availability and costs depend on future research and policy adaptations [13]. In addition, there are ongoing debates about mining uranium in Canada due to their potential environmental and health risks as well as their impacts on the traditional lands of Indigenous communities [14].

Fourth, further expansion of hydro capacities is both capital-intensive and under question due to the possible environmental impacts [15]. The impacts on indigenous lands for the storage of the dams are also debated in Canadian hydropower projects [16]. Finally, studying energy efficiency requires extensive research, demand-side modeling, and analyzing consumer choices, which is out of the scope of the current study.

In conclusion, expanding wind and solar and their requirements are followed for this thesis based on their availability proven by the resource analysis studies, their agreed feasibility in the analyses from the power system planning studies, and mentioned advantages compared to other expansion options.

From the demand side, other sectors which shape the remaining shares of emissions will follow similar emission reduction targets by electrifying their source of energy, e.g., electrifying transportation and buildings [1]. Therefore, the power system should follow a pathway that ensures that the expanded capacities meet the demand growth requirements while keeping the emission mitigation targets.

Canada's power system is going to be expanded to meet the growing electrification needs and being targeted to reduce its emissions simultaneously as policy targets and different future energy studies show [4]. Inherited variability from weather-dependent renewable energy resources and growing and changing electrified demand growth entails flexibility requirements for the power system.

Flexibility in a power system refers to its ability to adjust the supply and demand of electricity in response to changes in real-time conditions [17]. This can include changes in the availability of renewable energy sources, unexpected

variations in demand, or unexpected equipment failures. A flexible power system can respond quickly to these changes by adjusting the generation, storage, and distribution of electricity to maintain a stable and reliable supply [18]. Flexibility becomes increasingly important as power systems integrate more variable renewable energy sources, such as solar and wind power, and as electricity demand continues to grow [19]. A flexible power system can help to ensure that electricity is always available when it is needed, while also reducing costs and minimizing the environmental impact of electricity generation by integrating more variable renewable energy resources [20].

### 1.1.1 Scope of work

Flexibility can be provided through a variety of technologies and solutions. This thesis focuses on a wide range of flexibility options including and impacting different components of the power systems. These options are discussed in the current thesis and each chapter accordingly.

- **Energy storage systems:** Energy storage in power systems refers to the ability to store excess electricity generated by power plants, such as from variable renewable energy sources like solar or wind, for later use when electricity demand is higher or when there is insufficient generation capacity available. Energy storage can take many forms, including batteries, pumped hydro storage, compressed air energy storage, and thermal energy storage.
- **Transmission expansion:** Transmission as a flexibility option in a power system refers to the ability of the transmission grid to adjust the flow of generated electricity to different regions in response to changes in supply and demand. For example, if there is excess electricity being generated in one area, a flexible transmission system can redirect that electricity to another area where there is a shortage of electricity. Similarly, if there is a sudden increase in demand for electricity in one area, a flexible transmission system can quickly adjust the flow of electricity to meet that demand.
- **Integration of power systems:** Integrating power systems can deliver flexibility in many ways. This can lead to greater system flexibility and resilience, as well as more efficient and cost-effective electricity delivery. Integrating power systems can deliver flexibility through the sharing of generation or reserve capacity. By connecting power systems, excess electricity generated in one area can be sent to other areas where it is needed or used in the reserve capacity of one area to meet the demand from the neighboring one.
- **Hydropower capacities:** Hydropower can increase flexibility through its ability to respond quickly to changes in supply and demand balance. These power capacities can quickly adjust the amount of electricity they generate as per their faster ramping characteristics.
- **Demand response programs:** Operators of power systems can incentivize consumers to shift their electricity usage to times when renewable energy is abundant, which reduces the need to curtail renewable energy production. Demand response can also be used to reduce peak demand. By doing so, the reliability

of the power system is improved, and the need for further expansion in generation and transmission capacities can also be reduced.

### **1.1.2 Current research status**

Currently, there is a wide range of studies that discuss different aspects of power systems' transition and their flexibility requirements for integrating large VRE resources. The gaps in the current literature and modeling frameworks can be categorized into methodologies, coverage, and implications in the Canadian domain.

First, methodologies in the literature usually lack the main technical details needed to represent VRE and other assets in the power system [21]. Fine temporal resolution is also required to fully capture the variability of the VRE resources in real-time. However, this is mainly limited due to constraints in computational resources and modeling complexities [22]. This imposes issues such as overestimations in VRE resources in power systems planning tools [23]. The lack of fine spatial resolution in several studies also imposes estimates into the VRE resources availability which might result in unrealistic wind power and solar irradiation potential [24]. Studies considering demand-side flexibility options have limited interactions between the demand side and supply side [25], [26].

Second, studies that incorporate co-optimization methodologies and formulation mostly end up having non-linear and non-convex solution space which results in near-optimized estimations and limited implementation for vast and real-world power systems [27], [28]. These studies usually take one or two perspectives to co-optimize, such as transmission and operation, or generation and planning [29]. At the same time, the expansion planning point of view in this study incorporates transmission expansion, generation expansion for both VRE and non-VRE technologies, economic dispatch for a limited period throughout the year, and a high-level representation of interprovincial transmission corridors. This limitation is then resolved by incorporating a full unit commitment operational model that sees the system at the high-voltage transmission level for all hours during a year.

Third, current studies do not cover a wide range of sources for flexibility issues and do not provide various options to provide flexibility in the response to the issues. Many studies constrain VRE capacities in order to reduce flexibility issues [30], [31]. Most of the frameworks also do not integrate power operation and regional interconnections as options for enhancing flexibility. Third, to the author's knowledge, the usage of linked methodology incorporated in this study is rarely used to study power systems in Canada in the transition toward lower emissions.

Based on the discussed gaps, this research develops novel interlinked modeling frameworks that bring multiple improvements and a wide range of insights. These novelties are discussed in the next section.

### **1.1.3 The novelty of the proposed research**

Several novel contributions are introduced in this thesis that have a substantial impact on the field of research following the research questions and gaps discussed earlier. There are three main areas of novelty in this work:

novelties in the methods, various options for flexibility, and scenarios that represent various approaches to decarbonization.

- **Wide range of flexibility options:** : The thesis discusses a wide range of options for flexibility: storage, transmission expansion, demand response, and systems integration. These options are uniquely selected to analyze different perspectives of a power system: demand side, network side, and supply side. This enables a discussion on the effectiveness of these options in improving flexibility. The analysis of a variety of options also provides a greater understanding of how they compare in terms of operational and investment costs, the integration of variable renewable resources, and the reduction in emissions.
- **Various perspectives:** This thesis presents linked modeling frameworks that enable a broader analysis of the power system by integrating different perspectives. As a result, the analyses are improved compared to previous studies in several aspects. In the first place, linked frameworks that comprise two models can be used to analyze energy systems that are interconnected by considering their impacts on one another without compromising important features or technical aspects. Second, they are unique, if not the first, in the Canadian domain. Third, the used models represent wind and solar in a very granular temporal and spatial resolution which is new in studies on Canada's power systems. Fourth, the models are designed specifically to represent Canada's power system. As a result, they are very capable of covering basic important technical attributes for the systems, e.g., hydropower facilities, etc. Therefore, the methodologies are designed to have the most realistic representation of the systems undergoing the decarbonization pathways.
- **Possible pathways:** The three studies in the thesis analyze seven different scenarios in total which represent possible pathways to decarbonize Canada's power systems. The scenarios are designed to interpret the most important policy implementations, including carbon taxations, emission reduction targets, and provincial nuclear constraints. In addition, they serve to analyze the impacts of different uncertain parameters, such as electrified versus non-electrified demand growth, land use restrictions for wind power expansion, transmission expansion constraints, and net-zero versus zero-emission pathways.

In summary, this thesis provides a better understanding of Canadian power systems which are expanding to large shares of variable renewable resources by integrating insights from different perspectives using linked frameworks. Moreover, the methodologies maintain the validity of the models by enhancing spatial and temporal resolution and reducing technical compromises. In addition, the analyses discuss and compare a variety of solutions to the main problem of flexibility. Finally, it discusses various methods for decarbonizing Canada's electricity sector, including the uncertainties involved.

## **1.2 Research questions and objectives**

As described above, the current thesis investigates the decarbonization pathways of Canada's power system in terms of the flexibility required to integrate large shares of VRE capacities. The importance of flexibility and different options are described in the previous sections. Gaps in the literature are also presented in the previous section. Based on the discussions, three main research questions shape the three chapters of the thesis as presented in the following.

Chapter two discusses flexibility and its impact on large wind and solar capacities and then analyzes supply-side and network-side flexibility options, especially interprovincial grid expansion, and storage capacities. To that end, a bi-directionally linked framework is developed consisting of power system planning and operational models. The novel proposed framework is applied to analyze a zero-emission target for the power system, and its impact on the operation of four provinces as case scenarios. Changes in several operational metrics are analyzed over the iterative procedure, e.g., wind curtailment, load shedding, and expansion costs. The results deliver insights into the impact of the selection of grid expansion and storage expansion both on wind curtailment and their incorporated costs.

Chapter three focuses on the demand-side flexibility options, especially demand response programs. To analyze the demand response programs and their impacts on wind and solar integration, another interlinked framework is developed consisting of a power system operational model and the building energy simulation tool. This chapter delivers insights on the impacts of two different demand response programs on integrating VRE generation into the system, thus lowering curtailment, also savings in the operational costs caused by improving demand-side flexibility. This study also discusses the impact of the reaction on the demand curve coming from the demand side by implementing a demand response.

Chapter four investigates two other options as presented earlier, power systems integration and hydropower capacities. This chapter implements the same interlinked method with a one-direction data transfer. It also applies the operational analysis using an improved hydro modeling methodology. To answer the efficiency and effectiveness of these two options, four different scenarios including different integration levels and demand electrification rates are analyzed with the planning model. Then the outputs of the model for these scenarios are discussed in both generation and transmission capacities, as the expansion costs. The capacities are then operationally analyzed with the operational model and different metrics are assessed for the outputs.

## **1.3 Thesis structure**

The current thesis is structured as below. The second, third, and fourth chapters are manuscripts-based and discuss the introduced research questions accordingly. Each chapter has its literature review, methodology introduction, results, and discussion. In the 5<sup>th</sup> chapter, a high-level discussion and conclusion are presented. Appendix A includes verification and validation done on the modeling tools that are used in the thesis. Appendix B includes

supplementary terms and their definitions which are used in the thesis. Appendix C lists abbreviations and acronyms introduced. Appendix D lists sources for data and codes that are incorporated in the study.

## 2 Chapter 2: Integrated models in action: analyzing flexibility in the Canadian power system toward a zero-emission future

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### 2.1 Abstract

Canada's power system is directly responsible for around 9% of the country's greenhouse gas emissions. Integrating new variable renewable energy resources is posited as one of the core pathways to decarbonizing the system. However, the inherent variability of many renewable energy resources necessitates greater spatial and temporal flexibility. Transmission expansion can deliver spatial flexibility while bulk storage can deliver temporal flexibility. Assessing flexibility adequacy requires an operational perspective employing fine temporal and spatial resolutions. In this study, a novel bidirectionally linked framework is developed to leverage insights from both operational and planning models. Variable renewable energy curtailment is selected as a metric to analyze operational flexibility, which informs iterative revisions in the planning model. The results from four cases show that: (1) Transmission and storage capacities beyond the planning model's initial output are required to maintain sufficient operational flexibility in a zero-emission power system in 2050; (2) Wind capacity overestimation in initial results must be corrected; and (3) Increased total system costs can be partially offset by improvements in wind curtailment, congestion, and load shedding. It is concluded that the iterative expansion-dispatch framework proposed in this analysis yields important insights beyond stand-alone analyses, particularly in the context of a net-zero power system.

Keywords: power system, flexibility, variable renewable integration, decarbonization pathways, model integration

### 2.2 Introduction

Greenhouse gas (GHG) emission reduction targets established under international agreements have put pressure on every economic sector to decrease fossil fuel consumption and promote sustainable energy production. Canada is no exception to this global trend. The Canadian government aims to reduce GHG emissions by 31% below 2005 levels by 2030 [1]. Net-zero emission is also targeted pan-Canadian by 2050 [2]. To that end, ambitious emissions reductions must be achieved in every part of the energy sector across the country.

Electricity generation is responsible for 8.4% of Canada's emissions in 2020 as the sixth main contributor to the national emissions after oil and gas accounting for 26.6%, transportation for 23.7%, buildings for 13.1%, heavy industry for 10.7%, and agriculture for 10.2% [3]. Annual CO<sub>2</sub> equivalent emissions from Canada's power system

must be reduced to 40 megatons (Mt) below 2015 levels by 2030 to meet net-zero targets [1]. Future reductions are also planned by the federal government to be achieved via electrification in the transport sector, which puts another burden on the electricity sector and raises the demand substantially.

There are several conceivable approaches to reaching emissions reduction goals. On the demand side, the electrification of transportation and building systems, i.e., electric vehicles, electrified space heating, and building energy management systems have garnered much attention [32]. The demand growth that will be driven by this electrification is an added burden for the electricity system. As such, demand response in the transportation and building sectors is an important area of research, offering improvements in system flexibility.

On the energy supply side, integrating Variable Renewable Energy (VRE) into the power system is a key part of achieving emissions reduction goals. However, the weather-dependent nature of renewable resources and associated technical generation factors generally increase the degree of variability and uncertainty present in power systems as VRE is incorporated, raising more complex power quality control issues [33]. Integrating VRE necessitates enhanced flexibility within the power system, defined as the dynamic ability to respond to changes in demand and supply while maintaining system balance [34]. This concept is well established in power systems, as operators routinely manage diurnal, weekly, and seasonal variations in demand [17]. However, it has been shown that as installed VRE capacity grows, power systems face additional operational costs resulting from VRE curtailment compensation and network congestion [19]. Curtailment is defined as temporarily constraining the power production of a generating plant below its maximum possible output (given primary resource availability), possibly resulting from a lack of system flexibility.

Power system flexibility is essential, firstly, because more flexibility implies a more efficient power system that can utilize more generation from installed VRE capacity, and consequently, more flexible systems can typically integrate more VRE capacity [19]. Secondly, a flexible power system mitigates costs associated with VRE curtailment, congestion, and load shedding [20]. Thirdly, and most importantly, flexibility will tend to minimize GHG emissions by allowing the highest possible share of energy production from VRE resources.

Flexibility issues can be categorized by their underlying cause: spatial or temporal discontinuities. They also can be categorized by the source of the flexibility within the power system: the demand side, supply side, or transmission. Spatial flexibility issues can be caused by inadequate transmission capacity: for example, when the system cannot dispatch available wind energy due to grid congestion. Temporal flexibility issues occur when the demand side consumers and system operators are not sufficiently agile to respond to changing VRE production to avoid the need for VRE curtailment, unplanned changes to scheduled dispatch, or load shedding.

There are several flexibility options discussed in the literature. Cruz et. al categorize options into four categories: demand-side, supply-side, network-side, and other [18]. Demand-side flexibility options include demand response

programs and demand-side management, e.g., payment schemes for load shifting. Supply-side options include using conventional power plants as reserve capacity and strategic VRE curtailment at economically feasible rates [35]. Network-side flexibility options include the deployment of smart-grid technology, dynamic network reconfiguration, enhancing network interconnections, and network expansion. Other sources of flexibility discussed in the literature include (but are not limited to) improved multi-carrier energy systems integration via innovations such as power-to-X technologies and power-to-heat coupled with heat storage [36]. Bulk energy storage can be utilized throughout the power system to provide flexibility in the presence of growing VRE penetration, e.g., EVs on the demand-side and pumped hydro or large battery installations on the supply-side [37].

Although several options above build flexibility outside the boundaries of the power system, the present study focuses on flexibility options within the power system only. Therefore, options considered in this study are limited to supply and network options (including energy storage). Analyzing flexibility issues and appropriate solutions requires a modeling framework that can capture temporal wind generation variability within a spatial representation of the grid network. Computational modelling tools allow the analysis and assessment of power systems from different perspectives and have the potential to cover these requirements.

Curtailment has several drawbacks. Most importantly, it diminishes emissions reductions achievable in an ideally planned system. Moreover, higher levels of curtailment can compromise the profitability of VRE projects, potentially discouraging further investment. Historical analysis of European countries with the highest VRE penetration levels has demonstrated positive relationships between curtailment rates and VRE generation [38]. For example, Spain and Portugal have large, targeted supply contributions from VRE and exhibit approximately 2.5% curtailment due to a lack of flexibility provided by storage or interconnections [39]. *Figure 1* shows curtailment rates rising with increased VRE in Germany and Britain.

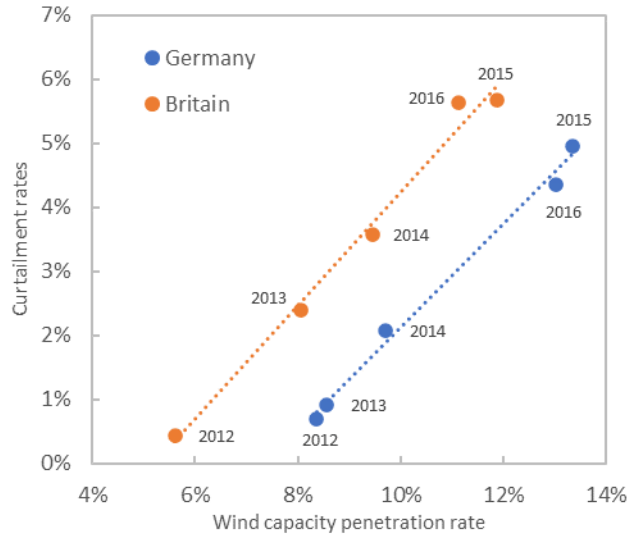


Figure 1 The impact of rising variable renewable energy penetration on VRE curtailment rates in Germany and Britain, 2012-2016-Data from [40], [41], idea adapted from [19]

While reducing VRE curtailment to a certain level might diminishes associated compensation costs in a power system, finding a cost-effective allowable curtailment rate for a given jurisdiction is a controversial topic among researchers. 4% to 5.5% curtailment rates have been suggested as economically feasible for Germany and Britain [42]. Conversely, Sinn et al. use a zero-curtailment target in Germany's power system for a 60% wind penetration scenario [43]. Zerrahn et al. claim that this target could lead to inefficient storage capacity and suggest that higher curtailment rates can be cost-effective in power systems with high VRE penetration [44]. ERCOT suggests 3% curtailment rates to be cost-effective in balancing Texas's power system [45].

Analytical tools used to study power systems decarbonization pathways can be categorized into four (non-exhaustive) groups: integrated assessment models, sector-specific planning tools, power systems dispatch/operation models, and power quality models. Integrated assessment models (IAMs) integrate different sectors, i.e., energy, economy, and society, into a single framework and account for inter-sectoral transactions. They are generally used at global or national scales to assess various transition pathways. However, due to their inclusion of distinct sectors and typically large scales, they tend to exclude fine temporal and spatial resolutions [46]. Other studies neglect technological details in power systems to maintain computational burden [47]. Multiple studies have tried to address those limitations. Capellan et al. incorporated exogenously determined limits to VRE expansion [48]. Riahi et al. added resource use constraints [49]. Pietzcker introduced land scarcity to optimization formulations to prevent excessively optimistic VRE expansions [21]. Brinkerink integrated more detailed representations via power system-specific models' linkage [50]. However, these studies report lower VRE curtailment rates and overestimate storage capacity relative to power system-specific models due to a lack of temporal and spatial resolution, and technical power system details [21].

With higher VRE penetration, power systems become more vulnerable to voltage and current harmonic distortions, voltage and frequency fluctuations, and voltage imbalances [51]. Specific modeling frameworks are required to analyze those issues within the power system. There are several efforts in power quality (PQ), reliability, and failure modeling available in the literature, mostly applied to test systems or smaller scale smart-grids and micro-grids [52]. Other studies implement PQ formulations in integrated distributed VRE resources and demand-side EV charging stations [53]. Giorjiev assessed a single power plant with a PQ management model [54].

Long-term planning or Capacity Expansion Models (CEM) are conventionally used to find cost-optimized future power system configurations over the span of years to decades. CEMs typically exhibit shortcomings in the context of investigating flexibility in high VRE penetration scenarios: overestimating VRE capacity (with associated lower utilization rates) [55], and underestimating variability due to insufficient time resolution (leading to lower anticipated system costs) [22]. As such, planning a power system to meet flexibility needs in the presence of high VRE penetration requires incorporating distinct but complementary operational insights.

Short-term operational optimization models or Production Cost Models (PCM) are primarily used to find the optimal generation state, or dispatch, of generation capacity for hourly (or smaller) intervals over a period of interest (typically days to years). Due to their short-term breadth and detailed temporal resolution, PCMs more effectively capture flexibility and other operational measures in a power system. They are also able to include detailed technical features, e.g., power flow, generator ramping, nodal marginal prices, etc. However, these models are not designed to optimize long-term planning objectives [24]. In summary, both planning and operational insights should be integrated to perform flexibility analysis for power systems. The literature contains numerous other modelling efforts aiming to explore the impact of flexibility in power system planning and operation, ranging from power system-specific models to integrated assessment tools. Several methods have been used to address this issue, as described below.

### **2.3 Single-model frameworks: enhancing the planning models**

The first approach enhances the operational representation of CEMS by integrating some of the operational features and constraints into a planning model. For example, Dolter et al. [7] implement ramp rates, operational constraints, locational wind profiles, and solar irradiation data in their framework. Barteczko-Hibbert et al. present a long-term investment planning model that considers life cycle costs and environmental impacts [56]. Wu and Huang incorporate learning curve theory and capacity credit in the model to better replicate VRE characteristics [57]. Welsch et al. added short-term variability of supply induced by VRE resources to the OSeMOSYS open-source modeling framework of [58].

However, such enhancement methods often entail limitations in fully representing the operational behavior or spatial and temporal span for the planning of power systems. The resulting frameworks often neglect thermal ramp

rates, a critical operational aspect. Due to computational constraints, most of the models are limited to representing optimal dispatch for only a small sample of days throughout the year. Most models exclude power flow, hence neglecting transmission grid specifications (voltage angle and reactance). Furthermore, the low temporal and spatial resolution common to CEMs limits the representation of VRE and requisite system flexibility. In conclusion, enhancing planning models with limited operational details does not fully capture the implications of VRE variability and flexibility.

Other studies tried to co-optimize some features of each two perspectives, such as co-optimizing transmission expansion planning or generation expansion planning with economic dispatch or power generation expansion planning with gas generation expansion planning. Alguacil proposed transmission expansion and economic dispatch optimization framework and tested the nonlinear optimization formulation on a 6-bus system with accurate near-optimized results [59]. Odetayo et al. developed a co-optimization framework for natural gas and power system expansion planning which resulted in nonlinear and nonconvex optimization problems that included power flow constraints. They tested out the co-optimization on 30-bus test systems which do not include VRE capacities and only have two gas plants included [29]. Clairand et al. developed a generation expansion planning model to be co-optimized with power supply and accounting for electric vehicle charging and induction stove demand for microgrids in remote communities, creating a nonlinear method to be solved for the small-scale grid [27].

As shown, co-optimization methods mostly result in complex nonlinear and nonconvex solution spaces which limits their expansion to real-world and country-wide problems, despite their novel perspective on the problem. These models are usually tested on standard limited bus systems, and their usage for policy or large-scale analysis is scarce in the literature, such as island microgrid small power systems. As a result, this study uses a large-scale Canada-wide capacity expansion model that co-optimizes the transmission expansion, generation expansion, and hourly economic dispatch for 21 days in a year. Then the results are further studied in a linked framework by a capable mixed integer Unit Commitment model which simulates the system's operation with detailed and fine resolution analysis to find any point of operational disadvantage. Details of the models and the selected approach are discussed in the methods section.

## **2.4 Multi-model frameworks**

Integrating two or more models by linking them and passing data between them is not limited to energy systems applications. Such multi-model frameworks are implemented across various domains to achieve insights in cases where different aspects cannot be adequately represented using a single model. Model integration methods have been implemented in studies that address the uncertain and dynamic nature of power systems in the presence of significant VRE contributions. These methods can capture operational details with the necessary fine spatial and temporal resolutions by, for example, allowing both CEM and PCM models to work together. Linked frameworks

have been proven to be more accurate. Welsch et al. found a 20% accuracy improvement in estimating the optimized hourly power generation from available plants [60]. Linking strategies can be classified into two categories, unidirectional and bidirectional.

#### **2.4.1 Unidirectional linkage**

A one-way model linkage involves passing data from one model to another, typically from the planning model to the operational model. Such linked models evaluate the operational feasibility of the planned system by running the results from a CEM as inputs to a PCM. One-way linked studies can produce reliability measures and flexibility assessments.

Several studies have analyzed high-resolution operational outputs from planned systems in one-way data pass from the planning model to the operational model [61]. Using the operational model PLEXOS in these studies identified underestimation of wind curtailment and overestimation of baseload plant utilization in single model results [62]. Unidirectional linked frameworks do not offer an adjustment for the given system from the initial iteration, and thus operationally infeasible planned systems are not corrected.

#### **2.4.2 Bidirectional linkage**

Bidirectional linkages have been implemented to address some of the shortcomings of the unidirectional linked approach. Such methods run models in iterative closed-loop frameworks, which pass selected data between two models in a back-and-forth manner until a co-optimized solution is found. The iterative loop stops whenever a convergence or exit criterion is satisfied. Research on bidirectional linkage in the literature is limited, particularly in the context of the Canadian power system.

Alimou et al. introduced a bidirectional iterative framework using the TIMES and ANTARES models with the loss of load expectation limit of 3 hours as the exit criterion [31]. Capacity credit values are selected as the feedback variable to guarantee that the system has enough reserve capacity to be able to fully utilize VRE resources. Another Seljom et al. used constraints to reduce maximum VRE capacity as the feedback when curtailment rates are over 10% [30]. Seljom et al. used results for electricity prices and hydropower operation as feedback [63] for the Norwegian power system since hydropower is dominant. Wyrwa et al. introduce a bidirectional linked framework with reserve capacity as the feedback and operational model feasibility as the exit criterion [64]. Gjorgiev et al. introduced a comprehensive multi-model framework consisting of three separate iterative loops for energy-economy, investment, and electricity security [65]. The energy-economy loop optimizes the generation mix and the security loop then provides grid expansion feedback (with a constant optimized generation mix).

The results of the above-mentioned bidirectional frameworks show that they can mitigate some of the issues regarding VRE development overestimation that is observed in the unidirectional frameworks, by implementing useful feedback. However, in most cases, feedback is designed only to manually constrain investment in VRE capacity

to handle flexibility issues. Most of the frameworks also do not incorporate grid expansion or regional interconnections as options for enhancing flexibility. Another general drawback of iterative linked frameworks is the computational burden induced by multiple model runs and manual data transfer handling. Also, in most cases, power exports to, or imports from, neighboring jurisdictions are not considered. The main features of the reviewed approaches in the literature are summarized in Table 1.

The main objective of this study is to assess 2050 scenarios for a decarbonized Canadian power system from an operational perspective. This paper proposed a novel bidirectional soft-linked and mostly automated framework that incorporates operational and planning models without compromising important details from either. In contrast to previous studies, this framework addresses both temporal and spatial flexibility issues and sends appropriate feedback that reflects requirements for both aspects. The selected feedback includes cost adjustments for transmission expansion and minimum storage capacity needed to minimize VRE curtailment to a specified level. Additionally, this framework incorporates power exchanges between jurisdictions as a parameter calculated endogenously.

*Table 1 Novel insights, limitations, and methods of linked frameworks analyzing power system flexibility with high VRE penetration identified in the literature*

<i>Study</i>	<i>Method</i>	<i>Insight</i>	<i>Limitations</i>	<i>Exit criterion</i>
<i>Welsch et al. [60]</i>	Unidirectional	A base for comparing multi-model and single-model one-way approaches	No feedback to the planning model	-
<i>Collins et al. [61]</i>	Unidirectional	A base for assessing planned power system	No feedback to the planning model	-
<i>Diakov et al. [66]</i>	Unidirectional	Cross-scale data translation	No feedback to the planning model	-
<i>Deane et al. [62]</i>	Unidirectional	New capacity disaggregation management approach	No feedback to the planning model	-
<i>Alimou et al. [31]</i>	Bidirectional	Loss of load criterion, capacity credit feedback	Constraining wind generation capacity	Loss of load hours less than 3 hours
<i>Pina et al. [30]</i>	Bidirectional	Year by year operational analysis	Constraining wind generation capacity	Capacity factor discrepancy
<i>Seljom et al. [63]</i>	Bidirectional	Linking an integrated energy system model with an operational model	Assesses hydropower and not VRE resources; power exchanges are not included; limited to sub-annual time intervals	Hydropower income

<i>Wyrwa et al.</i> [64]	Bidirectional	Checking the operational feasibility under high VRE penetration	Limited to reserve capacity change, no congestion analysis	Operational feasibility
<i>Gjorgiev et al.</i> [65]	Bidirectional	Energy-economy, investment, and security insights	Optimized generation static, limited to grid expansion	No need for further grid expansion

## 2.5 Methodology

This research introduces a framework that utilizes two power system models linked together through a bidirectional flow of information. This section reviews the two distinct models, the linkage strategy, and the metrics used to characterize system flexibility.

## 2.6 COPPER – the capacity expansion model

Canadian Opportunities for Planning and Production of Electricity Resources (COPPER) is a deterministic CEM that targets the nationwide Canadian electricity system and covers the horizon of 2020 to 2050 [6]. COPPER’s fine spatial resolution for wind and solar irradiation data facilitates the investigation of high VRE penetration scenarios. However, thermal generators are aggregated at the provincial level. Provincial nodes are connected via inter-provincial transmission corridors. The model balances demand and supply for 38 representative days within each year to check the adequacy of generation capacity. COPPER follows linear mixed integer optimization for cost minimization of Canada’s power system projection plans. Linear mixed integer formulation allows for efficient optimization convergence and binary adaptation of some parameters like project-based hydro expansion decisions. The main cost minimization formulation is as follows:

$$\min \text{system}_{totalcosts} = \text{cost}_{investment} + \text{cost}_{production} + \text{cost}_{operation \& maintenance} + \text{cost}_{carbon}$$

This minimization function is subject to various constraints which the most important ones are 1) hourly demand and supply balance, 2) planning reserve margin per location, 3) thermal unit technical constraints such as ramp rates and capacity factors, 4) hydroelectric constraints for different hydro facilities, 5) VRE hourly capacity factors and land use per location, and 6) Transmission and storage constraints. A further detailed explanation of the model’s formulation is presented in section 7.1.2.1.

The present study developed COPPER further to introduce geo-spatial variation in capital costs for wind generation and a new lower-bound constraint for storage capacity. These formulations are presented below. Current study also limits installed wind capacity to 2 MW per square kilometer to maintain available surface area constraints. This constraint is an estimate to maintain feasibility and minimum and maximum distance to urbanized areas and transmission lines which agrees with other Canadian renewable feasibility studies [67].

## 2.7 SILVER – the production cost model

SILVER includes optimal economic dispatch, day-ahead unit commitment (UC), and optimal power flow (OPF) with network constraints as separate modules [68]. Together they provide a more realistic representation of a power system. SILVER can effectively assess renewable energy resource integration scenarios and the retirement of emissions-intensive generation capacity [69]. SILVER solves a DC approximation of power flow within the transmission network with the following assumptions: line resistances are negligible; bus voltage magnitudes are set to 1.0 per unit. These assumptions are reasonable for high-voltage transmission networks, such as the cases considered in this study [70]. SILVER employs linear mixed integer UC (Unit Commitment) formulation which the objective function is abstracted in the following mathematical representation. Mixed integer formulation allows the model to account for the on or off status of the power plants and linear formulation guarantees an optimal solution and keeps the computational requirements manageable.

$$\min \sum costs_{t,g} = cost_{operation} + cost_{maintenance} + cost_{fuel} + cost_{emission}$$

The optimization function is solved at every timepoint for every  $t$  and every generation facility  $g$ , and is subject to constraints including 1) load and supply balance at each hour, 2) ramping constraints based on the technology, 3) maximum and minimum generation constraints for both thermal and VRE technologies, 4) transmission flow constraints, and 5) yearly capacity factor constraints. A further detailed explanation of the model's formulation is presented in section 7.1.1.1.

The model uses an hourly temporal resolution to model system operation and maintains computational tractability. Sørnes et al. conclude that hourly temporal dispatch results are more accurate by 20% compared to coarser resolutions [71]. Hoevenaars et al. claim that the accuracy gains for sub-hourly resolutions are only valid in certain power system configurations [72]. In addition, Shirizadeh et al. suggest that hourly resolution is adequate for power system-specific models and the lower accuracy with coarser resolutions only happens in some cases [73]. In conclusion, there is a large body of existing research supporting the use of hourly time steps for energy systems and power-only models which maintains accuracy and computational tractability.

SILVER and COPPER are selected for use in this study as they have been developed exclusively to investigate the Canadian power system with its specific complexities and characteristics, including, market structure, interconnections between provinces, installed hydro capacity and storage potential, and federal and provincial policies and targets. COPPER includes interprovincial connections as a source of flexibility. COPPER comprises a high spatial resolution specifically for siting VRE capacities appropriately. COPPER's detailed hydro modelling formulation as hydro assets provides extensive grid flexibility [7] The model also includes capacity planning reserve margins as a primary means of maintaining system reliability. The SILVER model version used in this study incorporates

interconnections between provinces as exogenous import and export. The model is based on the real-world transmission network and includes distinct hydro technologies representing extant assets in the system. Therefore, the multi-model framework utilized in this study allows the realistic representation of provincial and national power systems.

The linkage strategy is designed to transfer pertinent information between the two models while preserving the key insights that each generates. A detailed translation tool is developed to resolve the scale and resolution differences between COPPER and SILVER, as detailed in the following section.

## **2.8 Linking framework**

The critical first step for the data structure is to ensure that the relevant inputs and outputs are harmonized between the two models. While these two models differ in the input temporal and spatial data resolution, consistency is assured by adopting generation capacities and transmission lines data from a common database (the Canadian Open-source Database for Energy Research and Systems Modelling-CODERS database) [74]. Models use locational wind and solar resource capacity factor data from NASA's MERRA tool [75]. This study employs the same underlying data sources detailed in respective publications for both models including generation and transmission, hydro storage, hydro hourly, daily and monthly capacity factors, conventional generation capacity factors, demand profile, population growth rate, and power exchanges between Canada and the US. Data sources include provincial power system operators and publicly accessible data, such as BC Hydro, SaskPower, and Alberta Electricity System Operator. Where additional data is needed, e.g., line reactance values, the best available information available in the literature is used [76]. The SILVER provincial, SILVER national and COPPER models use the same hourly demand, locational wind and solar capacity factors, and base year generation capacity. Additionally, the SILVER national and COPPER models share interprovincial base year network data for generation capacity, voltage, and reactance from CODERS. The SILVER provincial model uses CODERS data for in-province transmission, including base year generation capacity, voltage, and reactance. Comparing SILVER national results with COPPER results shows some differences in power flow outputs. This discrepancy is caused by different power flow formulations between the two: SILVER runs optimal power flow with reactance and capacity constraints, while COPPER sees the connections as aggregated transmission capacities as power corridors and incorporates the demand and supply balance.

### **2.8.1 Transferring Generation and transmission data**

Figure 2 introduces the detailed process outline of the proposed linked framework and associated data flows. COPPER solves for the inputs defining the primary scenario as the initial step. The results are then translated to **Step 1** and **Step 2** in parallel: the former transfers generation capacities determined by COPPER and the latter determines interprovincial power flows using SILVER national. The resulting data is then fed to SILVER provincial and the subsequent results are analyzed against the specified exit criterion in **Step 3**. If VRE curtailment is found to be greater

than 5% in this step, feedback consisting of transmission expansion costs for congested lines is fed to COPPER in **Step 4**. In the absence of congested lines, minimum storage requirements are introduced to COPPER in **Step 5**. The loop stops when the exit criterion in **Step 3** is satisfied. The following sections discuss each step in greater detail.

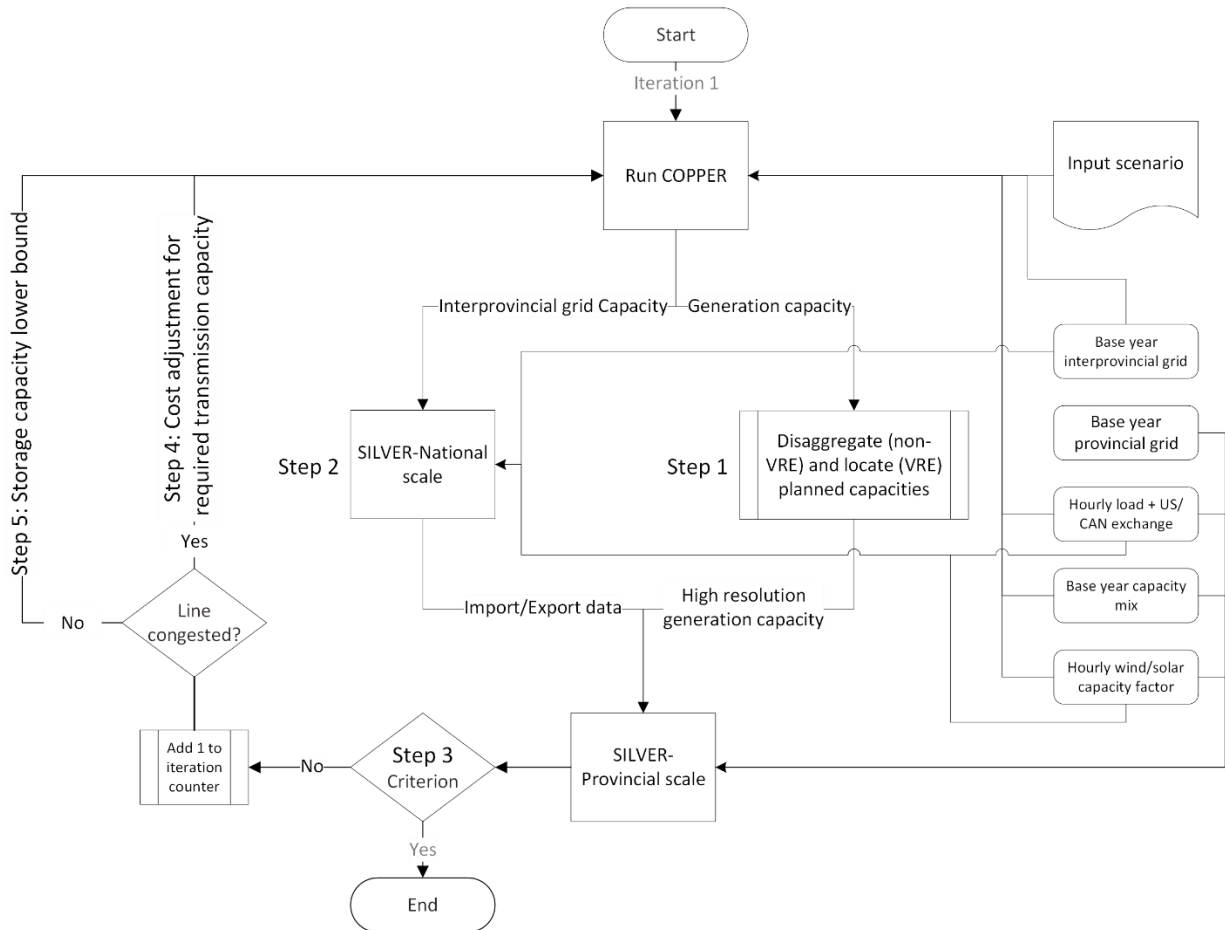


Figure 2 – Data flow and feedback steps in the linked framework

**Step 1** is designed to transfer generation capacity data from COPPER to SILVER. Due to the differing spatial resolutions used within COPPER and SILVER, new generation capacities prescribed for a province as a single node must be disaggregated and allocated at the transmission network level within each province. This resolution-matching procedure is introduced in an automated data translation module.

The translation module changes the capacity of available non-VRE plants in the base year until they are matched with total capacities from COPPER while keeping the changes to a minimum. In other words, if the suggested capacities by COPPER are lower than the sum of capacities of existing plants for each generation type, then existing plants are removed starting from the smallest. If the prescribed capacity in a province is larger than the sum of

existing capacities, the capacities are linearly added to existing capacity, starting from the smallest, until the capacity reaches 4 times the original existing capacity. The following algorithm shows how the procedure is applied to the non-VRE generation capacities. This algorithm iterates over the existing capacities in SILVER input  $C_{S,g}$ . Then the sum of generation types  $g$  is compared to the output of COPPER for that generation type  $C_{C,G}$ , and the new capacities are calculated or removed based on the conditions presented below.  $C_{C,G}$  is updated at the end of each if statement to be compared again at the start of the for loop.

*for*  $C_{S,g}$

*while*  $C_{C,G} \neq \sum_{g=1}^G C_{S,g}$

*if*  $C_{C,G} - \sum_{g=1}^G C_{S,g} < 0$  *then remove*  $C_{S,g}$  *and*  $C_{C,G} = C_{C,G} - C_{S,g}$

*if*  $C_{C,G} - \sum_{g=1}^G C_{S,g} > 0$  *then*

*if*  $C_{C,G} - \sum_{g=1}^G C_{S,g} > 4 \times C_{S,g}$  *then*  $C_{S,g}^{new} = 4 \times C_{S,g}$  *and*  $C_{C,G} = C_{C,G} - C_{S,g}^{new}$

*if*  $C_{C,G} - \sum_{g=1}^G C_{S,g} > 4 \times C_{S,g}$  *then*  $C_{S,g}^{new} = C_{C,G} - C_{S,g}$  *and*  $C_{C,G} = C_{C,G} - C_{S,g}^{new}$

*Equation 1 Algorithm implemented to calculate changes in the capacity based on COPPER outputs*

There are several factors justifying this method. Firstly, the supporting infrastructure for the plant, such as the electricity grid or the fuel pipelines, is already constructed. Secondly, constructing a new plant needs highly detailed technical, societal, and licensing assessments. Thirdly, it is assumed that smaller capacities have the least cost to be removed from the portfolio if they need to since they have the smallest accompanying infrastructure. Finally, this method implies a minimal impact on the available distribution network [66]. The result of this module is a heterogeneous installation or removal of generation capacities throughout each province following COPPER results. The Following snippet shows how this algorithm is implemented in the Python code. The complete code is available in the repositories introduced in Appendix D, Section 7.2.

```

for index, k in enumerate(copper_non_vre):
    result = k
    gen_type = result_summary_df.iat[index, 0]
    # Skip solar and wind
    if gen_type in ("solar", "wind"):
        continue

    # Subtract SILVER's total from COPPER's total (for given generation type)
    k -= model_input_df.loc[model_input_df['kind']
                           == gen_type]["[MW]"].sum()

    # This algorithm works in the following way: If the COPPER capacity is less than SILVER's,
    # it deletes generators from SILVER in order of increasing capacity, until the capacity in SILVER
    # matches. This code is not used for the scenarios with additional thermal units.
    while k != 0:
        smallest_capacity = None
        generator_to_remove = None

        # This loop looks for the generator (of kind == gen_type) with the smallest capacity
        for j, generator in model_input_df.loc[model_input_df['kind'] ==
        gen_type].loc[model_input_df["[MW]" > 0].iterrows():
            if smallest_capacity is None:
                smallest_capacity = generator.get(5)
                generator_to_remove = j
            elif smallest_capacity > generator.get(5):
                smallest_capacity = generator.get(5)
                generator_to_remove = j
            else:
                continue

        if smallest_capacity is None:
            break
        elif k < 0:
            if abs(k) > smallest_capacity:
                model_input_df.at[generator_to_remove, "[MW]"] = 0
                k = k + smallest_capacity
            else:
                model_input_df.at[generator_to_remove, "[MW]"] = smallest_capacity + float(k)
                k = 0
        elif k >= 0:
            model_input_df.at[generator_to_remove, "[MW]"] += float(k)
            k = 0
    model_input_df = model_input_df.loc[model_input_df["[MW]" > 0]

```

*Snippet 1 Code snippet for implementing the translation module for non-VRE generation types*

Expansions of VRE capacities provided by COPPER are represented in geographic locations in representative COPPER grid cells and are modelled as connected to the closest (geodesic) available transmission node. Hydro capacities are also expanded on a project-by-project basis in COPPER and defined as binary variables with pre-defined capacities and related parameters. Therefore, they are represented in SILVER as they are suggested in COPPER outputs with known location and capacity.

