The Techno-economic Impacts of Using Wind Power and Plug-In Hybrid Electric Vehicles for Greenhouse Gas Mitigation in Canada

by

Brett William Kerrigan
B.Eng., Carleton University, 2008

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Supervisory Committee

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Abstract

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The negative consequences of rising global energy use have led governments and businesses to pursue methods of reducing reliance on fossil fuels. Plug-In Hybrid Electric Vehicles (PHEVs) and wind power represent two practical methods for mitigating some of these negative consequences [1,2]. PHEVs use large onboard batteries to displace gasoline with electricity obtained from the grid, while wind power generates clean, renewable power that has the potential to displace fossil-fuel power generation. The emissions reductions realized by these technologies will be highly dependent on the energy system into which they are integrated, and also how they are integrated. This research aims to assess to cost of reducing emissions through the integration of PHEVs and wind power in three Canadian jurisdictions, namely British Columbia, Ontario and Alberta.

An Optimal Power Flow (OPF) model is used to assess the changes in generation dispatch resulting from the integration of wind power and PHEVs into the local electricity network. This network model captures the geographic distribution of load and generation in each jurisdiction, while simulating local transmission constraints. A linear optimization model is developed in the MATLAB environment and is solved using the ILOG CPLEX Optimization package. The model solves a 168-hour generation scheduling period for both summer and winter conditions. Simulation results provide the costs and emissions from power generation when various levels of PHEVs and/or wind power are added to the electricity system. The costs and emissions from PHEV purchase and gasoline displacement are then added to the OPF results and an overall GHG reduction cost is calculated.

Results indicate that wind power is an expensive method of GHG abatement in British Columbia and Ontario. This is due to the limited environmental benefit of wind over the nuclear and hydro baseload mixtures. The large premium paid for displacing hydro or nuclear power with wind power does little to reduce emissions, and thus CO_2e costs are high. PHEVs are a cheaper method of GHG abatement in British Columbia and Ontario, since the GHG reductions resulting from the substitution of gasoline for hydro or nuclear power are significant. In Alberta, wind power is the cheaper method of GHG abatement because wind power is closer in price to the coal and natural gas dominated Alberta mixture, while offering significant environmental benefits. PHEVs represent a more expensive method of GHG abatement in Alberta, since substituting gasoline for expensive, GHG-intense electricity in a vehicle does less to reduce overall emissions.

Results also indicate that PHEV charging should take place during off-peak hours, to take advantage of surplus baseload generation. PHEV adoption helps wind power in Ontario and British Columbia, as overnight charging reduces the amount of cheap, clean baseload power displaced by wind during these hours. In Alberta, wind power helps PHEVs by cleaning up the generation mixture and providing more environmental benefit from the substitution of gasoline with electricity.

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Nomenclature

Optimal Power Flow Formulation

G	Power generated	[MW]
P	Power transmitted across a line	[MW]
L	Non-PHEV Load	[MW]
V	PHEV Load	[MW]
C	Total Generation Cost	[$] (2009 CAD)
X	Line Reactance	[Ω]
R	Line Resistance	[Ω]
r_j	Maximum ramp rate of generator j	[MW/h]
c_j	Variable cost of power from generator j	[$/MWh]
v	Wind speed	[m/s]
h	Height	[m]
α	Surface Friction Factor	[-]
N	Number of PHEVs at bus *i*	

GHG Reduction Cost Calculations

C	Cost	[$]
E	Emissions	[t-CO_2e]
A	Emissions Reduction Cost	[$/ t-$CO_2$e]

Subscripts

t	Discrete time index	
i	Discrete bus index	
j	Discrete generator index	
k	Discrete transmission line index	
x	PHEV Penetration	[%]
y	Wind Penetration	[%]
max	Maximum	