**Step 2** is introduced to determine inter-provincial imports and exports from COPPER outputs as inter-provincial network grid data is not endogenous to SILVER provincial models. This is crucial when modeling at the national scale to characterize adjacent provincial electricity systems' interdependence and associated flexibility in the national-level system. To do so, the framework provides hourly line flow values for a full year exogenously to the SILVER provincial model. COPPER is not able to provide this data directly due to computational limitations and the lack of an optimal power flow solution.

A SILVER national model determines the optimal operational state for the Canadian power system using generation capacity data provided by COPPER. Transmission line voltage and reactance values are taken from the CODERS database and assumed to remain constant with expansions of transmission capacity calculated by COPPER. With the resulting exogenous power imports and exports for each province and the results of **Step 1**, SILVER provincial can be run.

### **2.8.2 Maximum feasible VRE curtailment rate as the loop exit criterion**

**Step 3** analyzes the provincial power system in terms of flexibility, using VRE curtailment as the relevant metric. Various studies mentioned before in the EU report cost-effective VRE curtailment rates ranging from 0% to 5.5% depending on the system's characteristics. Higher VRE penetration rates are relatively recent in the Canadian power system compared to European jurisdictions. Based on the above, a VRE curtailment rate below **5%** is selected as the iterative loop exit criterion (i.e., in this range, system flexibility is deemed to be sufficient).

### **2.8.3 Iterative feedback and resolution of flexibility issues**

The ultimate purpose of the linkage strategy employed in this study is to provide feedback to the planning model to ensure the resolution of flexibility issues associated with planned generation and transmission capacities. Network-side flexibility options are initially assessed at the national level within COPPER (i.e., interconnections between provinces). Transmission expansion inside the province as a flexibility resolution measure is provided as iterative feedback to the planning model, via **Step 4**. This step involves the analysis of SILVER provincial model outputs for line congestion. For the purposes of this analysis, a line is considered congested when power flow utilizes more than 80% of the rated physical capacity of the transmission line for continuous hours more than 10% of the time in a year. For congested lines, new line incremental expansion costs are approximated based available line's voltage level and

length using figures from the transmission line cost report released by the Western Electricity Coordination Council (WECC) [77]. These costs are added to the wind plant's capital cost at the same grid cell location and the new line capacity is added to SILVER input for the next iteration.

On the supply-side, available flexibility options include VRE curtailment and storage. The COPPER optimization formulation includes options for the restoration of hydro facilities into pumped hydro storage (PHS), building new pumped hydro, or building electrochemical battery storage facilities (assumed to be lithium battery (LB) facilities), with their respective costs. **Step 5** includes feedback for these flexibility options and a method to calculate minimum storage capacities. Several approaches have been introduced in the literature to find minimum feasible storage capacities. This study uses a combination of maximum feasible VRE curtailment (5%) and increased storage capacity for supply-side flexibility (storage only is likely to result in storage capacity over-estimation [78]). Energy stored in a PHS or LB plant in the presence of the 5% curtailed wind threshold is calculated using Equation 2, in which  $\alpha$  is the maximum curtailed wind threshold:

$$E_t^{store-in} = (E_t^{curtailed} - E_t^{available} \times \alpha)$$

*Equation 2 - Stored energy requirement in the presence of 5% curtailed wind*

The minimum storage capacity then can be calculated from  $E_t^{store-in}$  based on the storage technology. The time  $t$ , is the hour that the most severe curtailment occurs during the operational analysis during a year. While the excess energy above the curtailment threshold needs to be stored for one hour, storage capacity needs to be calculated based on the technologies. Both storage technologies can store 100% of their capacity at each hour. Therefore, the minimum capacity for all technology types at each balancing area  $ab$  is calculated by Equation 3. While this study only accounts for one period,  $pds$  is set to 2050.  $\eta_{st}$  is set to the average efficiency of the storage technologies, which is 80%.

$$SL_{pds,ab} = \frac{E_t^{store-in}}{1hr \times \eta_{st}}$$

*Equation 3 – Calculating the storage capacity required to respond to excess curtailment*

The feedback passes calculated minimum capacity using Equation 4, to COPPER as a new lower bound for storage capacity expansion. This constraint forces the model's total storage capacity at each period and each balancing area, including existing storage facilities  $ESC_{pds,ab}$ , and new built facilities for all technologies,  $\sum_{pds,st}^{PDS} NSC_{pds,ab,st}$ , to be higher than the suggested storage limit  $SL_{pds,ab}$ .

$$ESC_{pds,ab} + \sum_{pds,st}^{PDS} NSC_{pds,ab,st} \geq SL_{pds,ab} \forall PDS, ab \text{ where } pds \in 2050$$

*Equation 4 – The lower bound for storage capacity provided as feedback to COPPER*

An iteration completes when feedback from steps 4 and 5 is passed to COPPER. The subsequent iteration starts by running COPPER with new capital costs for congested lines and new constraints for minimum storage capacity. The iterative loop process and provision of feedback signals continue until the exit criterion in Step 3 (VRE curtailment rate below 5%) is met.

## **2.9 Results and discussion**

The result section includes the outputs and analysis for four case scenarios and the overall impact of the iterative process on the national power system outcomes in 2050.

### **2.10 Input scenario and cases**

The scenario for COPPER input in this analysis has the following features. The carbon price increases from 170\$ per ton in 2025 to 370\$ per ton in 2050 in 5-year periods. In accordance with Canada's net-zero goals, the system is set to be emission-free by 2050. This scenario does not limit the transmission buildout between provinces and does not put constraints on nuclear expansion. Demand growth rate, investment and operation costs, and technological attributes are all set to be the same with SILVER and COPPER original values from their respective studies. Four provinces each with substantial VRE development in COPPER's results, were selected as the case studies: Alberta, Saskatchewan, Newfoundland and Labrador, and Nova Scotia. Demand profiles are scaled to match the predicted provincial population growth and other factors like electrification and energy efficiency improvements are not included in the scenario. This scenario uses historical Canada/US power flow data as fixed values included in the input data. This means that the Canada and US transmission network is not endogenously modeled and is out of the model's boundaries.

### **2.11 Initial COPPER output**

The results for the input scenario are presented in Figure 3. The zero-emission constraint eliminates gas, diesel, and coal capacities from the system by 2035. The model also does not develop any additional emitting capacity since these capacities need to be phased out by the end of the projection period, i.e., 2050. There is 105 GW of wind capacity expansion from 24 GW to 129 GW. Solar capacity also grows from 3 GW to 25 GW in 25 years. Other shares of capacity will be 14 GW of nuclear and 80 GW of hydro facilities. The COPPER's results are consistent with Canada Energy Regulator-CER's "Canada's Energy Future 2020 report" [79]. Dolter et al. did not include the net-zero goal at the time of their study, namely introducing wind capacity and phasing out a large share of gas, coal, and other emitting resources by 2050 [7]. Wind development is mainly happening through the expansion in AB and SK While maintaining land-use constraints of 2 MW per square kilometer. This outcome is in general agreement with the assessment of onshore wind potential presented in the study by Dehghani-Sanji [5].

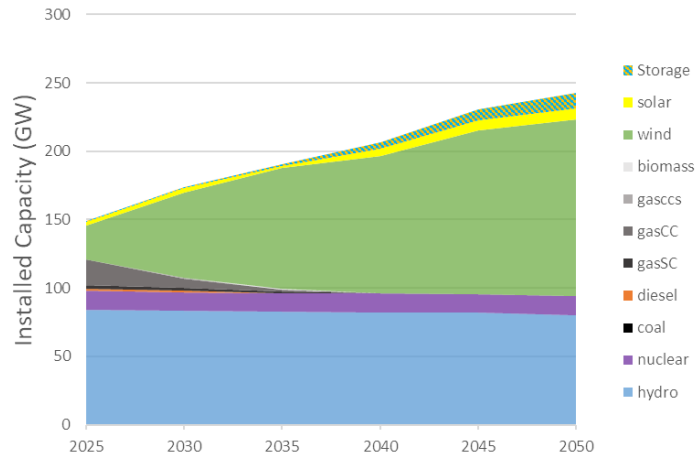


Figure 3 Canada's generation outline for the initial iteration

Additionally, COPPER expands or maintains the interprovincial transmission connections as presented below.

Table 2 transmission expansion results from COPPER initial output as capacities in MW

Transmission interface	Year	Capacity
Alberta and British Columbia	2025	1000
	2050	5500
Alberta and Saskatchewan	2025	306
	2050	3306
Manitoba and Saskatchewan	2025	440
	2050	1440
Newfoundland and Labrador and Quebec	2025	594
	2050	594
Newfoundland and Labrador and Nova Scotia	2025	1000
	2050	1000
Nova Scotia and New Brunswick	2025	650
	2050	1000

### 2.11.1 Case 1: Alberta

Alberta is an important candidate to analyze due to its power system's currently large contribution to the total emission, around 73% [69]. The initial solution from COPPER's results removes all the emitting capacities and adds 47 GW of wind power for Alberta. Table 3 presents capacities by generation type for Alberta and the other three cases from the initial COPPER output in 2025 and 2050 as the start and end of the simulation period, respectively.

Table 3 Initial COPPER output for four cases, total capacities reported in MW per generation type at the start (2020) and end (2050) of the simulation period

Case	Year	Diesel	Gas	Biomass	Wind	Solar	Hydro
Alberta	2025	0	12259	0	3303	1333	924
	2050	0	0	0	50340	1184	0
Newfoundland and Labrador	2025	291	222	0	1718	0	2479
	2050	0	0	0	3941	310	7382
Nova Scotia	2025	463	143	97	2039	0	553
	2050	0	0	0	3364	750	553
Saskatchewan	2025	0	1748	0	2480	40	1178
	2050	0	0	0	15722	0	863

The first version of COPPER’s output had a total of 1138 hours (13%) that were congested on two 240 kV lines. The first feedback addresses the costs related to expanding both lines' capacities and decreases the curtailed generation from 7.5 TWh (5.9%) to 6.7 TWh (5.3%). Analyzing the output from the second round of running COPPER shows that the network still has flexibility issues that result in curtailment rates above 5% for wind capacities due to an inflexible generation mix and beyond the congestions in the lines.

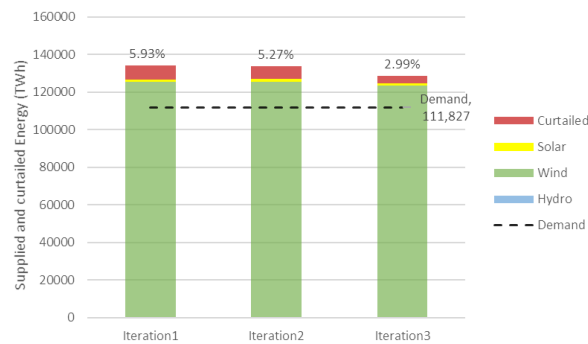


Figure 4 change in the yearly supply by source and curtailed wind during iterations in TWh, case of Alberta

Adding minimum storage capacity as feedback of the second iteration reduces the curtailment rate below 5%, i.e., 3.8 TWh (3%) in the third round as reported in Table 4. COPPER increases the Interprovincial transmission capacity between Alberta and British Columbia in the third iteration and brings more flexibility by adding power exchange capacities and reducing the curtailment hours beyond the criterion’s requirement. Additionally, wind generation capacity was reduced from 50.3 MW to 48.2 MW in three iterations due to cost adjustments for congested grid networks as presented in Table 4.

Table 4 curtailed wind generation in percent (%) in iterations for four cases

Cases	Iteration 1	Iteration 2	Iteration 3	Iteration 4	Iteration 5
Alberta	5.93	5.27	2.99	-	-
Saskatchewan	9.35	7.01	6.10	4.65	-
Newfoundland and Labrador	5.93	5.27	1.41	-	-
Nova Scotia	22.18	17.46	14.96	9.31	4.17

The final curtailment rate (<3%) for Alberta demonstrates how a grid transition from fossil-dependent to primarily wind has the capacity to dispatch most of the VRE generation. Moreover, interprovincial interconnections bring another factor to the province’s flexibility - British Columbia, with a very flexible network consisting mostly of hydro, contributes to Alberta’s flexibility and high wind utilization results.

**2.11.2 Case 2: Saskatchewan**

Saskatchewan introduces 16,000 MW of wind installations between 2020 and 2050 based on COPPER initial simulations. The expansion results in overall threefold growth in the province’s capacity. All of the base-load gas plants are removed by 2030 in the case of Saskatchewan. The province also has a good wind capacity potential based on meteor data. Thus, COPPER plans the system to expand wind in SK and use it to dispatch to neighboring provinces, Alberta and Ontario through Manitoba.

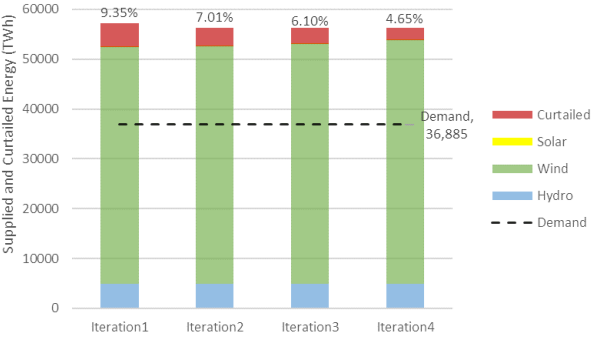


Figure 5 change in the yearly supply by source and curtailed wind during iterations in TWh, case of Saskatchewan

The system experiences a 4.8 TWh of curtailed wind generation over 1400 total congested hours (16%) in a couple of transmission lines in the first iteration as represented in Figure 5. The initial feedback to COPPER introduces the costs of developing the lines in congested locations. Over the next three iterations, the system resolves flexibility issues by introducing the necessary storage capacity to absorb the curtailed energy.

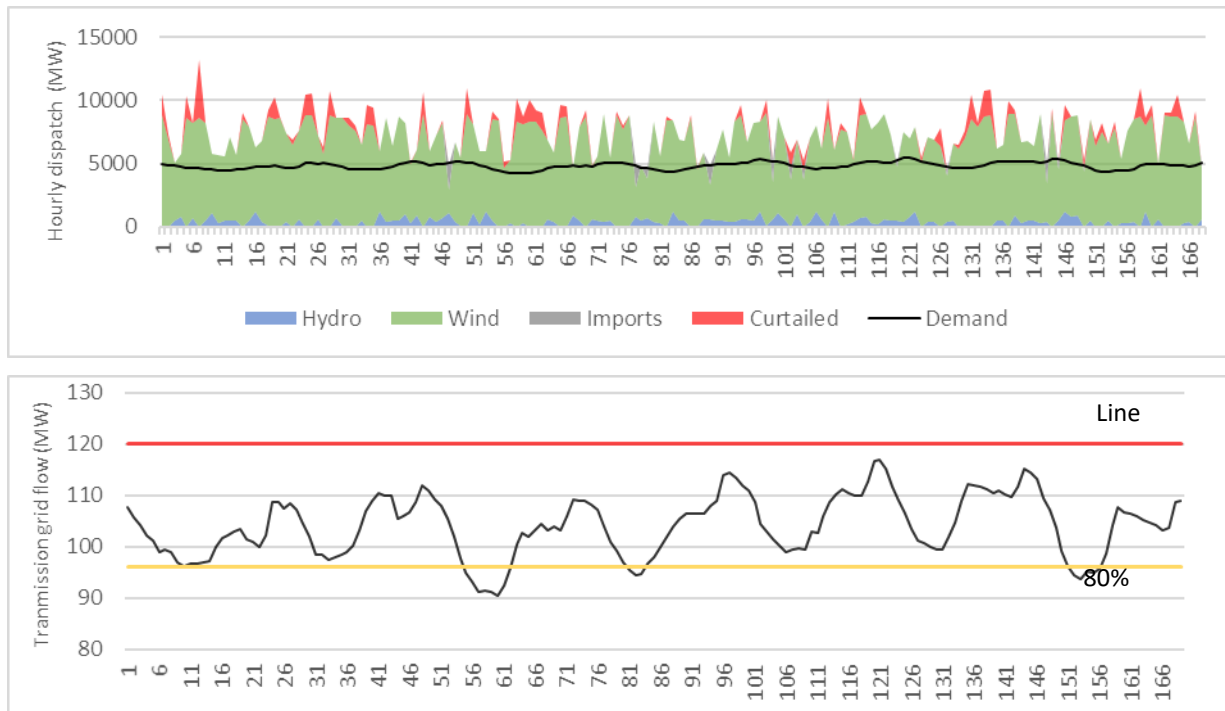


Figure 6 Power dispatch and line flow through a congested line in sample hours, case: Saskatchewan

The sample hourly dispatch and line flow diagrams from the first iteration analysis of Saskatchewan shown in Figure 6 emphasize the impact that grid constraints have on wind dispatch. The specific grid is congested more than 80% of its capacity in almost all of the hours represented, hence substantial curtailed wind despite the demand and export opportunities.

Like the case of Alberta, Saskatchewan’s wind capacity is reduced by the costs associated with expanding the grid network in the second iteration. Over the next four final iterations, the framework doubles the storage capacity from 720 MW to 1580 MW as shown in Table 5. This additional storage enables the system to bring some of the wind capacity back to the mixture. However, the final wind capacity of 15.1 GW is still lower than the initial overestimate of 15.7 GW. Compensating mitigated wind capacities was achievable when the system became flexible enough to receive the generation by introducing enough storage capacity in this case.

Table 5 Storage capacity in MW between iterations for four cases

Cases	Iteration 1	Iteration 2	Iteration 3	Iteration 4	Iteration 5
Alberta	3230	4178	8950	8950	8950
Saskatchewan	720	720	1340	1580	1580
Newfoundland and Labrador	207	207	207	207	207
Nova Scotia	631	631	1155	1671	2246

### 2.11.3 Case 3: Newfoundland and Labrador

Newfound and Labrador hydropower will expand by the end of 2041 when the Churchill Falls contract expires adding 5,328 MW of power to the province’s total capacity. Wind and solar capacity expand from 1718 MW to 4250 MW from 2020 to 2050. The 250% capacity increase can potentially be a burden to the grid. In contrast, hydro generation capacity brings a faster ramp capability to the mix.

In fact, the expanded capacity does not pose major flexibility issues for NL’s grid network, as shown to be negligible: 227 hours for one grid line (2.6%) over the year. A high-voltage grid network with high capacities contributes to lower congested hours. This less congested network, along with around 7,000 TWh of electricity export through the interprovincial grid, resulted in surpassing the criterion in the first iteration (4.13% curtailment rate).

### 2.11.4 Case 4: Nova Scotia

Nova Scotia is selected because of its relatively high wind and solar capacity expansion growing from 2 GW to 4 GW from 2020 to 2050, at which point VRE capacity share accounts for around 72%. All capacities of the province’s emitting generation phase out from 2040 onward, following the emission-free constraints. Therefore, the system needs to absorb the variability by its limited lower voltage and capacity network. The system also relies heavily on imports, mainly from Newfoundland and Labrador, consisting of wind and hydro.

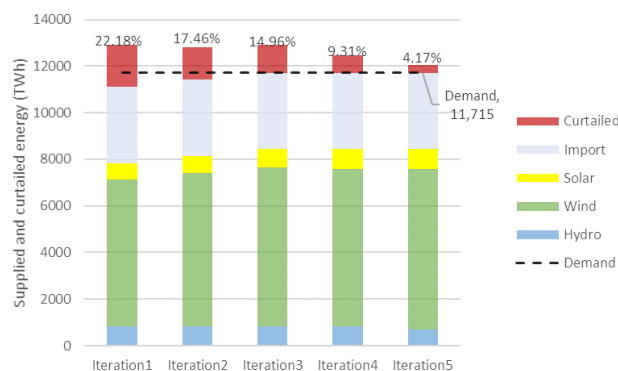


Figure 7 change in the yearly supply by source and curtailed wind during iterations in TWh, Nova Scotia

In the first iteration, 1.8 TWh (22%) of wind generation is curtailed, and 5% of the load is shed over the highly congested lines as visible in Figure 7. Thus, the system faces an alarming reliability issue in this case. In two subsequent iterations, the systems adjust grid capacity allowing it, to accommodate the expanded capacity. It was only after these two rounds that the system was able to operate without any shedding and the congestion rates dropped. Afterward, the framework introduced new storage capacities to bring enough flexibility to the system to utilize the wind capacity above 95% of its potential in five iterations.

Highly congested lines resulted in feedback for cost adjustments in the second and third iterations. The share of storage capacity is also relatively higher compared to other cases. This confirms that more flexibility is needed in Nova Scotia due to the high amounts of transmitted wind-generated energy from NL and PEI. By the final iterations that followed, wind capacity increased to 3.1 GW, which is lower than the initial 3.4 GW. This adjusts the investment overestimate for this province along with mitigated costs curtailment, congestion, and shedding that utilizes more wind capacity.

### 2.11.5 Impact on Canada’s power system

Canada’s overall generation outline differentiates during the iterations due to the feedback from four cases as represented in Figure 8. Wind Capacity is not replaced by an emitting generation type in order to maintain no emission input. As a result, COPPER expands wind generation in not affected provinces and interprovincial corridors to preserve demand and supply balance for the provinces in which the wind capacity is reduced.

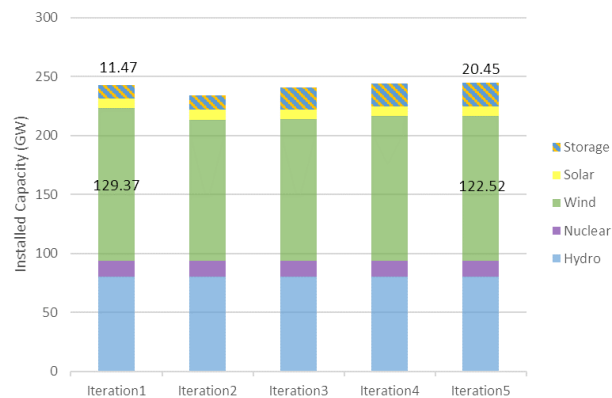


Figure 8 Change in Canada’s capacity outline from over five iterations - 2050

A substantial difference in the results is observed when the framework signals COPPER’s input with grid expansion costs in the first and second iterations. The required costs were not accounted for in the initial COPPER iteration. Capacity adjustment is partly compensated for in later iterations by introducing the required operational storage facilities. By the final iteration, the total wind capacity changes by 6%, decreasing from 129 GW to 122 GW. The total installed storage capacity increases from 11.5 GW to 20.4 GW, enabling the system to meet the maximum curtailment criterion. Thus, imposing the curtailment criterion is effective in mitigating the spatial and temporal flexibility issues. However, reducing the curtailment rates to below 5% values seems to be accompanied by extra costs for the system.

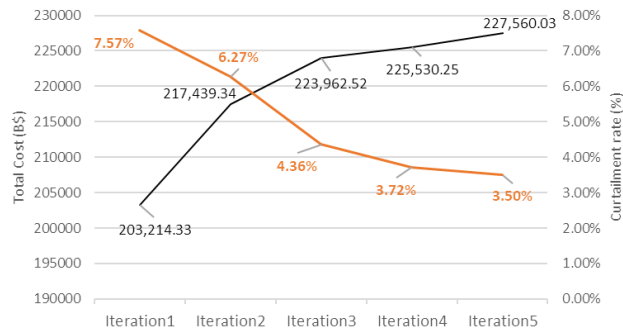


Figure 9 Canada’s power system total cost and curtailment change in five iterations over iterations - 2050

Including the costs necessary for expanding grid lines, while minimizing congestion and storage capacity increases system costs by 12% relative to the initial iteration as shown in Figure 9 in which iteration 1 represents the initial outputs of COPPER before any operational feedback. At the same time, curtailment rates for the four cases dropped from 7.57% in the initial input data to 3.50% in the last iteration. The cost increase of over 24 billion CAD is for the system’s expansion and operation costs for the whole 30-year planning horizon – 2020 to 2050. At the same time, if a very low rate of \$40 per MWh is selected for wind generation, the curtailment costs are dropped from 0.56 billion CAD to 0.36 billion CAD for the year 2050 only.

## 2.12 Discussion

Conventional power systems models, planning and operational, have shown to have fundamental weaknesses when they try to navigate the transition to a low-carbon future. A linked framework leverages both a cost-effective plan and the operational feasibility of the power system. The main question of this project is, “Is the capacity expansion suggested by the power system’s planning model (COPPER) operationally flexible, specifically given the high VRE shares?”

To answer this question, this study analyzes the proposed optimal power system mix in terms of flexibility. Curtailment is selected as a metric to identify flexibility issues that could be caused by transmission network constraints and operational inflexibility. To the authors’ knowledge, there is no previous study that has used this approach to address two aspects of flexibility issues in a linked framework. An iterative feedback is developed that stops when curtailment drops below 5%, as a proxy for system operational flexibility. This criterion is used as an external metric for both models but calculated based on the results from the operational model.

The two models used in this framework investigate the transition to decarbonization at two different scales. This difference in scale involved complicated data translation data techniques in the framework. At the same time, it brings insights from different scales that were not available before. In addition, electricity exchanges between jurisdictions in Canada will have a significant role in shaping the net-zero future of the national power system and

should not be neglected. In contrast to the previous studies, this framework endogenously implements and includes the provincial interconnections characteristics and power flow.

This study analyzes and addresses spatial and temporal flexibility issues in the power system at the same time and avoids limiting VRE capacity by three main characteristics. First, the transmission congestions must be addressed alongside significant VRE capacity expansion which necessitates grid expansion. Second, the minimum storage capacities must be introduced to achieve temporal flexibility. Third, the proposed framework can find the optimal storage capacities resulting from a determined curtailment rate. Consequently, the results are argued to be closer to an optimal solution for operation and planning combined. And third, including the intra-provincial grid network with power flow analysis characteristics.

This study has the following agreements compared to linked frameworks in previous studies: (1) Wind capacity overestimations are corrected through the iterations of the linked framework the iterations. (2) Curtailment rates are reduced to the desired level by modifying the generation mixture. (3) Grid expansion played a crucial role in bringing flexibility to the system.

This study used a soft-linked approach to transfer data between two power system models. While a soft-linked framework has the advantages of being “practical”, “transparent” and “learning”, hard-linking has merits of “productivity”, “control”, and “uniqueness” [80]. Hard-linking CEMs and PCMs is limited due to their fundamental difference in optimization formulation. Running multiple models in soft-linked frameworks needs both extensive human and computational resources. Therefore, novel alternative approaches like metamodel multi-objective optimization could be followed in order to bring a hard-linked framework with limited human intervention.

The results and conclusion of this study were limited to four cases, and results were only analyzed for the final year of the planning horizon, 2050, which includes the highest VRE capacity expansion values. However, further analysis could be done for the intermittent transition years to seek flexibility issues and resolutions in the subsequent studies. This study includes a selection of flexibility options that are internal to the power systems due to the scope of the work: interconnections between provinces, provincial transmission expansion, pumped hydro, and battery storage systems on the supply-side. In addition, this study uses DC approximation for short-term operational optimization for analyzing the power system’s flexibility and does not include the power system’s voltage and frequency quality and harmonics assessments. The scenario that is assessed in this study is limited to demand growth related to population growth and does not include electrification, and efficiency improvements.

### **2.13 Conclusion**

All four cases analyzed in this study proved that variability of the expanded wind resources could result in curtailment, investment miscalculation, load shedding, and infeasibility (when supply can’t meet demand). These insights show that the results from a standalone planning model do not sufficiently account for flexibility

requirements. By including power flow formulations and constraints, the linked framework brings a more realistic representation of the operation of the planned power system.

This paper's linking strategy incorporated two features as feedback to the planning model that improved the estimation of wind generation capacity compared to the planning system's standalone results. First, the feedback includes the costs of expanding the required transmission capacity, which addresses spatial flexibility adequacy. Second, additional storage was introduced for the scenarios, which was caused by requiring further flexibility. As a result, wind capacity is reduced after the first iteration, which is primarily a result of in-province transmission expansion costs. Then it slowly balanced back to a higher capacity in the presence of adequate storage up to a still lower level than the initial planning output.

By comparing the four included cases line congestion contributed less to causing curtailment than inadequate storage capacity in Canada's power system. Line congestion becomes slightly more important in smaller provinces with limited grid capacity than in larger ones with a complex transmission grid. Transmission expansion impacts the cost to increase after the first iteration, as presented in Figure 8.

Integrating the 5% maximum curtailment criterion in four cases contributed to adding storage capacities. Storage capacities are precisely selected using state-of-the-art formulation found in the literature implementing a deep and fine operational analysis. As a result, Canada's power system total cost for its 30-year planning horizon increased by 24 billion CAD (12%) through the five iterations, including the transmission expansion costs. Curtailment, congestion, and load shedding add costs in real-world power system operation. The earlier estimate of the curtailment costs justifies a significant portion of this cost jump. Therefore, although curtailment is an effective metric that contributes to improving flexibility as feedback to the planning model, finding a cost-effective rate seems crucial. A sensitivity analysis for curtailment rates vs. the system's total costs minus the costs related to congestion, curtailment, and load shedding could identify the specific cost-efficient curtailment rate.

## 3 Chapter 3: Demand response programs: comparing price signals and direct load control

The content of this chapter is submitted and revised once for Energy  
Mohammad Miri, Madeleine McPherson

### 3.1 Abstract

Canada's power system is responsible for 9% of national emissions, 53% of which occur in the province of Alberta. Integrating new variable renewable energy resources is a key part of the supply-side decarbonization pathway, while end-use electrification unlocks further opportunities on the demand side. The inherent variability of variable renewable energy output necessitates network flexibility. Many supply-side flexibility solutions require significant investment; demand-side management programs could deliver network flexibility at a lower cost. An integrated framework consisting of demand and supply models investigates the efficacy of demand response programs for improving network flexibility in Alberta's power system, as measured by multiple operational metrics. The framework is applied to two demand response programs: real-time pricing and direct load control. These programs are assessed for two generation capacity mixes derived from an expansion planning model. Results indicate that substantial network flexibility benefits are achievable in a zero-emission power system via both programs resulting in avoided wind curtailment by 7.7%. Improvement in operational costs, up to 1.4% of the base output, is also observed in all scenarios accompanied by savings in household power bill expenditure by up to 15%. These improvements, however, are only achieved fully when sufficient flexible load is provided.

*Keywords: network flexibility, demand response, linked modeling frameworks, variable renewable energy*

### 3.2 Introduction

Greenhouse gas (GHG) emission mitigation targets established under international agreements have placed a burden on every economic sector to decrease their reliance on fossil fuel resources while transitioning toward more sustainable energy options. Canada has committed to a target of reducing GHG emissions to 30% below 2005 levels by 2030 [1] and aims to reach net-zero emissions by 2050 [2]. Corresponding national-level emissions mitigation goals have been set for all energy and non-energy sectors.

Alberta's power system has significant potential to help reach the targeted goals. While only 9% of Canadian GHG emissions come from the electricity sector as of 2020, this figure rises to 13% for Alberta, which represents 53% of national emissions from electricity production [81]. Environment and Climate Change Canada anticipates an emissions reduction of approximately 64% for the national electricity sector by 2030 [1]. Thus, Alberta's power system plays a pivotal role in the decarbonization of Canada's electricity supply.

GHG emissions mitigation options vary by sector and regional availability of primary energy resources. On the demand side, electric vehicles (EVs) and the electrification of building systems, including electric space heating and building energy management systems, have received considerable attention [32]. The building sector accounts for approximately 11% and 7% of GHG emissions nationally and in Alberta, respectively [81]. This sector can reach a 66% emission reduction by 2030 through electrification [1]. On the supply side, the integration of variable renewable energy (VRE) sources into the power system has been the primary emissions mitigation plan.

Both demand and supply-side mitigation options have far-reaching impacts on the power system. Electrification of end-uses significantly increases demand growth, which requires detailed planning for the provision of sufficient future network and generation infrastructure [82]. Given that VRE resources exhibit pronounced weather-dependent uncertainty, associated technical and operational considerations tend to result in greater complexity of their integration into power systems at higher penetration levels [83].

Pronounced demand growth stemming from electrification coupled with the integration of VRE necessitates enhanced flexibility within power systems. Flexibility is defined as the ability to adapt to changes in demand and supply while maintaining balance over various timeframes [33]. System operators routinely manage daily, weekly, and seasonal demand variations in power systems [17]. In the absence of sufficient system flexibility, VRE output curtailment occurs more frequently, especially in wind capacity [20]. VRE curtailment compensation payments and network congestion issues increase operational costs as VRE installed capacity grows [19]. Therefore, flexibility is an essential quality that, principally, provides the capability for the power system to operate more efficiently and utilize more VRE generation.

There are several available options for enhancing flexibility discussed in the literature, via both spatial and temporal avenues, and on both the demand and supply sides. Demand-side options prominently feature a variety of demand response (DR) programs, such as price incentives for load shifting, real-time price-sensitive scheduling of home heating and cooling, and flexible EV charging schemes. Reserve capacity, storage, and operationally feasible VRE curtailment apply to the supply side, while smart-grid technologies and network expansion affect flexibility at the network level [35]. Other options commonly discussed include power-to-X technologies, heat storage, and energy systems integration (sector coupling) [37].

While most supply-side flexibility options require large investments and significant time for implementation, demand-side flexibility options are typically less capital-intensive. For example, Staudt et al. studied the adequacy of Germany's power grid in the presence of high VRE and EV penetration and found that a coordinated EV charging market facilitates VRE integration while reducing grid expansion requirements [84]. Similarly, Kirkerud et al. suggested that the need for additional peak generation and battery storage in Europe may be alleviated by demand response, even as the share of VRE increases substantially [85]. On the other hand, Miri et al. investigated the supply-

side flexibility potential of storage and network expansion options and found that these resulted in increased investment costs throughout the system [86]. In many cases, demand-side options require lower investment than supply-side options and, in some cases, they reduce the need for peaking and transmission expansion. Stawska et al. also discuss potential local grid congestion that can be caused by unbalanced DR implementation [87].

Many studies have analyzed the potential of DR as a demand-side flexibility option, including identifying associated challenges and barriers. The barriers to the implementation of DR programs primarily involve investment, behavioural, and technological factors. For example, smart meters, smart thermostats, and related technologies are central to the implementation of DR programs but have investment and education requirements [88]. Additionally, uncertainty regarding full costs and the effective signalling of these costs to the market has been identified as another challenge for DR program implementation [89].

However, the benefits of DR programs are widely believed to be greater than their downsides regarding system flexibility and reliability when the programs are well-established in the proper responsive sector [90]. Firstly, DR programs deliver cost savings for consumers through a combination of direct incentives and moving demand to periods with lower prices. Secondly, there is typically a system-wide reduction in costs as low-cost generation capacity is utilized more effectively [91]. Thirdly, raising the utilization of VRE generation results in GHG emissions reductions. Finally, demand response programs reduce capital costs related to expanding peaking and transmission capacities [92].

Due to these benefits, many jurisdictions covering a wide variety of market structures are implementing and experimenting with different DR programs. Torriti et al. state that savings from pan-Europe DR programs would avoid billions of Euros of investments in peak generations and savings in consumers' bills by shifting the load according to price incentives [93]. Kiliccote et al. reviewed fourteen DR programs implemented in different sectors throughout the US before 2019 and concluded the positive impacts of the programs for both large and smaller consumers [94].

Canada is not an exception in implementing DR programs. Currently, there are fourteen active provincial DR programs in Canada, mainly employing incentive-based designs and typically excluding residential loads [95]. Of these, two are applied in Alberta's power system. Alberta Electricity System Operator (AESO) offers a scheduling load reduction program for large consumers that have continuous operations, which can reduce demand by 300 kW within a period of 10 minutes [96]. Additionally, Capital Power has a peak demand reduction program for consumers with more than 1 MW maintained during monthly peak demand events [97]. Alberta has not implemented any residential DR program as of the time of this study.

Depending on the kind of applied program, DR programs contribute to power system flexibility and VRE integration by modifying demand to align more closely with VRE output, although operational and technical details vary by

program type. Programs can be variously categorized by separating them into price-based and incentive-based programs or voluntary consumer-level and direct operator control programs [98]. Price-based, or time-based, programs encourage consumers to shift their consumption from high-cost to low-cost periods via a wide range of dynamic or static pricing schemes. Smart meters can assist consumers in managing their demand in real-time in programs like Real Time Pricing (RTP), while pricing schemes can range from predetermined cost periods to dynamic, market-based prices varying over hours, days, weeks, or years in other program types [99]. Electricity prices are dynamically updated hourly or daily in RTP, and as such, these are often purported to be the most efficient DR program type [100].

Direct load control (DLC) is another important subcategory, including a variety of programs and implementations in different sectors. DLC, as one of the most implemented options, is designed to manage partial loads of small commercial or domestic customers, typically following an alert to the consumer. In the residential sector, controlled assets include those not required on demand, such as air conditioning, space heating, and hot water. To maintain the comfort of the tenants, most schemes provide an opt-out or override option incurring either a fine or loss of the relevant incentive. The current study covers one price-based and one direct operator-controlled program.

DR programs have a wide range of ancillary impacts and are applied within various contexts. As such, there is a large body of literature employing a diverse set of tools to model DR impacts specific to the sector in question, and the relevant DR program and research questions. Boßmann et al. reviewed 117 studies, finding that while the majority cover DR programs in the building and electricity sectors, more work is needed on RTP and DLC programs including their combined impact [101]. Specifically, the automated DR schemes that are designed in this study are analyzed in a work by Samad et al. which conducts research on multiple case studies of implemented similar schemes [102]. Their findings show exceptional output compared to other non-smart schemes in case studies and suggest further research to be done for opportunities to evolve these schemes as virtual power plants in the future.

The objective of the current study is to identify the potential of automated DLC and RTP programs within the residential building sector regarding power system flexibility and the associated impact on VRE integration. The subsequent section reviews modeling efforts in the literature relevant to this specific context and discusses the justification for the present work.

### **3.2.1 DR modeling studies**

Several methods have been applied to analyze the implications of DR in power systems. These methods mainly comprise quantitative modeling tools, such as building simulation models, and power system operation optimization models, and can typically be separated into three categories: demand-side, supply-side, and integrated. Notably, demand-side models cover a broad variety of sectors, including buildings, transportation (prominently featuring EVs), and industrial [103].

Numerous demand-side studies use building performance simulation (BPS) to investigate the potential of DR in relation to energy cost savings, energy management, energy storage options, and transitions toward zero-emissions smart cities. For example, Homaei et al. analyzed battery storage with different models of power tariffs based on the Norwegian power system to calculate optimal battery size for demand-side flexibility [104]. Claus et al. investigated building envelopes and heating systems to compare the contributions of technology options toward flexibility in the Norwegian building sector [105]. In a subsequent study, they investigated the heating system control schemes and their impacts on DR performance in buildings [106]. While many studies include a high degree of technical detail specific to building assets, including envelope, heating and air conditioning systems, and integrated storage, they tend to suffer a common limitation: power system and energy supply aspects are mainly modeled as exogenous. Thus, these studies are not designed to assess the supply-side impacts of DR programs. Consequently, there is no feedback from changes in supply stemming from DR implementation to many demand-side model parameterizations.

Supply-side modeling efforts mainly represent DR implications by altering aggregate demand curves through the introduction of constraints and assumptions following the goal of finding impacts of demand response on the requirements and operation of electricity systems, e.g., spinning reserve capacities, loss of load, etc. Several studies have attempted to overcome limitations common to these models. McPherson et al. attempted to overcome drawbacks related to high-level assumptions involved in altering aggregate demand by introducing high-resolution constraints to the simulation of DR events, including their duration, frequency, and time between sequential events [107]. Imani et al. studied distinct DR programs to identify their impacts on total operational costs, customer savings, and load curves in a sample microgrid but did not include any analysis of the potential for VRE integration [108]. These supply-side models have no representation of the demand-side impacts of DR implementation, e.g., the impacts of load curve changes on electricity prices. Canteli et al. note demand-independent pricing, resulting in suboptimal DR performance based on exogenous historical price data, as another drawback of supply-side DR studies [109].

Integrated supply- and demand-side studies try to minimize the drawbacks of considering whether demand or supply is in isolation, often using coupled modeling frameworks. For example, Wang et al. introduced a multi-objective optimization formulation that maximizes indoor comfort for a sample building while minimizing the operational costs of only a detached power and heat cogeneration plant [110]. Nyholm et al. linked a building stock model to a limited power system dispatch model to analyze heating operations on an hourly basis, without a detailed representation of transmission or generation assets [26]. Angenendt et al. modeled an integrated system consisting of heating, thermal storage, a solar photovoltaic (PV) array, and battery storage for the scale of a single house [111]. Seattle et al. developed and applied bi-directionally linked demand and supply models at the city scale, using wind

curtailment as the only signal for DR events under assumptions of fixed load in non-DR sectors [112]. While the latter includes an integrated building and power operation model, most of the studies have linked modules that only capture a small part of the analyzed systems, due to their computational complexity.

Other studies tried to cover other aspects of DR, their implementation, efficiency, and effectiveness. Boßmann et al. categorize these studies into two groups of control strategies and pricing schemes and subcategorize them into the impacted sector, either end-uses or electricity system [113]. Studies on pricing schemes mainly focus on electricity pricing, demand elasticity, and their implications on either the performance of power systems or electricity consumption, as studied by [114]. They usually lack insight from both impacted sides at the same time and analyze only the demand side or the supply side. Studies in the second category cover control strategies for implementing DR programs. They mainly focus on the effects of DR implementation technologies in single or multiple end-uses, e.g., EVs, thermostatic loads like heating, etc., or on electricity loads, like the study by Shao et al. [115]. Studies in this category rarely cover the impacts of such load changes on the operation of the power system. Table 6 summarizes the methods, achievements, key findings, and shortcomings of the selected studies in the literature that used linked or integrated frameworks.

*Table 6 Summary of selected studies analyzing the role of DR programs in integrating large shares of VRE capacities*

<i>Study</i>	<i>Methods/Models</i>	<i>Achievements</i>	<i>Key findings</i>	<i>Shortcomings</i>
<i>Wang et al. [110]</i>	Multi-Objective optimization of operation costs and comfort level	Proposed an operation model for building energy systems with time of use pricing scheme	Aligned dispatch of source, load, and storage, while maintaining comfort levels and low costs	Exogenous impact from and to the grid, only local generation/storage is impacted, and electricity prices are fed exogenously
<i>Nyholm et al. [26]</i>	Building stock model linked to load shifting sub-model	Developed a sub-model capable of optimizing the load shifting based on spot prices and constrained to indoor temperatures	Significant shifting load is available through space heating, winter load shifting led to more hours in load increase rather than load decrease	A single detached house is analyzed, the sub-model is not capable of capturing power systems dynamics, nor calculating prices endogenously
<i>Angenendt et al. [111]</i>	Single building model including a PV solar plant and battery storage	Integrated generation, storage, and load management of a single house, using a lifetime investment and operation costs minimization	Coupled storage and power-to-heat systems can reduce costs for the demand-side and increase self-sufficiency, Efficiency reduction happens if heat storage is considered an option	Exogenous grid connection and electricity exchanges, no system-wide impacts studied for both building stock or power system

*Seattle et al.*  
[112]

Linked framework of the building, EV, and power system's DC unit commitment at city scale	Proposed a linked framework of a power system operations model with building stock and EV charging models, including the retrofitting options for both sectors	Incorporating demand response strategies makes the case's decarbonization targets achievable, but increases the electricity prices for consumers	Fixed sectoral load profile other than building and EVs, DR scheme design solely based on wind curtailment occurrence, exogenous capacity expansion based on estimation
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The present study proposes a novel approach to cover the discussed shortcomings of the various studies available in this domain. Namely, a coupled, iteratively solved modeling framework is developed for the analysis of demand-side flexibility options in residential buildings, in the context of a power system with high VRE penetration. Critically, this framework captures both demand- and supply-side implications stemming from DR deployment, in contrast to much of the reviewed literature. This includes the impacts of electricity prices on both demand- and supply-side and the effects of changing the load from the DR implication on the electricity system. Using both demand- and supply-side metrics as bidirectional signals offers a means to produce more reliable and detailed insights regarding DR as a flexibility option. The current study also goes beyond previous studies by analyzing the impacts of the DR programs on the integration of VRE resources. It also addresses shortcomings regarding the abstract representation in both demand and supply-side modeling. As such, the proposed method effectively tackles drawbacks characteristic of predominant modeling tools which treat supply and demand as independent.

The very contributions of this work are as follows:

- The integrated modeling framework implements a capacity expansion planning model to explore the potential paths to follow electrification, and deep and net-zero targets in the power system. Therefore, the impact of DR is assessed on an optimized generation portfolio instead of an estimated expanded grid;
- A detailed building energy simulation model represents realistic and real-time load curve changes impacted by DR, such as the rebound effect discussed by Tomat et al. as a new peak created after a DR event [116];
- Load shifting is aimed at maintaining residents' comfort by moving the load in time rather than investigating peak shaving;
- Current work investigates the impacts of load curve changes stemming from a DR event on power system operating costs and electricity prices at the same time, which provides the opportunity to discuss economically optimal VRE curtailment rates under DR programs.
- The linked modeling framework incorporates a load curve prediction model, enabling the inclusion of fluctuating non-DR loads;

- The linked data flow uses marginal prices and flexibility metrics, i.e., VRE curtailment and network congestion, which allows a wider range of insights and a more robust representation of RTP and DLC programs;
- The linked framework is developed in a state-of-the-art automated data management framework using data management tools that ensure repeatability and consistency in the linkage workflow. DR implementations are also automated using EnergyPlus measures capabilities for Building Management Systems (BMS).

The following section covers the methodology details used in this study. Then, the results from the developed scenarios are presented, followed by a discussion and conclusion.

### **3.3 Methodology**

This study introduces a framework that incorporates two linked models: a demand-side building archetype energy simulation program (EnergyPlus) and a supply-side power system operation optimization model (Strategic Integration of Large-capacity Variable Energy Resources - SILVER). Consequently, the framework proposed here falls into the integrated category discussed in the introduction.

This section outlines the two primary models, data flows and sources, and the linking structure and process, as summarized in Figure 10. In summary, after data is prepared and fed into models, a set of runs is done for the capacity expansion planning model to develop the generation portfolio. The generation portfolios for each scenario are translated to be assessed via the bidirectionally linked section of the framework.

In the iterative part, the generation portfolio and proper load profile are first run by the power system's operational model. DR events are then triggered based on the program's design to resolve flexibility issues. Then the building simulation model responds to the DR triggers and the updated demand profile is sent to the production cost model to analyze for improvement in flexibility metrics as the feedback in the bidirectional loop. Each iteration starts with an operational simulation for the power systems and ends with an archetype simulation by the building energy model. This iterative loop continues until no further improvement is available. Details of each step are described in the following subsections.

#### **3.3.1 Input data preparation**

The input data flow for this framework is illustrated on the left side of Figure 10. The provincial power system representation is populated primarily by transmission network and generation capacity data gathered from the system operator, e.g., BC Hydro, Alberta Energy System Operator (AESO), etc., and various other publicly available data from Statistics Canada contained within the Canadian Open-source Database for Energy Research and Systems Modeling (CODERS) database [74]. Unknown parameters, such as line reactance, are estimated using standard methods available in the literature [117]. Wind and solar capacity factor data are based on historical potential data

from Modern-Era Retrospective Analysis for Research and Application (MERRA-2) [118]. The data are then translated to capacity factors using methods presented in a work by McPherson et al. called GRETA (Global Renewable Energy Atlas and Time-series) [119].

### 3.3.1.1 *Projected power system portfolios*

A supplementary translation tool is used to prepare future power system configuration scenarios (from a third model outside the bidirectional linkage, Canadian Opportunities for Planning and Production of Electricity Resources COPPER) as inputs for the optimization model. This study incorporated a data linking tool developed by Miri et al. to translate COPPER outputs future configurations for Alberta's power system [86]. Data management and linking tools were based on the previous study, but improved for the current research, to include proper representation for the specific case of Alberta. These improvements include proper hydro facilities translation in terms of location for specific projects and improved vectorized calculations for efficient performance.

COPPER is a capacity expansion model that optimizes generation and transmission capacities at the national level based on defined technology costs, VRE potentials, and demand profiles characterizing various scenarios. COPPER follows linear mixed integer optimization for cost minimization of Canada's power system projection plans. Linear mixed integer formulation allows for efficient optimization convergence and binary adaptation of some parameters like project-based hydro expansion decisions. The main cost minimization formulation is as follows:

$$\min \text{system}_{totalcosts} = \text{cost}_{investment} + \text{cost}_{production} + \text{cost}_{operation \& maintenance} + \text{cost}_{carbon}$$

This minimization function is subject to various constraints which the most important ones are 1) hourly demand and supply balance, 2) planning reserve margin per location, 3) thermal unit technical constraints such as ramp rates and capacity factors, 4) hydroelectric constraints for different hydro facilities, 5) VRE hourly capacity factors and land use per location, and 6) Transmission and storage constraints.

Basing the current work on COPPER outputs allows a realistic representation of power system decarbonization pathways, as described in the Scenarios section below [6]. These scenarios are exogenous to the iterative procedure and, as such, are treated as constant. This is considered a reasonable assumption for the purposes of the current study as COPPER considers representative days only for the balancing of demand and supply, and aggregate adjustments made to building sector demand are considered to be minor compared to overall peak system demand.

### 3.3.1.2 *Sectoral hourly demand profiles*

This study uses an open-source statistical model, Demand for Energy Services, Supply and Transmission in Europe (DESSTINE), to produce sectoral demand profiles under two distinct scenarios [120]. With the lack of complete predictions from the load curves in Alberta, this tool ensures that sectoral demands are accounted for and not assumed to be fixed. The sectoral demand categorization proposed by Andersen et al. was used which enables capturing further electrification or base scenarios for each sector [121]. DESSTINE is an open-sourced statistical

model developed to predict future electricity demand using macroeconomic and historical data for energy use as inputs, in addition to scenario-based population, economic growth, and electrification rate projections [122]. It uses normative scenarios like IEA's (International energy agency) Energy Technology Perspective [123], and IIASA's Global Energy Assessment Roadmap [124] to project energy end use based on macroeconomic parameters such as population, income, energy prices, and details from each sector. It accounts for efficiency improvements, electrification, and base year technology mix to calculate primary energy supplies [125]. Then the electricity profile is generated by using pre-defined daily demand profiles for both winter and summer and for weekdays and weekends. Then it adds stochastic factors to account for natural variation [126]. Finally, it scales residuals based on the difference between the actual and simulated demand curves to preserve the exclusive features of the historic load.

This model has been used in similar studies. For example, Staffel et al. used DESSTINE to study the implications of weather variations on demand curves in Britain [127], and Omotola et al. used this model to project demand curves in support of power system planning for 14 Western African countries [128]. Data from Natural Resources Canada was used to populate the macroeconomic and sector-based energy use model inputs [129]. Population growth data for the model is also captured from Canada's Energy Future estimates [4].

### **3.4 Linkage strategy**

Input data illustrated on the left side of Figure 10 are exogenous to the iterative coupled framework. The general bidirectional data flow through the iterative process consists of two basic steps: first, passing the building sector demand profile to the power system operation model, and second, feedback to the building archetype model to modify demand as a response to VRE supply for a specific period. These steps are iteratively repeated until curtailment and costs can no longer be reduced.

Managing data flows between models, with various data structures, are managed automatically by data management Python scripts and mathematical, statistics, and data libraries like Pandas [130] and NumPy [131]. The models' deployment and runs are managed manually.

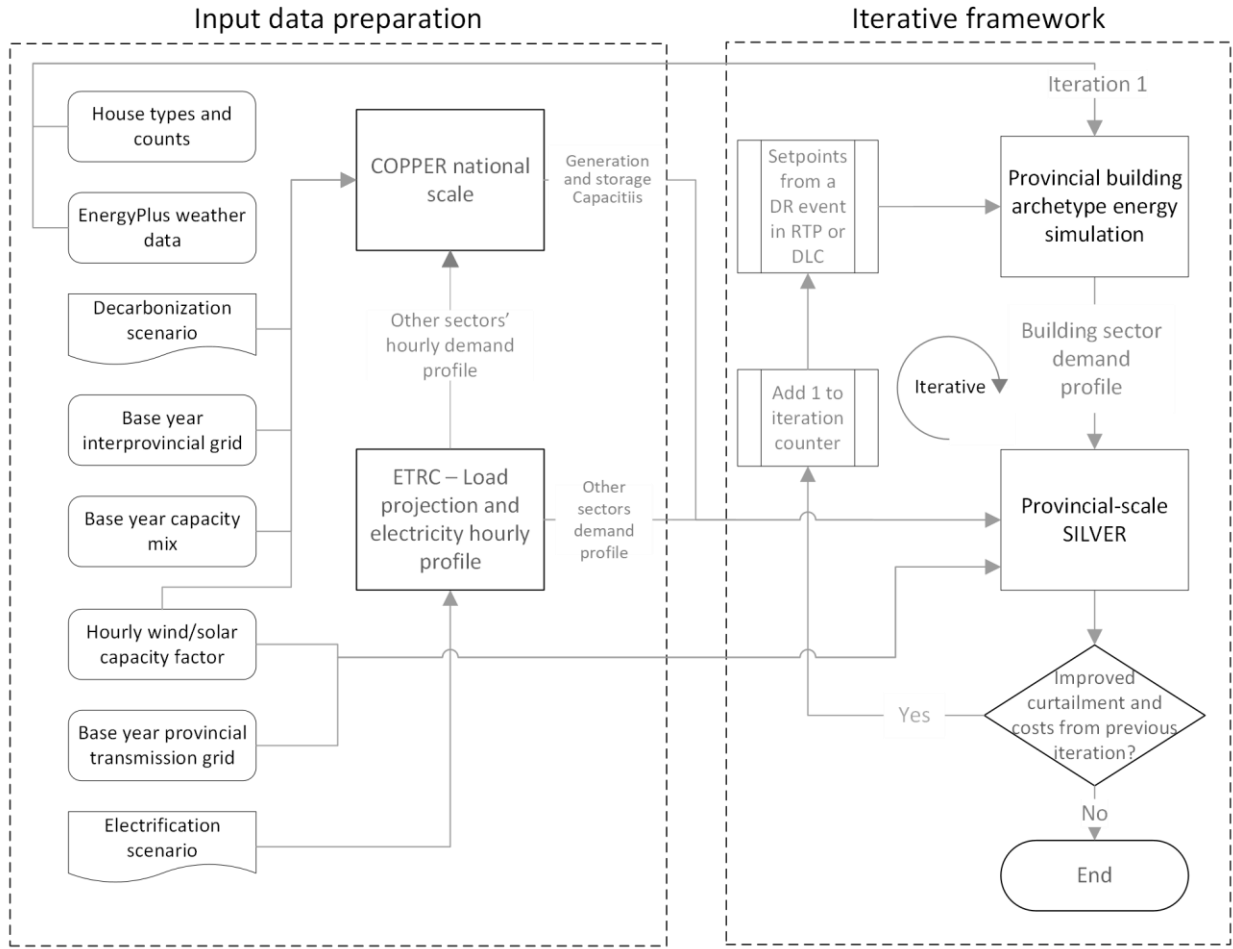


Figure 10 Modeling elements and data flow (left: input and scenario data preparation, right: iterative, bidirectional coupled framework)

### 3.4.1 First pass: building sector demand profile

The initial data pass consists of the building sector demand profile and demand projections for other sectors from DESSTINE supplied to the system operation model. The building archetype model used within the iterative coupled framework uses EnergyPlus and Openstudio software to simulate hourly heat exchange between building envelopes and their environment and has been previously utilized in other studies [132]. Building geometries, size, construction materials, and window locations are specified for each archetype based on the census data for the dwelling types in the province [133]. The aggregate annual hourly demand profile is constructed by scaling proportionately by census house type counts and then their participation in the program explained further below. The developed load profile is validated in comparison to the historical load profile of the base year of 2018. Different archetypes included in this model have heat pumps as their main heating device controlled by a controllable smart thermostat followed by the

governments of Canada Greener Home program rebating heat pumps installation [134]. The amount of electrification through heat pumps though varied between scenarios as discussed further in the related section.

Space heating is simulated as flexible using 21 °C as the base business-as-usual temperature in the first iteration. Measure files are automation scripts based in the Ruby language which are used to represent different interventions through the building simulations, like energy management tools, etc. This study used measure files to simulate DR programs by establishing new temperature setpoints for building archetype desired heating states. DR programs are not analyzed for cooling usage in the warmer months and are out of the scope of this study.

Temperature setpoints were selected as the building archetype model variables. Reducing space heating setpoints decreases winter demand and raising it results in an increase in the load. These capabilities are used to respond in DR events to instances of power system inflexibility. The precise way these setpoints are modified can be used to represent various DR program designs.

To use the building energy simulation results over the larger provincial scale, hourly load profiles are multiplied by the number of houses reported in the census data. However, to have a better estimation of the energy requirements from the building sector, the building simulation results are calibrated with the annual total energy use reported in [129]. At the time of the study, there is no publicly available report for the sectoral hourly energy use for Alberta. Therefore, annual energy use is the best source to rely on for estimating sectoral use.

The study considers the following assumptions to simplify the modeling for the large modeling spatial scale as it is used in other building archetype models. First, the model consists of three different building types, and the configuration stays the same over the simulation horizon. The load from the building stock changes by including a greater number of buildings in the power demand. Second, the shape of the buildings is simplified as there is no detailed data for the building configurations that cover the whole province of Alberta. And if there is such data, creating the model would be out of the scope of the current study. Finally, historic weather and temperature data are also employed as modeling inputs.

### **3.4.2 Second pass: system operation feedback to the demand-side model**

The power system operation model, SILVER, is used to trigger and simulate DR events. The SILVER version utilized in this study uses a unit commitment formulation to identify minimum cost power system operation subject to hourly demand and supply inputs over the course of one year [68]. The model has been specifically developed to analyze Canadian provincial power system operations [69] and uses an hourly time resolution, which is in line with the accepted state-of-the-art for power system operation models [71].

System simulation in SILVER is performed for the provincial transmission network using a DC load flow approximation, omitting line reactance to reduce computational intensity and a justified estimation for high voltage

grid configurations [135]. This study is focused on the higher provincial scale and the distribution network with lower voltage levels is not included in the grid configuration. As such, the building stocks in the network are connected to the transmission nodes without distribution losses and configurations.

SILVER employs linear mixed integer UC (Unit Commitment) formulation which the objective function is abstracted in the following mathematical representation. Mixed integer formulation allows the model to account for the on or off status of the power plants and linear formulation guarantees an optimal solution and keeps the computational requirements manageable.

$$\min \sum costs_{t,g} = costs_{operation} + costs_{maintenance} + costs_{fuel} + costs_{emission}$$

The optimization function is solved at every timepoint for every  $t$  and every generation facility  $g$ , and is subject to constraints including 1) load and supply balance at each hour, 2) ramping constraints based on the technology, 3) maximum and minimum generation constraints for both thermal and VRE technologies, 4) transmission flow constraints, and 5) yearly capacity factor constraints.

Both DR programs considered here use price outputs to trigger DR events. Therefore, pricing schemes have a direct impact on the simulation of DR programs. As suggested by current studies such as by Heptonstall et al., electricity costs should fully account for operational inflexibilities as indicated by VRE curtailment, network congestion, and load shedding [136]. However, system operation costs are case-specific and sensitive to scenario details, including extant network assets, their attributes and configuration, and generation capacities. Nodal marginal pricing (MP) reflects locational costs arising from patterns in demand, generation, and transmission system constraints, and are subject to congestion, varying generation mixes over time, and generation deficits [137]. SILVER calculates MP based on operational costs for each generation type and the dispatched generation pattern for each hour and reports the corresponding results at the level of transmission buses.

Marginal prices can signal flexibility issues in a variety of ways. First, in terms of generation patterns, as VRE operational costs are lower than conventional, non-VRE generation types, fluctuating VRE output is utilized preferentially requiring flexibility in non-VRE capacities to keep supply and demand in balance. Second, in terms of transmission network constraints, VRE output is only fully utilized if there is sufficient network capacity available, and thus different MPs between adjacent nodes can signal constrained transmission. Third, using marginal prices can capture benefits in multiple levels of the interconnected markets. From the generation perspective, reduced marginal prices ensure the supply-side benefits from reduced costs of electricity. From the transmission point of view, using signals that include the marginal price disparities between locations guarantees that the congestion is reduced. And from the consumer perspective, it reduces the electricity charges by signaling to shift the load to hours

with lower costs. Therefore, marginal price is utilized within the formulations of the two DR programs in consideration, as described below.

### 3.4.2.1 DR program 1: Real-time pricing

The RTP program relies solely on marginal prices to trigger DR events. This assumes participating customers are fully aware of real-time prices and can respond accordingly using smart meters, thermostats, and other technological means. The price-based trigger uses a 24-hour moving horizon to determine a high-price threshold (HPT) and low-price threshold (LPT). For each hour, the spot price is checked against these thresholds. For this study, an LPT of 5% above the 24-hour minimum price and an HPT of 95% of the 24-hour maximum were selected. This narrow threshold band is justified by the price inelastic electricity demand reported within Canada by different models according to a study by Latif et al. [138]. Price inelasticity implies that end users are rarely willing to change their demand based on their reflected bills of higher electricity prices. As such, a narrower threshold would imply that the end users are only willing to change their demand or respond to a DR event, only when the prices are too high, or too low.

$$MP_{LPT} = MP_{min}^{day} + t_l \times (MP_{max}^{day} - MP_{min}^{day}) \mid MP_{HPT} = MP_{min}^{day} + t_h \times (MP_{max}^{day} - MP_{min}^{day})$$

In which  $t_l$  and  $t_h$  stand for lower and higher thresholds, and  $MP_{max}^{day}$  and  $MP_{min}^{day}$  stands for daily maximum and minimum marginal prices.

The setpoints temperature for space heating in the building archetype model are uniformly adjusted based on the average spot price outputs produced by SILVER. If the price in a given hour is below the LPT, the temperature setpoints are increased to 23 °C. If the spot price is above the HPT, the setpoints are decreased to 19 °C to delay the start of the heating. If the spot price of the current hour is between the LPT and HPT, the temperature setpoints remain at 21 °C. The mathematical abstract formulation is presented below.

$$\begin{aligned} & \text{if } MP_h > MP_{HPT} \\ & \text{then: } TS_h = TS_{min} \\ & \text{else if } MP_h < MP_{LPT} \\ & \text{then: } TS_h = TS_{max} \end{aligned}$$

In which,  $MP_h$  is the marginal price in the specific hour,  $TS_h$  is the setpoint temperature for the specific hour of the DR event, and  $TS_{min}$  and  $TS_{max}$  is the minimum and maximum defined setpoint temperatures. These altered setpoints are selected to remain within the range of typical thermal preferences [139].

### 3.4.2.2 DR program 2: Direct load control

DLC is used to control demand directly during DR events to manage various flexibility issues such as demand peaks, supply shortages, and transmission network congestion. As with RTP, DLC is also assumed to be implemented in residential buildings via technological devices including smart thermostats. In contrast to RTP, DLC DR events utilize

a more complex heuristic to modify temperature setpoints in participating buildings. Network operators apply three primary criteria to trigger a DR event: 1) emergency situations affecting generation, transmission, or distribution assets, 2) MP, and 3) adverse weather conditions such as extreme temperatures that are likely to sharply increase demand. DR events are typically triggered manually at the partial discretion of network operators, which can be suboptimal in some cases [25].

To represent DLC, a price-based congestion metric is applied in addition to the price-based thresholds detailed above to trigger DR events. The coupled framework determines these metrics by comparing MP at different nodes. For example, when variations in nodal MP stem from un-dispatched low-cost generation capacity due to transmission capacity limits, or when sum generation capacities are insufficient to meet system demand, congestion is assumed to be occurring. The following formulation represents the DLC triggering events mathematically:

$$\begin{aligned}
 & \text{if } MP_h > MP_{HPT} \text{ and } MP_h \neq LMP_{ave} \\
 & \text{then: } TS_h = TS_{min} \\
 & \text{else if } MP_h < MP_{LPT} \text{ and } MP_h = LMP_{ave} \\
 & \text{then: } TS_h = TS_{max}
 \end{aligned}$$

In which,  $LMP_{ave}$  stands for the average of the location of marginal prices. When congestion-based MP signals co-occur with spot prices outside of price-based thresholds, a DR event using DLC is triggered. However, the systems' operator has a different sensitivity to the operation costs. Therefore, the thresholds are selected to be wider, 10% for the DLC criteria. When these criteria are met, temperature setpoints are modified as per the procedure described above for the RTP program.

The exit criterion is explained in the following formulation in which  $E_{t,g}$  is the available energy for VRE capacities  $g$  in hour  $t$ , and  $P_{t,g}^{iter\ n}$  is the output of that capacity  $g$  in hour  $t$  representing the outputs of iteration number  $n$ .

$$\begin{aligned}
 & \text{if } \sum_{g=1}^G \sum_{t=1}^T E_{t,g} - P_{t,g}^{iter\ n} \geq \sum_{g=1}^G \sum_{t=1}^T E_t - P_t^{iter\ n-1} \\
 & \text{and } TotalCost_{oper}^{iter\ n} \geq TotalCost_{oper}^{iter\ n-1} \\
 & \text{then: exit iterative loop} \\
 & \text{else if } \sum_{g=1}^G \sum_{t=1}^T E_{t,g} - P_{t,g}^{iter\ n} < \sum_{g=1}^G \sum_{t=1}^T E_t - P_t^{iter\ n-1} \\
 & \text{or } TotalCost_{oper}^{iter\ n} < TotalCost_{oper}^{iter\ n-1} \\
 & \text{then: run(DLC or RTP) and add 1 to iteration counter}
 \end{aligned}$$

Where the operational total cost  $TotalCost_{oper}^{iter\ n}$  is calculated based on the model's objective function output:

$$TotalCost_{oper} = \sum_{t=1}^T \left\{ \sum_{g=1}^G [C_g(P_{t,g}) + C_{c(g)} \times |u_{t,g} - u_{t-1,g}|] + M_t \times \sum_{s=1}^S P_{t,s} \right\}$$

Where the  $C_g$  is the generator's cost function depending on the power output  $P_{t,g}$  at time  $t$ . The startup and shutdown costs  $C_{c(g)}$  are applied when a generator's status  $u_{t,g}$  is changed between successive hours.  $M_t$  is the marginal cost for the hour  $t$  in the storage facilities.

### 3.5 Scenario details

The impactful parameters in the analysis of the current study are VRE penetration rate and electrification. The VRE penetration level is a sensitive parameter as this study aims to analyze changes in the importance of DR with varying degrees of VRE predominance. A high VRE penetration case is established based on a strict zero emissions constraint and the future availability of proven technologies only. A low VRE penetration case applies a net-zero constraint but allows additional generation options including gas-fired plants with carbon capture and storage. Different VRE penetration levels are achieved by analysis within the COPPER model in the input data preparation phase.

Another set of critical parameters relates to future demand profiles, which will significantly impact the availability and efficacy of DR programs. Demand projections depend largely on expectations regarding the degree of electrification, represented here by high and low cases. These projections result in the total annual demand in 2050 to be 2.1 times the base year 2018 for the electrified case, and 1.3 times in the low electrification case. The high electrification case is paired with high VRE penetration as these outcomes are deemed likely to co-occur, and similarly, low electrification is paired with low VRE penetration to produce two basic scenario types for use in this study. This assumption follows the pattern from Canada's emission mitigation targets, as the reductions are targeted in all sectors, thus the higher electrification in all sectors is most likely to occur when the power system follows the mitigation goals via integrating more VREs in the system [1]. If the system does not follow deep decarbonization in the power system, then it is more likely that other sectors will miss the mitigation targets as well. Table 7 summarizes the most important parameters and variables considered in defining scenarios.

*Table 7 Most important parameters used to build the scenarios*

<i>Parameter</i>	<i>High VRE, high electrification (ELEC, zeroemit)</i>	<i>Low VRE, low electrification (BAU, emit)</i>
	<i>Demand growth rate (2050/2018)</i>	2.1

<i>Gas carbon capture and storage</i>	Not allowed	Allowed
<i>Carbon pricing from 2022 to 2050 (\$/ton)</i>	\$50 to \$370	
<i>Wind land-use constraint (MW/sq-km)</i>	2	
<i>Interprovincial grid expansion</i>	Allowed up to threefold of the current capacity	
<i>Emissions in 2050</i>	Zero	Non-zero, only allowed with CCS

Carbon pricing ranging from \$50 in 2022 to \$370 in 2050 per ton CO<sub>2</sub>e is utilized for both scenarios. This pricing scheme follows the federal increasing prices of \$15 per year from 2022 to 2030 (reaching \$170 per ton CO<sub>2</sub>e) and then a \$10 increase per year until 2050 (reaching 370 per ton CO<sub>2</sub>e) [140].

The two capacity outlines are operationally analyzed with a representative range of DR program participation rates: from 10% to 25% of the residential building stock. The effectiveness and impact of DR programs are analyzed using operational costs for 2050 (in 2018 CAD), percentage of wind curtailment improvements, and wind integration improvements (additional output, in MWh). The resulting changes in the load curve based on programs, participation rates, and electrification and VRE penetration scenarios are analyzed.

### 3.6 Results

This section presents outputs from the capacity expansion planning model and delivers analyses of different aspects of the implemented DR programs and their impact on the system's operation based on the iterative linkage method.

#### 3.6.1 Generation expansion plan for two input scenarios

COPPER plans for the expansion of the power system to meet the different constraints for emissions and two input demand growth scenarios as described in the previous section. Results presented in Table 8 show that biomass and gas-fired generation lacking carbon capture and storage (CCS) will be phased out by 2050 for both scenario types due to the net-zero emissions constraint. Notably, gas-fired capacity with CCS expands substantially if allowed under the net-zero constraint; this appears to happen in place of more than 6 GWh of storage which would otherwise be

required in the high VRE case to support flexibility requirements. No storage is built for the low load and low VRE scenario, as the variability in relatively smaller VRE capacities is well captured by flexible Gas CCS plants which can support the times VREs are not available. Solar PV also plays a larger role in the low VRE case as a lower electrified demand can be met effectively by the cheaper solar PV even with a lower capacity factor compared to wind.

*Table 8 Proposed plans for generation and storage capacity in 2050 for the two scenarios compared to the base year*

<i>Scenario type</i>	<i>Simple Cycle Gas (MW)</i>	<i>Combined Cycle Gas (MW)</i>	<i>Gas with Carbon Capture and Storage (CCS) (MW)</i>	<i>Biomass (MW)</i>	<i>Wind (MW)</i>	<i>Solar Photovoltaic (PV) (MW)</i>	<i>Hydro (MW)</i>	<i>Storage Lithium Battery (LB) (MWh)</i>
<i>Base year (2018)</i>	1,134	14,140	-	423	3,303	1,333	924	-
<i>High VRE, high electrification 2050</i>	-	-	-	-	74,288	4,995	-	6,545
<i>Low VRE, low electrification 2050</i>	-	-	9,586	-	19,603	13,333	-	-

In the zero-emission and high VRE scenarios, the system requires a considerably larger firm capacity with the absence of conventional generation capacities. Therefore, it largely selects wind capacities over solar PV which have considerably higher capacity factors. For both scenario types, the wind is the most prominent generation capacity, growing by almost 6-fold and 22-fold from the base year value in the low VRE and high VRE cases, respectively (in the latter, to balance highly electrified demand with a lack of conventional generation capacity). The required firm capacity is provided by Gas accompanied by CCS in the net-zero scenario. Selecting Gas CCS, since gas plants are currently abundant in Alberta, is in accordance with the latest established regulations in Canada which allows for further implementation of such technologies to reach targeted goals by 2050 [141]. This technology, compared to others such as hydrogen, has seen more implementation historically and has more realistic cost projection curves as a result. It is also notable that hydrogen technology in particular, only reaches low levels of emissions when sourced from renewables or accompanied by CCS when produced from fossil fuels [142]. As a result, this study excludes hydrogen from the range of obtainable technologies for Canada’s power system transition.

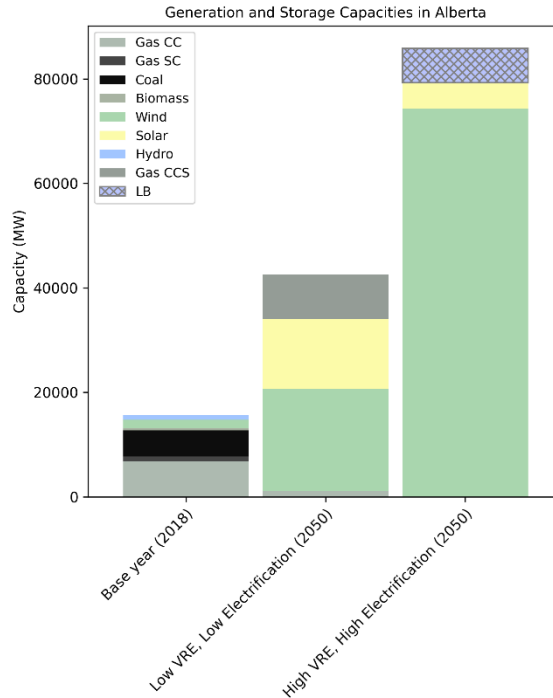


Figure 11 Generation portfolio based on the capacity expansion outputs for two input scenarios

The outlined generation portfolios for the two scenario inputs are analyzed using the iterative linked framework. The impacts of implementing DR programs are then assessed through the iterative linked models. Different implications of the DR programs, participation rates, and iterations are discussed in the upcoming subsections.

### 3.6.2 Participation rate and effectiveness of DR implementation

One of the main features of the method used in this study is realistically representing DR events in the affected buildings and the impacts of this implementation on the power system. These impacts can be varied by the share of the building stock that is participating in the program. The results for different participation rates are presented in Figure 12. In general, there is a positive impact from adding more participating building stock to the demand response program. Both operational costs and wind integration are generally improved in higher participation rates. The effectiveness of the impacts between different participation rates is, however, varied.

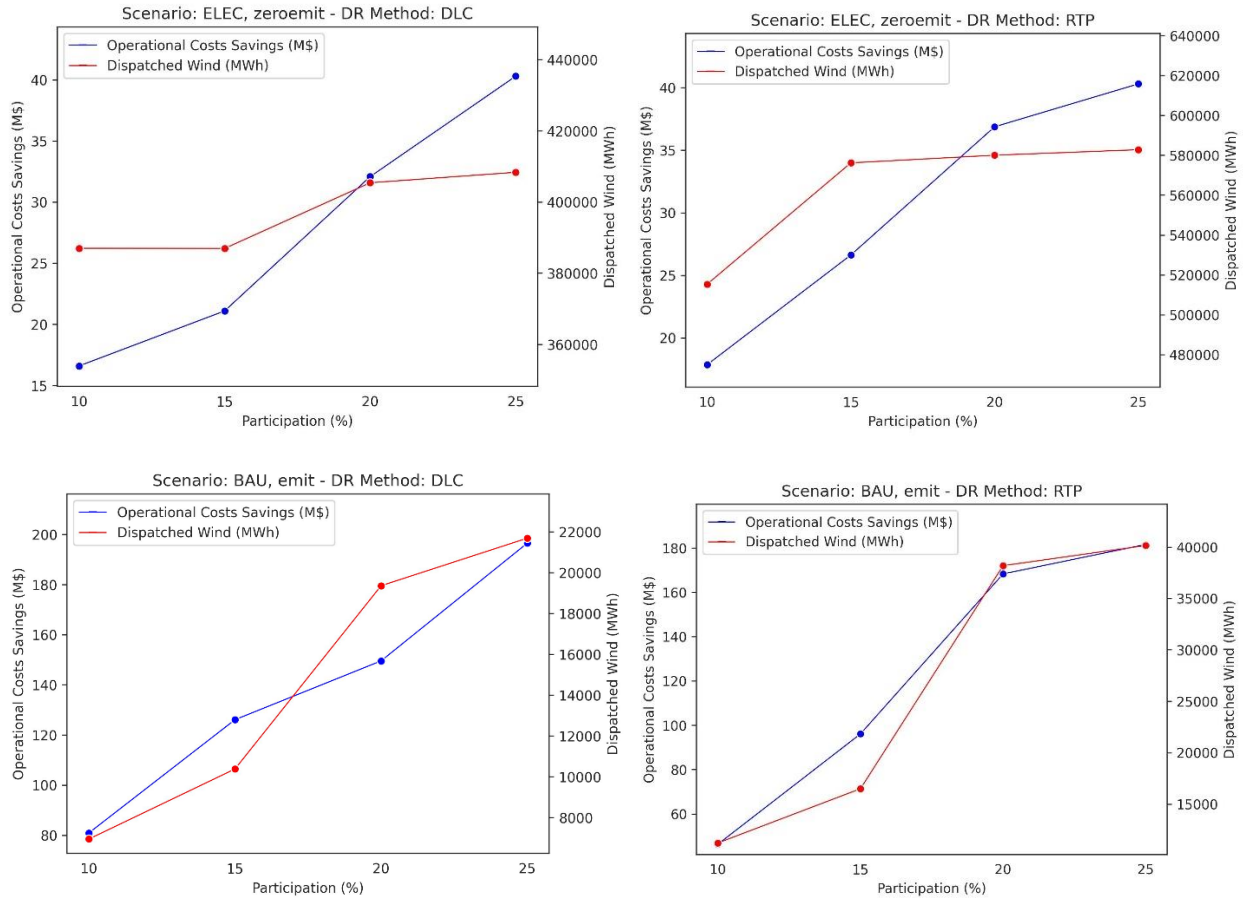


Figure 12 Impact of participation rate on operational costs and improvements in wind integrations (Note: ranges for y axes are different for clearer visualization)

Savings in operational costs are mainly improved by increasing participation rates for DLC. However, RTP mainly benefits from the improvements in operational costs up to 20% participation rate and the improvements are minor after that. This difference stems from the fundamental difference in the design of triggers for the two programs. Larger bulks of moved energy from higher prices to lower prices by triggers in RTP at 25% participation would settle to a generally more harmonized cost for the 24-hour period. The high price threshold cannot capture sharp increases in the marginal prices when they are generally in a narrower range. Therefore, the effectiveness of designed RTP triggers is limited by adding more participating buildings. However, the overall impact is seen to be the same for the two programs, while the wind integration gains are shown to be the same.

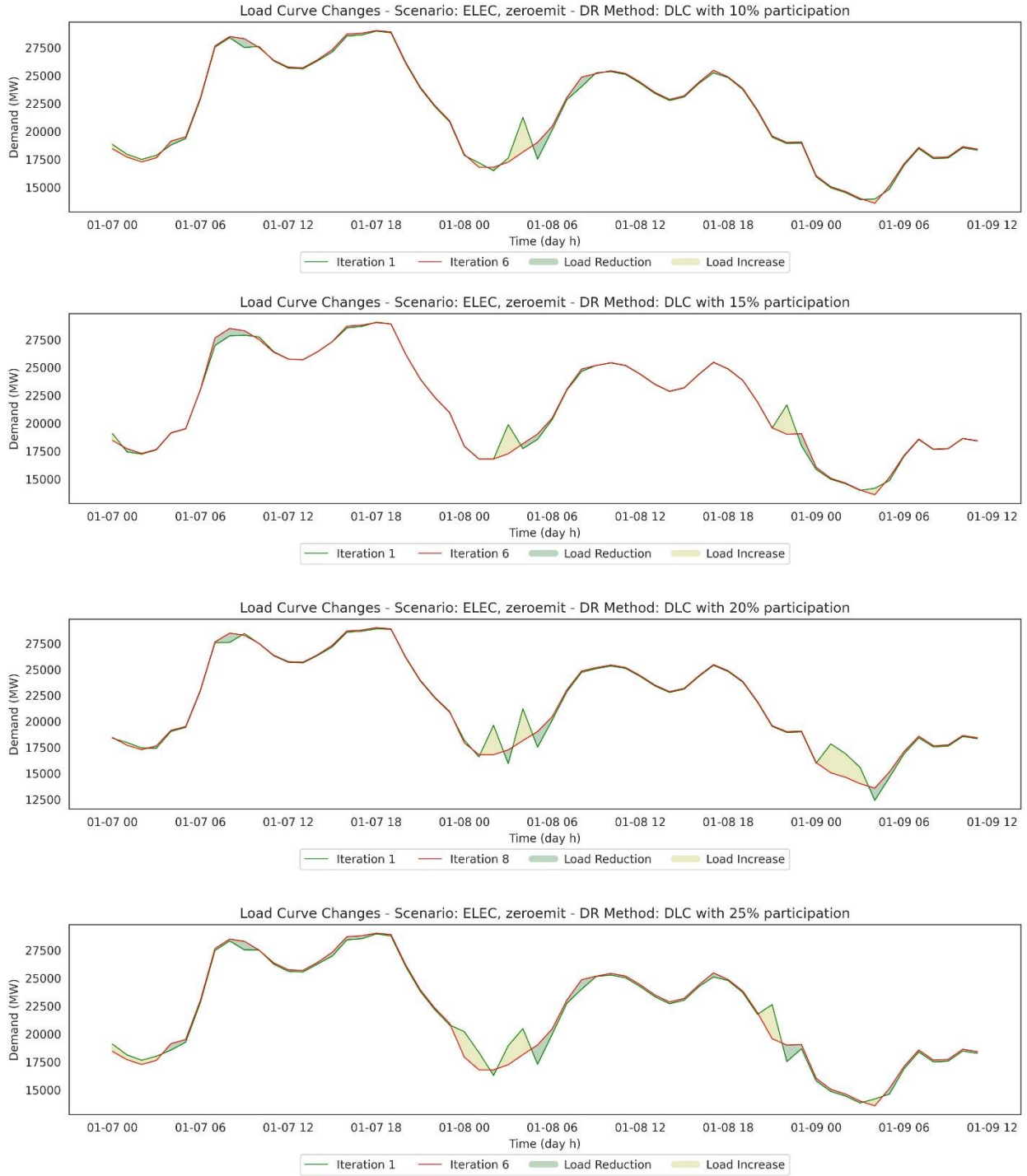
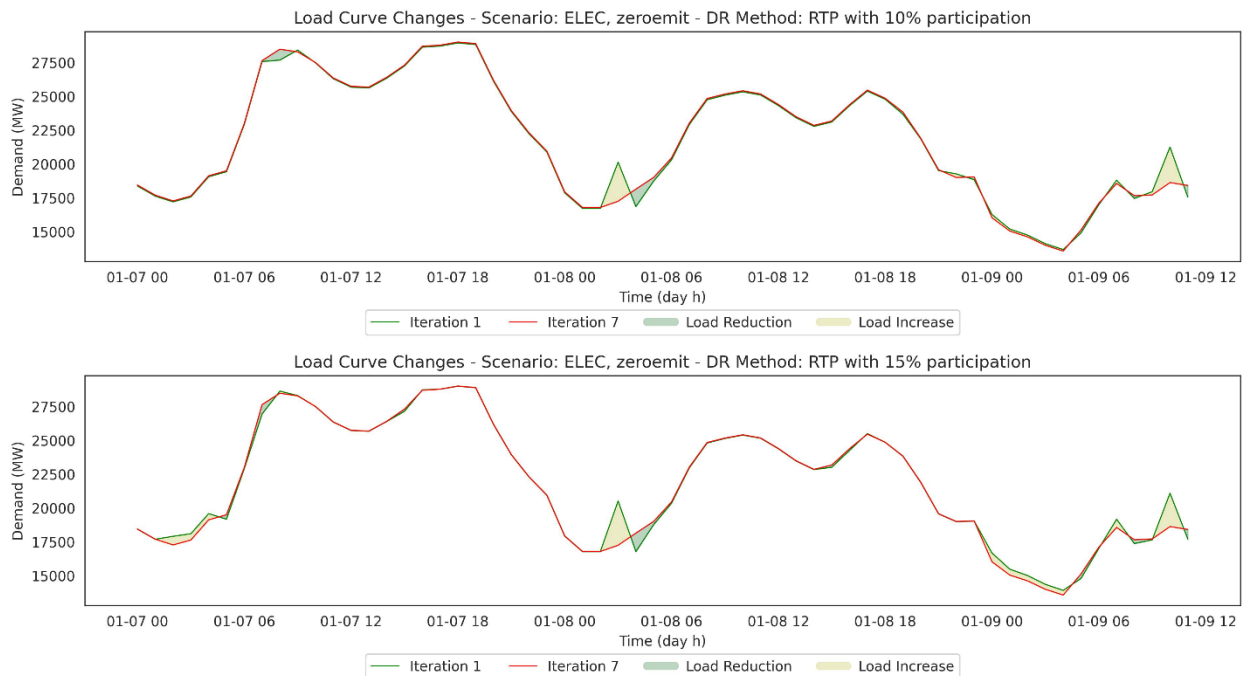


Figure 13 Changes in Alberta's demand curves in 2050 impacted by DLC with high electrification and VRE integration in the different participation rates

All four cases share the same feature of not gaining much improvement for wind integration for the 25% participation rate compared to the 20% participation rate. This observation is largely attributed to the rebound demand that occurs after each DR event. A period of increase in the buildings' heating by increasing the setpoints is followed by a decrease in load to reach the same normal temperature [143]. This rebound demand might conflict with the VRE availability profile in some cases. By increasing the participation rate, the moved energy is larger and would further impact the wind integration. This observation is also can be noticed in Figure 13 and Figure 14 where each decrease in the load shaded in green is followed by an increase shaded in yellow to compensate for the lowered indoor temperature.

The changes in load in lower demand peaks, such as reductions following the increases which are referred to as the rebound effect, are observed to be larger compared to the ones in the high peaks. The building stock configuration in the model remains as basic insulation and further improvement in efficiency and insulation is not considered. Therefore, buildings have lower thermal inertia, which concludes that the system sees relatively less reduction in load when the setpoint is decreased, but higher fluctuations when the setpoint is increased. The entirety of the shifts are ensured to be equal in both programs.



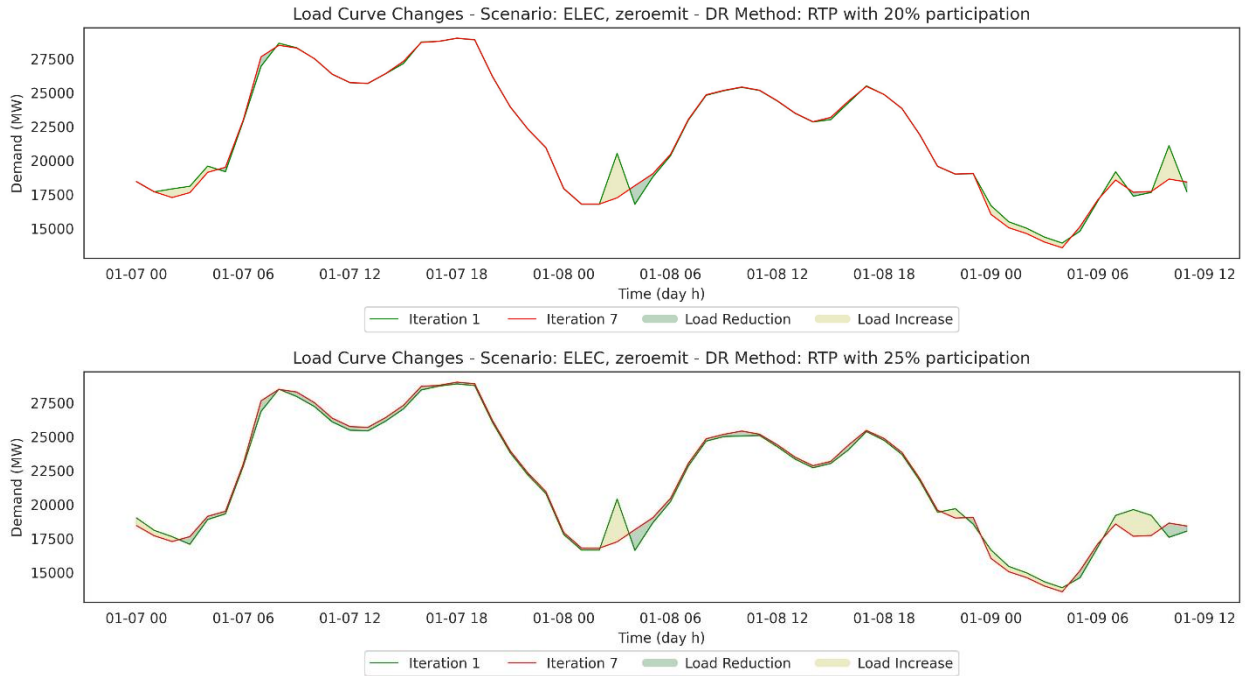


Figure 14 Changes in Alberta's demand curves in 2050 impacted by RTP with high electrification and VRE integration in the different participation rates

It is shown that low electrification and VRE electrification scenarios are impacted by the increasing participation rates. However, As shown in Figure 15, demand shifts are smaller compared to high electrification and VRE integration scenarios. While the triggers are designed the same for these scenarios, the smaller flexible load stemming from not electrified building shows its impact on the load changes to be very minimal by adding more participants to the DR program. As a result, the participation rate increase only helps marginally to improve the outcomes of DR implementation.