Acronyms

AER	All-Electric Range
AESO	Alberta Electricity System Operator
CANDU	CANada Deuterium Uranium
CERI	Canadian Energy Research Institute
CanWEA	Canadian Wind Energy Association
CF	Capacity Factor
CHP	Combined Heat and Power
CV	Conventional Vehicle
DOE	(US) Department of Energy
EIA	Energy Information Administration (USDOE)
EREV	Extended Range Electric Vehicle
GHG	Greenhouse Gas
HEV	Hybrid Electric Vehicle
ICE	Internal Combustion Engine
IESO	Independent Electricity System Operator
Li-Ion	Lithium-Ion
LUEC	Levelised Unit Electricity Cost
NG	Natural Gas
OPG	Ontario Power Generation
O&M	Operations and Maintenance
PHEV	Plug-In Hybrid Electric Vehicle
PV	Photovoltaics
RES	Renewable Energy Source
RRA	Revenue Requirement Application

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1. Introduction

Global energy use is increasing exponentially as the economies of both developed and developing countries continue to expand [3]. Recent attention has been paid to the negative consequences of rising global energy use, including rising costs, decreasing supply security and increasing environmental pollution, all of which have led governments and businesses to investigate methods of dealing with this problem [4,5].

One of the most frequently discussed methods of reducing reliance on fossil fuels has been the adoption of renewable energy technologies [1]. Wind power is among the most mature renewable energy technologies, and the industry has been quickly expanding over the past 15 years [6]. However, several barriers impede the widespread adoption of wind power. The primary disadvantage of wind power is that it is highly variable, and power output cannot be predicted reliably. Because the output of wind turbines is non-dispatchable, its adoption will induce changes in the scheduling of traditional generation, potentially increasing costs and emissions. Aggravating this issue is the inability of some traditional generation to ramp its output fast enough to accommodate changes in wind power production [7].

Another proposed method of reducing reliance on fossil fuels has been the electrification of the transportation sector [2]. Currently, over 99% of transportation in Canada is powered by fossil fuels [8], making vehicles a significant source of greenhouse gas (GHG) emissions. Plug-In Hybrid Electric Vehicles (PHEVs) are being developed as an alternative to conventional internal combustion engine (ICE) vehicles. PHEVs employ a large on-board battery that permits driving in all-electric mode for short distances. Once the onboard battery has been depleted, a traditional gasoline engine turns on and powers the vehicle until the driver can recharge the battery, thereby providing the same range as conventional vehicles (CVs). PHEVs have also been discussed as a source of flexible electricity demand that can quickly vary charge rate in response to electricity price or other utility signals [9]. This flexible demand could act as a buffer for wind power, mitigating some of the negative effects of intermittency.

The economics and GHG reduction potential of PHEVs and wind power is highly dependent on the characteristics of the power network into which they are integrated. In the case of wind power, the displaced generation and other changes in dispatch schedule will dictate the cost and avoided GHG emissions. For PHEVs, the characteristics of the marginal generation source during charging hours will dictate the cost and environmental impact of using electricity instead of gasoline for transportation. To quantify the effectiveness of PHEVs and wind power as methods of GHG abatement, the cost of GHG reductions (in \$/t-CO_2e) is determined. This work investigates how GHG costs change with varying degrees of PHEV and wind penetration, the effects of daily PHEV charging patterns, and how results change between several different Canadian jurisdictions.

This study aims to answer these questions using an integrated energy systems model. An Optimal Power Flow (OPF) algorithm is formulated to assess changes in power generation cost and emissions due to the introduction of wind power and PHEVs. The model solves a 168-hour dispatch period for both summer and winter demand conditions. The PHEV loads are added to the system in three distinct scenarios: uncontrolled charging, overnight (off-peak) charging and utility controlled charging. While future integration of PHEVs may not follow any of these scenarios entirely, they do serve as bounding conditions for the best and worst cases of passive PHEV integration (i.e. no utility intervention) and the best case for active PHEV integration (i.e. utility controlled).

The OPF is formulated for three separate jurisdictions, namely British Columbia, Ontario and Alberta. Large-scale network models are formed for each jurisdiction, and include actual transmission, generation and load data from the public domain. These models simulate the geographic distribution of generation and loads, and the constraints on the local bulk transmission system.

A literature review of existing energy systems models, OPF formulations, wind integration studies, and PHEV grid-impact studies is presented in Section 2. The details of the OPF formulation used in this thesis, including the constraints, objective function, and generation technologies, are provided in Section 3. The details of the British Columbia, Ontario and Alberta network models, including the generation mixtures, demand centres and transmission constraints, are presented in Section 4. PHEV technology and economics, as well as PHEV load modelling, is discussed in Section 5. The results from the OPF models, including changes in generation costs and emissions due to the addition of wind and PHEVs, are presented in Section 6. The costs and emissions from PHEV ownership (including purchase cost and gasoline displacement) are then added to the OPF results to calculate overall CO_2e reduction costs. The sensitivity of CO_2e costs to variations in generation and PHEV costs are discussed in Section 7. The key findings of the work are highlighted in Section 8, and recommendations for future improvements are discussed in Section 9.

2. Literature Review

This section presents research related to the modelling of existing and future energy systems. The first section discusses various integrated energy system models, including optimal power generation dispatch and other power grid models. The second section describes research related to the effects of integrating intermittent renewable power into existing power networks. The third section describes the grid effects of electrifying transportation through the use of PHEVs.

2.1. Energy Systems Modelling

Energy is a fundamental building block of modern civilization, and thus the study of energy systems has become essential to understanding and improving the energy supply to all nations [3]. Questions revolving around the energy system of a nation or region are frequently addressed through the implementation of techno-economic energy system models. These models may answer questions about the supply, conversion, allocation, or conservation of energy. Jebaraj and Iniyan [10] provided a thorough review of such energy system models, focusing on energy planning, energy supply-demand, forecasting, optimization and emission reductions.

The context and scale of energy system models can vary widely. Tzeng et al. [11] used a multi-criteria method to evaluate the alternatives for new energy system development in Taiwan, where both conventional (i.e. fossil fuel based) and renewable energy systems were supply options. Results ranked solar thermal energy as the first priority for development, with solar photovoltaics (PV), wind and geothermal energy assigned second priority. Sinha [12] developed a model that simulated the performance and economics of a remote combined wind/hydro/diesel plant with pumped storage, and found the pumping capacity of the reversible turbine was rarely used in cases where natural inflow to the reservoir was available. Groscurth [13] developed regional and municipal scale energy system models with the goal of minimizing primary energy demand, emissions and cost. Alam et al. [14] developed an integrated rural energy system model for a Bangladeshi village, which balanced the benefits of producing biogas for cooking with the conversion of food-producing land to livestock pasture. Joshi [15] created an energy planning model for both domestic and irrigation sectors in an Indian village, using a mix of energy sources and conversion devices while minimizing cost. Results show that wood and agricultural residues are preferred energy sources for cooking, diesel-powered irrigation pumps are preferred for irrigation, and biogas is only economical for lighting when the conversion efficiency is above 4%.

The approaches used in the integrated energy system models described above can be used in many different applications. The same principles of cost minimization and choice of energy conversion technology also apply to power generation planning and optimal generation dispatch. Optimal generation dispatch, or optimal power flow (OPF) is a technique used to determine the lowest possible cost of generation for a set of demand conditions, subject to the constraints imposed by the operational and physical limits of the transmission system. OPF is a well established field, and there are many different approaches to the OPF formulation. T.S. Chung [16] used a recursive linear programming approach which minimized line losses as the objective function. Lima et al. [17] used a Mixed Integer Linear Programming (MILP) method to study the optimal placement of phase shifters in large scale power systems. G.W. Chang [18] also employed a MILP approach which included unit commitment of thermal generators. Berizzi et al. [19] presented Security Constrained Optimal Power Flow that solved nonlinear objective functions and constraints using successive quadratic programs with linear constraints.

2.2. Grid Integration of Renewable Energy

Many of the OPF formulations described above are used in the study of conventional grid infrastructure. However, future grids will be fundamentally changed with the inclusion of intermittent renewable energy, and the issue of reliably integrating these resources must be addressed.

Several attempts have been made at understanding the impacts of large-scale renewable energy integration into existing energy systems. Albadi and El-Saadany [20] provided an excellent overview of wind power intermittency impacts on power systems. The impact of wind on thermal generator part-loading, reserve requirements, and generation scheduling were all outlined. Also discussed were changes in system robustness, transmission capacity requirements, and the need for more short-timescale regulation due to high-frequency wind power fluctuations. The paper concludes that current forecasting methods provide about 80% of the benefits that would be gained from perfect wind speed forecasting.