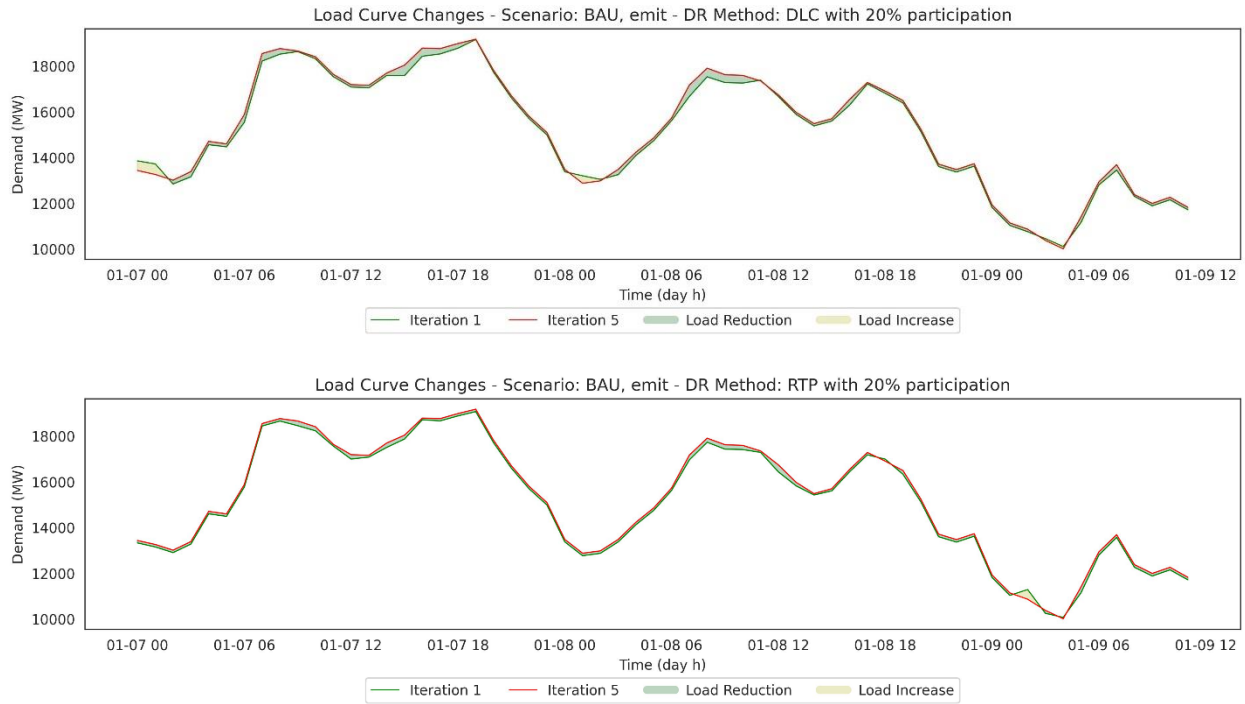


Figure 15: Changes in Alberta's demand curves in 2050 for the first and last iterations for low electrification and VRE integration

### 3.6.3 Impacts of iterative procedure on the metrics

The iterative procedure is selected in this study to represent the evolving changes over time and analyze the improvement capability of demand curves when DR is already implemented. A sampling at a 20% participation rate, successive changes in the wind curtailment rate, and operational costs through six iterations (of the bidirectional framework) are presented in Figure 16. In general, further improvements in costs and wind integration are observed over the iteration in all cases.

There is a general decrease observed in wind curtailment by deploying DLC, until the fifth iteration in which curtailment increases slightly. Operational costs also drop precipitously from iteration four to five, by approximately \$32 million to \$29 million by 2050. This trend in operational costs can be attributed largely to the role of network congestion as a primary trigger for DLC DR events. The resolution of congestion is followed by the integration of more wind potential in the system, hence, periods with higher wind output (and lower operational costs) are only fully utilized by demand shifts in later iterations. In other words, early iterations tend to reduce demand peaks while later iterations shift to maximizing available wind capacity. This is because of the design of the trigger for the DR events in the DLC. Higher peaks tend to be more aligned with the congested lines in the first few iterations. As the iterations continue, the tendency to shift load from lower peaks is more feasible as there is not as much line congestion.

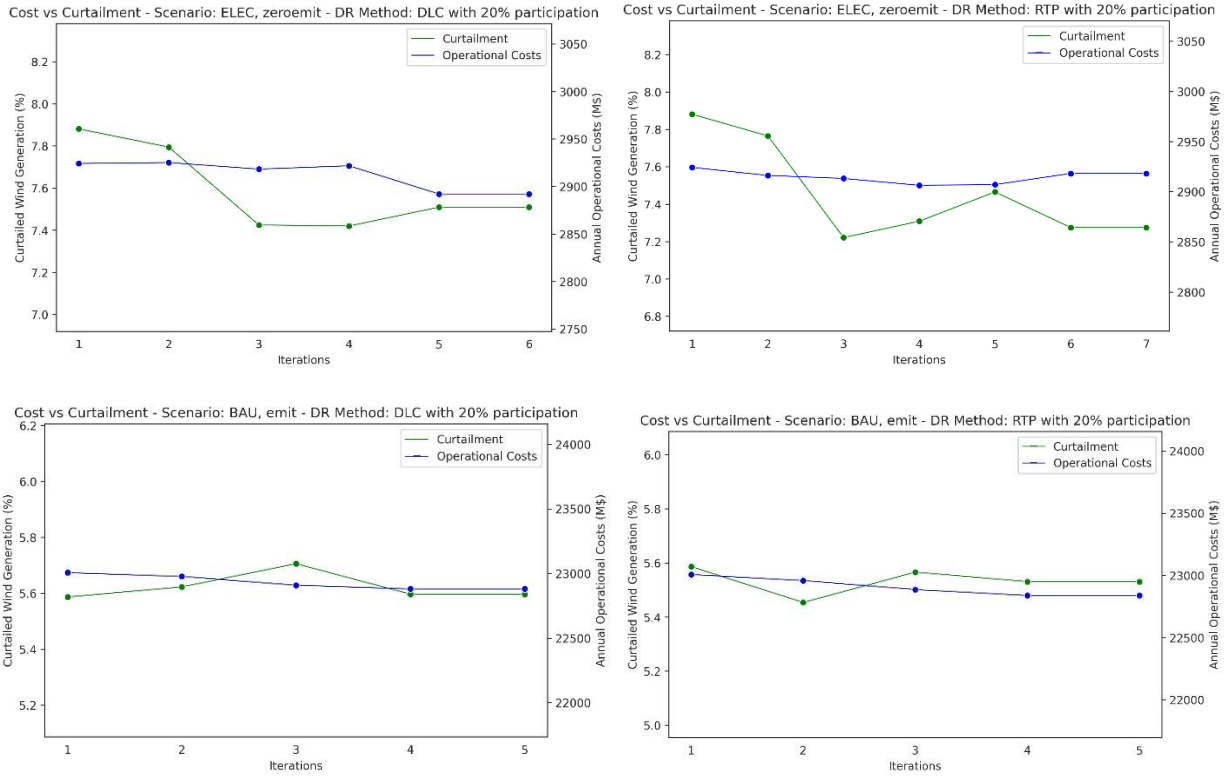


Figure 16 Changes in wind curtailment and annual operational costs over (Note: ranges for y axes are different for clearer visualization. Iteration counts vary, based on the iteration exit criterion)

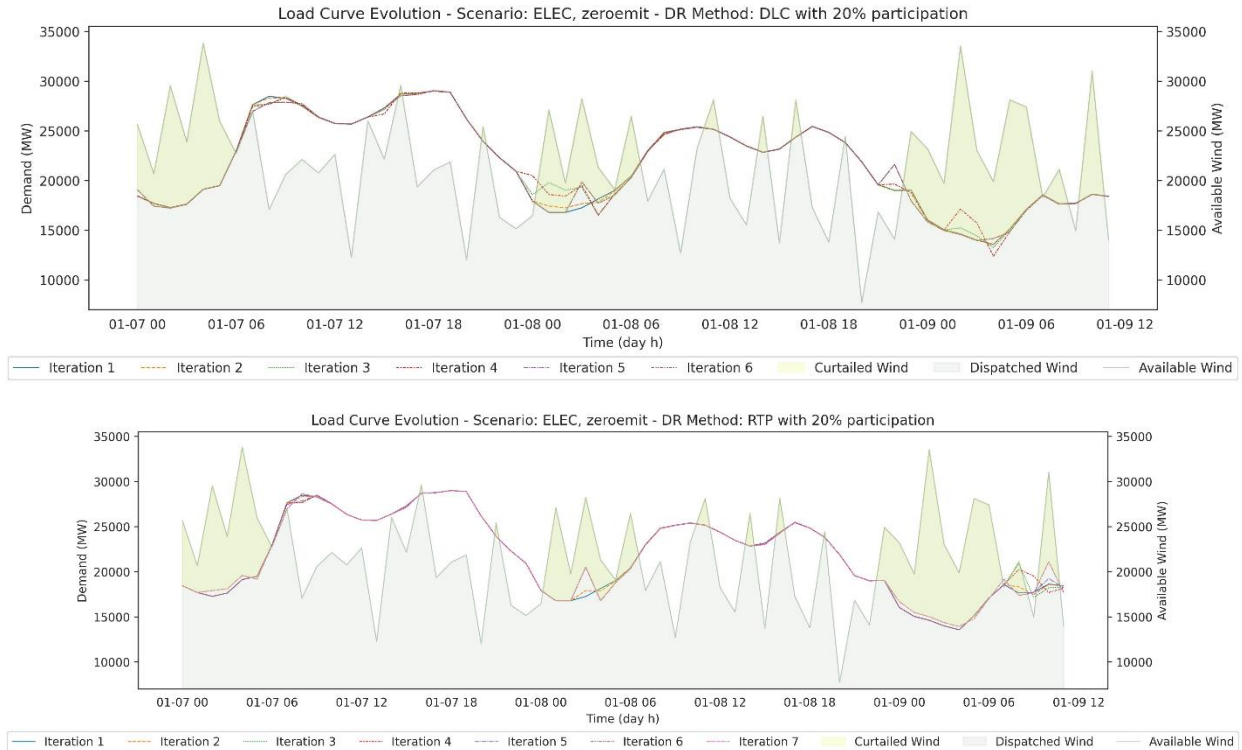
Similar to DLC, both wind curtailment and operational costs are improved by an RTP program (lower right panel in Figure 16). However, costs increase slightly after the fourth iteration as the LPT is satisfied for a shorter period in each successive iteration. This results from demand shifts which, while not considerably lower prices, cause costs in the 24 hours to converge and become more uniform. Improvement in curtailment also shows a steeper trend in the first two iterations while mostly settling in the later iterations. This happens because marginal prices are affected by the changed demand profiles as the iterations continue. While DR tries to reduce the load in the higher marginal prices and increase it in the lower marginal prices, the general profile of the prices becomes more uniform, and thus, less sensitive to the price threshold. This is also visible in the number of DR events which decreases at each iteration. While the costs and curtailments are changing over the iterations for low-VRE and low-electrification scenarios, these impacts are very small. This observation also stems from the lower available flexible demand, smaller VRE capacities, and generally higher marginal prices which diminishes further improvements by going into iterations.

### 3.6.4 Effectiveness of DR programs to integrate VRE generation

One of the main benefits of implementing DR programs is to integrate more VRE generation. This section analyzes the effectiveness of different programs to achieve this goal in terms of changes in the load curve over implementing

DR programs. In general, both programs show effectiveness in moving the load from the periods with lower available VRE generation to higher ones.

Comparing the load curve changes during the iterations, it is notable that shifted demand increments are wider and more frequent for the modeled DLC program relative to RTP. However, it can be observed in Figure 17 that for the sampled period, the RTP implementation was able to match with available VRE generation in the final iteration. This is because RTP is signalled only by marginal price while DLC has other congestion factors included. As a result, low-priced VRE generation is preferred with a price-signal trigger so the demand can be shifted to those hours.



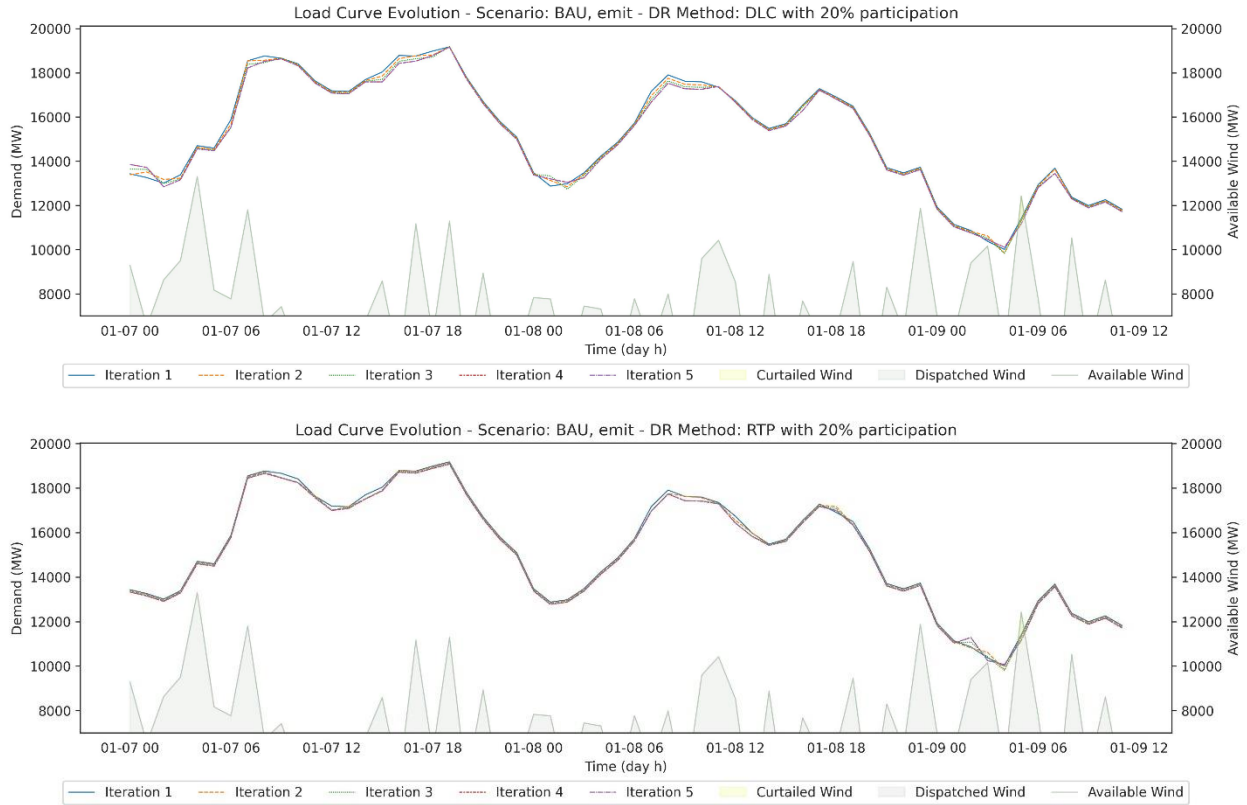


Figure 17 Evolving demand curve over successive iterations and utilized wind capacity (Note, y-axis are varied between plots for better visualization)

As observed in Figure 17, the smaller VRE capacities also have a visible impact on the effectiveness of implementing DR in this generation portfolio. There is not enough available VRE generation that can be captured by moving the flexible load from lower potential periods to the higher ones. This concludes to ineffective implementation of the DR program in integrating VRE capacities in the absence of large shares of VRE capacities and impactful flexible load through electrified building stock.

### 3.6.5 General impacts of implementing DR programs

Both scenarios under two DR program implementations gained improvements both in operational costs and wind integration as represented in Table 9. Comparing the outcomes in all four case scenarios shows that the RTP program demonstrated greater improvements than DLC in integrating available VRE resources, particularly in the high VRE scenarios. It is also observed that the household power expenditures are impacted for all scenarios under impacted by all DR programs, more significantly with RTP implementation and in electrified and high VRE penetration scenarios.

In the low-VRE and low-electrification scenarios, the results from both DR programs are limited to reductions in operational costs. This is mainly because, with the smaller VRE capacities, curtailment occurs mainly due to various factors other than demand and supply imbalances, such as a congested network, and thus cannot be resolved by making the demand more flexible. Also, there is not enough VRE capacity available in these cases for the DR implication to have an impact. In addition, the non-electrified residential load is not impactful enough so there will be no further improvement achievable over the iterations.

*Table 9 Comparison of performance metrics for four 2050 scenarios (based on the 20% participation rate in all cases)*

No	VRE Penetration	Electrification	DR program	Wind integration improvement (MWh)	Annual Operational Cost savings (mil. \$)	Savings in household electricity bills (mil. \$)
1	High	High	DLC	408,345 (0.46%)	40.3 (1.36 %)	2.95 (9.03%)
2	High	High	RTP	582,789 (0.66%)	41.2 (1.39 %)	4.92 (15.07%)
3	Low	Low	DLC	20,682 (0.10 %)	196.5 (0.85 %)	0.86 (3.82%)
4	Low	Low	RTP	40,152 (0.14 %)	181.6 (0.79 %)	1.37 (6.11%)

Overall, while RTP programs showed to have a more significant impact on integrating VRE capacities, both programs exhibited their capability in matching the load with the available VRE potential only when first there are larger VRE capacities installed, and second, the shiftable load is large enough to have an impact on integrating VRE available resources.

### **3.7 Discussion**

The objective of this study was to investigate the impact of two distinct DR program designs, DLC and RTP, on flexibility and VRE integration in alternate futures of Alberta’s power system using a novel integrated supply and demand framework. The results of the present work have policy relevance by characterizing how DR programs can deliver much-needed flexibility for the integration of significant VRE capacities in Alberta in line with decarbonization priorities. To this end, the proposed coupled framework consisting of three models, including a capacity expansion model, a power system operation optimization model, and a demand-side building archetype model, offers a more robust approach compared to prior studies.

This framework analyzes the role that DR could play in the mixed projected generation expansion planned for Alberta’s power systems. Multiple metrics are selected to track flexibility improvements at different VRE penetration and electrification levels. These metrics include wind curtailment rates, improved wind integration, operational costs, and characterization of resulting demand profiles.

The iterative process between demand-side and supply-side models is designed to maximize effectiveness, stopping when no further improvements are possible. The methodology offers improvements compared to previous studies in the integrated analysis of both demand and supply impacted by DR programs across multiple scenarios. These

improvements include a full representation of the power system's operation as well as building stock energy simulation, which enables realistic capture of the impacts of implementing DR on both supply and demand sides. In addition, the framework uses real-time marginal pricing from the operational model as the DR triggering signal. This signalling mirrors the realistic operation of the power system including the cost of generation, integration of VRE generation, and congestion issues. Therefore, the methodology proposed here allows for a more detailed as well as endogenous method for triggering DR events compared to previous studies.

The following observations from this study are in agreement with the previous studies. First, implementing DR programs reduces the system-wide operational costs by moving the demand from higher-priced periods to lower-priced times. Second, price-induced DR programs contribute to improving the integration of large VRE capacities by matching the demand to the available low-cost electricity generation by those capacities. Third, Participation in DR programs can contribute to the overall effectiveness of the implemented program. Furthermore, results from this study bring the following additional insights compared to the previous studies. First, comparing price-induced and network flexibility triggers shows how two RTP and DLC programs can differentiate. Second, adding more participants to the DR programs is discussed as not always contributing to more effectiveness. Third, different decarbonization pathways can result in varied impacts from the implementation of DR programs.

The four cases considered demonstrate the importance of both electrification and VRE penetration levels for the effectiveness of DR programs in integrating available VRE resources. While demand-side flexibility options are typically claimed to be cheaper, and the results of this study support the likelihood of whole systems cost improvements achievable through their implementation, there are several outstanding issues and uncertainties facing the widespread viability of residential DR programs. For example, DR programs are not without their investment requirements which may be substantial in some cases. Furthermore, while this study assumed reliance on smart meters and smart thermostat devices, the practicality of their usage in this context alongside other means of passive and active end-user control is an important area of ongoing DR research. Complementary to the savings in the operational costs reported in this study, the US Department of Energy reports 1.25 as the ratio of equipment and administration costs to benefits of operation and capacity investment from implementing DR programs [144]. Also, savings on the demand side reported in Table 9 justify the initial investment in the devices required to implement such programs.

The generation expansion proposed by modelling is in alignment with similar studies in the literature. Arjmand et al. also applied capacity expansion modelling to multiple scenarios, showing approximately the same trends for generation capacity expansion in Alberta [6]. Dolter et al. found the same pattern characterized by wind capacity expansion and the phase-out of GHG-emitting generation capacities across Canada [7]. Similarly, the latest Canada's

Energy Future results also show a substantial expansion in the wind capacities across Alberta along with Gas CCS, which is the difference between zero-emission and non-zero-emission scenarios in the present study [4].

Critically, these studies and the present work alike are based on an assessment of onshore wind potential presented by the Pan-Canadian Wind Integration Study, which identified a wind capacity density of 2 MW per square kilometre to be a suitable estimate for Canada given land use constraints [145]. However, such installed capacity densities have not yet been observed over broad geographical scales. As such, this density limit is a foundational assumption and known uncertainty for the present study. Detailed consideration of achievable real-world wind densities in Canada under high VRE penetration scenarios is left for future research. In addition, this study uses the most up to date data and tools for VRE hourly profiles for more than 2100 points Canada-wide which is not available in similar studies in the literature. It is assumed that the future profiles are determined with historical data and no stochastic variation, based on climate change and other factors considered in the model.

The implementation of DR programs is subject to the identified limitations. This study focuses on two DR programs applicable to the residential building sector only using a single automatic thermostatic control strategy based on several reasons. First, residential heating and cooling accounts for 40% of the sector's energy demand [146]. Second, RTP and DLC, have been identified in the literature as two of the more promising DR programs available [100]. Third, there are multiple industrial demand response programs already implemented in Alberta as discussed earlier, but there is no residential DR program available in the province. Fourth, the installation of heat pumps is part of energy efficiency and retrofitting programs Canada-wide following the sector's emission reduction targets mentioned earlier and brings great opportunity for DR implementation [134]. Fifth, this study focuses on the implications of the variable response from the demand side such as the rebound following the implementation of DR programs on the supply and operation of the power system. However, further analysis could be done to additionally research other possible paths.

There is a single load elasticity assumption discussed in this study; further discussion would benefit from analyzing other elasticity options. For maintaining the computational feasibility, three building archetypes are used to represent Alberta's building stock. A more detailed and varied range of archetypes might reveal greater DR benefits as the demand rebound effect would be more limited in well-insulated buildings.

This study also does not include storage characteristics for buildings or opt-out options for DR participants, which might promote DR implementation without adversely impacting user-user comfort. However, this limitation is mitigated by using a relatively narrow thermal setpoint range of  $\pm 2^{\circ}\text{C}$  with the assumption that buildings maintain interior temperatures at  $21^{\circ}\text{C}$  regardless of occupancy. More advanced and efficient thermostat programming and other efficiency improvement programs would likely produce additional benefits but are out of the scope of the present work. While the peak supply capacities might be reduced as a result of reduction achieved by implementing

DR programs, the single exogenous capacity data from the capacity expansion model limited further analysis for reductions in peak capacity requirements.

### **3.8 Conclusion**

The power system of Alberta is accountable for substantial decarbonization due to its current dependency on emitting generation and is also responsible for supporting electrifying other sectors that are striving for emission mitigation goals. This study analyzes opportunities available in DR for integrating larger VRE shares in Alberta's power system. Various conclusions can be drawn from this study, both for Alberta's power system decarbonization specifically and to a limited extent for other jurisdictions facing similar conditions and trends. These findings should be supplemented by future research aimed at understanding power system transitions across a broad set of diverse contexts.

*Decarbonization in Alberta can be effectively promoted through the application of DR programs in the residential sector.* By expanding VRE generation capacities, particularly wind, Alberta is well-placed to reduce power sector emissions throughout the province. The electrification of building sector demand not only mitigates emissions directly through improved efficiencies but also assists the integration of more VRE capacity through the flexibility afforded by greater DR potential. This is especially apparent in the case of high VRE penetration.

*Efficient DR implementation for the integration of available VRE resources is visible in higher VRE penetration rates and requires enough electrified building stock as a flexible load.* When comparing two capacity expansion scenarios, the lower VRE and lower electrified scenario showed limited improvements for integrating more VRE generation with smaller VRE resources. On the other hand, DR programs remain effective in reducing the operational costs of generating electricity, even with low VRE penetrations and corresponding minimal improvements in VRE integration.

*Higher participation does not always improve the performance of DR programs.* This observation relates primarily to the outlined rebound effect demonstrated here and noted in the literature, particularly at higher participation rates. Further research regarding the effects of DR trigger harmonization should be performed, and staggering regional demand curves are advisable to investigate opportunities to mitigate the drawbacks of DR program implementation at scale.

*DR programs require initial capital outlays, but these investments are likely dwarfed by significant realizable operational cost savings.* While upfront costs are not included in the analysis presented here, indicated savings over typical planning horizons and capital lifetimes are substantial. At the same time, this reduction in operational costs is most likely accompanied by savings in investments required for supply-side options and flexibility requirements, such as storage or network expansion, as well as peak supporting capacities.

*DR based on real-time pricing offers the greatest VRE-integration benefits. As such, the use of price signals to trigger DR events alongside improving responsiveness during these events should be a primary focus for the promotion of VRE resource integration and power system decarbonization.* Marginal prices as signals for DR events offer the advantage of representing a greater number of conditions including available but unused VRE resources, network congestion issues, and the operation of high-priced inflexible generation assets. Furthermore, locational marginal prices can be utilized in RTP to improve the congestion reduction benefits of this DR program.

This paper contributes to understanding the key advantages of DR programs for integrating wind and solar resources as solutions to power systems' decarbonization. It is shown that implementing DR in the residential building stock of Alberta would benefit the power system both in reducing costs and working more efficiently by integrating more available wind and solar resources. Further analysis using locational marginal prices and implementing sub-regional DR programs could contribute to more improved design of DR technologies and cover other flexibility issues like line congestion.

## 4 Chapter 4: Integrated planning and operation of power systems: Flexibility in high penetration of wind and solar

The content of this chapter is submitted to the following journal: Renewable and Sustainable Energy Transition  
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### 4.1 Abstract

Canada has set a target to become net zero by 2050. One of the key pathways for achieving this goal and supporting electrified demand is to expand variable renewable energy capacities. Such integration requires flexibility measures to respond to inherited variability, such as a reactive generation mix, responsive demand, or transmission. This study aims to find the impacts of coordinated planning and integrated operation of two power systems, one with flexible hydro capacities and the other with high shares of variable renewables. The present study uses a linked framework of planning and operational models to analyze different integration levels, load electrification scenarios, and sensitivity to hydropower constraints. The results show that the systems can achieve zero-emission goals with around one-third of the capital requirements when there is no constraint on the grid expansion between the two jurisdictions. Flexibility metrics, like curtailment, perform better when the large wind capacities in one power system are coupled with flexible hydro capacities in the other through the expanded grid. A sensitivity analysis is also done on hydropower constraints which shows a positive correlation between minimum hydropower output and curtailed wind generation when the integration is limited.

*Keywords: flexibility, power systems integration, hydropower, climate change, energy transition, variable renewable energy*

### 4.2 Introduction

Canada's power system contributed to 9% of national carbon emissions in 2020, emitting 62 Mt of CO<sub>2</sub> equivalent [3]. The sector aims to reduce 40 Mt, about two-thirds of emissions, by 2030 [1] and achieve net zero by 2050 [2]. To achieve these goals, the core pathway involves replacing emitting generation capacity with variable renewable energy (VRE) resources, alongside options like carbon capture and storage (CCS) technologies or nuclear power plants. Additionally, emission mitigation plans necessitate changes in fossil-intensive sectors like buildings, transportation, and industry. Transitioning these sectors to electricity as the main option drives substantial demand growth for major end uses [32]. Consequently, the power system must develop feasible expansion plans that cater to both demand growth and emission reduction goals.

Flexibility is a fundamental operational requirement for a power system, ensuring a balanced supply and demand while providing reliable electricity to consumers with consistent voltage and frequency [86]. Conventional power plants offer flexibility by adjusting output based on predictions or real-time needs. In contrast, VRE generators like wind and solar lack this flexibility, relying on solar irradiation and wind profiles. Inadequate flexibility can lead to voltage and frequency fluctuations, outages, grid congestions, and system failures, all incurring operating costs [147]. Moreover, it may result in curtailing VRE resources, reducing profitability, and substituting with more emitting but flexible capacity, thereby increasing emissions.

A power system offers flexibility through various features in supply, demand, and network sides [18]. Conventional power plants and power storage provide supply-side flexibility [35]. As Canada's power system expansion centers around integrating large VRE capacities to meet rising demand, flexibility must extend to other areas. Demand-side management programs like demand response, and shifting demand loads through price incentives, help incorporate flexibility into the demand side. The power system's network can enhance flexibility by increasing grid integration, and interconnectivity (delivering excess VRE generation to locations with unmet demand) and using smart grid technologies [20].

This study focuses on two major flexibility options: integrating and interconnecting power systems and hydro capacities. Integrating and interconnecting power systems have been shown to increase operational efficiency and flexibility considerably in both interconnected systems [18]. Integrated power systems utilize power flows between connected balancing areas, resulting in smoother VRE output under varying load and generation conditions, reducing the need for other flexibility options. Nagel et al. found that deeper integration between Nordic countries with high hydro capacities and Central European countries supports VRE integration, reduces emissions, and lowers operational costs during system transitions [92]. Canadian power markets, however, exhibit diverse structures, vertical integration, and ownership, leading to nearly disconnected provincial sub-systems [148].

Increasing hydro capacity is the other option that supports flexibility and facilitates the expansion of wind and solar [149]. Canada's power system includes large hydropower capacities providing more than 60% of total annual energy [81], which can act as substantial storage, enhancing flexibility. For instance, Norway's power system, comprising 95.3% hydropower capacity, was studied to be able to eliminate energy deficits and become a power exporter in the coming decades [150]. However, weather dependency in hydropower plants is often a bottleneck and is addressed differently [151]. Climate change-induced temperature rise affects hydropower availability and operation, extensively studied using regional-scale modeling tools [152]. This uncertainty in hydropower output stems from various sources, such as freshet flooding, unproductive spills, and earlier snowmelt, depending on reservoir, region, and climate change impacts [153]. Yang et al. further analyzed the impact of VRE integration on hydro plants, considering mechanical wear due to fast ramping required with wind output and water input fluctuations [154].

Thus, hydropower plays a crucial role in integrating VRE capacities, and the uncertainties necessitating an accurate representation.

British Columbia (BC) and Alberta (AB) are important cases for studying flexibility in integrated power systems. Alberta's power system contributes 53% of the national emissions through electricity production and would need substantial changes to meet mitigation goals [81]. Previous work has found substantial wind expansion potential in Alberta [5]. However, the transition toward expanding VRE capacities poses concerns for flexibility and reliability. Interprovincial integration offers a solution, utilizing British Columbia's large hydro capacities to provide flexibility for both BC's and Alberta's power systems.

Analyzing the intermittent and weather-dependent VRE generation necessitates methods to be able to capture the inherited variability of the resources both spatially and temporally. At the same time, frameworks should have the ability to plan for optimized possible pathways to emission mitigation targets in the selected power system. Various methodologies and modelling tools are proposed in the literature to analyze power systems integration and flexibility requirements in the presence of large VRE capacities.

Capacity expansion models used to study future power system plans lack the necessary features to handle technical details and fine spatial and temporal resolution for analyzing VRE resource operation [23]. Some studies have enhanced capacity expansion models to address operational perspectives, but they often have limited operational parameters and only simulate limited hours/days over the multi-decade horizon. Linking frameworks overcome these limitations, providing detailed operational analyses for power system transition [60]. These frameworks can consist of various modeling formulations and differ in how they transfer data consistently across different temporal and spatial scales and resolutions.

Several studies apply linked frameworks to deliver richer insights into analyzing power systems and impacts from different decarbonization pathways. Miri et al. introduced a bi-directionally linked framework to study power systems with large VRE capacities resulting in suggestions for transmission and storage expansion, as sources of flexibility [86]. Seljom et al. used an operational model to improve the detail in a planning model and found that hydropower output and income increase with the presence of large VRE capacities via interconnected power systems of Norway and the neighbouring countries [63]. Table 10 summarizes selected studies in the context. In conclusion, the linked power system models effectively capture the required technical details, and temporal, and spatial resolution for analyzing integrated power systems' flexibility.

*Table 10: Summary of selected studies analyzing the role of power systems integration and hydropower as flexibility options toward decarbonization*

<b>Study</b>	<b>Methods/Models</b>	<b>Achievements</b>	<b>Key findings</b>	<b>Shortcomings</b>
Rinaldi et al. [155]	Single macro electricity model	Including power-to-gas, grid expansion,	Transmission expansion and long-	Not modelled hydro capacities included

	expansion/dispatch model	and storage technologies as a source of flexibility in the wind and solar-dominant power systems	term storage are the key paths to ensure reliability and flexibility in a VRE-based power system, reducing system costs	minimal technological operation constraints, modelled operation for a limited hour
<i>Rodriguez et al.</i> [156]	Single capacity expansion model with hourly operational analysis	Analyzed multiple interconnection options through American northeastern provinces and states, analyzed no-trade scenarios	Higher integration reduces the decarbonization costs by effective expansion and operation of wind capacities, especially when load growths are substantial	No operating ramping constraint, no unit commitment, no intra-provincial grid, no capacity reserve margin, aggregate VRE potential data,
<i>Yuan et al.</i> [157]	Expansion/dispatch model coupled with a top-down economic model	Emissions from all sectors, economy-wide impacts, conventional power resource modelling, capacity reserve requirements	Even with a 50% expansion, the system utilizes the transmission lines with substantial economic benefits for the electricity prices, more electrification with emission caps	Regional aggregated wind and solar potential inputs, no endogenous modelling for hydro facilities, exogenous transmission expansion parameters, always available hydropower from Quebec
<i>Seljom et al.</i> [63]	Bidirectional linkage of an energy system model and a power market model	Novel linkage and convergence strategy based on interlinked power market and income for the host's power system included a wide range of sectors	The hydropower output and income increase with the presence of large VRE capacities via interconnected power systems of Norway and the neighbouring countries	Aggregated hydro representation, coarse temporal resolution, no flexibility analysis for VRE resources
<i>Miri et al.</i> [86]	Bidirectionally linked capacity expansion and operation model	Analyzed storage and intra-provincial grid as options, iterative procedure with feedback	Supply-side flexibility options, while being crucial for integrating VRE, increase the expansion costs	Excluded hydro capacity expansion, excluded inter-provincial grid expansion as a response to flexibility issues, simplified hydro cascade modelling, no integrated operation analyzed

To date, to the authors' knowledge, there are few (if any) studies available that analyze expansion planning and operation of large-scale integrated power systems in a linked framework that includes substantial technical and operational details. The current study applies a unidirectional linked framework consisting of operational and planning models that include improvements in relation to the established literature as follows:

1. The linkage methodology used in this study delivers the most achievable insights considering the computational limits and tries to reduce the simplifications and assumptions to as low as possible. In other words, linked models include a detailed and granular temporal and spatial resolution for wind and solar capacities, which is crucial when analyzing intermittent capacities.
2. Other real-world technical constraints like ramping constraints and costs, unit commitment, minimum flows, and cascading hydro are all included in the operational model. These important attributes give a more realistic representation of the operation of the power system and, therefore, better insights that mirror the impacts of large intermittent VRE capacities.
3. The linked framework enables analyzing a variety of flexibility metrics, operational costs, power trades between jurisdictions, and sensitivity of the systems to climate impacts from the operational perspective. At the same time, it keeps the capability to study capacity expansion decisions, generation expansion costs, transmission expansion costs, and other planning metrics impacted by different policy choices and load estimates.

The main objective of this study is to assess various transition pathways for the power systems for the case of two Western Canadian provinces of British Columbia and Alberta, from both a capacity planning and operational point of view in terms of flexibility requirements for large VRE capacities. This study provides insights from both operational and planning perspectives, including analysis on VRE curtailment, operational and planning costs, capacity expansion details, and results power flow in interties in the given scenarios. No other study has been found to specifically analyze the incorporated planning and operation of the two power systems in British Columbia and Alberta.

The remainder of this paper is organized as follows. First, details of the methodology are described in the next section. Following that, the structure of the scenario inputs is presented. In the result section, the outcome of the model is first discussed from the planning perspective before the operational impacts of different integration scenarios are analyzed. Finally, a discussion and conclusion of the insights from this study.

### **4.3 Methodology**

This research uses a linked framework to study flexibility in British Columbia and Alberta's operations with integration and in the presence of high VRE penetration. The linked framework presented here was developed previously by Miri et al., though it has undergone some redevelopments to make it suitable for the research question

at hand [86]. This study incorporates a one-directional linkage as presented below and added the features presented further. This section reviews the linkage strategy, the included models, and modelling assumptions and formulations.

#### **4.3.1 Linkage strategy**

As presented in Figure 18, the linkage is comprised of one-way data flow from the capacity expansion outputs to the operational inputs.

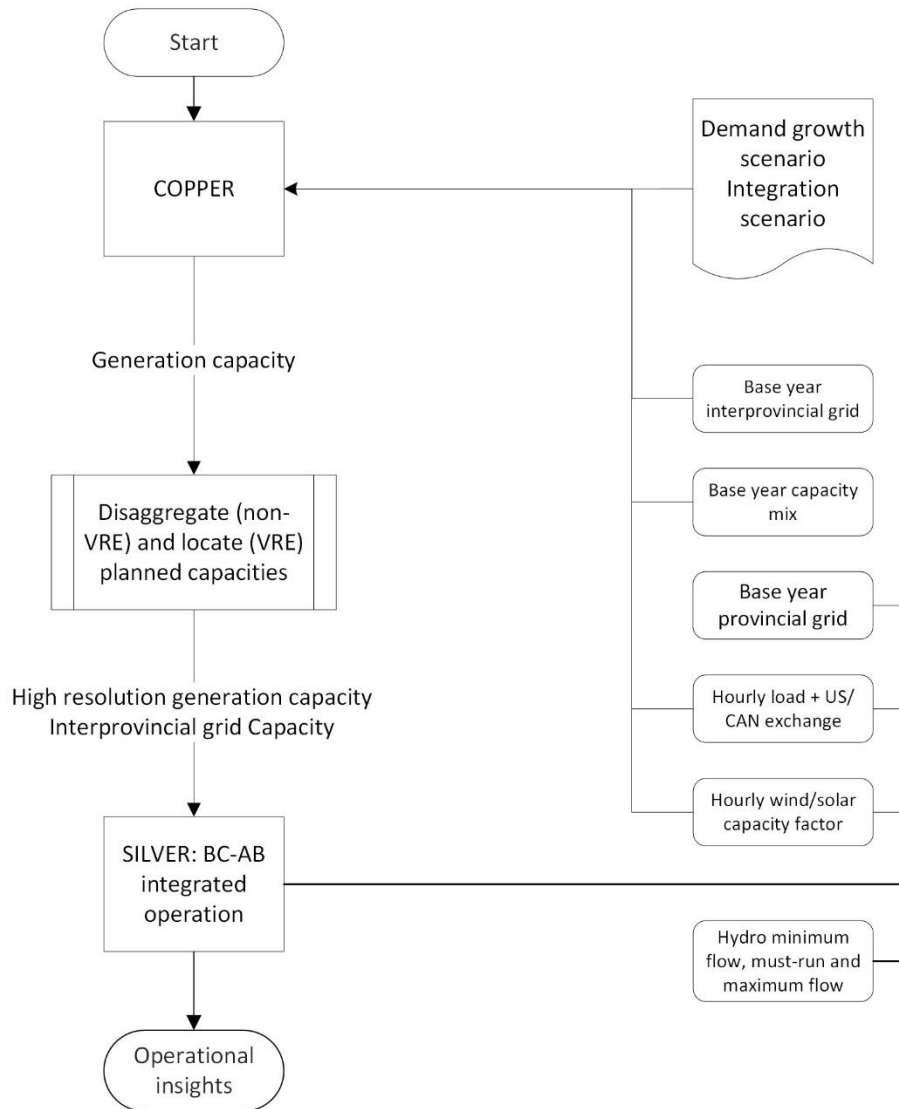


Figure 18: Data flow steps in the linked framework

#### 4.3.1.1 Power system structure

As there are several sources of data included in this interlinked system, they are separated into exogenous and endogenous data. Exogenous data input for the framework is represented in the boxes on the right side in Figure 18. Provincial transmission level network structure, wind and solar capacity factors, load profiles, and base year exchange data are gathered from the power operators and other open access data sources, which are collected in the CODERS database [74]. Line reactance values are calculated based on a validated load ability formulation which is broadly used in the literature [76]. Cost calculations for both models are based on the Lazard calculated investment, fixed, and variable operational costs for 2018 [158].

Endogenous data for the future expansion plan for generation and interprovincial transmission capacity is translated from a capacity expansion model and then sent to the operational model. This translation module prepares the generation capacities of each generation type and the interprovincial power network based on input scenarios presented in the following sections. It utilizes COPPER as the capacity expansion model that plans for the optimized generation and transmission capacities at the national level with the inputs of costs, VRE potentials, demand profiles, and various scenarios [6]. COPPER follows linear mixed integer optimization for cost minimization of Canada's power system projection plans. Linear mixed integer formulation allows for efficient optimization convergence and binary adaptation of some parameters like project-based hydro expansion decisions. The main cost minimization formulation is as follows:

$$\min \text{system}_{totalcosts} = \text{cost}_{investment} + \text{cost}_{production} + \text{cost}_{operation \& maintenance} + \text{cost}_{carbon}$$

This minimization function is subject to various constraints which the most important ones are 1) hourly demand and supply balance, 2) planning reserve margin per location, 3) thermal unit technical constraints such as ramp rates and capacity factors, 4) hydroelectric constraints for different hydro facilities, 5) VRE hourly capacity factors and land use per location, and 6) Transmission and storage constraints.

Changes in the generation capacity portfolio for non-VRE generation are translated into additions or removal from the available capacities in the base year. VRE capacities are represented at the same spatial resolution and are connected to the closest geo-locational bus in the provincial grid.

New wind capacity installation is limited to 0.5-MW per square kilometre to maintain wind turbulence constraints, which in turn affects the efficiency of wind farms [159]. The cap is also used as a means of maintaining land use constraints that are identified as an issue for resource estimation in several studies [160].

#### **4.3.2 Operational analysis using production cost modelling**

As the data is prepared by the translation module presented earlier, they are then operationally analyzed in a production cost model (PCM), SILVER, presented by McPherson et al. The SILVER model solves a network-constrained unit commitment (UC) for the real-time demand data based on the generation and transmission capacities of AB-BC integrated power systems [69]. As the systems are only analyzed at the transmission level, line resistances are negligible, and bus voltage magnitudes are set to 1.0 per unit. Therefore, the model optimizes the power system's operation by solving a DC power flow approximation which is generally supported by the literature [70]. SILVER is an hourly dispatch model with extensive technical details on both VRE and hydropower [68]. However, system reliability factors, like voltage and frequency quality, are not included in this model and are out of the scope of this study.

SILVER employs linear mixed integer UC (Unit Commitment) formulation which the objective function is abstracted in the following mathematical representation. Mixed integer formulation allows the model to account for the on or off status of the power plants and linear formulation guarantees an optimal solution and keeps the computational requirements manageable.

$$\min \sum costs_{t,g} = costs_{operation} + costs_{maintenance} + costs_{fuel} + costs_{emission}$$

The optimization function is solved at every timepoint for every  $t$  and for every generation facility  $g$ , and is subject to constraints including 1) load and supply balance at each hour, 2) ramping constraints based on the technology, 3) maximum and minimum generation constraint for both thermal and VRE technologies, 4) transmission flow constraints, and 5) yearly capacity factor constraints. However, system reliability factors, like voltage and frequency quality, are not included in this model and are out of the scope of this study.

#### **4.3.2.1 Integrated operation of Alberta and British Columbia**

The impacts of integrated operations can be captured only when both systems are modelled in the same boundary. While Miri et al. introduced a method to capture the flow between the systems, hourly import and export data were still considered exogenous to the provincial operation models [86]. In the present study, both systems are operating in a single boundary, and interconnections between British Columbia and Alberta are treated as transmission lines within that boundary. Using this method, the flow through interties is endogenously optimized based on the total costs, demands, and generation capacities as the two systems work together.

Right now, British Columbia and Alberta are operating separately, and their flow through the interties is predetermined 24 hours in advance through various agreements [148]. Rodriguez et al. introduce different options for integration, such as trade only with no expansion in the transmission, trade with expansion in transmission, and pooled capacity between the jurisdictions [156]. These options can also be combined for deeper integration as another option. COPPER captures trade between jurisdictions and is unable to model capacity pooling. However, this study represents different levels of integration between power systems by developing scenarios for different transmission expansions while energy trading is available in all cases.

#### **4.3.2.2 Hydro modelling improvements in SILVER**

Improved formulation for hydro facilities incorporated in this study enables capturing fluctuations in hydro outputs due to environmental and operational parameters. As discussed, British Columbia has 18 medium and large-sized hydroelectric facilities with a maximum power capacity of greater than 50 MW. The sizes range from large 2480-MW plants owned and run by the main utility provider, BC Hydro, to several smaller run-of-river (RoR) systems operated by Independent Power Producers that sell their electricity to BC Hydro [161]. As the present study looks deeper into the integrated operation of British Columbia and Alberta's power system in terms of flexibility, a further

improvement in the hydro representation in British Columbia is crucial to address the flexibility overestimation of hydro facilities.

Table 11 summarizes the differences and improvements between the two methodologies. In general, the present study improves SILVER’s cascading model in three distinct ways with respect to hydro generation representation, shown below. First, the hourly minimum generation constraint, which includes cascading hydro and RoR must-take values. Second, it represents RoR capacities as inflexible capacities. And third, capacity factors include both cascading characteristics and RoR fixed hourly generation values.

*Table 11 Comparison between the present study’s hydro formulation with previous SILVER versions*

<b>Feature</b>	<b>Base SILVER model [69]</b>	<b>Cascading model [162]</b>	<b>Present study</b>
<i>Cascading characteristics</i>	No	Yes	Yes
<i>Hourly minimum power constraint</i>	No	Only include minimum flow for cascading hydro	Must-take and minimum flows for cascading
<i>Hydro RoR presentation</i>	Yes, as a flexible hourly generation capacity	Yes, as a flexible hourly generation capacity	Yes
<i>CF calculations</i>	As maximum capacities with a 100% ramp rate	Cascade data	Cascade data + RoR + large hydro must-take values

Exogenous inputs for all hydro units in SILVER are maximum power capacities, variable operation, and maintenance costs, efficiencies, GHG emission potentials, and operational reserve coefficients. Saffari et al. introduced a cascading hydro formulation to accurately represent hydro capacities in British Columbia [163]. The cascading hydro model introduced new constraints to represent water discharge, stored water volume, and water spillage [163]. The following set of constraints shows the current cascading modeling implemented in SILVER using the formulation suggested in [164]. Equation 5 to Equation 7 constrain the amount of water discharge  $D_{g,t}$ , stored volume  $C_{g,t}$ , and water spillage  $W_{g,t}$  at each generator. Equation 8 calculates the stored volume of the lower cascading facility by its storage minus discharge and spillage in the previous hour, plus spillage and discharge from the upper facility two

periods before plus the water inflow in the same period  $Y_{i,t}$ . Output of the unit is calculated in Equation 9 which depends on the average height of the water  $\bar{H}_g$ , efficiency of the unit and a constant  $K$  which is calculated based on gravity acceleration constant. The total output of the hydro generation facility is limited to an upper bound in a month by Equation 10. Equation 11 constrains the stored water at the end of each operational period (month) to be within a higher and lower boundary.

$$D_g^{\min} < D_{g,t} < D_g^{\max} \forall t \quad \text{Equation 5}$$

$$C_g^{\min} < C_{g,t} < C_g^{\max} \forall t \quad \text{(A. 14)} \quad \text{Equation 6}$$

$$W_g^{\min} < W_{g,t} < W_g^{\max} \forall t \quad \text{(A. 15)} \quad \text{Equation 7}$$

$$C_{g,t+1} = C_{g,t} - D_{g,t} - W_{g,t} + D_{g-1,t-\tau} + W_{g-1,t-\tau} + Y_{i,t} \forall t \quad \text{(A. 16)} \quad \text{Equation 8}$$

$$P_{g,t} = K \times \eta_g \times D_{g,t} \times \bar{H}_g \forall t \quad \text{(A. 17)} \quad \text{Equation 9}$$

$$\sum_{t=1}^T P_{g,t} < P_g^{\max \text{ per month}} \quad \text{(A. 18)} \quad \text{Equation 10}$$

$$Perct_{Down} \times C_g^{\min} \leq C_{g,t} \leq Perct_{Up} \times C_g^{\max} \quad \text{(A. 19)} \forall t \quad \text{Equation 11}$$

This study adds a further constraint to the hydro operation in SILVER. To realistically represent large-scale hydro generation acting partly as a baseload provider following a predetermined schedule and partly as a peaking plant that can provide flexibility to the system during peak hours. **Error! Reference source not found.** represents the minimum output of the cascading and storage hydro capacities and **Error! Reference source not found.** constrains the inflexible output of the RoR capacities. **Error! Reference source not found.** replaces the previous formula used to constrain the hourly output of RoR capacities (named as hourly):  $P_{g,t} < P_g^{\max, \text{hourly}}, g \in \{hydro_{hourly}\}$

Figure 19 represents how the present study estimates hydro must-take and hydro flexible shares. The dark blue area shows the run of river generation, the plain blue is the minimum must-take for large hydro capacities, and the shaded area is the maximum must-take for large hydro capacities. The light blue area is calculated based on cascading characteristics. The dashed line shows the maximum installed capacity for all hydropower capacities.

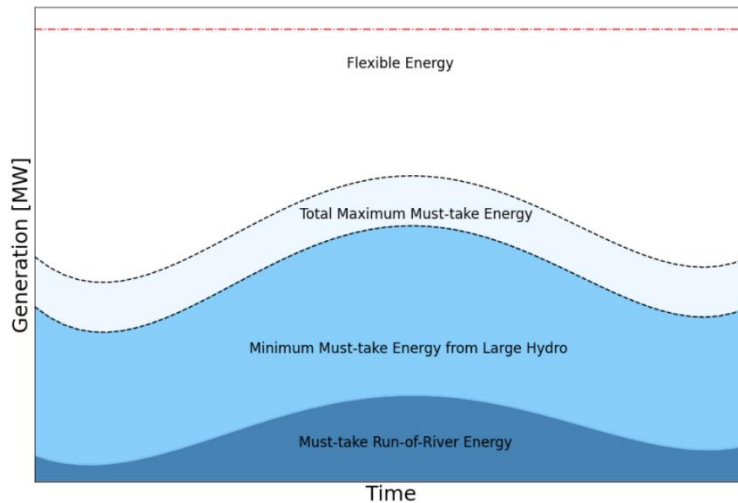


Figure 19:  $Hydro_{must-take}$  and  $hydro_{flex}$  representation.  $Hydro_{must-take}$  provides a certain amount of energy to meet reliability requirements and water license commitments.  $Hydro_{flex}$  is flexibly dispatchable at any time of the year.

The differentiation between  $hydro_{must-take}$  and  $hydro_{flex}$  is based on British Columbia Hydro's definition of must-take energy, which is described as energy from hydroelectric facilities that do not have storage capabilities, and, thus, must be used immediately to meet the load. The must-take portion of hydro mainly consists of RoR facilities from independent power producers (IPPs) and larger reservoirs that also must provide a certain amount of must-take energy to meet reliability requirements and water license commitments as they operate as baseload and peaking facilities simultaneously [165]. All hydroelectric facilities with negligible storage potential that are contributing to British Columbia Hydro's must-take energy share to increase electricity generation significantly during the freshet due to larger inflow volumes [165]. To account for an adequate portion of must-take energy, the available energy within the model is dispatched based on a partially predetermined and flexible profile. Based on the  $hydro_{must-take}$  and  $hydro_{flex}$  classification, this study assumes a total energy generation from hydroelectric power sources of 60 TWh within the province of British Columbia [166]. It is estimated that approximately 41 TWh are dispatched to meet operating constraints, while 19 TWh are flexibly dispatchable at any time of the year [165].

$Hydro_{must-take}$  is forced to obey numerous modelling constraints, as it operates on a pre-determined (based on historical data) schedule that SILVER is replicating. First, RoR facilities in British Columbia provide a minimum power generation to the grid as they are dependent on natural river flows and do not have the ability to store water to react to changes in demand. To capture this behaviour in SILVER,  $hydro_{must-take}$  must generate a minimum amount of power in every time step. The minimum amount of power that all RoR facilities must generate in every time step is described by aggregated existing and committed RoR facilities over a one-year period [167]. Total RoR energy results in an average energy contribution to British Columbia's power grid of 6,700 GWh/year, with approximately 43% of

energy occurring during the freshet period. Average monthly capacity factors for RoR energy generation were calculated using the following:

$$CF_{RoR,\tau} = \frac{E_{RoR,\tau}}{\sum_{t=1}^{720} G_{RoR,t}}$$

*Equation 12 Formulation for average monthly capacity factor in RoR facilities*

In which the  $CF_{RoR,\tau}$  is the average monthly capacity factor for RoR facilities,  $E_{RoR,\tau}$  is the total energy output of those facilities in a year, and  $G_{RoR,\tau}$ , is the maximum power of the RoR facility. Power generation from RoR facilities in every time step is then determined using Equation 13, in which  $P_{RoR,\tau}$  is the power output of each RoR facility at each timestep. The same formulation is used to calculate the must-run output of large hydro facilities.

$$P_{d,g,t} = CF_{RoR,\tau} * G_{RoR,\tau}$$

*Equation 13 Formulation for hourly output of RoR facilities*

Constraints added to the model's code to better represent the hydro capacities are included in the following snippet. In this code, hydro\_cascad\_pmin and hydro\_hourly\_pmin are tables that are exogenously calculated based on Equation 12 and Equation 13 and inserted to model as input.

```
#####
# Adding Minimum power output constraint for cascading hydro plants
#####
def min_power(model, t):
    return self.power(t) >= self.status(t) * self.hydro_cascade_pmin.ix[t]
self.add_constraint_set('min gen power', times.set, min_power)

#####
# Adding in hourly generation constraint for hourly hydro generators
#####
if (self.kind == 'hydro_hourly'):
    def hourly_min_power(model, t):
        return self.power(t) >= self.status(t) * self.hydro_hourly_pmin.ix[t]
    self.add_constraint_set('hourly_min_power', times.set, hourly_min_power)
```

*Snippet 2 Constraints for hourly minimum generation from cascading and RoR hydro plants*

The model is tested to see if the constraints are properly improving the results in a scenario for British Columbia, including the base year (2018) capacities and demand profiles. The results in Figure 20 show that the new constraints hydro facilities provide more electricity based on new constraints.

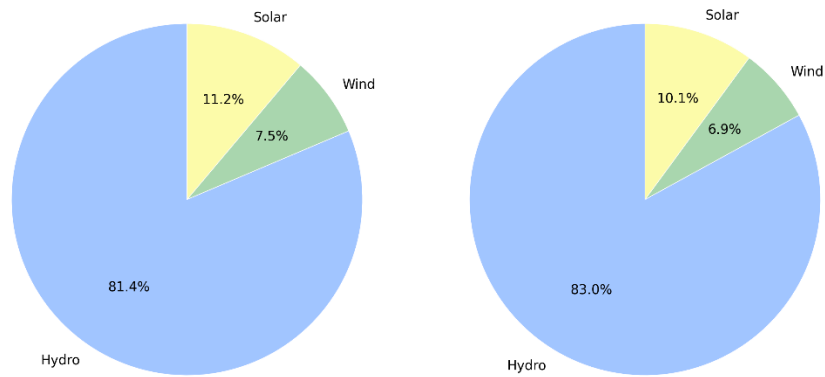


Figure 20: Test-scenario: total power generation from different generation types, left-SILVER model with cascading constraints only, right-SILVER model with cascading, RoR, and must-take constraints

The hourly dispatch results also show how the hydro<sub>must-take</sub> constraints reduce the flexibility to integrate the available VRE. As seen in Figure 21, solar and wind facilities are forced to reduce their generation due to the must-run requirements imposed by both the hydro<sub>must-run</sub> and RoR capacities. In conclusion, the hydro RoR and must-take constraints seem to improve the representation of the hydro facilities by delivering anticipated results of reduced flexibility for VRE integration in the system. Steep ramping characteristics visible on the cascading model on the left side of Figure 21 are limited by the must-take constraints that are present in the improved model.

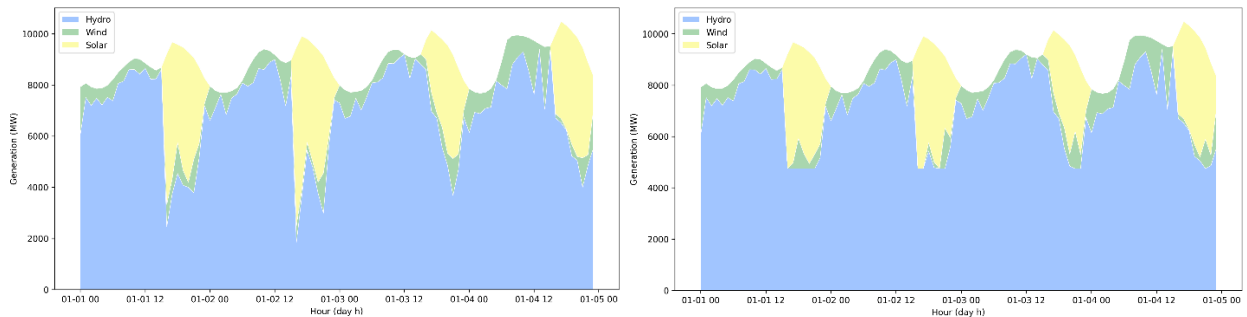


Figure 21: Test scenario: hourly dispatch, left-SILVER model with cascading constraints only, right-SILVER model with cascading, RoR, and must-take constraints

### 4.3.3 Integration and electrification scenarios

This study developed capacity expansion scenarios based on different electrification scenarios. A zero-emission target is set for the target year in all scenarios. Carbon emissions cannot be captured within COPPER's range of technologies as there is no emission sink capacity available. All scenarios follow a growing carbon tax from \$170/ton to \$370/ton from 2030 to 2050 as a national taxation policy impacting all provinces. This assumption follows a pattern of a \$15/ton yearly increase in carbon pricing from 2023 to 2030 with a yearly \$10 increase from 2030 to

2050 [168]. British Columbia is set to follow the Clean Energy Act in prohibiting nuclear expansion in achieving its energy transition targets [169]. However, The Government of Alberta considers both nuclear and small modular reactors as technologies to meet the province's future energy needs [170]. There is also a capital cost evolution for VRE technologies applied in all scenarios based on Canada Energy Regulator (CER) reports [4].

For the electrification rate, the non-electrified (base load growth) scenario includes a 1.5 times demand growth between 2018 and 2050 for both provinces based on population growth projection profiles. The other growth scenario (high load growth) takes a 2.5 times demand growth to represent the electrified load curve for 2050. As a comparison, CER reports around 47% increase in demand from 2021 to 2050 [4]. The selected range mirrors the annual increase in demand with the range of 1.27% to 2.9%, which represents medium to high population and economic growth as well as electrification in transportation, building, and industrial sectors.

This study defines two integration options as follows:

- Trade with fixed transmission capacity (FTC). Systems are fully integrated and trade in real-time based on competitive prices and load requirements. However, the grid capacity is limited to available resources. This fixed grid constraint is put for all inter-provincial capacities.
- Trade with expanded transmission capacity (ETC). In this scenario, COPPER utilizes grid expansion as an option to develop a more integrated national-scale network, in which the cost of grid expansion competes with other expansion costs in the objective function.

Two electrification demand growth scenarios combined with the two integration scenarios build the base four scenarios presented in Figure 22. The outputs of these four scenarios are then operationally analyzed using the SILVER production cost model.

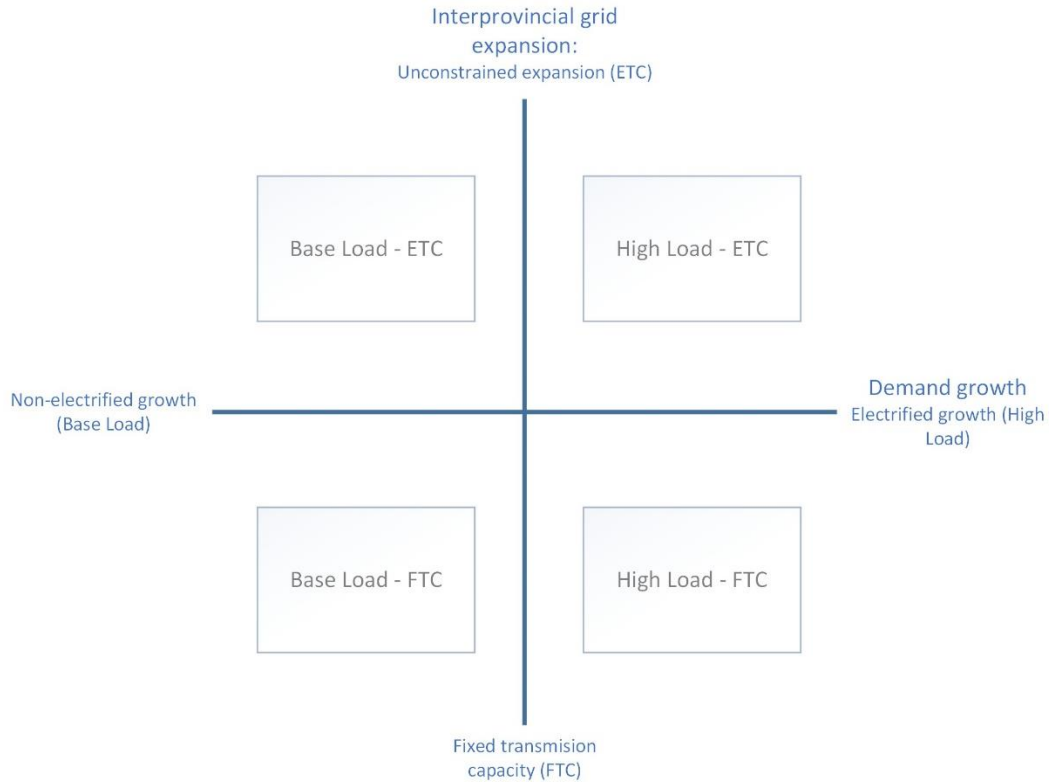


Figure 22: Scenario matrix based on uncertainties in demand and grid integration

## 4.4 Results

In this section, capacity expansion results from COPPER are analyzed for the four scenarios from both firm and VRE perspectives. Next, the operational insights are presented and compared in terms of VRE integration, costs, and interprovincial flows. Finally, a sensitivity analysis for the hydro constraints is presented.

### 4.4.1 Impacts on firm and transmission capacities

Different demand profiles and integration parameters have a substantial impact on how the expansion planning takes place for the power systems in British Columbia and Alberta. The capacity expansion portfolio for the four scenarios is presented for British Columbia (left) and Alberta (right) in Figure 23 below. Firm capacities are expanded to support the demand and for the 15% operational reserve margin, along with the large VRE capacities to follow the zero-emission constraints. COPPER refrains from expanding CCS and removes all existing emitting capacities based on the zero-emission constraints in all scenarios. CCS is not implemented because the current capture technologies are not able to remove all emissions from the sources [171] and the current modelling approach does not simulate emission sinks. Biofuel capacities remain or get expanded in the results in all scenarios as they are set to have zero emissions.

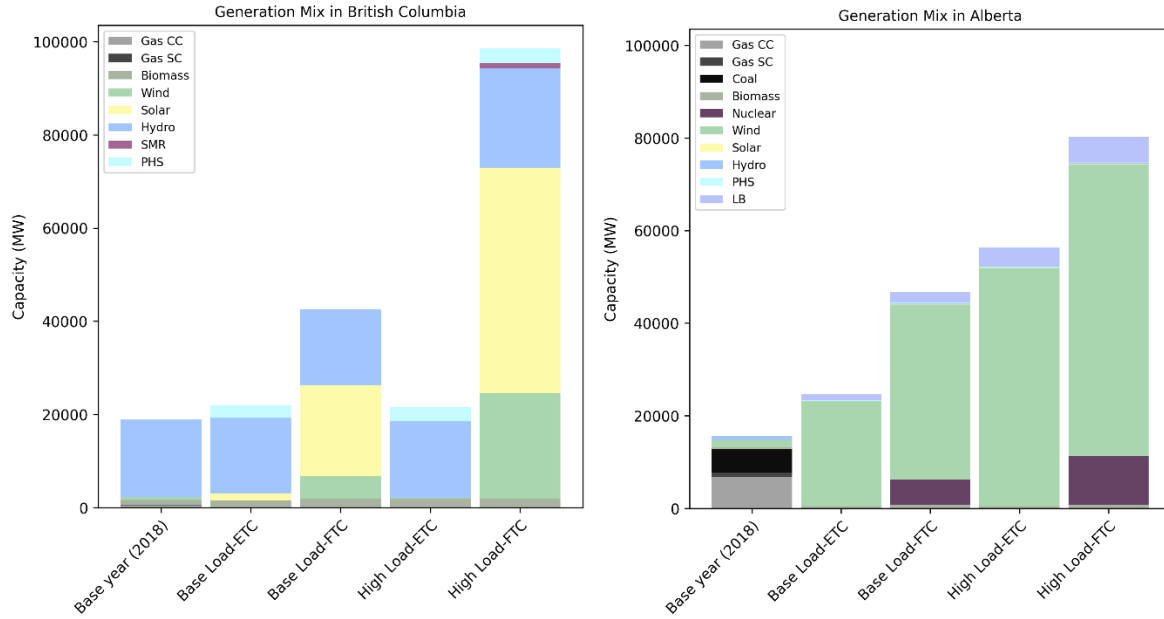


Figure 23: Capacity expansion results in 2050 for four scenarios compared to the base capacities, left: British Columbia, right: Alberta

A substantial portion of hydro capacities is retired in the unconstrained transmission expansion scenarios (ETC) when they reach the end of their expected life in Alberta. COPPER expands Lithium Battery (LB) storage capacities in two scenarios to meet the flexibility needs of VRE capacities based on cost and availability. Retirement is supplied exogenously based on the plants' expected life with no associated costs, while refurbishment incurs costs depending on each hydro project's specifications. Therefore, hydro projects may be retired, refurbished, or renewed based on cost comparisons with other flexible options. 156 MW of hydro is refurbished as a pumped hydro storage facility in all scenarios. In high-load scenarios, COPPER expands hydro projects across multiple locations in the provinces. Despite substantial demand growth in British Columbia under High Load-ETC, the capacity remains almost intact as the system primarily relies on expanded VRE capacities in Alberta through the interties.

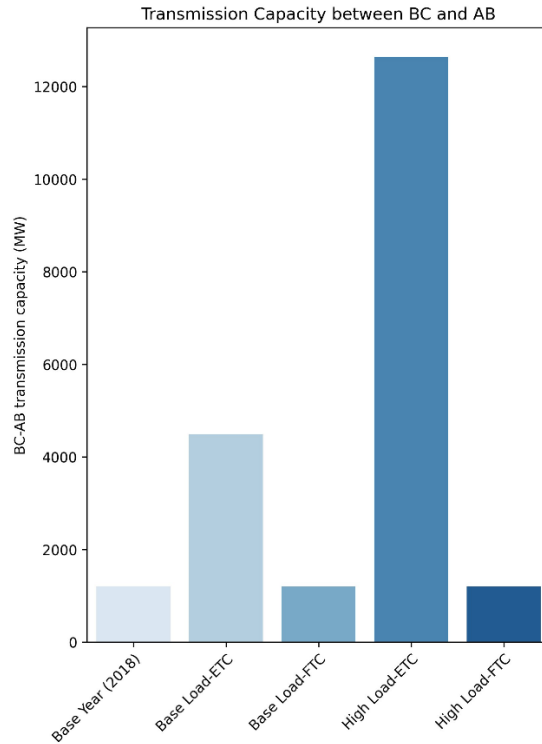


Figure 24 Transmission expansion outputs in comparison with the base capacity

Transmission expansion results represented in Figure 24 show a larger expansion being built in the High-Load scenario compared to Base Load as expected based on the scenario selections. FTC scenarios also result in non-emitting nuclear power plants in Alberta as the firm generation capacity since enough firm capacity is not provided by limited connection to British Columbia’s power system. In both high-load scenarios, the systems expand battery-based storage capacity to provide minimum flexibility requirements for large intermittent VRE, which cannot be provided by nuclear. There is also a small modular reactor developed for British Columbia in High Load-FTC, which is in line with NRCan’s SMR action plan [172]. This is allowed in the system only as a reserve margin and not operated in most of the hours in a year, unlike the nuclear in Alberta, since British Columbia’s hydro operates based on lower costs and more flexible ramping constraints.

#### 4.4.2 Impacts on VRE expansion plans

VRE expansion plans are influenced by system integration and load increases. Wind capacities are expanded in Alberta across all scenarios, aligning with the region's available wind potentials. In British Columbia, solar expansion is particularly substantial, especially in Fixed Transmission Capacity scenarios, for several reasons. First, is the projected technological evolution, leading to lower solar capital costs compared to wind by 2050. COPPER utilized estimates of capital cost reductions based on Canada's Energy Future 2021 [4], as shown in Table 12. Consequently,

when both technologies have similar capacity factors, the system favors solar over wind due to this cost advantage. Combining this capital cost gain with other upcoming factors, it becomes more favourable to invest in additional solar capacities in British Columbia for FTC scenarios.

Table 12: Cost projection for wind and solar capital cost based on current policies [4]

	2030	2040	2050
Capital Cost of Wind (2020CAN\$/kilowatt(kW))	1226	1184	1117
Capital Cost of Solar (2020CAN\$/kilowatt(kW))	1066	772	561

Second, the location of higher wind potentials is primarily situated in remote areas of British Columbia, leading to increased transmission connection costs since COPPER considers the distance of VRE expansion from each grid cell to the nearest bus on the grid. Figure 25 illustrates the relationship between distance and the capacity factor of each grid cell. In British Columbia, a positive correlation is evident between the wind capacity factor and distance, indicating that higher potential locations are farther from the grid. Conversely, Alberta shows a slightly negative correlation, suggesting that higher potential locations are not solely remote. Moreover, grid distances in British Columbia cover a wider range compared to Alberta, as shown by the difference in x-axis values (700 km vs. 300 km) in both plots based on maximum distances. Figure 25 (right) also reveals several locations in Alberta with higher capacity factors that already have direct grid access (zero estimated distance).

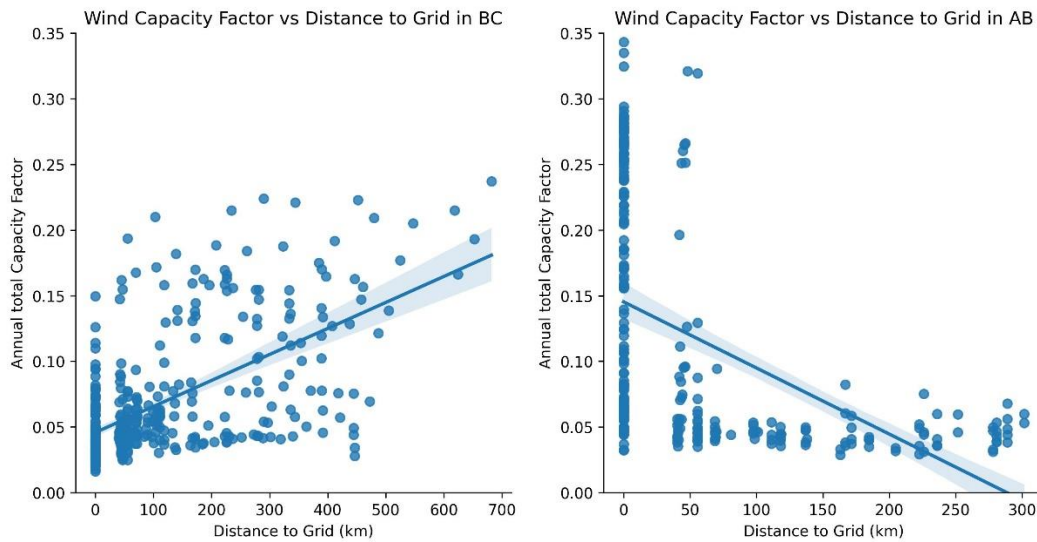


Figure 25: Relationship between yearly capacity factors of grid locations and their distance to the grid for British Columbia (left) and Alberta (right)

Third, Alberta has many more locations with higher wind potentials, as represented in the duration curves in Figure 26. It is also notable that the average for all locations is noticeably higher for Alberta. On the other hand, the solar potential in British Columbia is in a higher range in all locations while it is approximately the same.

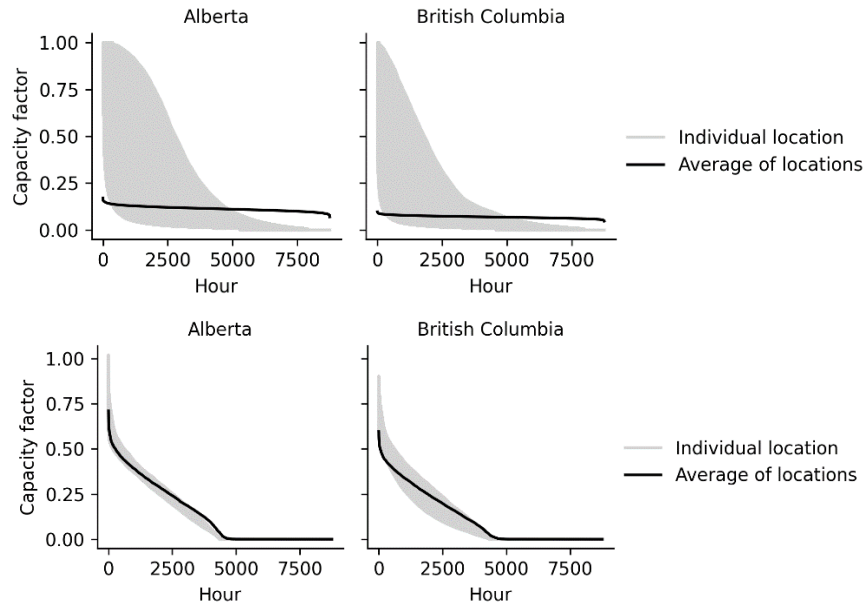


Figure 26 Duration curve of capacity factors in individual locations and as averaged for wind (top) and solar (bottom)

The histogram of the distribution of the average capacity factor in all locations for wind and solar, depicted in Figure 27, also strengthens the argument that wind is available in around a higher range in Alberta compared to British Columbia. The tendency toward the average of 13% in Alberta shows that the output of wind can be a more reliable source for power generation in contrast to a wide range of different capacity factors with a peak in the very low end. In comparison, wind capacity factors in British Columbia have an average peak which is around 8%.

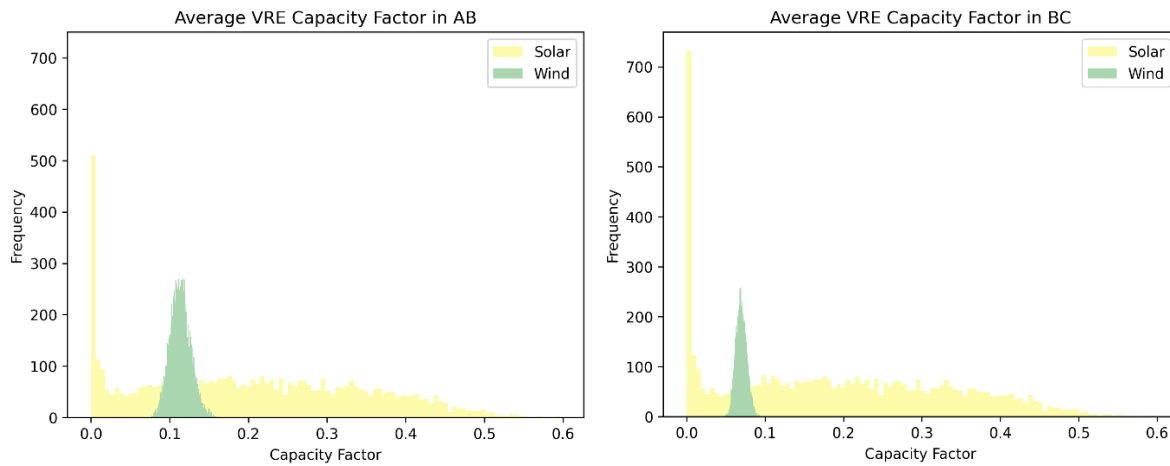


Figure 27: Spatial average capacity factors for wind and solar in Alberta (left) and British Columbia (right)

In summary, British Columbia has a higher potential for solar in less remote locations, resulting in its expansion in competition with wind. But when the wind is available with a higher capacity factor in locations closer to the grid in Alberta, the model chooses wind over solar despite its higher capital costs. The ETC scenarios enable British Columbia’s power system to incorporate available wind in Alberta and reduce the requirements for solar expansion.

#### 4.4.3 Impacts on the expansion costs

The capacity portfolios discussed previously result in different final costs. First, fulfilling higher demand in high-load scenarios requires more investment which is reflected in the total and broken-down costs in Table 13. Still, the costs between scenarios show that the major difference between scenarios comes from the constraint on the grid capacity expansion between the provinces. Comparing ETC and FTC for both high and base loads shows that integrating the two power systems using the transmission expansion would reduce the capital cost by more than 2.6 times in the first two and 2.8 times in the second.

Table 13: Total costs compared between four scenarios – All in 2018 million CAD -The Capacity Expansion costs include capital costs for the whole horizon of simulation (from 2018 to 2050)

	Base Load-ETC	Base Load-FTC	High Load-ETC	High Load-FTC
<b>Capacity Expansion Costs for British Columbia</b>	1,935	4,721	2,630	22,684
<b>Capacity Expansion Costs for Alberta</b>	7,777	21,547	17,327	36,656
<b>Transmission Expansion Costs</b>	227	-	1,048	-
<b>Total</b>	9,940	26,269	21,006	59,340

Two reasons contribute to the higher costs in the FTC scenarios compared to the peer ETC scenarios with equivalent load inputs. First, limited access to neighbouring province firm capacities, specifically hydro in British Columbia, necessitates building more expensive capacities as evident in capacity outputs. Second, expanding local VRE capacities in the absence of the expanded interties requires longer transmission interconnection and expansion in locations with lower potentials. This has two impacts on the system. Firstly, it raises the costs per unit of expanded capacity, resulting in higher expansion costs for the second and fourth scenarios. Secondly, the model must build larger capacities in regions with lower resource potential, resulting in substantially higher capital costs.

#### 4.4.4 Impacts on the operational costs

As per the integrated operation model, provincial power systems can exchange electricity based on their respective demand and the competition between the available generation units according to their operational costs through the planned interties. The model is run for a full year representing a single period in 2050. Results from these

analyses are summarized in Table 14. The cost calculations are based on 2018 CAD and annualized fixed O&M, variable O&M for biomass, nuclear, and hydro capacities, and fuel costs for biomass and nuclear capacities.

*Table 14: Annual operational costs and dispatched electricity from the capacities analysis for the four the scenarios*

<b>Scenarios</b>	<b>Base Load-ETC</b>	<b>Base Load-FTC</b>	<b>High Load-ETC</b>	<b>High Load-FTC</b>
<b>Annual variable operation and maintenance costs (2018 thousand CAD)</b>	399,865	535,357	442,155	642,037
<b>Annual fixed operation and maintenance costs (2018 thousand CAD)</b>	2,320	4,497	3,747	8,264
<b>Unit price of electricity based on operational costs (2018 CAD/kWh)</b>	0.023	0.042	0.035	0.074

Both constrained integration scenarios show higher operational costs compared to their counterparts with expanded transmission. Despite High Load-ETC having a higher total demand than Base-Load FTC, the electricity price is lower in the former. These observations stem from two factors. Firstly, in FTC scenarios, the expanded firm generation capacities (nuclear and biomass) have higher variable O&M costs. Secondly, as the system cannot fully utilize the available VRE capacities, the cheap generation from those sources is substituted by hydro or nuclear capacities, which have substantially higher variable costs.

#### **4.4.5 Impacts on the VRE integration**

The constrained integration of the two power systems results in a substantially curtailed generation from VRE resources, especially when the system is supporting the higher demand in the electrified scenario. The total generated and curtailed wind and solar generation is represented in Figure 28 for all scenarios. The curtailed energy in the high-load scenarios is notable compared to the base load. This is more important for a system that already has a large demand that can absorb the available generation from the VRE capacities, but the flexibility constraints reduce the efficiency of the installed VRE capacities.

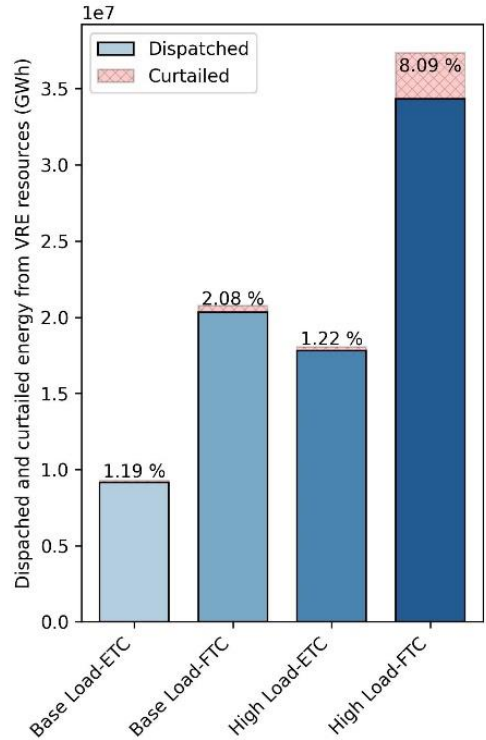


Figure 28: Annual total dispatched and curtailed (also presented in text) VRE generation

The main source for the flexibility issues is the bottleneck of the limited transmission capacity between the two systems, which cuts the access of high VRE capacities in Alberta to flexible hydro capacities in British Columbia. This is confirmed by the fact that the grid between the two provinces is congested at almost all hours in the FTC scenarios, as reported in Table 15. The integrated power system tries to dispatch available wind throughout the long-range grid, but the maximum capacity inhibits the flow between the provinces. Hence the generation is curtailed. The same observation is depicted in Figure 29 for sample operation hours, which compares high-load ETC and FTC scenarios.

Table 15 Utilized line flow between the systems for the four scenarios

Scenarios	Base Load-ETC	Base Load-FTC	High Load-ETC	High Load-FTC
<b>Utilized line capacity (%)</b>	43.4%	91.0%	40.6%	97.6%

Installed transmission grid capacity in ETC is ten times that of FTC, but annual total line flow is only four times larger in FTC due to dispatching large VRE capacities. This shows that the intertie's maximum capacity remains underutilized in ETC, avoiding flexibility issues from the transmission side.

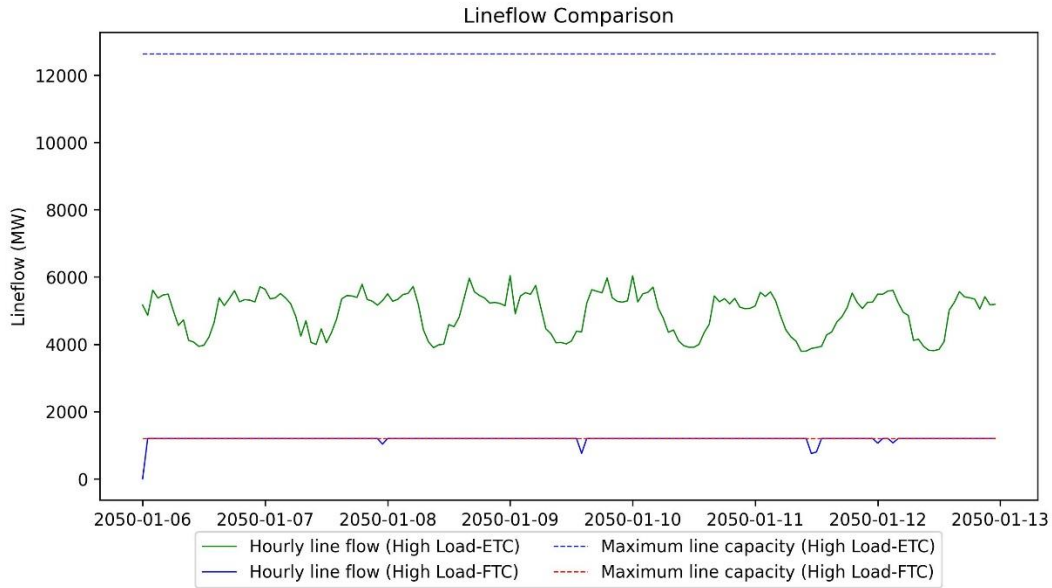


Figure 29: Hourly line flow in the interties between Alberta and British Columbia – sampled for the first two weeks of the year

Figure 30 shows a sample range of hourly generation dispatch output for two FTC scenarios. Red-filled areas indicate more severe curtailment of wind and solar capacities in High Load-FTC compared to Base Load-FTC during certain hours. Base Load scenario experiences flexibility issues too, but smaller VRE capacities can utilize the intertie more effectively, resulting in fewer curtailed hours. It is notable that nuclear generation maintains a minimum output constraint in the presence of abundant wind capacities in High Load-FTC but primarily operates at maximum capacity when VRE generation is lower in Base Load-FTC.

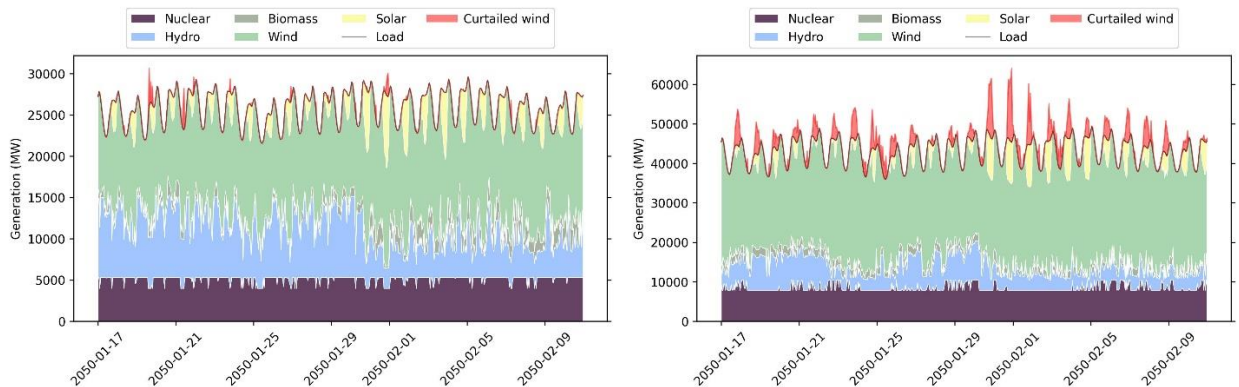


Figure 30: Hourly dispatch of electricity for the constrained scenarios, Base Load (left), High Load (right) (The scales are different and selected based on the maximum values for each output)

#### 4.4.6 Sensitivity of the VRE integration to hydro flexibility

Two integrated power systems benefit from flexible assets in one system to harness higher VRE potential in the other. However, uncertain hydro flow requirements can affect VRE integration and system flexibility as discussed earlier. For instance, Hamududu et al. suggest that climate change would positively impact yearly hydropower water inputs in North America [173]. These changes in inflow amounts and freshet periods influence the output of hydro plants to meet operational and environmental constraints.

This study emphasizes the significance of addressing uncertainty in one of Canada's largest hydro-dominated power systems. A random generator formulates a fluctuation range for both RoR and storage capacities during the freshet period. Starting with minimal constraints representing a dry freshet period, the runs continue until the system becomes operationally infeasible, capping at 50% of the maximum plant capacity, indicating surplus supply in certain hours. Figure 31 illustrates the correlation results.