Maddaloni et al. [21] built a generic load balance model to quantify the economic and environmental effects of integrating wind power into three typical generation mixtures. The mixtures used were coal-dominated, hydro-dominated and a mixture of equal parts hydro and natural gas (NG). Results indicated an increase in system cost of 83%-280%, and an emissions decrease of 13%-32%, both depending on the types of generation displaced by the introduction of wind and decreased generator efficiencies at part loading.

Luickx et al. [22] presented a case study on wind power in the Belgian electricity sector. Using a Merit Order model and several different days of wind speed and load data, the cost and emissions reduction potential of wind was investigated. The study found that integration of perfectly forecasted wind would usually lead to price and emission decreases in the Belgian system, as wind injections prevents the need to dispatch more expensive marginal generators in the merit order. When forecast errors were introduced to the wind model, large portions of the cost savings were sometimes lost. The cost reduction findings of Luickx et al. contradict the results of several studies [20,23,24,25], which estimate that wind integration costs can vary from roughly $2-$10/MWh, depending on location.

Lund [7] investigated the impacts of wind integration on the Danish electricity system, which has significant amounts of generation from Combined Heat and Power (CHP) plants. Several different wind integration strategies were evaluated based on their ability to avoid excess power generation, the ability to reduce CO_2e emissions, and the ability to increase power exports in the Nord Pool electricity market. Results indicated that CHP plants exacerbate wind integration issues due to the additional heat delivery constraints on the energy system. Increasing the flexibility of heating demand, using technologies such as central boilers or heat pumps, was found to strengthen the regulation capabilities of the system and improve the ability of the Danish system to absorb wind power.

Lund [26] also investigated the optimal combination of solar PV, wind and wave power in the Danish electricity supply, with the intent of seeking maximum benefit from the different fluctuation patterns characteristic to each renewable energy source (RES). The total amount of renewable energy generation was varied, and the optimal mixture of generation technologies changed as the total amount of renewable power changed. At all RES levels, roughly 50% of the RE generation came from onshore wind. At low RES levels, PV was found to cover 40% of RE capacity and wave power only 10%. However, at higher RES levels, PV's share of RE capacity dropped to 20% while wave generation rose to 30%. The author stressed that other measures need to be taken for these scenarios to become technically feasible, including the development of a flexible demand system and the electrification of the transport sector.

Parsons et al [27]. reviewed several detailed investigations of wind power impacts on ancillary services in the US. The studies were conducted for Minnesota and two locations in the north-western United States. The investigations focused on three utility time frames, namely regulation, load following and unit commitment. The sum of these integration costs were found to be between $0.05-2.17 per MWh of wind power generated, which is relatively small compared to the actual cost of wind power. The report went on to stress that results of these studies were only relevant for the small amounts of wind power expected in the near future, and may change at higher wind penetrations.

2.3. Grid Impacts of PHEVs

A considerable amount of the literature on PHEV technology is focused on the drive train or energy storage system design. However, there are also many studies which investigate the net emissions from PHEVs and their impact on the power generation sector.

Stephan and Sullivan [28] analyzed the effect of charging a significant number of PHEVs in the US, using available night-time spare electric capacity in the short term, and using new baseload technology in the long term. With the existing mix in the US, PHEVs were found to reduce CO_2e emissions by 25% relative to conventional hybrids in the near term, and up to 50% in the long term.

Samaras and Meisterling [29] presented a life cycle assessment of GHG emissions from PHEVs in the United States. Results indicate that PHEVs reduce life cycle emissions by 32% relative to CVs, but have small reductions when compared to HEVs, primarily due to the carbon intensive electricity mix in the US. With a low-carbon grid mixture, PHEVs were found to reduce emissions by about 57% and 39% relative to CVs and HEVs respectively. Under a carbon-intensive electricity mixture, PHEVs were found to have higher lifecycle emissions than HEVs. Also concluded in this work was that the battery-related GHG emissions accounted for 2-5% of total life cycle emissions.

Jansen et al. [30] investigated the impacts of PHEV deployment in the western US grid. Using a single-node simulation and two bounding charge profiles (off-peak and uncontrolled charging), the impacts on generation dispatch were investigated. The generation dispatch was estimated based on historic hourly load and generation data. This approach enabled the calculation of hourly emissions intensities and accurate assessment of PHEV related changes in generation-related emissions. This model did not include any grid-related constraints, such as generation ramp rates or transmission limits, and did not include any discussion of PHEV economics.