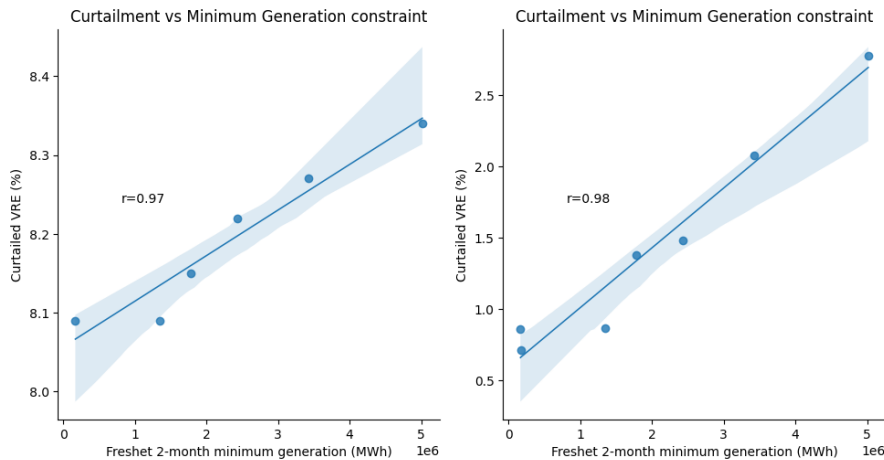


Figure 31 Correlation between the increase in the freshet minimum output constraint and the total curtailed VRE from left to right, High Load-FTC (left), Base Load-FTC (right) (y-axes scaled differently for better visualization)

All scenarios showed a positive correlation between the minimum freshet output for May and June with the share of curtailed VRE generation. However, the Base Load scenarios showed a larger impact on the output of hydropower. This is because VRE capacities are relatively smaller in non-electrified scenarios. Therefore, a larger portion of the VRE capacities is affected by the implication of the minimum output changes. The unconstrained integration scenarios showed minimum correlation with the change of the must-take values. This is because, first, the capacity of the interties is high enough so that the excess generation can be distributed effectively in the system. Second, the flexibility through the expanded interties gives the opportunity for the system to reduce generation from more expensive capacities, which are mainly biomass and nuclear, instead of wind and solar. Therefore, there is a negative correlation between the minimum must-take hydro generation and biomass electricity output.

All scenarios exhibited a positive correlation between the minimum freshet output for May and June and the curtailed VRE generation share. However, Base Load scenarios had a larger impact on hydropower output due to relatively smaller VRE capacities in non-electrified scenarios. Consequently, a larger portion of VRE capacities was affected by the minimum output changes. Unconstrained integration scenarios showed minimal correlation with changes in the must-take values. This is attributed to the high inertia capacity, enabling effective distribution of excess generation in the system. Moreover, the flexibility offered by expanded inertias allows the system to reduce generation from more expensive capacities (biomass and nuclear) instead of wind and solar, leading to a negative correlation between minimum must-take hydro generation and biomass electricity output.

## **4.5 Discussion**

This study researches the impact of integrating power systems that have large shares of VRE capacities and hydropower dominating the generation portfolios. In brief, this study addresses the question: “How does integrating power systems that have high VRE penetration rates from one side and large flexible hydro capacities from the other side impact the trajectories of decarbonization pathways?”

To do so, four scenarios representing different approaches toward power systems’ decarbonization are developed. The four scenarios are then applied in a linked modelling framework, including a national-scaled power system planning model and a power system operational model with detailed technical attributes and granular spatial and temporal resolutions. Various metrics are selected to extensively analyze the outputs from the framework, which include system operational and investment costs, capacity mix outcomes, flexibility metrics, and the system’s sensitivity to hydropower changes through climate change scenarios. The selected metrics have a wide range of insights in analyzing the possible pathways of decarbonizing the power systems of Alberta and British Columbia.

The capacity expansion planning model results align with previous studies, both utilizing the same model and other models in Canada. Dolter et al. examined the system under constrained transmission and zero-emission scenarios, introducing nuclear capacities in certain provinces (scenarios 1 and 3 in this study) [7]. Canada’s Energy Future report for 2021 by CER, wind and gas CCS are the main sources of electricity in Alberta, differing from this study’s results as this study’s modeling framework does not account for emission sinks and considers CCS technologies [4]. Furthermore, differences between CER results and this study include solar capacities compared to wind expansion in British Columbia, which is extensively discussed in the results section based on VRE profiles and assumptions.

Results of the linked framework have shown agreement with the established literature from different perspectives. First, planning costs are reduced by the integration of power systems. Second, the operational and electricity costs are benefited by improving the integration and efficiency of wind and solar operations. Third, improvements in flexibility are observed by integrating large VRE capacities with flexible hydro capacities.

As an improvement over prior studies, this framework's planning model offers a fine spatial resolution, allowing in-depth analysis of wind and solar capacity factors compared to other available models. The enhanced wind and solar potential inputs yield significant insights into VRE capacity expansion in different regions and under various parameters. Additionally, the linked framework provides operational insights that planning models often neglect, such as line flows, cascading characteristics, and hourly wind and solar outputs.

The results of this study conclude with the following observation. While some pathways require more capital, integration is a more cost-efficient option that delivers flexibility via various instruments:

- *Spatial flexibility issues:* When the non-dispatchable available wind capacity does not match the demand in the same region, the interconnection to other jurisdictions can potentially absorb the available supplied wind. The interconnection with integrated cooperation reduces the need to extensively expand the intra-provincial VRE capacities and other flexibility requirements, such as grid expansions within the jurisdiction, and storage, as shown in the cost comparison results for the four scenarios in Table 14.
- *Supply-side flexibility sources:* By integrating the two systems, highly flexible supply sources like hydro become available, which brings flexibility from the supply side to the system. As Alberta has smaller firm capacities in the second and fourth scenarios (Figure 23), it relies on the flexibility of the large hydro capacities in British Columbia.
- *Cost-efficient expansion and operation:* The integration of the power systems enables jurisdictions around the two provinces to gain access to areas with high wind and solar potential, allowing them to benefit from cheaper power production. However, the expanded transmission is not fully used in the unit commitment model. While the costs imposed by the expanded interties are a smaller share of the total capacity expansion costs, overestimation of the capacities should be noted.
- *Reduced curtailment:* As the integration of the two systems can absorb a substantial amount of available wind capacity by matching the supply and demand, it also reduces wind curtailment, which is observed in the operational analysis in different scenarios (Table 15). Grid expansion and integrated operation both have an impact on reducing curtailment rates which result in reduced operational costs by abating the unused available capacity.

The proposed methodology has some limitations and is based on some simplifying assumptions to maintain computational feasibility:

- The planning model simulates provincial interconnections as a fully integrated single-operated market with available interties, constrained or expanded based on the scenario, assuming real-time transactions in perfect competition. Thus, analyzing current system conditions with fixed power transfers is limited using this model.

- COPPER considers VRE locations' distance to the grid as a cost function in the optimization's objective but lacks insights into the planned VRE expansion's land features. Although a conservative 0.5 MW/km<sup>2</sup> constraint for wind farms is chosen in this study, other aspects like topology and current land use may impact results.
- The models used in this framework are deterministic, assuming perfect foresight of load curves, wind and solar potential, and hydropower constraints. Uncertainty is addressed through scenarios and sensitivity analysis for load curves and hydro capacity factors. However, further probabilistic analysis could provide better insights into inherent variability.
- Interprovincial grid expansion, a vital flexibility source in the COPPER model, impacts planning and operational costs. While operational costs decrease by integrating cheap wind and solar power, grid expansion cost sensitivity to initial price inputs is worth considering. More accurate estimation based on topologic features and remote access may impact cost efficiency improvements.

#### **4.6 Conclusion**

The combination of impacts from decarbonizing the power system and holding it accountable for expanding electrification in other sectors bring a considerable burden on the system's reliable operation. This study explores opportunities in integrating the power systems of British Columbia with rich, flexible hydro capacity and Alberta with high potential for decarbonization and large wind capacity factors. Various conclusions can be drawn from this study specifically for decarbonizing pathways of the two systems and, to some extent, for other jurisdictions following similar energy transition pathways.

*Integrating systems reduces intra-jurisdictional capacity requirements to achieve decarbonization targets, especially through the expansion of VRE capacities.* By limiting the integration of the two systems, local demand must be met by nearby capacity as each subsystem has constrained access to other available resources in the neighbouring provinces. This becomes more crucial as VRE capacities increasingly penetrate the portfolios with expansion into locations with lower potential. Larger firm capacity and operational reserve margin are also needed in these cases when VREs are unavailable. Integration is shown in this study to alleviate potential large land use due to solar expansions in British Columbia and shift the development toward more available onshore wind potential in Alberta.

*Integration becomes more important as the load expands through decarbonizing other sectors.* Comparing outcomes from different load scenarios showed that there are more severe impacts when the demand has grown larger since additional capacity is needed to support the load. The impacts range from capacity capital costs to efficiency of VRE integration and more. This shows that deep decarbonization through electrification requires even more unified and high-level collaboration between power authorities to reduce costs and inefficiencies.

*Even with enough firm capacity, disconnected power systems face a large loss of cheap electricity.* Even though the system tries to come up with a solution to support expanded VRE capacities, a fair amount of curtailed energy remains because of limited flexibility through constrained integration. A lack of transmission capacity would result in an inefficient and unused capacity and very cheap electricity that could be generated from those resources. Disconnecting the power systems in British Columbia and Alberta reduces access to the flexible hydro capacities in BC, which is followed by relatively substantial curtailment rates for wind generators in AB.

*Integrating systems through expanding interties promotes transition through a much cheaper alternative.* The disconnected transition is shown to impact the costs both from the expansion and operational aspects. This would result in higher electricity prices for consumers, more expensive investment requirements from the market and governments, and even lost profit for assets that face curtailments. On the other hand, integrated power systems are shown to have a much more economically feasible expansion plan and access to cheaper and more flexible energy from either side. Collectively, expanding interties imposed relatively lower costs to the system to deliver the same amount of electricity. However, it should be noted that current market structures are highly different between the two provinces, and a strategy should be followed to transition toward the integration of these two regions.

*Climate change impacts should be considered as a potential threat to the systems' required flexibility.* While the hydro capacities play a crucial role in integrating variable renewable energy as a source of flexibility, the impacts of climate change on the hydropower requirements need to be noted as a source of uncertainty in modelling future decarbonization pathways. This uncertainty is shown to impose an impact on the integration of VRE generation. Other factors impacting VRE integration are their availability dynamics induced by climate change and policy-induced restrictions to expand these resources, especially in Alberta.

These findings should be supplemented by research on the integration of power systems as they transition in a variety of contexts. Further research is required to assess other integration potentials, additional options for market cooperation, and more accurate formulation for interties expansions. Other impacts from climate change and uncertainties in policies can also expand the vision toward VRE integration.

## 5 Discussion, conclusion, policy implications, and future work

### 5.1 Discussion

This dissertation provides insights into the operational requirements for delivering flexibility to Canada's power system to integrate more variable renewable resources when following decarbonization pathways. This study assists policy and decision-makers by analyzing the decarbonization of the power systems mainly through two pathways of integrating VRE resources and electrifying demand and finding challenges that these paths contribute. During the thesis, we deliberately analyzed gaps in the literature and tried to address them in the previous three chapters. In the second chapter, a linked framework of power system planning, and operational models is developed to fill in the gaps that are found in the available literature. The limitations of the current studies are found to be (1) having detailed technical representation for the intermittent and weather-dependent wind and solar capacities, (2) fine temporal (i.e., hourly) and spatial (i.e., sub-regional, provincial) resolution for the operation of the power systems, and (3) analyzing various flexibility options instead of limiting the wind and solar capacities. This chapter contained methodology, data, results, discussion and limitations, and conclusions for one planning scenario and four provincial operational case scenarios. The main objective of this paper is to answer the question: "Is the capacity expansion suggested by the power system's planning model (COPPER) operationally flexible, specifically given the high VRE shares?". It answers this question in the light of broader question of flexibility requirements for the large VRE penetration scenarios and analyzing network-side and supply-side solutions of inter-provincial transmission and storage capacities.

The third chapter finds gaps in the literature for analyzing demand-side flexibility options, especially demand response programs. The limitations of the current studies in the domain are found to be (1) under-representing either supply-side or demand-side with small-sized models resulting in neglecting technical details, (2) representing only one side and therefore not being capable of capturing interactions between demand and supply, and (3) using historic price signals for applying demand response triggers. This chapter introduces a different linked methodology containing a supply-side operational model and building energy simulation model that follows to address the above-mentioned gaps. It also brings novelties in terms of analyzing costs and flexibility requirements at the same time by choosing proper metrics. The paper answers the question of whether the flexibility requirements in Alberta's power system can be achieved using different kinds of demand response programs in the building sector. This question contributes to another perspective of the thesis theme, which is focused on demand-side flexibility.

In the fourth chapter, we used the same linkage framework that is introduced in the second chapter, to analyze other perspectives of flexibility in the power systems. This is done by finding the gaps in the literature as (1) analyzing the integrated operation of two power systems in terms of achieving high levels of decarbonization through VRE capacities, (2) investigating future scenarios for power systems integration from a capacity expansion model instead

of projecting scenarios, (3) including technical details in the operation of the systems especially for hydro capacities, including hydro cascading and must run constraints, ramping, and unit commitments. The same SILVER and COPPER linked analysis is applied for different scenarios in the integrated operation of the two systems in terms of transmission capacities to analyze its impact on integrating large VRE capacities for British Columbia and Alberta. This chapter answers the question “Can integration of power systems, especially in the presence of large hydropower capacities, lead to the integration of VRE resources more efficiently and effectively?”. Answering this question delivers insights from a new perspective for flexibility in terms of power systems integration and hydropower facilities.

During this research, the most impactful inputs are analyzed through variations in inputs and scenarios, which some were included in the chapters, and some others were not included. Following table includes all scenarios that were analyzed with the modeling suites applied in this study. These variations are in addition to the sensitivity analyses provided in the appendix for validation and verification of the models.

Parameter	Scenarios	Use
<b>Demand</b>	1.5x growth from the base year (2018)	David Suzuki Foundation’s clean power report [174] and Chapter 2
	Sectoral electrification demand scenario from external resources’ modeling	David Suzuki Foundation’s clean power report
	Macroeconomic demand growth modeling for electrified and non-electrified scenarios	Chapter 3
	1.4x and 2.8x growth rate from the base year (2018)	Chapter 4
<b>Interties’ expansion</b>	Unbounded transmission expansion	Chapter 2 and 4
	2x growth cap from base year’s capacities	Chapter 3
	Fixed interties	Chapter 4
<b>Wind land constraint</b>	2 MW/km <sup>2</sup>	Chapter 2, and3
	1.5 MW/km <sup>2</sup>	Chapter 4
<b>Silver’s spatial resolution</b>	Plant level in the provincial models	Chapter 2, 3, and 4
	Provincial aggregated capacities in the national model	Chapter 2

<b>Silver's scale</b>	Provincial	Chapter 2, and 3
	National	Chapter 2
	Interconnected provinces	Chapter 4
<b>Wind and solar data</b>	MERRA 2 – 2018 data	Chapter 2, and 3
	MERRA 2 – 2021 data	Chapter 4
<b>Wind and solar capital costs</b>	Over 3000 set of datapoints with a range extracted from similar studies	Used in sensitivity analysis and in a co-authored work under review
<b>Carbon pricing scheme</b>	95-370 CAD/ton range from 2018 to 2050	Chapter 3, and 4
	95-170 CAD/ton from 2018 to 2035	Chapter 2
	95 to 600 CAD/ton range for 2050 in sensitivity analysis	Used in a co-authored work under review
<b>Carbon intensity targets</b>	Zero-emission by 2050	Chapter 2, and 3, and 4
	Net-zero emission by 2035	Chapter 3, and 4

These parameters are designed to fulfil the related study's requirements for each chapter as well as testing the models' general sensitivity to different input parameters. As an example, higher load scenarios caused exponential expansion of VRE capacities to reliably support the demand. Also, limiting inerties showed to increase the system's total costs compared to scenarios that had no cap for expanding transmission. However, other parameters, or other options for the mentioned parameters can impact the results which is reflected in the following section.

These sensitivity analyses of the parameters showed how the pathways can heavily impacted by other factors that are out of the boundaries of a power system or enforced by policies and regulations. As a result, covering a wide range of difference as happened in this study gives a more reliable outcome covering the uncertainties stemming from the sources of changes in those input parameters. Various parameters have different sources of uncertainty that will impact their path in the future.

Demand will be changed based on various factors, such as macroeconomic growth, population growth, and technological changes. Carbon pricing and carbon intensity targets are the other factors that are determined by different levels of government and their policies according to global agreements and pledges such as the Paris agreement. In addition, cost parameters are prone to change in the future according to the changes in the global

market, technology evolution and the changes in the price of materials and resources. The intertie expansion is also impacted by the provincial and federal governments' policies and regulations.

Different parameters have different impacts on the projected decarbonization pathways for the Canadian power system with the carbon intensity target being the most influential on the technology mixture and the demand being the most impactful on capacities. Demand pushes the capacity meaning that the model needs to provide enough power to meet the demand, no matter which path it chooses to expand the capacities. On the other hand, zero-emission toggle pushes the model to utilize only non-emitting technologies, such as VREs and nuclear.

Directly comparing these two impactful parameters is not straightforward since other parameters has been changed between the various studies that used them. However, using some sample output variables will give a general sense of how the demand and emission targets results changes in the most crucial output variables of the modeling frameworks.

Raising the demand growth rate from 1.4 to 2.8 compared to the base year, increases the system's total costs to 2.1 times higher. It also substantially increases capacity of VRE resources to almost triple in size. This confirms that the demand has a substantial impact on the systems expansion outcomes. On the other hand, the emission targets also shown to have large impacts on systems costs and emissions. Putting zero emission cap on the system increases the systems costs by more than 25% in some scenarios. It also removes 45 Megatons of emissions from the Canadian power system by 2050. This target along with other constraint in the selected scenarios, pushes the system to expand VRE capacities by more than 20% compared to the net-zero emission targets.

In conclusion, both parameters are explored through research tasks in this dissertation and showed substantial impact on the system's costs, operational flexibility, and most importantly, emissions. The changes imposed from the mentioned parameters show that policy making around emission targets, electrification goals, and systems' efficiency can result in different costs and emissions impact Canadians. Therefore, these policies should rigorously be analyzed when regulations are designed in different levels of jurisdiction.

The three studied flexibility options can result in a comparison by different metrics and impacts. As a result of this thesis, the flexibility options can be ranked merit-based in this order: 1-Integrating power systems, 2-Supply-side options, 3- Demand-side options.

In the first rank, integrating power systems is shown to eliminate a substantial amount of costs required both in investment and operation to support grid's decarbonization through VRE expansion. Compared to two other options, this option reduced the need for local capacity expansion, and reduced operational costs by giving access to available cheaper options from the other power market. However, integrating two power markets require substantial cooperation between the two systems, some policy and political efforts, and potential restructuring of the markets to enable their complete integration as represented here.

In the second place, supply side options are shown to be crucial to support system's reliable and affordable operation even when the inerties are expanded. These options along with the local transmission expansion requires extensive investment but shown to be inevitable to achieve decarbonization goals by expanding VREs. At the same time, this option is shown to be the most effective in resolving bottlenecks for integrating large VRE capacities, reducing curtailment. Including this option in decarbonizing power systems require local policy and investment intervention, such as subsidies to expand storage and local transmission.

In the third place, demand-side options and demand response, shown to be effective both in reducing the operational costs and improving VRE capacities integration. This option also has the potential to limit the need to expand supply side options for delivering flexibility, but not extensively studied in this thesis. It is also observed that this option has relatively limited impact on these metrics compared to the other options, at least for the residential sector. This is due to the nature of the analyzed programs and the delayed thermostatic effect as well as the lack of inclusion for their initial investment costs.

This observation agrees with the other studies conducted research on comparing flexibility options. Negel et al. [92] compared different options and concluded that sectors coupling, and transmission expansion are the top two most impactful paths to lowering the costs and providing flexibility. They also found that hydropower and transmission investment have a strong synergy to reduce costs and profit producers which is in line with the current thesis findings. Cruz et al. [18] emphasizes the role of network side options as the conventional options are not adequate to accept large shares of variable renewable energy capacities. Ding et al. [20] discusses energy storage and demand side management and concludes that energy storage prevails the demand side management in terms of integrating more VRE resources in the systems which is also observed in the current thesis. Alexopoulos et al. [35] conclude that a variety of flexibility options should be accompanied the decarbonization pathways for the case of Greece.

## **5.2 Conclusion and policy suggestion**

Above mentioned parameters are developed as scenarios in the three manuscripts and analyzed by the linked frameworks that contribute to deep insights and findings of the decarbonization pathways for Canada's power system. Following conclusions can be drawn from the analyses presented in this dissertation.

1. *Flexibility issues are crucial and need to be analyzed for designing regulations* Integrating large wind and solar capacities following deep decarbonization targets can lead to some flexibility issues that result in loss of generation, network congestion, and sometimes loss of load. Therefore, deep decarbonization pathways should be clearly and deeply analyzed both in terms of planning and operation to reach a general optimal solution in both aspects.
2. *Adding VRE capacities require some flexibility preconditions in the power system.* In response to the flexibility issues, Canada needs to address the issues by improving investments in expanding the

transmission lines and storage capacities. Such expansions introduce additional capital costs to the system which might have been neglected without analyzing the operation of the system for future scenarios. It also observed that COPPER overestimated wind capacities when it has no feedback from fine spatial and temporal resolution operational analyses. In conclusion, it is shown that introducing proper transmission and storage capacity should therefore correct the overestimation and resolve flexibility issues.

3. *Systems integration is shown to be the most impactful option to bring flexibility and need to be explored across Canada.* Integrating power systems is shown to have significant benefits both in the expansion and operation of a decarbonized power system. While Alberta can deliver a large portion of VRE requirements, integrating its system into British Columbia's power system is shown to reduce the expansion costs by up to threefold, and electricity prices by twofold. These considerable improvements are allowed by large hydropower facilities available in British Columbia which have quick ramping characteristics. Therefore, integration of the power systems, especially in the mainly disconnected power systems across Canada, could contribute to decarbonizing the system with lower expansion costs and ensuring efficient operation of VRE resources.
4. *Demand side options impose less cost and are shown to be effective to mitigate flexibility issues which need to be followed along other options.* Incorporating demand-side flexibility options is shown to have a substantial impact on flexibility measures to integrate more VRE capacities efficiently. Similar to the national level, flexibility is shown to be an issue for Alberta as one of the provinces with the highest potential for wind and solar expansion. But this requirement is observed to be more crucial when other sectors are electrified, and a deeper zero-emission goal is targeted. Demand response is analyzed to be one of the solutions that contribute to incorporating more wind and solar capacity in the system, leveling the demand curve, lowering operational costs, and reducing congestion throughout the network. It is also discussed to have relatively lower investment requirements compared to storage and transmission expansion sometimes reducing the need for those options. As a result, demand-side options should be considered as a feasible pathway that can contribute to delivering efficiency in integrating large VRE capacities as well as reducing the investment requirements for network and supply-side flexibility options.
5. *Modeling frameworks with emphasis on operational flexibility should be utilized to study regulations and policy designs.* Linked frameworks and the discussion stemming from them around flexibility bring insights for the researchers, stakeholders, utilities, and policymakers that were not achieved in the single model analyses. The current thesis introduces several new tools and perspectives to the researchers in the power system that can be used for a wide range of analysis and further development. The tools developed during this thesis have been incorporated into various studies by the researcher in the SESIT team at the University of Victoria. The tools and frameworks are developed using state-of-the-art knowledge of the current

policies and programming practices. However, they should be maintained with the most recent policies. They can also be further developed to expand their capabilities to include wider analyses and studies related to the domain.

### 5.3 Future work

Modeling frameworks inherited limitations due to their nature of optimization for a long horizon and data gaps. These paths are recommended to be followed for future research:

1. The current modeling includes unit commitment with DC flow formulation. Further analysis can be done by adding other possible operational aspects, like the AC power flow, reliability, voltage, and frequency quality. These metrics can give a deeper understanding of the impacts of the integration of large VRE capacities into the system.
2. Interprovincial transmission flows are considered to be fixed over the boundaries of the operational model. This limits the representation of competing neighboring markets that can transfer energy based on real-time requirements and costs. Further research could be done to improve toward a more realistic representation of the interconnected which are interacting with each other.
3. Several paths can be followed to improve the general representation of national-level expansion planning. Wind and solar capacities are currently constrained by a uniform MW/km<sup>2</sup> factor for all grid locations. Adding land features, like terrains, as costs of building wind and solar capacities and their performance, and cities to limit the expansions, would result in a more accurate representation of wind and solar capacities.
4. One of the main limitations of the translation tool was that the intra-provincial transmission capacities are considered to be fixed over the horizon of the expansion planning. Future research can be followed to address this issue as the COPPER model considers some preliminary costs according to the connection from the wind and solar capacities to the grid which might be updated to represent more accurately and translated into transmission expansion.
5. Demand response programs that were represented in the second chapter were only limited to the building sector and two selected programs. Further research for the impact of other sectors with larger shares could give a wider range of insights from implementing such programs in integrating large VRE capacity shares.
6. Further improvement in COPPER can also result in having a variety of power system integration options. Right now, COPPER models the Canadian-wide power system as a single integrated market. However, there are multiple different integration options, levels, and considerations that can be included, including capacity

transfers, capacity pools, and energy transfers. These options can be analyzed as other options compared with the transmission expansion scenarios giving alternative insights.

7. This study relies on historical and macroeconomic projection for demand, with perfect foresight assumptions and models them in the analytical and deterministic optimization frameworks. Further sensitivity analysis for scenarios such as demand reduction, could result in other pathways that align with efficiency improvement, societal changes, and passive options. In particular, societal changes are out of scope of this study, but can potential reduce the expansion, operational, and other related costs induced by pathways studied during this thesis.
8. Also, this study uses historical data for wind, and solar hourly profiles with the same deterministic assumptions. Expanding on wind and solar potential projection could reflect future uncertainty and climate change induced impacts on these resources that can potentially change the outlined pathways.
9. The reliability of the power systems is also analytically determined by generation and transmission reserve margins and Unit Commitment hourly analyses for yearly operational integrity (Especially in Chapter 2). Future work can implement probabilistic modeling approaches to further analyze reliability in the studied power systems, especially with high intermittent variable renewable energy resources. The methods include but are not limited to Monte-Carlo approaches which are widely used in reliability-specific studies in the context of power systems.

## 6 References

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## 7 Appendix

### 7.1 Appendix A: Models Verification and Validation

Four different modeling suits are used in the four chapters of the current thesis. This section covers a variety of verification and validation methods applied in these modeling suites. Different methods of validation and verification are used where possible for the models based on the standard testing and validation methods [175], [176]. When some areas were not available, proper justification and limitations is proposed. At the end of this appendix, the limitations stemming from data availability and modeling assumptions are acknowledged.

#### 7.1.1 SILVER

SILVER is used throughout this thesis to analyze the operation of the power systems to find flexibility issues in a fine hourly temporal resolution and fine spatial resolution of the system as per each transmission bus. The model is initially developed by Dr. McPherson [177] and enhanced in the SESIT team at the University of Victoria. The original paper for the version of the model that is used in this thesis can be found in [69]. The current thesis utilized SILVER in a variety of scenarios for decarbonizing Canada's power system. The model is mainly run for a sample year in 2050 and the input scenarios are built on the outputs of COPPER. Therefore, to the knowledge of the author, there is no other study found that follows the same methodology and operationally the same Canadian domains that have been analyzed here in the current study. However, there are a few studies that have some high-level operational insights that can be compared with the insights of this study as listed below.

Saffari et al. conducted an operational analysis of the current situation of the Canadian power systems for integrating renewable energy resources using the same SILVER model [69]. Their findings show that the hydro-dominated generation capacities and expanded transmission would help the Canadian power system to integrate more VRE resources. However, they only studied the grid with the current generation capacities and demand. While studying the same transmission system with generation capacities and grown demand in 2050, we found some flexibility constraints on the transmission side in some provinces which is reflected in the second chapter. But hydro dominance of BC and its impact on VRE integration is studied in the fourth chapter and showed agreement with the findings of the mentioned study.

Rodriguez et al. studied the integration of multiple power systems in Northeast America (including Quebec and Ontario) under decarbonization targets with an approximate operational module [156]. Their model excluded operational details and sub-regional transmission grids resulting in optimistic outputs for the system's operation. However, their analysis shows that the operational costs for the decarbonized power system are lower when systems are integrated and have expanded inerties. This observation is in agreement with the findings of the current thesis which is presented in detail in the fourth chapter.

Gjorgiev et al. proposed a linked framework and assessed the power system's dispatch in the presence of high renewable capacities in 2050 for a test system [54]. This study showed that transmission bottlenecks can contribute to sub-optimal dispatch of electricity when there are large shares of VREs in the system. As a result, their model signaled the system with recommendations for expanding the transmission. Their finding is similar to what was concluded from the operation and planning linkage study conducted in the second chapter of the current thesis.

Other studies showed the positive impact of storage capacities and their importance in integrating large VRE shares in the power systems using an operational analysis modeling framework [44], [78]. This study also confirms that storage capacities are required for further integrating VRE capacities by analyzing the system operationally using the SILVER model.

Further to a high-level comparison of the outputs from the SILVER model in this thesis and other studies, the model is validated by testing the constraints, running sensitivity analysis on different variables, and comparing results with other established unit commitment models using the same set of inputs.

#### 7.1.1.1 SILVER's formulation

This study uses SILVER's Unit Commitment optimization functionality. Following are the details of the optimization formulation and the constraints that the objective function is subjected to. The following table describes the parameters and variables in the model.

<b>Symbol</b>	<b>Definition</b>
<b>Sets</b>	
$t$	Time, hourly intervals in SILVER
$g$	Set of generation facilities in model's input
$s$	Set of storage facilities in model's input
$i, j$	Nodes ( $i$ ), and adjacent nodes ( $j$ )
<b>Parameters</b>	
$C_g$	Generation cost for generator $g$
$C_{c(g)}$	Startup cost for generator $g$
$P_{\min(ij)}, P_{\max(ij)}$	Minimum and maximum flow through lines connecting nodes $i$ and $j$
$X_{ij}$	Reactance of the line connecting node $i$ , to node $j$
$P_{\min\text{ramp}(a)}, P_{\max\text{ramp}(a)}$	Minimum and maximum ramp rates for thermal generator $a$
$T_{a,\text{minup}}, T_{a,\text{mindown}}$	Minimum length of on and off periods for thermal generator $a$
$\alpha_{s,g}, \alpha_{s,p}$	Storage and generation efficiencies for storage facility $s$
$E_{s,\text{min}}, E_{s,\text{max}}$	Maximum and minimum stored energy in storage facility $s$
$D_g^{\min}, D_g^{\max}$	Maximum and minimum water discharge in hydro facility $g$
$C_g^{\min}, C_g^{\max}$	Maximum and minimum stored volume in hydro facility $g$
$W_g^{\min}, W_g^{\max}$	Maximum and minimum water spillage from facility $g$
$Y_{i,t}$	Water inflow to a hydro storage
$K$	Constant representing gravity
$\eta_g$	Generation efficiency of the hydro facility $g$
$H_g$	Average stored water height of the hydro facility

$Perct_{Down}, Perct_{Up}$	Minimum and maximum tolerable percentage of stored water
$P_g^{max, hourly}, P_g^{max, daily}, P_g^{max, monthly}$	Maximum output of different hydro generation types
<b>Variables</b>	
$P_{t,g}$	Output of generation facility $g$ , at timepoint $t$
$u_{t,g}$	Status of generation facility $g$ , at timepoint $t$ (0 for off, 1 for on)
$M_t$	Marginal cost of generation from storage facilities at timepoint $t$
$P_{t,s}$	Generation output of storage facility $s$ at timepoint $t$
$P_{ij}$	Flow through lines connecting node $i$ , to node $j$
$\theta_i, \theta_j$	Voltage angle for nodes $i$ and $j$
$T_{a,up}, T_{a,down}$	Length of periods for on (up) and off (down) status of thermal generator $a$
$E_{s,t}$	Stored energy in storage facility $s$ , at timepoint $t$
$D_{g,t}$	Discharged water from hydro facility $g$ , at timepoint $t$
$C_{g,t}$	Stored water in hydro facility $g$ , at timepoint $t$
$W_{g,t}$	Spilled water from hydro facility $g$ , at timepoint $t$

#### 7.1.1.1.1 SILVER's UC objective function

$$\min \sum_{t=1}^T \left\{ \sum_{g=1}^G [C_g(P_{t,g}) + C_{c(g)} \times |u_{t,g} - u_{t-1,g}|] + M_t \times \sum_{s=1}^S P_{t,s} \right\} \quad (A.1)$$

Where the  $C_g$  is the generator's cost function depending on the power output  $P_{t,g}$  at time  $t$ . The startup and shutdown costs  $C_{c(g)}$  are applied when a generator's status  $u_{t,g}$  is changed between successive hours.  $M_t$  is the marginal cost for the hour  $t$  in the storage facilities.

#### 7.1.1.1.2 Optimization constraints

The constraint represented in A. 2 ensures that the output from the generation and storage units is equal to the load at each hour  $t$ . This power balance needs to be satisfied at each node.  $P_{ij}$  is the power flow through the adjacent nodes.

$$\sum_{g=1}^G P_{t,g,i} + \sum_{s=1}^S P_{t,s,i} - \sum_j P_{ij} = P_{t,load} \quad \forall t, buses (i) \quad (A.2)$$

Constraints in A. 3 through A. 4 are representing the transmission power flow constraints regarding the DC estimation as discussed in the dissertation. A. 3 limits the power flow in a transmission line within its physical constraints. Real power flow based on DC formulation is calculated in A. 4 in which  $X_{ij}$  is the reactance of the line and  $\theta_i$  and  $\theta_j$  are the voltage angles for each of the nodes.

$$P_{\min(ij)} \leq P_{ij} \leq P_{\max(ij)} \quad \forall \text{ lines } (ij) \quad (A.3)$$

$$P_{ij} = \frac{1}{X_{ij}} (\theta_i - \theta_j) \quad (A.4)$$

Following constraint represented in A. 5 keeps the output from each generation and storage unit (a) between a minimum output and the unit's maximum output power.

$$P_{\min(a)} \leq P_{t,a} \leq P_{\max(a)} \forall t, a \text{ where } u_{t,a} = 1 \text{ (A. 5)}$$

The constraint in A. 6 limits the ramping of each generation and storage unit to a minimum and maximum ramping parameter.

$$P_{\minramp(a)} \leq P_{t,a} - P_{t-1,a} \leq P_{\maxramp(a)} \forall t, a \text{ (A. 6)}$$

Constraint A. 7 limits the number of hours a generation or storage capacity should be turned on. And A. 8 constrains the hours a unit should be turned off before it can be turned on again before two instances of changing status.

$$T_{a,\text{up}} \geq T_{a,\text{minup}} \forall a \text{ (A. 7)}$$

$$T_{a,\text{down}} \geq T_{a,\text{mindown}} \forall a \text{ (A. 8)}$$

Storage facilities have the constraints represented in A. 9 to A. 12. A. 9 forces either of the binary variables for the storage capacities,  $u_{s,p,t}$  and  $u_{s,g,t}$  to be 1 at the same time. So, those facilities cannot store (p) or generate (g) simultaneously. A. 10 calculates the output of the storage units in which  $\alpha_{s,g}$  and  $\alpha_{s,p}$  represents efficiency for generation and pumping respectively. The energy level at each time and each unit is constrained by the energy level at the previous hour minus generated electricity plus stored electricity as shown in A. 11. Finally, energy storage is limited to the unit's maximum and minimum energy storage capabilities as shown in A. 12.

$$u_{s,p,t} + u_{s,g,t} \leq 1 \forall s, \forall t \text{ (A. 9)}$$

$$P_{s,t} = \alpha_{s,g} p_{s,g,t} u_{s,g,t} - \alpha_{s,p} p_{s,p,t} u_{s,p,t} \text{ (A. 10)}$$

$$E_{s,t} = E_{s,t-1} - \frac{p_{s,g,t}}{\alpha_{s,g}} + \alpha_{s,p} p_{s,p,t} \text{ (A. 11)}$$

$$E_{s,\min} \leq E_{s,t} \leq E_{s,\max} \text{ (A. 12)}$$

The following constraints are also in effect when the model includes cascading hydro (Chapter 4). A. 13 to A. 15 constrain the amount of water discharge  $D_{g,t}$ , stored volume  $C_{g,t}$ , and water spillage  $W_{g,t}$  at each generator. A. 16 calculates the stored volume of the lower cascading facility by its storage minus discharge and spillage in the previous hour, plus spillage and discharge from the upper facility two periods before plus the water inflow in the same period  $Y_{i,t}$ . Output of the unit is calculated based on A. 17 which depends on the average height of water  $\bar{H}_g$ , the efficiency of the unit and a constant  $K$  which is calculated based on the gravity constant. The total output of the hydro generation facility is limited to an upper bound in a month by A. 18. A. 19 constrains the stored water at the end of each operational period (month) to be within a higher and lower boundary.

$$D_g^{\min} < D_{g,t} < D_g^{\max} \forall t \text{ (A. 13)}$$

$$C_g^{\min} < C_{g,t} < C_g^{\max} \forall t \quad (A. 14)$$

$$W_g^{\min} < W_{g,t} < W_g^{\max} \forall t \quad (A. 15)$$

$$C_{g,t+1} = C_{g,t} - D_{g,t} - W_{g,t} + D_{g-1,t-\tau} + W_{g-1,t-\tau} + Y_{t,t} \forall t \quad (A. 16)$$

$$P_{g,t} = K \times \eta_g \times D_{g,t} \times \bar{H}_g \forall t \quad (A. 17)$$

$$\sum_{t=1}^T P_{g,t} < P_g^{\max \text{ per month}} \quad (A. 18)$$

$$Perct_{Down} \times C_g^{\min} \leq C_{g,t} \leq Perct_{Up} \times C_g^{\max} \forall t \text{ where } t = t_{end} \quad (A. 19)$$

Chapter 4 introduced an additional constraint on all of the hydro facilities that constrain the output of the plant to be higher than a minimum environmental and system operator's designated boundary as represented in A. 20 in which  $P_{d,g,t}$  is an input parameter calculated based on historical data. The output of the run-of-river plants must be equal to their hourly discharge values as represented in A. 21.

$$P_{g,t} \geq P_{d,g,t} \forall t, d, g \in \{hydro_{flex}\} \quad (A. 20)$$

$$P_{g,t} = P_{d,g,t} \forall t, d, g \in \{hydro_{RoR}\} \quad (A. 21)$$

Hydro modeling in SILVER for chapters 2 and 3 is based on the following constraints in which the maximum power output of the hydro capacities is capped based on their hourly, daily, and monthly operation characteristics.

$$P_{g,t} < P_g^{\max, hourly}, g \in \{hydro_{hourly}\} \quad (A. 22)$$

$$\sum_{t=1}^{24} P_{g,t} < P_g^{\max, daily}, g \in \{hydro_{daily}\} \quad (A. 23)$$

$$\sum_{t=1}^{720} P_{g,t} < P_g^{\max, monthly}, g \in \{hydro_{monthly}\} \quad (A. 24)$$

### 7.1.1.2 Validating constraints

SILVER unit commitment module solves the cost minimization formulation that ensures the operability of the system hourly under several different technical and non-technical constraints. These constraints contribute to the core rationality of the model in analyzing the operation of the power system. The most important constraints that have a direct impact on the current thesis's analyses are tested and validated and the results are presented below.

1. **Constraint A. 2:** A fundamental constraint of the model is the balance between demand and supply. The very basic function of the model is to ensure that the demand is met with the available generating capacities at each hour. This constraint is tested in different scenarios and different provinces which have various sets

of generation technologies. Results presented in Figure 32 show that the balance between demand and supply has always complied with different variations of mixtures in generation portfolios and load curves.

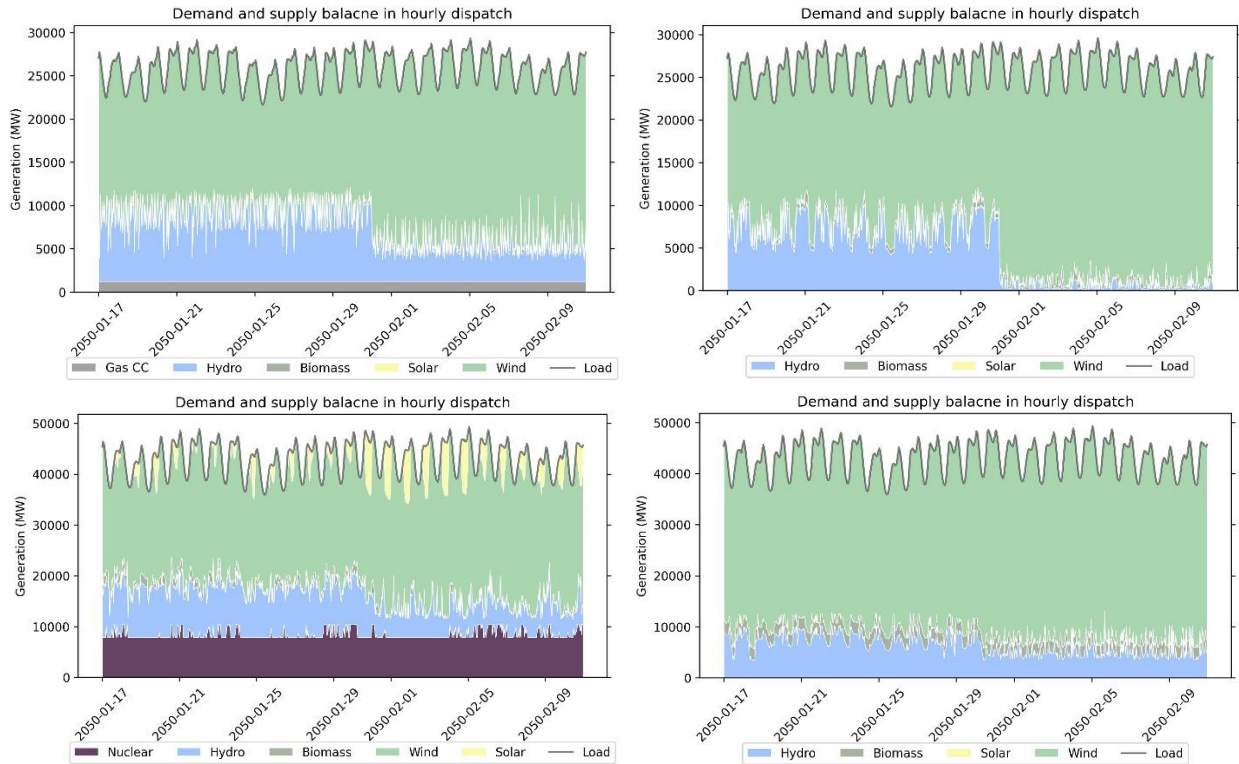


Figure 32 Hourly dispatch and demand validating the demand and supply balance constraint in different scenarios and generation portfolios

- Constraint A. 5:** The maximum and minimum power output of the generating facilities is another important constraint that ensures that different power plants can only generate within their maximum power boundaries and capacity factors at each hour. This is tested for multiple power generation types in different scenarios and jurisdictions. Some generation types also have a minimum generation constraint which stops them from producing less than a certain amount of output when they are turned on. The constraint is tested for multiple different technologies, like nuclear, biomass, and natural gas (NG) plants with different capacities, various input scenarios, and zero or non-zero minimum output. The results for sample tests presented in Figure 33 show compliance with the minimum and maximum output constraints in all situations.