Lund and Kempton [31] evaluated the integration of wind power and PHEVs in Vehicle-to-Grid (V2G) mode. A fleet of PHEVs was assumed to have a high power connection (10 kW) to the grid, and a large on-board storage device (30 kWh). The single-node model, with generation aggregated by type, quantified the effects of wind integration by the amount of curtailed wind power and the net CO_2e emissions from the electricity system. Results indicated that scheduled off-peak charging enabled less frequent wind power curtailment, due to higher load in traditionally low-load hours. The intelligent dispatch of vehicles showed improvement upon scheduled night charging in both metrics. The ability for the PHEVs to discharge (i.e. provide V2G) provides small benefits on top of the intelligent dispatch scenario. This model did not include any operational constraints on generation or the transmission system.

Göransson et al. [32] also investigated the impacts of PHEV and wind integration on an electricity system. The western Danish system was modelled, with an installed capacity of 25% wind power and 75% thermal generation (mix of coal, gas and CHP). Similar to Lund and Kempton [31], several different PHEV integration strategies were investigated. The novel inclusion in this work was the variation in emissions due to start up and part loading of generators, and spatial resolution given to loads and generation. Results indicated that uncontrolled charging resulted in generation emissions increases of up to 3%, while active integration of charging (with V2G) resulted in emissions reductions of 4.7% relative to a system without PHEVs. This study was limited to only one region, and did not discuss generation costs or PHEV economics.

3. Optimal Power Flow Formulation

To quantify the economic and environmental impacts of wind and PHEV adoption in regional power systems, a network model is created for each jurisdiction. The network model employs an Optimal Power Flow (OPF) formulation with a linear objective function and linear constraints, and assesses changes in generation dispatch due to the inclusion of wind and PHEVs. This section will describe the details of the OPF formulation, the generation types modelled in this work, and finally how the cost of generation is broken down for use in the OPF.

3.1. Optimal Power Flow Formulation

In a power flow model, power balance must be ensured at each bus at all times, as represented in Figure 1. The power generation (if any) injected into the bus must be balanced by the load, PHEV load, and/or by power exports through the transmission line. Conversely, if power generation is insufficient to meet load and PHEV load, power must be imported via the transmission line. The power balance equation is formalized in Equation 1:

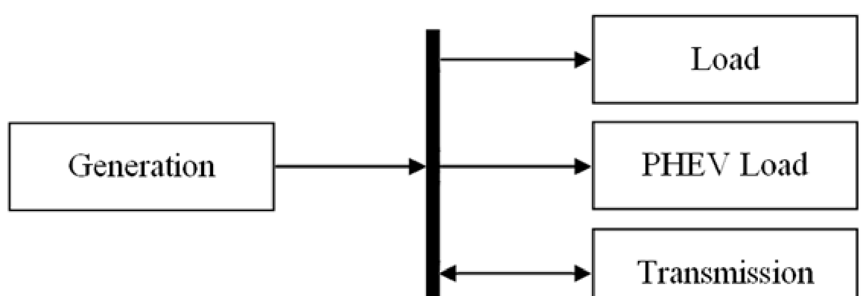

Figure 1: Representation of power balance at each bus *i*

$$\sum_{j}^{gens} G_{i,j,t} - L_{i,t} - V_{i,t} - \sum_{d} P_{i,d,t} = 0 \;\forall\; i = 1,2 \ldots, I \;\&\; t = 1,2 \ldots T, \qquad (1)$$

where G denotes generation by generator j at time t and bus i, L refers to non-PHEV load and V refers to PHEV load. The power transfer through a transmission line is denoted as $P_{i,d,t}$, where i is the originating bus and d is the destination bus. Power transfer through a transmission line may be defined as positive or negative, depending on the direction of flow. Power can be transmitted in either direction, but may have different flow limits in each direction due to operational constraints. Generation, load and PHEV loads are always non-negative.