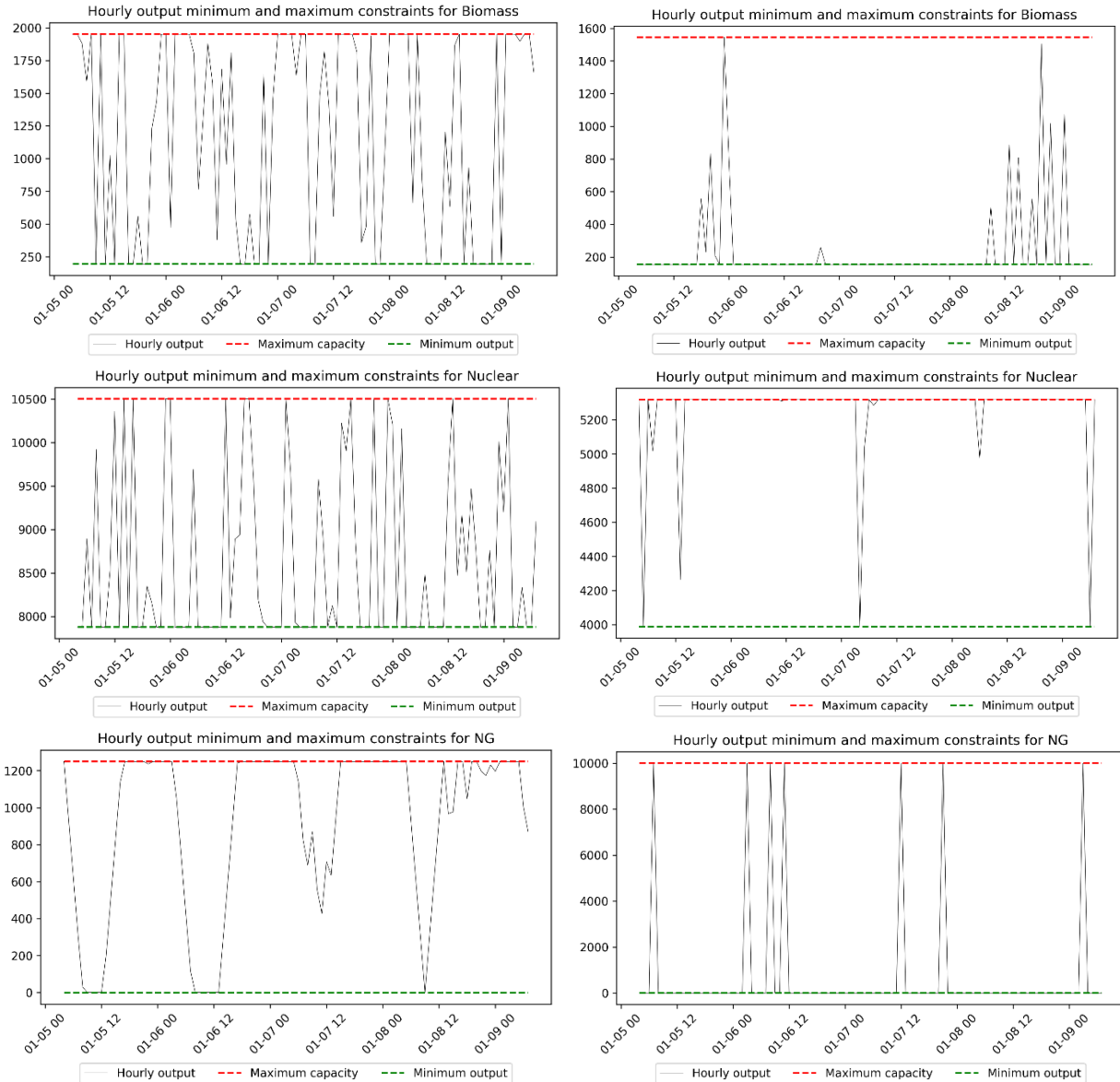


Figure 33 Hourly output of generation units compared to their maximum and minimum output constraints

- Constraint A. 20, and A. 21:** In addition to the above, a constraint for hydro capacities is set in the last chapter of the thesis which limits the minimum generation from hydropower plants to be over a certain amount at each hour. The input for this constraint is calculated based on historical generation values from hydropower plants in BC. Hourly output of the storage hydropower units should always be more than the set value and the Run of River plants should always operate at the given hourly rate. This constraint is tested for multiple power plants in different hours and for different constrain values. Results represented in Figure

34 show that the outputs from both cascading and run-of-river hydropower plants comply with the constraints.

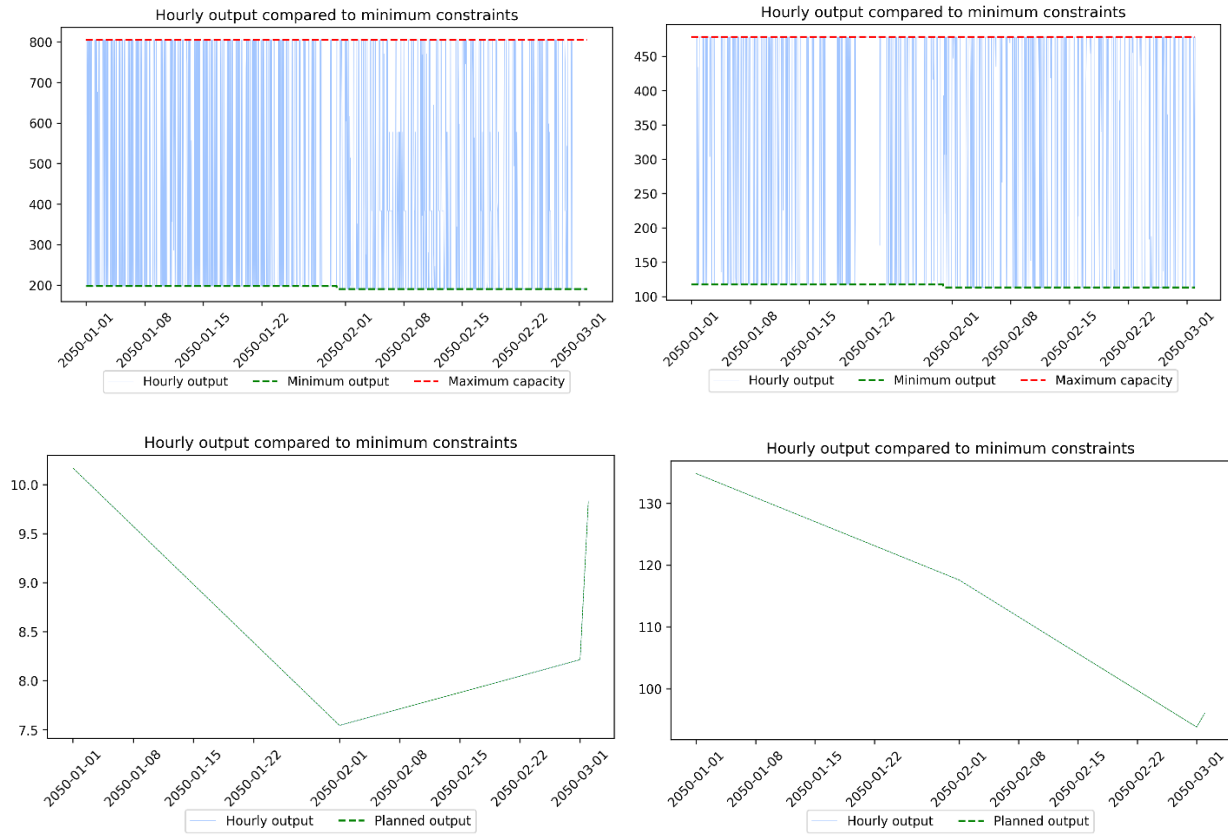


Figure 34 Hourly output for hydro generation units compared to their maximum and minimum output constraints

- Constraint A. 5 (For hourly variation in VREs):** In SILVER, wind and solar capacities can generate electricity to a maximum limit based on the availability of wind and solar irradiation respectively. Data in a fine spatial and hourly temporal resolution is used in the model for the capacity factor of wind and solar at each hour. This constraint is tested for multiple locations and various generation capacities. Results represented in Figure 35 show the compliance of wind and solar capacities with their hourly available energy at each location.

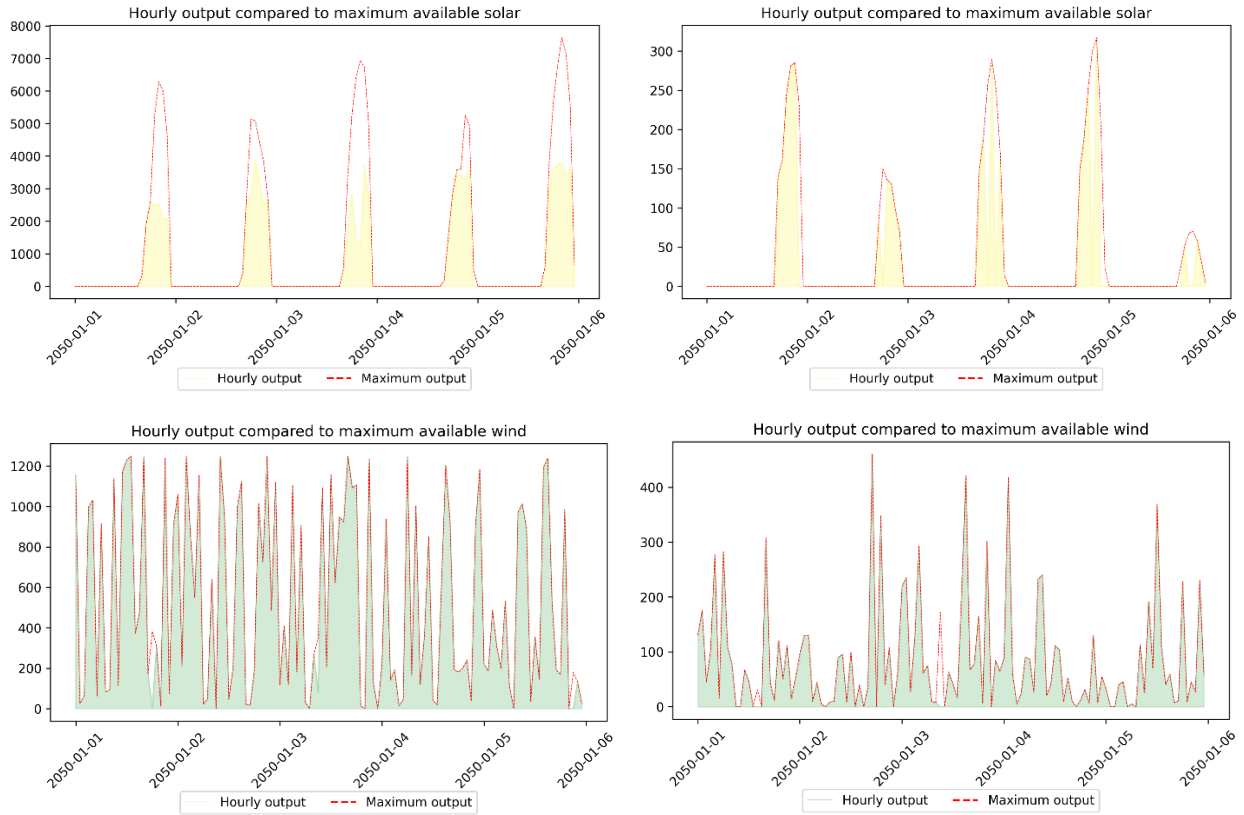


Figure 35 Wind and solar output compared to their maximum available potential for different locations and capacities

- Constraint A. 3:** Another major constraint that has a direct impact on analyses throughout the thesis is the maximum allowed power flow in the province's transmission lines. This constraint gives evidence for the line congestion which is used for the feedback loop in the linked framework that is introduced in the methodology of the second chapter. The constraint is tested over a variety of transmission lines and for different values. Results represented in Figure 36 demonstrated that the hourly flows through the transmission lines followed the maximum capacity constraint. Negative values show the flow in the opposite direction.

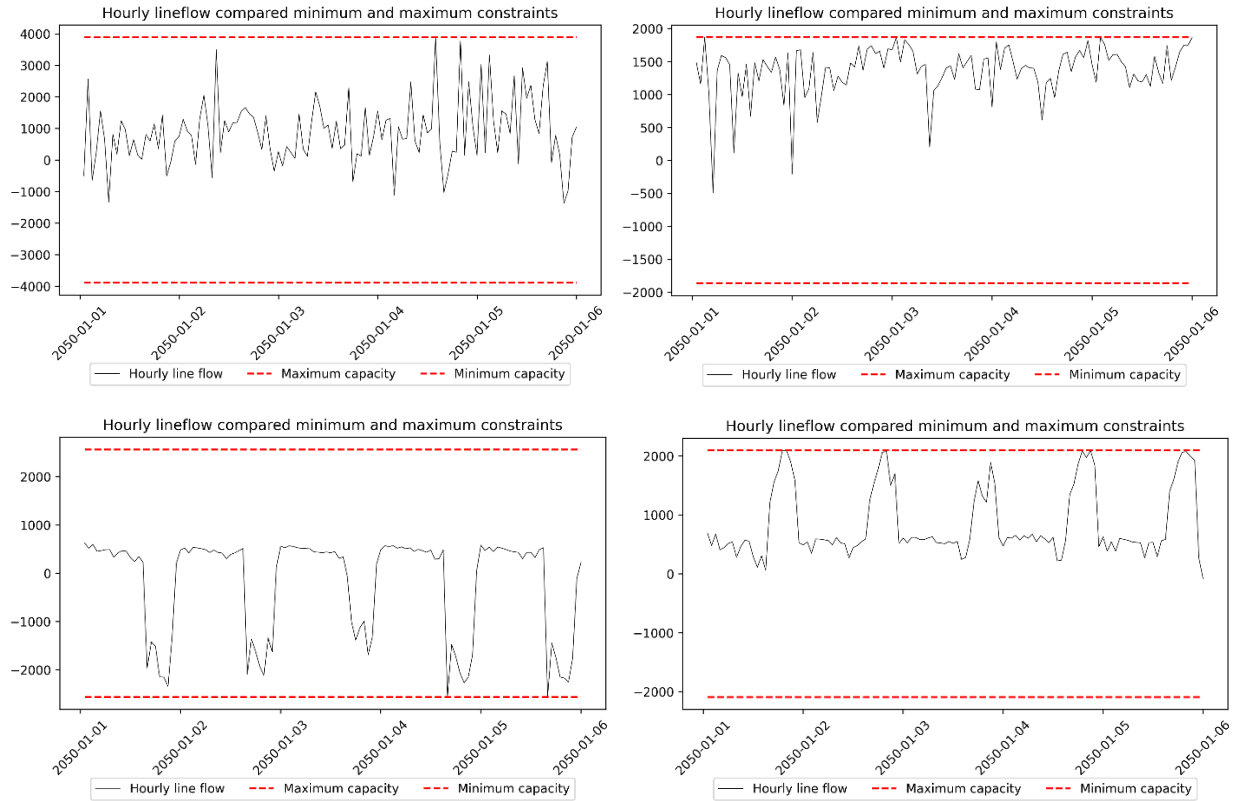


Figure 36 Hourly line flow compared to line flow capacity limits

### 7.1.1.3 Sensitivity analysis

Multiple variables are involved in shaping SILVER’s objective function and constraints. While it is assured that these data are gathered from reliable sources, their impact on the modeling outcomes is also tested and compared to the rational operation of a power system. This study tried to include the most impactful variables in the sensitivity analysis which are described below. One-way sensitivity analysis is chosen to analyze SILVER.

1. As the pivotal solution to decarbonize the power system, wind, and solar expansion is selected to be analyzed in this study. VRE capacities are tried to be accurately represented in SILVER by fine spatial and temporal resolution. The hourly capacity factor data is also calculated based on real-world historic wind and irradiation potential. However, a slight change in such data could potentially lead to errors in estimating the potential and output of these sources. Adding to the previous test for the capacity factor constraint, the sensitivity of the output from wind and solar capacities to the capacity factor inputs is analyzed. According to the results of the analysis represented in Figure 37, outputs from wind and solar have a perfect positive correlation with the potential inputs accordingly. This shows that the system complies with the given hourly potentials for wind and solar capacities at each location.

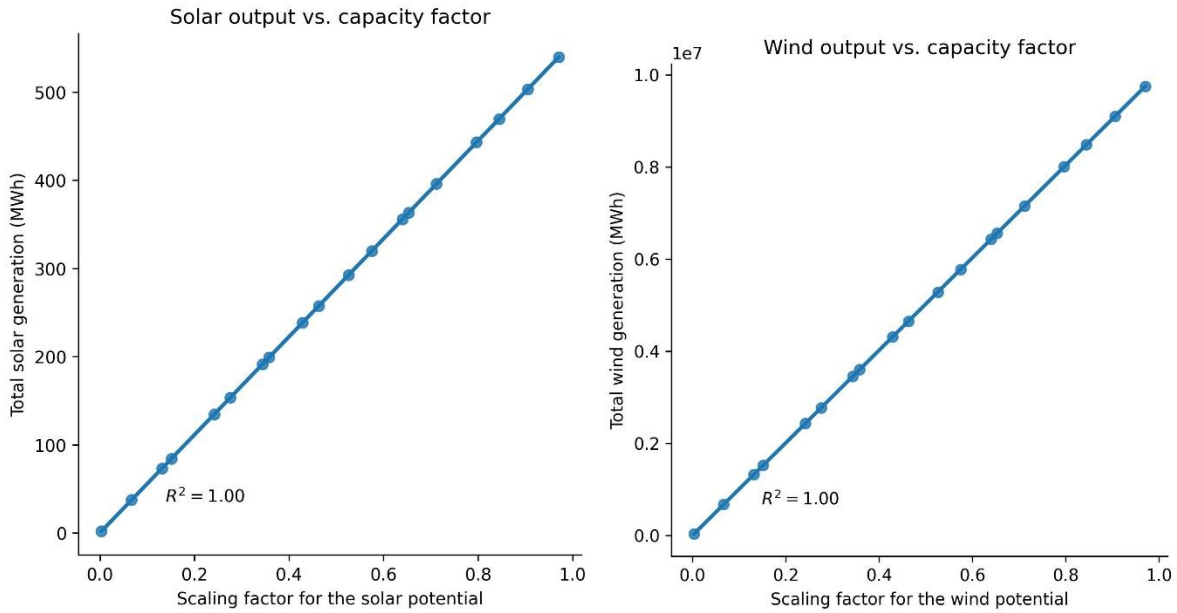


Figure 37 Sensitivity analysis for wind and solar outputs compared to their potential input, scaled with a factor ranging from 0 to 1 of the current values

- Hydropower capacities are selected to be studied as a source of flexibility. The contribution of hydro sources to bring flexibility, however, can be limited by their operational and environmental constraint. As such, the minimum generation constraint of hydro resources was analyzed for sensitivity on both hydro and VRE outputs. Results represented in Figure 38 show that the generation from the hydro capacities perfectly follows the constraint that is tested above. Increasing minimum generation constraints also contribute to lowering output from wind and solar capacities in general. This is aligned with the total demand and supply balance constraint and also impacts the flexibility that hydro capacities can provide which is discussed further in the fourth chapter.

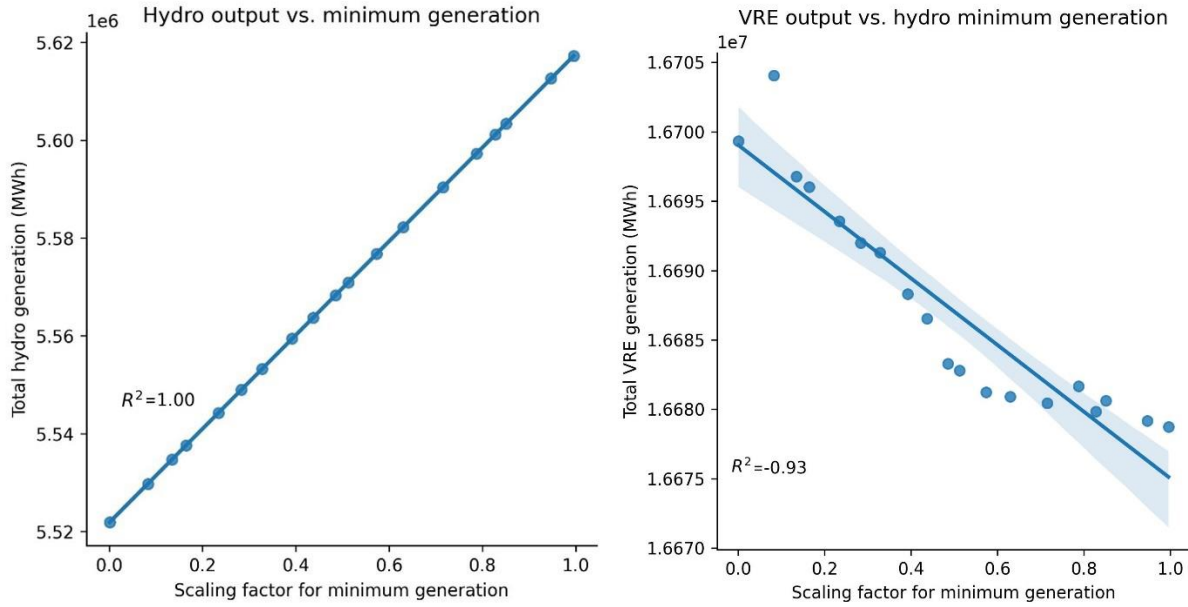


Figure 38 Sensitivity analysis for hydro and VRE output compared to hydro minimum generation, scaled data between 0 to 1 of the values used in the fourth chapter

- Lines capacities that are tested for the validity of the constraints also impact the VRE integration as a source of flexibility. This is tested and validated through different input scenarios and generation mixtures in a sensitivity analysis comparing the generation of VRE resources with different line capacities. The analysis presented in Figure 39 shows that the VRE generation is correlated with the line capacities which was predicted and very well conducted during the thesis.

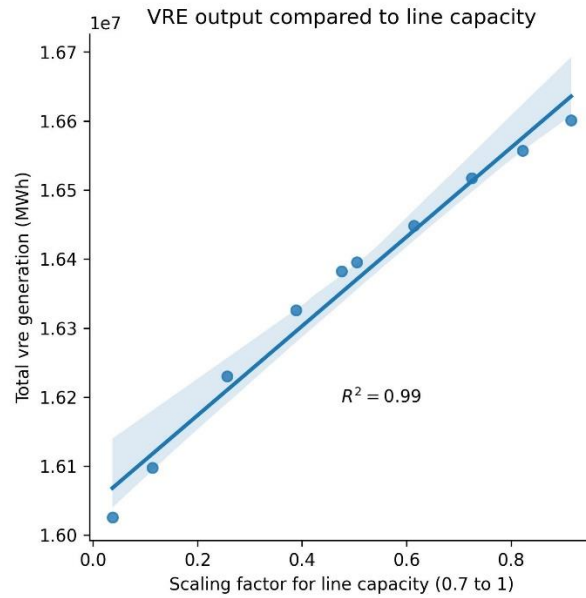


Figure 39 Sensitivity analysis for VRE output compared to line capacity (changed from 70% to 100% of the line capacities)

Verification and validation of SILVER comprised of three components, comparing outputs with similar studies, checking, and verifying most important and related constraints, and verifying sensitivity for the main variables and their impacts on the most important metrics and outputs. The presented results show the performance of the model under a range of inputs and validate its rational outputs.

#### 7.1.1.4 Comparing outputs with other unit commitment studies

The current thesis uses the network-constrained Unit Commitment functionality of the SILVER model. We analyzed the outputs of the unit commitment module with several studies in the literature that have their input data available. There are some areas where SILVER formulation differs from those selected studies, i.e., separated fixed and variable operational costs, separated hot and cold startup times, and the inclusion of ramping costs. However, the outputs show that the model can produce almost identical outputs with the given shared inputs with those studies. The results are analyzed for a 24-hour period of the system's operation, and the inputs can be found in [178]. Figure 40 represents the production costs for the simulated power system compared to the reference [178].

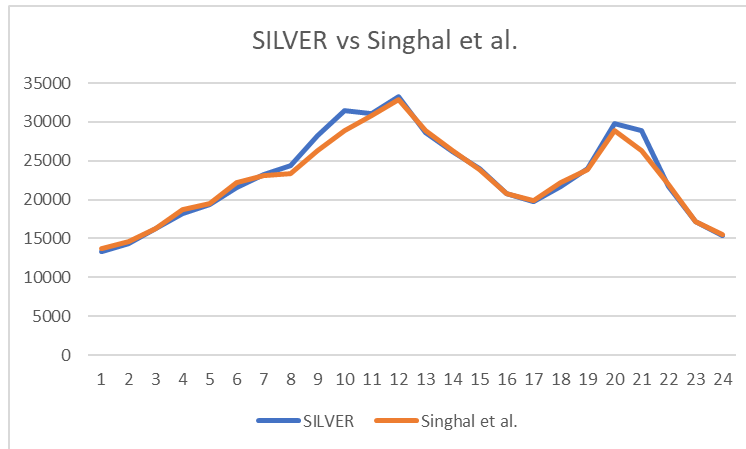


Figure 40 Hourly production cost output for the reference input scenario, SILVER's output compared to [178]

While there are differences in a few hours stemming from the different formulations, the optimization output for minimized costs is in agreement between the two models with an average of 2.28% difference for all 24 hours. Furthermore, Table 16 summarizes the total production costs output for the 24-hour period compared to other studies that solved different production cost minimization formulations for the same input. The results show a maximum 2.3% difference between the outputs of SILVER and other Unit Commitment models given the same set of inputs.

Table 16 Comparing SILVER's output to other Unit Commitment models, the total operational costs output

<b>Model/Study</b>	<b>SILVER</b>	<b>Singhal et al. [178]</b>	<b>Singhal et al. [178]</b>	<b>Singhal et al. [178]</b>	<b>Singhal et al. [178]</b>	<b>Kazarlis et al. [179]</b>	<b>Simopoulos et al. [180]</b>	<b>Juste et al. [181]</b>
<i>Total costs</i>	552836.64	545837.84	555814.11	553507.85	550805.02	565825	565828	564551
<i>Delta (%)</i>	-	1.28%	-0.54%	-0.12%	0.37%	-2.30%	-2.30%	-2.07%

### 7.1.2 COPPER

COPPER is a capacity expansion planning model that is used in this study for the core responsibility of projecting the power systems' expansion over different decarbonization policy inputs. COPPER was developed by the SESIT team at the University of Victoria in Python programming language and the original paper for the model can be found in [6]. COPPER results are established foundations for multiple studies and the results are verified by comparison with a variety of studies for Canada's power system. The current thesis also utilizes COPPER in multiple scenarios and different input variables. Arjmand et al. have also done validation for the main constraints on the model as well as high-level verification of the results in comparison to similar studies.

The current study mainly assesses zero emission targets in most of the scenarios in which gas-fired capacities are not explored even with carbon capture and storage technologies. This input is followed because first, the model is limited in assessing net-zero constraint as there is no sink for emissions modeled. Second, the current study aims to assess the impacts of large sources of renewable energies, which are mainly developed under such ambitions. And third, carbon capture and storage technologies are not removing emissions by 100%.

Despite the above-mentioned fundamental difference COPPER results align with outcomes from other established capacity expansion planning studies in Canada. Some examples are as follows. Dolter et al. showed that most of the coal and gas plants are phased out 2050 under carbon pricing policies by 2050 and a large portion of the renewable energy sources will be wind and will be built out in Alberta and Saskatchewan along with transmission expansion to meet the projected demand growth [7]. Canada’s Energy Future is the annual and official energy report for planning and policy implementation for all energy sectors in Canada. The results of the latest version of this study showed the same wind expansion growth dominantly in Alberta along with Carbon Capture and Storage which is excluded in the current modeling results by maintaining the zero-emission constraint [4]. Zinaman et al. showed that wind would be the dominant renewable capacity in an integrated study of Canadian and US power systems [182].

Further validation of the model is categorized in the upcoming subsections, including constraint validation and sensitivity analysis. Testing side by side with other models is not feasible for COPPER, first due to the special treatment of variable renewable energy resources which is based on specific grid locations om Canada. Second, unfortunately, current COPPER’s source code has some parameters hard-coded in the model, such as naming the provincial boundaries, linking Canadian-specific grid cells to load zones, etc. Therefore, the development of a more general version of the model that can handle other non-Canadian or Canadian studies with different parametrizations is out of the scope of the current thesis and left for further research and development.

### 7.1.2.1 COPPER’s formulation

COPPER uses a mixed-integer linear programming formulation to explore the cost-optimal mix for the future of the electricity system. The objective function and main constraints of the model are described below. Table 17 summarizes the definition of sets, variables, and parameters defined in COPPER.

Table 17 Definition of COPPER sets, variables, and parameters

<b>Symbol</b>	<b>Definition</b>
<b>Sets</b>	
<b><i>ab, abb</i></b>	Set of balancing areas
<b><i>pds</i></b>	All periods from the reference year until the target year (e.g., [2020, 2025, 2030, ..., 2050])
<b><i>h</i></b>	Set of running hours
<b><i>d</i></b>	Set of running days

$m$	Set of running months
$S$	Set of seasons (winter, summer)
$p$	Set of all power plant types
$gc$	Set of grid cells for renewables
$th(p)$	Set of thermal plants (a subset of $p$ )
$st$	Set of energy storage technology types
$re(p)$	Set of renewable plant types (wind, solar)
$hrp$	Set of all hydroelectric renewal, repowering and greenfield development projects
<b>Parameters</b>	
$ETC(pds,ab,p)$	Existing capacity of thermal plant type $th$ in balancing area $ab$ and period $pds$
$ERC(pds,gc,re)$	Existing capacity of renewable type $re$ in location $gc$ in period $pds$
$ESC(pds,ab,st)$	Existing capacity of energy storage type $st$ in $ab$ , in period $pds$
$EHC(pds,ab)$	Total existing hydroelectric capacity in $ab$ and period $pds$
$ETRC(pds,ab,abb)$	Existing transmission capacity
$CV(ab,s,re)$	Capacity value of renewable type $re$ in season $s$ and $ab$
$D_{pds,h,ab}$	Hourly electricity demand (MW)
$DUS_{pds,h,ab}$	Hourly import/export to the US (MW)
$PD(pds,s)$	Peak demand of season $s$ in period $pds$
$T_{pds,h,abb,ab}$	Transmission flow from $abb$ to $ab$ at hour $h$ and period $pds$ (MW)
$TL_{ab,abb}$	Transmission loss between $ab$ and $abb$ (between 0-1)
$PRM$	Planning reserve margin
$CC(pds,ab,p)$	capital cost of different generation and storage technologies
$CC(pds,ab,st)$	
$RCC(pds,gc,re)$	renewable capital cost
$HCC(pds,hrp)$	capital cost of potential hydroelectric projects
$TCC(pds,ab,abb)$	New transmission capital cost for line between $ab$ and $abb$ in period $pds$
$RCF(pds,h,gc,re)$	The capacity factor of renewable type $re$
$HRC(hrp)$	Hydroelectric renewal, repowering, and greenfield development capacity for project $hrp$
$DRH(pds,d,hrp),$	The historical data of small reservoir and large reservoir potential hydroelectric projects( $hrp$ ), this parameter shows the available reservoir in each period for all potential projects
$MRH(pds,m,hrp)$	
$MF(hrp)$	Minimum flow of potential hydroelectric project ( $hrp$ )
$FOM(pds,p), SFOM(pds,st),$ $HFOM(pds,hrp), TFOM(pds,ab,abb)$	fixed operation and maintenance cost of different assets in power system
$VOM(pds,p)$	Variable O & M cost of thermal unit type $p$
$FC(p)$	Fuel cost of plant type $p$ (\$ perMWh)
$TEI(th)$	Emission intensity of thermal plant type $th$ (tonne CO <sub>2e</sub> per MWh)
$Rup(th), Rdown(th)$	Ramp up and ramp down rates of thermal units

<b><math>MaxCF(th), MinCF(th)</math></b>	Maximum/minimum capacity factor of thermal plant $th$
<b><math>MRC(gc, re)</math></b>	The maximum capacity of renewable type $re$ that can be built in location $gc$ due to the land use limitations
<b><math>SH(st)</math></b>	maximum number of hours that energy storage can be discharged from fully charged state
<b>Variables</b>	
<b><math>NTC(pds, ab, th)</math></b>	New capacity of thermal unit type $th$ in $ab$ in period $pds$
<b><math>NRC(pds, gc, re)</math></b>	new renewable capacity
<b><math>NTRC(pds, ab, abb)</math></b>	New transmission corridor capacity (MW) between $ab$ and $abb$ in period $pds$
<b><math>NSC(pds, ab, st)</math></b>	New energy storage capacity of type $st$ in $ab$
<b><math>HRB(pds, hrp)</math></b>	Hydroelectric renewal binary in period $pds$ for project $hrp$ (binary variable)
<b><math>R(pds, ab, p)</math></b>	Total retirement capacity of existing assets
<b><math>PG(pds, h, ab, p)</math></b>	Hourly generation of different plants in each period and $ab$
<b><math>Rout(pds, h, ab, re)</math></b>	The generation (MW) of renewable type $re$
<b><math>SE(pds, h, ab, st)</math></b>	Stored energy in energy storage type $st$
<b><math>ESin(pds, h, ab, st), ESout(pds, h, ab, st)</math></b>	Energy storage charge (ESin) and discharge (ESout) rates in MW
<b><math>DRout(pds, h, hrp)</math></b>	Small reservoir hydroelectric renewal/greenfield development projects ( $hrp$ ) generation at hour $h$ in period $pds$
<b><math>MRout(pds, h, hrp)</math></b>	Large reservoir hydroelectric renewal/greenfield development projects ( $hrp$ ) generation at hour $h$ in period $pds$

#### 7.1.2.1.1 Objective function

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

$$\min total_{system\ costs} = \min(InvestmentCost + MaintenanceCost + ProductionCost + CarbonCost) \quad (A.1)$$

In which:

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

$$MaintenanceCost = Fixed\_O\&M + Variable\_O\&M$$

$$\begin{aligned}
&= \sum_{pds,ab,th} (ETC(pds, ab, th) + NTC(pds, ab, th)) \times FOM(pds, th) \\
&+ \sum_{pds,gc,re} (ERC(pds, gc, re) + NRC(pds, gc, re)) \times FOM(pds, re) \\
&+ \sum_{pds,ab,st} (ESC(pds, ab, st) + NSC(pds, ab, st)) \times SFOM(pds, st) \\
&+ \sum_{pds,hrp} HRB(pds, hrp) \times HFOM(pds, hrp) \\
&+ \sum_{pds,ab,abb} (ETRC(pds, ab, abb) + NTRC(pds, ab, abb)) \times TFOM(pds, ab, abb) \\
&+ \sum_{pds,h,ab,p} PG(pds, h, ab, p) \times VOM(pds, p) (A. 3)
\end{aligned}$$

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

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

#### 7.1.2.1.2 Optimization constraints

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

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

**Planning reserve constraint:** The planning reserve margin constraint ensures sufficient generation capacity is available to maintain adequate reliability in the power system. One of the main differences between variable renewable energy capacity and conventional generation capacity is that a portion of the installed capacity of the

former can be considered as firm capacity while almost the whole installed capacity of the latter counts toward firm capacity. A planning model without this constraint might overestimate the availability of REs and their contribution to the required firm capacity. In a scenario with high penetration of renewable energy, planning reserve margin constraint might affect the results significantly, and thus is important to represent in long-term planning analysis. COPPER models planning reserve margin requirements by considering a capacity value for each renewable energy in each balancing area and season and enforcing the following equation. In this thesis according to the data from the utilities and other studies we enforce a 15 percent planning reserve margin

$$\sum_{ab,th} (ETC_{pds,ab,th} + NTC_{pds,ab,th}) + \sum_{gc,re} (ERC_{pds,gc,re} + NRC_{pds,gc,re}) \times$$

$$CV_{ab,re,s} + \sum_{ab} EHC_{pds,ab} + \sum_{hrp} HRC_{hrp} \times HRB_{pds,hrp} + \sum_{ab,st} (ESC_{pds,ab,st} + NSC_{pds,ab,st}) -$$

$$\sum_{ab,p} R_{pds,ab,p} \geq PD_{pds,s} \times (1 + PRM) \forall pds,s \quad (A.7)$$

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

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

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

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

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

$$\sum_{h=1}^H PG_{pds,h,ab,th} \leq \left( ETC_{pds,ab,th} + \sum_{pds=1}^{PDS} (NTC_{pds,ab,th} - R_{pds,ab,th}) \right) \times$$

$$MaxCF_{th} H \forall PDS \in pds, ab, th \quad (A.10)$$

$$\sum_{h=1}^H PG_{pds,h,ab,th} \geq \left( ETC_{pds,ab,th} + \sum_{pds=1}^{PDS} (NTC_{pds,ab,th} - R_{pds,ab,th}) \right) \times$$

$$MinCF_{th} \times H \forall PDS \in pds, ab, th \quad (A.11)$$

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

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

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

**Hydroelectric development:** In addition to the existing hydroelectric capacity in Canada, several potential greenfield developments are under consideration. Furthermore, repowering and renewal projects can add to existing hydroelectric assets. Considering hydroelectric development in ESPMs requires significant data collection and modelling efforts such that many ESPMs ignore the expansion of hydroelectric [183]. However, the contribution of hydroelectric greenfield development to Canada's GHG reduction targets could be significant, COPPER models possible hydroelectric renewal and repowering projects using integer variables to assess which projects are considered part of the optimal mix. For the hydroelectric projects that are part of the optimal mix (their integer value is one), the investment cost including required transmission line cost, if any as well as fixed and variable O&M costs are added to the objective function, and the generation of new hydroelectric projects ( $DRout$ ,  $MRout$ ) contributes to the total supply in each hour. Also, their constraints are modeled using the following equations.

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

$$\sum_{h \in d} DRout_{pds, h, hrp} \leq DRH_{pds, d, hrp} \times HRB_{pds, hrp} \forall pds, d, hrp \in small_{reservoir} \quad (A. 14)$$

$$\sum_{h \in M} MRout_{pds, h, hrp} \leq MRH_{pds, m, hrp} \times HRB_{pds, hrp} \forall pds, m, hrp \in large_{reservoir} \quad (A. 15)$$

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

$$DRout_{pds, h, hrp} \leq HRC_{hrp} \times HRB_{pds, hrp} \forall pds, h, hrp \in small_{reservoir} \quad (A. 16)$$

$$MRout_{pds, h, hrp} \leq HRC_{hrp} \times HRB_{pds, hrp} \forall pds, h, hrp \in large_{reservoir} \quad (A. 17)$$

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

$$DRout_{pds, h, hrp} \geq MF_{hrp} \times HRB_{pds, hrp} \forall pds, h, hrp \in small_{reservoir} (A.18)$$

$$MRout_{pds, h, hrp} \geq MF_{hrp} \times HRB_{pds, hrp} \forall pds, h, hrp \in large_{reservoir} (A.19)$$

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

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

**Renewable energy constraints:** There are two main constraints for wind and solar power plants. The first constraint limits the output of renewable power plants to the total installed capacity and the second constraint caps the amount of wind and solar that can be installed in each grid cell according to the land availability (surface condition).

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

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

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

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

**Energy storage constraints:** Energy storage types are modelled using a set of constraints that limit the generation to installed capacity in each hour, maximum energy to the storage capacity, and estimates the hourly available energy based on the charge, discharge, and efficiency. Equation (A. 24) limits the maximum energy ( $SE$ ) that can be stored in the storage:

$$SE_{pds, h, ab} \leq (ESC_{pds, ab} + \sum^{PDS} NSC_{pds, ab, st}) \times SH_{st} \forall PDS \in pds, h, ab (A.24)$$

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

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

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

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

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

**Minimum storage capacity constraint:** The following constraint keeps the minimum storage capacity above the input level calculated in the linkage framework.

$$ESC_{pds,ab} + \sum_{pds,st}^{PDS} NSC_{pds,ab,st} \geq ESL_{pds,ab} \forall PDS,ab \text{ where } pds \in 2050 \quad (A.28)$$

### 7.1.2.2 Validating constraints

The COPPER formulation is based on numerous constraints that should be met to ensure that the model results are in line with the real-world implications of the power systems. The optimization formulation then tries to find the best solution that falls in the area within the given constraints. The constraints are checked to be met in several scenarios and the results for some sample scenarios are presented below.

1. **Constraint A. 6:** Supply and demand should be equal at all hours that the model is simulating. This is the core constraint that ensures that the model expands the capacity of the generation to meet the demand. COPPER models sample representative days on an hourly basis. Testing the outputs from multiple scenarios shows that they comply with the demand and supply equality constraint. Some sample outputs for sample hours are presented in Figure 41. While the outputs from generation types differ in different scenarios, they all show compliance to meet the exact demand at each hour.

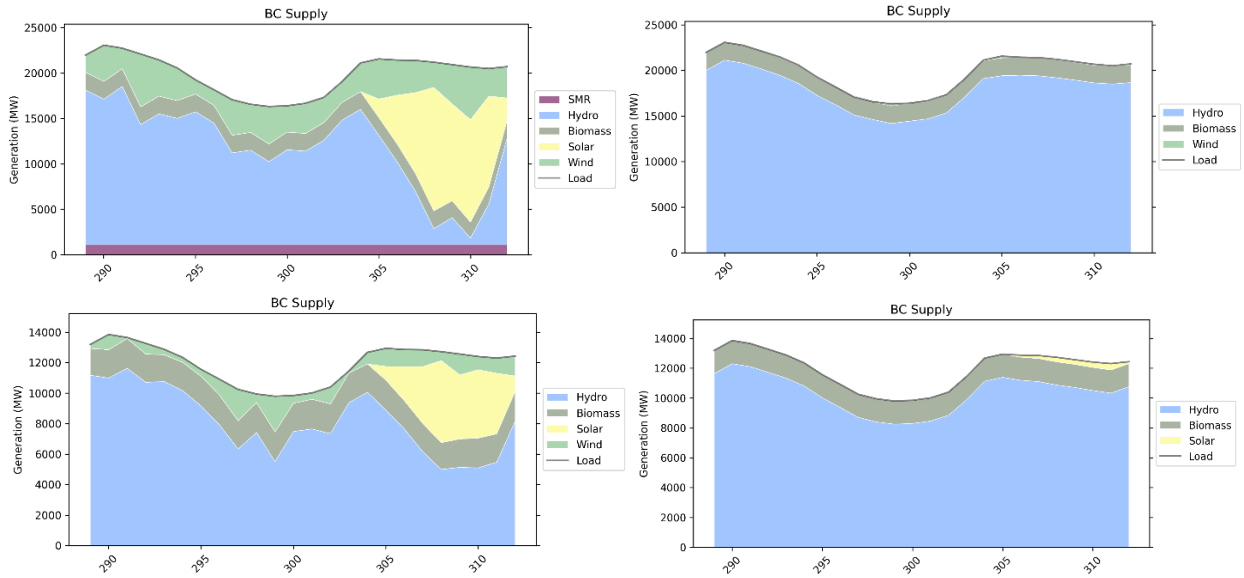
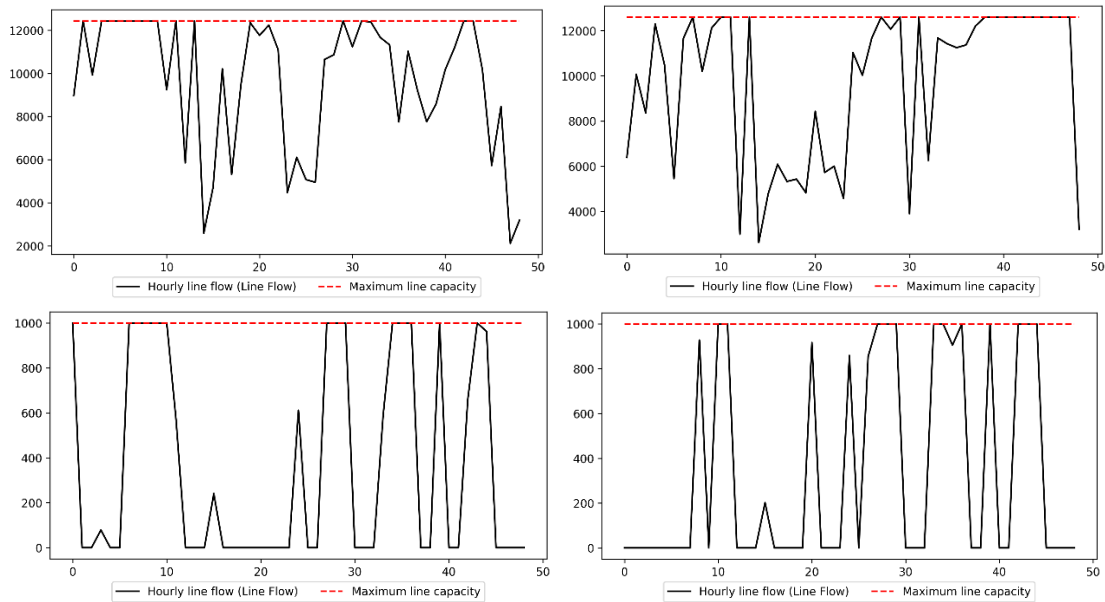


Figure 41 Supply and demand equality in sample hours for different scenarios for demand and other options

- Constraint A. 23:** Transmission capacity. One of the main sources of flexibility assessed in the current study, especially in the first and third manuscripts, is the transmission between the provinces. Another pivotal constraint ensures that the flow through the interties is never exceeded from the nominal capacity. Several different capacities for the same intertie between British Columbia and Alberta are tested to ensure compliance with the constraint. The results represented in Figure 42 validate the compliance of the constraint in different situations.



*Figure 42 Hourly line flow compared to the line's maximum capacity*

- Constraints A. 18 and A. 19:** Hydroelectric is also discussed as another source of flexibility throughout this study. Therefore, accurately representing the models is a practice that is followed to prevent over-estimation of flexibility in representing hydropower in the model. COPPER implements a 10% minimum generation constraint uniformly set for all the hydro capacities. The constraint is tested for different scenarios as presented in Figure 43 which shows compliance to the constraint for various situations. The other constraint for the hydro capacities is the storage for large hydro, which is tested and shown that the output does not exceed the storage capacity.

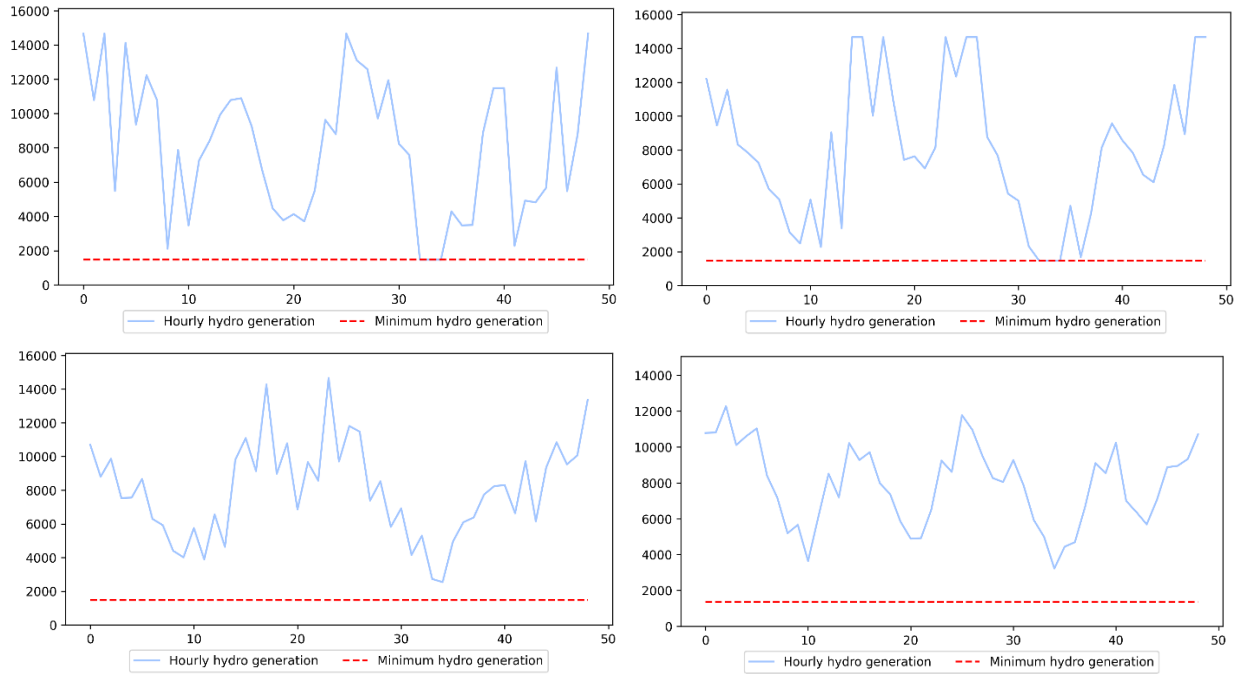


Figure 43 Hourly hydro output compared to minimum generation constraint

4. **Constraint A. 28:** One other constraint that is implemented in COPPER in the current study (Chapter 2) is the minimum storage capacity which is selected to be the response to the flexibility issues in the system. This constraint is also tested for different scenarios and under various input values. The tests included only one minimum limit value for all provinces to check compliance for all provinces. The results shown in Figure 44 confirm that the model complies with the given constraint. There is no scenario in the model that builds storage less than the given constraint. It is also notable that the model decides to build more storage in Alberta and British Columbia when there is a small minimum constraint for all other provinces. But when the model builds out enough storage in all provinces constrained by the minimum value, the outputs for these two provinces also drop to the minimum value. This specific test was done on the single constraint for storage at each iteration and not any other variable is changed.

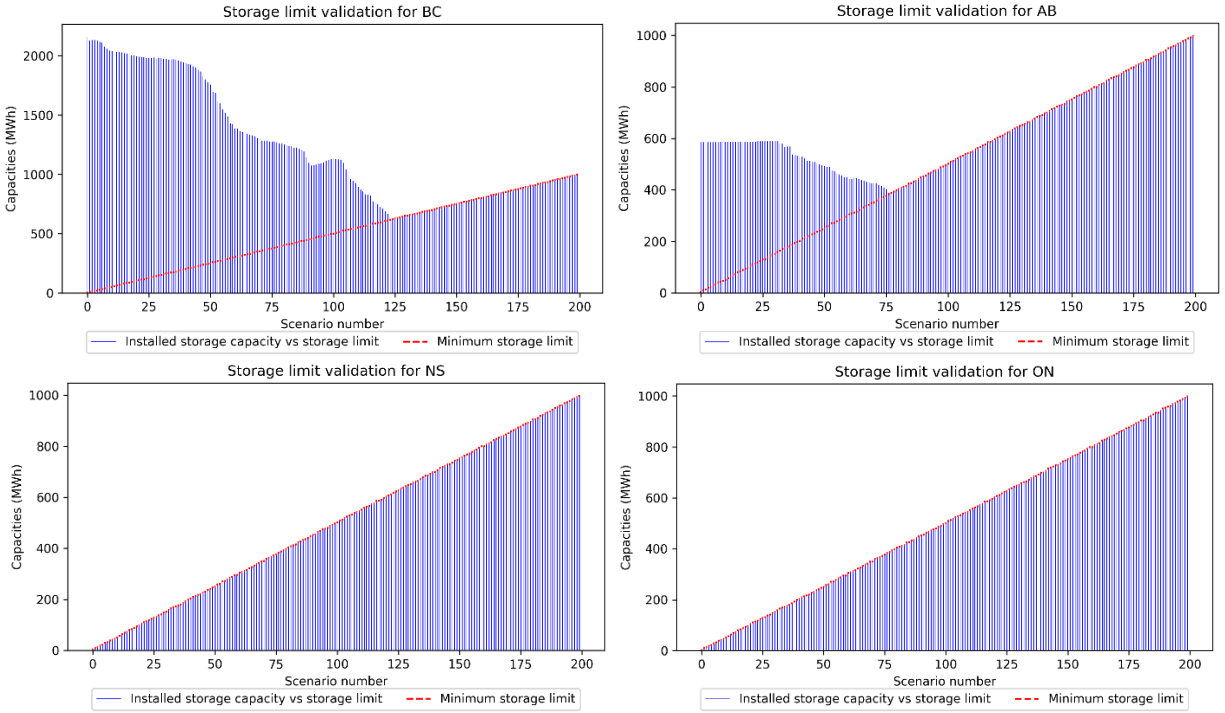


Figure 44 Testing the minimum storage constraint for different provinces over various input limits

- Constraint A. 22:** Another core constraint for this study was the land use limit for wind capacities. Two different values are implemented evolving through the studies, 2.0 MW per squared kilometer and 0.5 MW per squared kilometer. The former value is suggested by several studies like the Pan-Canadian wind integration study [145] while the more conservative studies recommend the latter to ensure limiting wind turbulence effect from one turbine to another. Both values are assessed for in model output and show that the constraint is correctly implemented as shown in Figure 45.

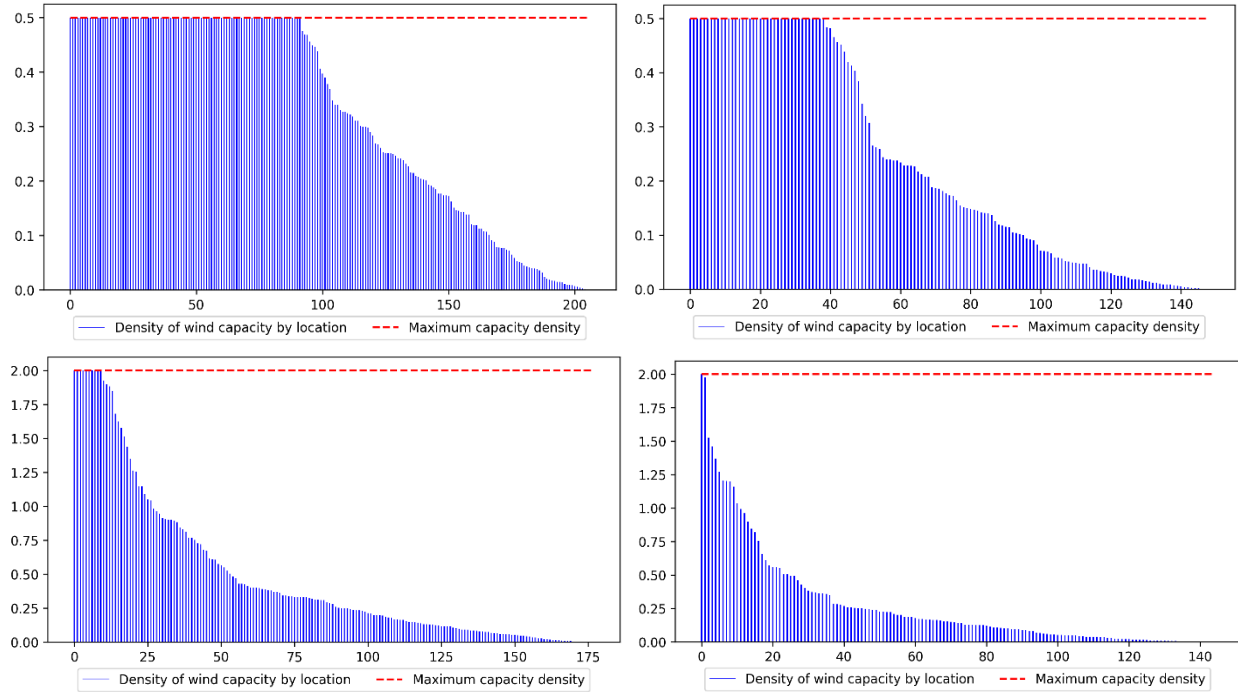


Figure 45 Wind capacity constraint compared to maximum allowance for different density inputs

### 7.1.2.3 Sensitivity analysis

Throughout the current thesis, several input scenarios are developed that follow the goal of the chapter it involves. While these scenario inputs are not considered sensitivity analysis, the results can be tested as a high-level verification test. The main changes between the scenarios are the projected demand curves and the constraints on emissions. As such, several outputs of the model are assessed by the different inputs for demand and emission constraints. Multi-way sensitivity analysis is done for some parameters to prevent inaccurate outputs by not accounting for interactions between inputs in the model. Variables selected for the multi-way sensitivity analyses are carbon taxation costs, capital costs for technologies, and demand.

1. Carbon tax as a policy tool in COPPER has a significant role in decarbonizing the power system and is modeled to represent current Canadian policies in place. The carbon tax policies are set to increase to up to \$170/ton by 2035 in a \$10/year increase. We tested the model to have a range of \$0 to \$20 increase from 2020 to 2050 to analyze the sensitivity of different outputs to this change in input. Results are presented in Figure 47 for emitting capacities, emissions, wind capacity, and solar capacity.

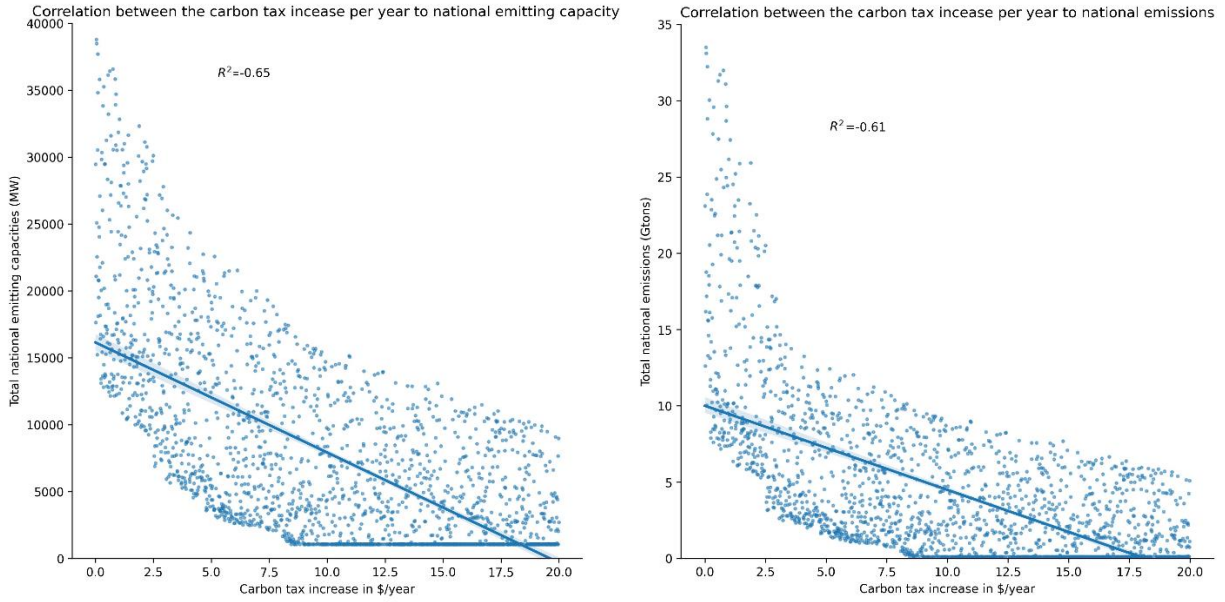


Figure 46 Correlation between a carbon tax increase and emitting capacities and emissions

Both emitting capacities and emissions show negative correlations with increasing the annual carbon tax rise. This observation is in general agreement with how the systems should work, the model avoids building out and generating emitting capacities to reduce costs in the objective function as the carbon costs increase.

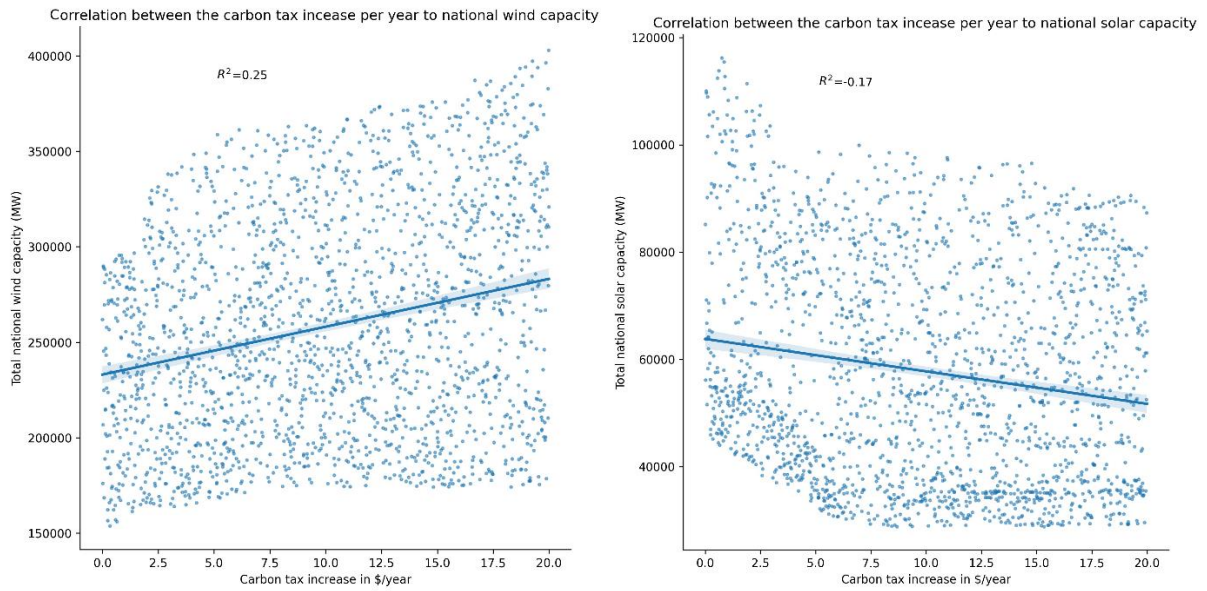


Figure 47 Correlation between a carbon tax increase and wind and solar capacities

Wind capacities are observed to increase over the increasing annual tax rise. The model builds out more wind capacities as it retires more emitting capacities observed above. While the wind investment costs also vary between the runs, the decision to build out wind in competition with other non-emitting capacities influences the correlation. Solar capacities, on the other hand, are less developed by increasing carbon taxes with a slight negative correlation. This is an observation that is discussed in the discussion of the third manuscript in depth. In summary, when the model meets more requirements from the VRE capacities in the higher carbon taxes, the model chooses wind capacities over solar for three reasons. First, wind capacities will tend to be less expensive in the future as outlined in the evolving investment costs in the inputs. Second, wind potentials are studied to be higher throughout different regions in Canada which results in higher capacity factors. Third, wind locations with higher capacities are closer to the grid compared to solar capacities, resulting in a final lower investment cost for transmission buildouts. For deeper analysis please see chapter 4.

2. Demand projection is the main drive for expanding the generation capacity and is uncertain for long temporal horizons like COPPER which sees until 2050. Electrification scenarios are another source that contributes as a burden as well as uncertainty. As a main constraint which is discussed above, COPPER should ensure that the demand is equal to the supply at sample hours, thus the model should show a correlation in the supply and demand in changing load curves. The generation capacity should therefore be sensitive to the changes in demand based on the balance between demand and supply.

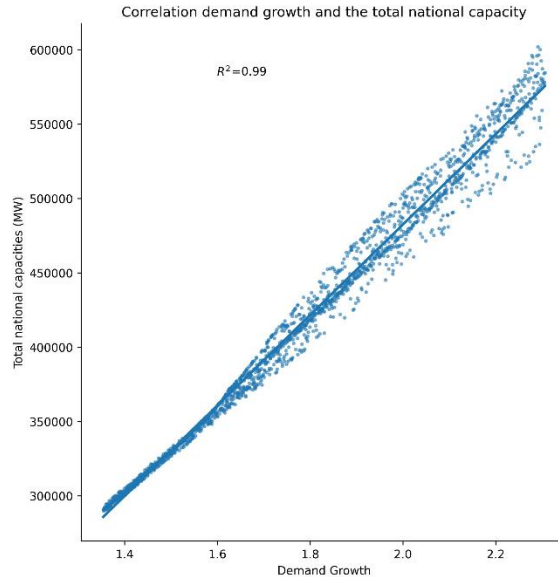


Figure 48 Correlation between increasing demand with the total generation capacity

The results are represented in Figure 48 which shows a very strong positive correlation between the total installed capacity and the rate of growth in demand between 2050 and 2018. This analysis gives other evidence for the validation of the model as compliance with the demand and supply balance constraint is proved.

- Investment prices in variable renewable energy resources also have a major impact on the resulting generation capacity output as a main part of the model's objective function. Lower costs would result in a larger share in the outputs and higher costs would result in lower shares. This hypothesis is also tested for wind capacity in a range of capital costs. The results show that the installed generation capacity for wind is reducing with the rise in the capital costs, which should be the results as the capital costs are included in the objective function of the cost minimization formulation. The results are represented in Figure 49. It is also notable that the wind capacities seem to be limited to a minimum at higher prices as there is a need for them to meet the demand in the presence of other constraints like reserve margins and inputs for limiting emitting capacities.

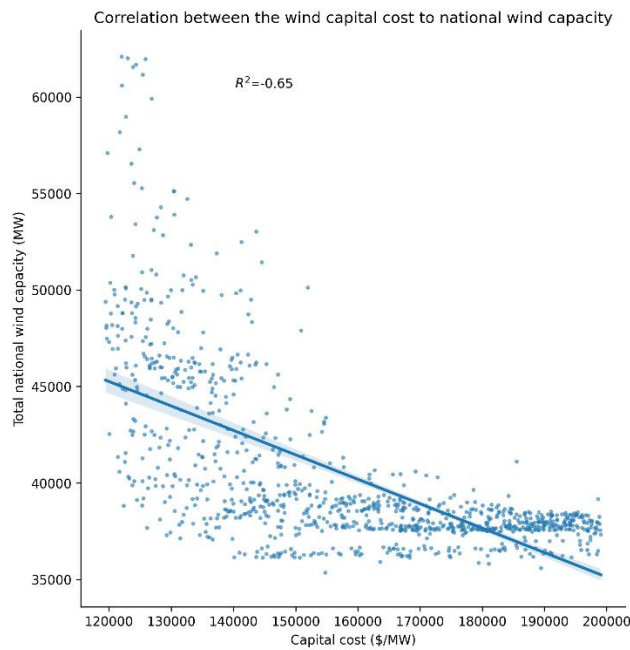


Figure 49 Correlation between capital costs and capacities for wind generation

Validation of COPPER included three different aspects, comparing the results with other similar studies in the Canadian domain, testing the most important constraints, and sensitivity analysis for the different variables. These analyses validate the model's formulations and show its performance under a variety of inputs.

### 7.1.3 DESSTINEE

Chapters 2 and 4 of the current study use historic load curves scaled by different growth factors as their main assumptions. But as the sectoral breakdown of the load curves was needed in Chapter 3, DESSTINEE is utilized to create and project load curves in 2050.

DESSTINEE is an open-sourced statistical model that uses Excel to calculate the load projections for different sectors under various input scenarios [120]. The model has been implemented in several studies to estimate the end-use data for all energy sectors in different jurisdictions and regions. The model uses simple formulation and proceeds in the following steps. First, the model is calibrated with the base year energy use for each sector. For this study, we used comprehensive energy use data from Natural Resources Canada [129] and cross-checked the data with other available tables from the Canada Energy Regulator [184]. Second, the model creates scenarios based on population and economic growth data which is captured from Canada's Energy Future report for 2021 [4]. Third, an estimate of the technology mixture is given to the model to provide the electrification or business-as-usual scenarios. Fourth, the model uses these data to calculate the final energy demand in 2050 for ten key energy vectors. Finally, the model stochastically synthesizes a one-year electricity demand profile taking the annual data and building the hourly profile for each sector. This relies on historical weather data (gathered from [185]), and daily profiles for different types of end-use which are pre-defined.

The source code and the Excel file of this model are accessed via their website [122]. Projections for the demand growth are mainly based on different policy scenarios for growth factors for different fuels and end-use and sometimes differ by a wide margin. An efficient scenario of DESSTINEE projects total electricity demand to grow up to 321,271 Terajoules in 2050. Non-efficient scenario leads to the final 354,581 total electricity demand. CER's projection for electricity in Alberta ranges from 322,935 to 377,376 Terajoules in Alberta for efficient and business-as-usual scenarios accordingly. The numbers for the total energy forecast as the first step lay in the same reasonable range.

Another source for the power load projection is Alberta Electric System Operator's (AESO) long-term outlook [186]. This report is renewed every two years and demands as well as other aspects for the power system in the province for the next twenty years. AESO reports the annual peak loads only which range from 13014 MW to 17464 MW based on different scenarios for 2041 based on the 2021 outlook [186]. More detailed hourly data is not available. These peak loads are in a reasonable range with the peaks in projected BAU and electrified scenarios used in the third chapter accounting for the fact that they are representing the curve in 2050.

To compare the outputs of the hourly profile, the output of the model for Alberta in 2018 is tested with historical electricity profile data that are available in the CODERS database [74]. The output from the model is visually in

agreement with the scaled historic demand curve as presented in Figure 50. It confirms that the projected load curve can capture fluctuations in load from the various sectors.

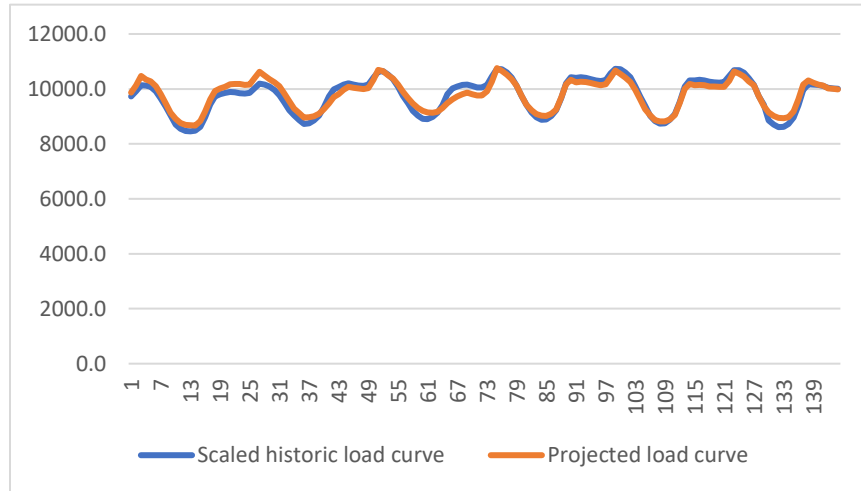


Figure 50 Model output comparison between microeconomic projection output (DESSTINEE) and scaled historical data

The above comparison is also statistically tested with the metrics suggested in [175]. First, the histogram represented in Figure 51 for the two datasets shows that they have a very close mean, but the modeled data have a slightly smaller standard deviation. This means that the projection used a smaller hourly range of variations in estimating the load curve. Having an agreement in average and standard deviation for the 8760 data points is another source to validate the data projected using the DESSTINEE model.

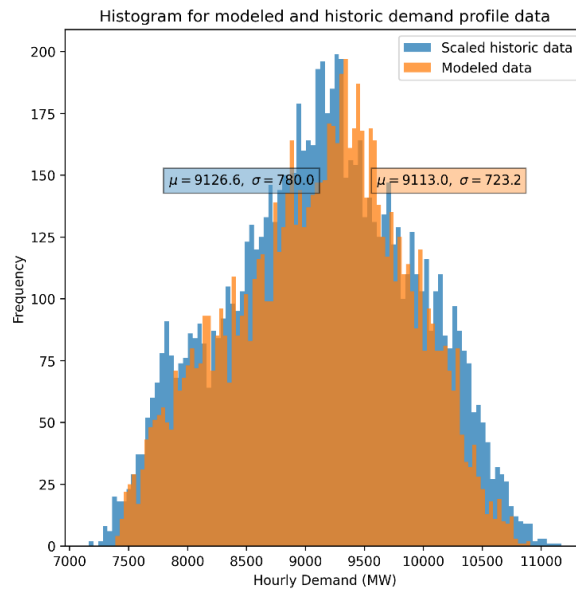
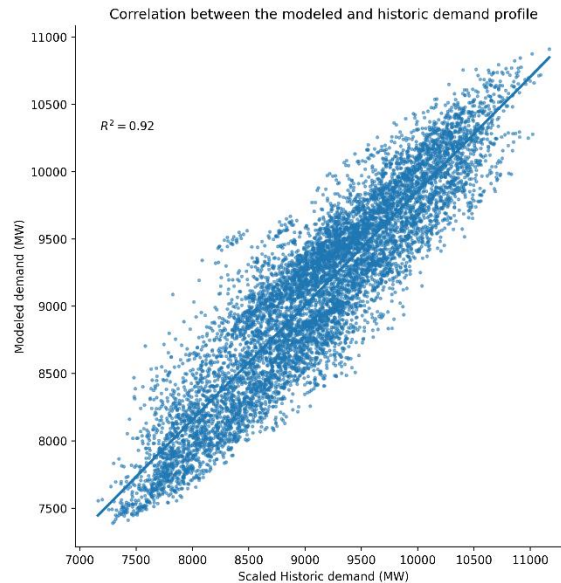


Figure 51 Histogram for two modeled and scaled datasets

Second, [175] suggests a correlation between the modeled data and scaled historical data is another source of validation. The result of the correlation study is represented in Figure 52 and shows an acceptable correlation between the two datasets with a linear correlation factor of 0.92. The mean absolute error between the two data is reported to be 267.49 which is between 2.43% and 3.56% of the hourly values.



*Figure 52 Correlation analysis between the modeled demand curve and the scaled historical demand curve*

While the model is not an optimization model, testing constraints are out of the scope of validation of this tool.

#### **7.1.4 EnergyPlus**

EnergyPlus is an open-source and widely used model in the energy building simulation domain which was developed by the Department of Energy of the US [187], [188]. Several studies applied this model to precisely simulate the energy requirements of a building within the given physical characteristics and weather data [189]–[191]. As per the models' documentation, the model is tested with ASHRAE 140-2011 standard methods, and the outputs are validated in comparison with outputs from other building energy simulation models over different features, like windows, shadings, ventilation, changes in thermostat setpoints and more including 100 test cases [192]. The results of these validation studies show that the outputs of the model were in the range of the outputs for all other models except seven cases in which the outputs are within 5.5% out of the range of data.

EnergyPlus is also validated through several simulation studies where the modeled data was comparable to available measured data [193]–[195]. EnergyPlus is used in the second chapter of this study to calculate the hourly load from the residential sector in Alberta. The second chapter of the current study mainly focuses on the relative results for different given thermostatic constraints. The main purpose of using an energy simulation was to analyze the load

changes reacting to thermostatic intervention. As such, the absolute simulation results are not used in this study and therefore not reported as an output.

While thermostatic changes are the main source of impact in the current study's analysis, a sensitivity analysis, and a test on the thermostat constraint are done for this variable as outlined below. First, the sensitivity analysis was conducted on a range of setpoints to see the impact on the energy output. Theoretically, a lower thermostatic setpoint in winter and a higher setpoint in winter should result in generally lower energy use. Meanwhile, a higher setpoint in winter and a lower setpoint in summer should increase energy use. This hypothesis is tested through the EnergyPlus model on the building types represented in the current study.

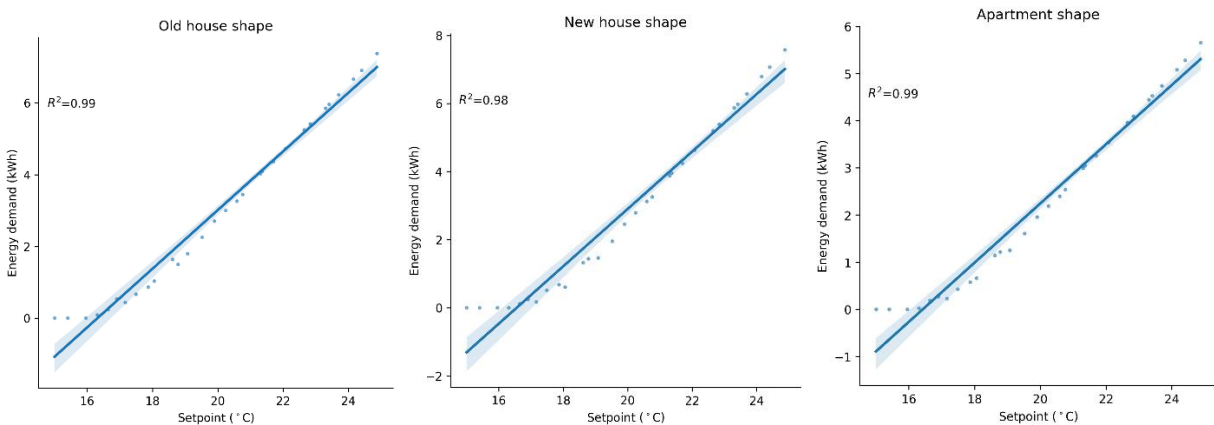


Figure 53 Sensitivity analysis of the three modeled building type energy use outputs over the range of thermostat inputs in winter

Change in the setpoint shows a strong positive correlation with the energy demand in the hour in which the change happens. This is shown to be true for the three building types that are used in this study. It is also notable that the load does not change and drops to almost zero when the setpoint is under 17 Celsius degrees. The very minimal load happens because the building has enough energy from the previous hours stored as heat and does not need to turn on the heating when the thermostat is set to too low temperatures. The range of temperatures and the date and hours are selected with a Latin Hypercube random generating engine.

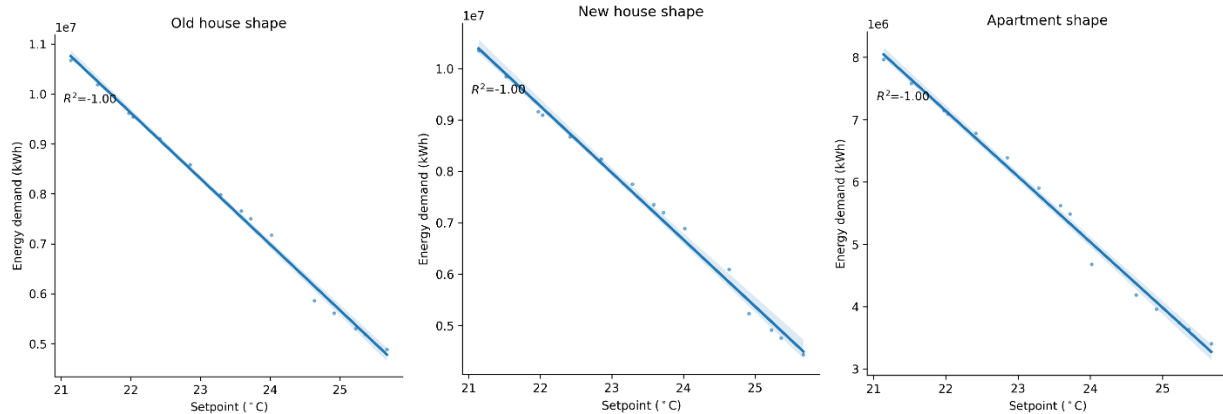


Figure 54 Sensitivity analysis of the three modeled building type energy use outputs over the range of thermostat inputs in summer

The same sensitivity analysis is also done for summer hours and is represented in Figure 54. The result shows that there is a completely negative correlation between the setpoint and hourly load for all three house types. The  $r$  value for all three house shapes is calculated to be 1 which shows the perfect correlation. The sensitivity analyses set the basis performance of the building model to be used as intended in this study, which is to see the response of the building stock to the changes in the thermostatic setpoint.

### 7.1.5 Modeling and data limitations

While the data is shared between the models, this section discusses the main data limitations and their entailed modeling limitations and assumptions. Specific limitations in each study are also addressed in the discussion section of the chapter.

During the thesis, a comprehensive search to access complete and proper data is done individually as well as among the group members. However, there is still missing data at the time of this study which is set to be modeled using as accurate as possible assumptions.

1. Hydroelectric capacity factor hourly data for many hydropower facilities. As one of the discussed sources of flexibility, as well as comprising 60% of the total capacity of Canada's power system, hydropower data with finer resolution could improve the representation of the model. Although this limitation is tackled in SILVER by introducing cascading hydro and must-run constraints (discussed in Chapter 4), the data was only gathered for BC. In addition, COPPER includes the mentioned 10% hydro generation minimum limit to mimic the must-run requirements, lacking detailed representation for cascading hydro capacities.
2. Land use data as a COPPER-specific constraint is another assumption that is based on uniform and general inputs gathered from available studies. While two different values are analyzed and discussed in the study,

more detailed and location-specific data could help to inform the real potential and costs related to wind and solar expansion.

3. While emerging technologies like Small Nuclear Reactors, Carbon Capture and Storage, and Lithium Battery Storage are modeled in the frameworks, other newer technologies are excluded due to computational limitations and lack of data availability. These technologies include hydrogen, offshore wind, geothermal, and tidal turbines.

In addition to the above lack of data for modeling, further assumptions are needed as the models are optimizing for a long-term horizon, in which some data are not available. The models use a deterministic approach when it comes to modeling the unavailable data, but sensitivity analysis and a variety of scenarios are selected to tackle this limitation for the most important variables. List of these data and the entailed assumptions are listed below:

1. COPPER does not provide outputs for grid expansion at the sub-provincial level. Therefore, there is no input for grid expansion at that level for future scenarios. To address this limitation SILVER model is using the current transmission network to analyze future generation and demand expansion scenarios. This fine resolution is still ahead of many recent studies as addressed in the literature review in the second chapter. In addition, the limitation is tried to be addressed by feedbacking transmission expansion costs to COPPER which is signaled by congestion analysis in SILVER. For a complete discussion see chapter second's methodology.
2. As stated above, wind and solar data are from historical sources with fine temporal and spatial resolution. SILVER and COPPER both assume wind and solar potentials to be fixed for each location and each hour. In the real world, this assumption might be contradicted by the impacts of climate change and other environmental variations. This limitation comes from the deterministic formulation of the models which is selected for the current study.
3. Building archetypes which are modeled as approximate in the building model are also assumed to remain the same in the future projections. While the building features might be changed by renovations over time, the change in the load for the envelope impacted by the change in the thermostatic setpoint would have the same impact on changing the load. This is the fundamental fact that all demand response scenarios are based on and shown to be true in the previous sensitivity analysis for different building types.

In conclusion, considering that this thesis is mainly policy-oriented, the assumptions are selected to be the best approximation to the real-world representation of the studied energy systems. The discussed assumptions are also discussed to be improvements for the other studies available at the time of writing the thesis. Detailed discussions about the gaps and improvements are presented in the introduction to each chapter.

## 7.2 Appendix B: Supplementary terms and definitions

### 7.2.1 Power systems

A power system is a network of infrastructure and equipment used to generate, transmit, and distribute electricity. It includes power plants that generate electricity, transmission lines and substations that transport electricity over long distances, and distribution lines and transformers that deliver electricity to consumers. The power system also includes control systems, such as energy management systems, that help to manage and optimize the operation of the system.

### 7.2.2 Generation capacities and technologies

Generation capacity in a power system refers to the maximum power output that a power plant or generator can produce at a given time. This capacity is typically measured in megawatts (MW) or gigawatts (GW) and reflects the total installed capacity of a plant power system.

Common generation technologies used in power systems include:

- **Fossil fuel power plant:** Power plants based on fossil fuels produce electricity by burning coal, natural gas, or oil. While they provide a steady source of energy, they emit greenhouse gases and other pollutants.
- **Nuclear Power Plants:** These power plants use nuclear reactions to generate heat, which is used to produce steam that drives turbines to generate electricity.
- **Renewable Energy Power Plants:** These power plants generate electricity from renewable sources such as solar, wind, hydro, geothermal, and biomass.
- **Other sources of power generation** include newer emerging technologies, such as wave or tide harvesting plants, geothermal heating, and cooling, etc.

Generation capacities and technologies used in a power system depend on a variety of factors, including the availability of fuel resources, environmental regulations, and load from the consumers.

### 7.2.3 Transmission and distribution systems

Transmission lines carry high-voltage electricity over long distances from power plants to substations, which then distribute the electricity to local distribution networks. Transmission lines are designed to minimize power losses over long distances by transmitting electricity at high voltages, typically ranging from 69 kilovolts (kV) to 765 kV or higher, depending on the distance and the amount of power being transmitted. The high voltages also help to increase the efficiency of the power system and reduce the amount of electricity lost as heat during transmission. On the other hand, distribution systems are designed at lower voltages to keep up with safety regulations, while maintaining the load requirements.

#### 7.2.4 Variable renewable energy resources

Variable renewable energy resources refer to renewable energy sources that can fluctuate in output due to natural variations in weather patterns, such as wind speed, cloud cover, and sunlight intensity. Examples of variable renewable energy resources include solar and wind power, which can generate electricity depending on the amount of sunlight or wind available.

#### 7.2.5 Metrics to detect flexibility issues

Through the thesis, different parameters are introduced and used as metrics to detect flexibility issues within the studied power systems. These metrics include but are not limited to what follows:

- **Curtailement:** Curtailment occurs in power systems when there is excess electricity available to be generated by available resources, but the system is not flexible enough to immediately absorb the available capacity. In such cases, the excess electricity must be either stored or curtailed, which means it is deliberately not used and is instead lost. Curtailment of variable renewable energy is typically a last resort in the lack of adequate flexibility because it results in wasted energy and increases the cost of electricity generation. As sufficient flexibility options contribute to reducing curtailment in wind and solar, curtailment itself can be used as a metric to measure how flexible a power system is.
- **Grid congestion:** Grid congestion in a power system occurs when there is too much demand for electricity on a particular section of the power grid and the existing transmission infrastructure is unable to meet that demand. This results in bottlenecks, where the electricity supply is limited, leading to potential power outages, voltage imbalances, or blackouts. Grid congestion along with curtailment can be used as metrics to detect if the flexibility is constrained because of the network or not.
- **Load shedding:** Load shedding in power systems is the deliberate and temporary reduction of electricity supply to certain areas or consumers to prevent a widespread power outage or blackout. It is a controlled way of balancing the supply and demand of electricity during times of high demand or when there is insufficient generation capacity available to meet the demand. Therefore, load shedding can be utilized to detect the most critical flexibility issues in the system.

## 7.1 Appendix C: List of Abbreviations

DEFINITION	ABBREVIATION
ALBERTA	AB
ALTERNATING CURRENT	AC
ALBERTA ELECTRIC SYSTEM OPERATOR	AESO
BRITISH COLUMBIA	BC
BUILDING PERFORMANCE SIMULATION	BPS
CANADIAN DOLLAR	CAD
CARBON CAPTURE AND STORAGE	CCS
CARBON CAPTURE, UTILIZATION AND STORAGE	CCUS
CAPACITY EXPANSION MODELS	CEM
CANADA ENERGY REGULATOR	CER
CAPACITY FACTOR	CF
CANADIAN OPEN-SOURCE DATABASE FOR ENERGY RESEARCH AND SYSTEMS MODELLING	CODERS
CANADIAN OPPORTUNITIES FOR PLANNING AND PRODUCTION OF ELECTRICITY RESOURCES	COPPER
DIRECT CURRENT	DC
DEMAND FOR ENERGY SERVICES, SUPPLY AND TRANSMISSION IN EUROPE	DESSTINEE
DIRECT LOAD CONTROL	DLC
DEMAND RESPONSE	DR
ENERGY TRANSFER REFERENCE CASE	ETRC
EUROPE	EU
ELECTRIC VEHICLE	EV
GREENHOUSE GAS	GHG
GLOBAL RENEWABLE ENERGY ATLAS & TIME-SERIES	GRETA
GIGAWATTS	GW
HIGH-PRICE THRESHOLD	HPT
INTEGRATED ASSESSMENT MODELS	IAM
INTERNATIONAL ENERGY AGENCY	IEA
LITHIUM BATTERY	LB
LIFE CYCLE ASSESSMENT	LCA
LOW-PRICE THRESHOLD	LPT
MODERN-ERA RETROSPECTIVE ANALYSIS FOR RESEARCH AND APPLICATIONS	MERRA
MARGINAL PRICE	MP
MEGAWATTS	MW
NATURAL GAS	NG

<b>NEWFOUNDLAND AND LABRADOR</b>	NL
<b>NATURAL RESOURCES CANADA</b>	NRC
<b>NATIONAL RENEWABLE ENERGY LAB (US)</b>	NREL
<b>OPTIMAL POWER FLOW</b>	OPF
<b>PRODUCTION COST MODEL</b>	PCM
<b>PRINCE EDWARD ISLAND</b>	PEI
<b>PUMPED HYDRO STORAGE</b>	PHS
<b>PHOTOVOLTAIC</b>	PV
<b>REAL-TIME PRICING</b>	RTP
<b>SUSTAINABLE ENERGY SYSTEMS INTEGRATION &amp; TRANSITIONS GROUP</b>	SESI
<b>STRATEGIC INTEGRATION OF LARGE-CAPACITY VARIABLE ENERGY RESOURCES</b>	SILVER
<b>SMALL MODULAR REACTOR</b>	SMR
<b>TERAWATTS</b>	TW
<b>UNIT COMMITMENT</b>	UC
<b>UNITED STATES</b>	US
<b>VARIABLE RENEWABLE ENERGY</b>	VRE

## 7.2 Appendix D: Data and source codes

Data sources are all listed in the chapters and can be accessed by request. All models, analysis, post-process, linking, and visualization codes can be accessed through their respective repositories and websites as presented in the below table:

<i>No.</i>	<i>Repository name</i>	<i>Repository address</i>
1	COPPER model	<a href="https://gitlab.com/McPherson/copper">https://gitlab.com/McPherson/copper</a>
2	SILVER model	<a href="https://gitlab.com/McPherson/silver">https://gitlab.com/McPherson/silver</a>
3	Thesis-specific visualization, linking, data management, post-processing, and visualization tools	<a href="https://github.com/smmiri/etl-visuals">https://github.com/smmiri/etl-visuals</a>
4	EnergyPlus	<a href="https://github.com/NREL/EnergyPlus">https://github.com/NREL/EnergyPlus</a>
5	OpenStudio (Graphical user interface for EnergyPlus)	<a href="https://github.com/NREL/OpenStudio">https://github.com/NREL/OpenStudio</a>
6	DESSTINEE	<a href="https://sites.google.com/site/2050desstinee/">https://sites.google.com/site/2050desstinee/</a>