The objective of the optimal power flow is to minimize the cost function (Equation (2)), subject to the power balance constraints shown in (1) and the ramping, generation capacity and transmission constraints shown in Equations (3) through (7):

$$\min C = \sum_{t}^{T} \sum_{j}^{gens} G_{j,t} c_j \qquad (2)$$

$$G_{j,t} - G_{j,t-1} \leq r_j \qquad (3)$$

$$G_{j,t} - G_{j,t-1} \geq -r_j \qquad (4)$$

$$G_{j,t}, L_{i,t}, V_{i,t} \geq 0 \qquad (5)$$

$$G_{j,t} \leq G_{j,max} \qquad (6)$$

$$P_{i,d,min} \leq P_{i,d,t} \leq P_{i,d,max} \qquad (7)$$

where C denotes the total generation cost, c_j refers to the variable cost of generator j, and r denotes the maximum hourly ramp rate. T represents the total length of the planning period, and is set to 168 hours for all simulations in this work.

3.1.1. Losses

The optimal power formulation used in this study is a simplification of the traditional OPF model. Many OPF models use an AC power flow formulation, which includes both real and reactive components of power. The AC formulation is physically accurate, as real power networks have to consider reactive power support and voltage management issues. However, in certain instances, a DC Power Flow formulation may provide an acceptably accurate simplification to AC Power Flow [33,34].

The major simplification of the DC power flow is that only active power flows are considered, neglecting voltage support, reactive power management and transmission losses. By assuming that line resistances are negligible, the optimization problem becomes linear, resulting in reduced computational burden relative to the non-linear AC formulation. The validity of this assumption was investigated by Purchala et al. [33], and was found to be highly dependent on having a flat network voltage profile, and on the *X/R* ratio of the transmission lines in question (where the *X* is the line reactance and *R* is the line resistance). Since only the major interconnections of the bulk transmission network are modelled in this study, it is assumed that the utility maintains these nodes at the nominal transmission voltage (usually 240 kV or higher) [35]. Purchala's investigation suggested that for lines with *X/R* ratios above 4, neglecting losses resulted in modest error. Tests on randomly generated networks revealed that for lines transferring over 22MW of power, the error is less than 5% for 95% of hours investigated, and averages only 1.5%. The bulk transmission lines in British Columbia (and presumably Ontario and Alberta) have *X/R* ratios above 4.0 [36]. For this reason neglecting power losses was assumed to introduce minimal error to the OPF, and thus a full DC power formulation is used in this thesis.

This assumption is confirmed by Overbye et al. [34], who compared the effectiveness of AC and DC Power flow models for congestion management problems. The authors formulated AC and DC network models and calculated Locational Marginal Prices (LMPs) at each node to determine areas of high transmission cost. While there were slight differences between models, the DC formulation encountered all the same transmission constraints as the AC model, and deviated from the AC model in few locations. The authors concluded that the DC power flow does a good job of revealing the same flow patterns as the AC model, while saving considerable computation time. These results imply that the generation dispatch schedule found by a DC load flow formulation would closely follow the dispatch schedule of the AC formulation, as desired in this thesis.

3.1.2. Solver

The ILOG CPLEX optimization package from IBM is used to find solutions to the OPF, and is run from the MATLAB runtime environment. The cost minimization function, transmission constraints and power balance described previously are all linear, enabling short solve times. Since the model uses linear constraints and a linear objective function, the solver automatically uses zero as a starting point initialization. Each one-week simulation period has around 4000 variables, and solves in less than five seconds. This simulation is then repeated for over 200 different combinations of PHEV and wind penetration levels for each jurisdiction. Total emissions and costs are then extracted from the OPF solution.

3.2. Generation Types

All jurisdictions studied in this work have a different mixture of generation technologies, each with different costs, operational constraints and emissions intensities. This work assumes that a specific generation type will have the exact same characteristics in all jurisdictions. What follows here is a brief description of the operational limitations, levelised costs, and related lifecycle emissions for each generation type modelled in this work.

3.2.1. Hydro

Hydroelectric power uses the gravitational or kinetic energy of water to turn turbines. Power can be generated from the natural flow of rivers or streams (known as Run-of-River hydro) or from large storage reservoirs. Reservoir hydro installations are fully dispatchable, with some operational restrictions on reservoir height. Run-of-River (RoR) installations are not fully dispatchable, since they depend on the natural flow of the stream or river to generate energy. For the purposes of this study, only dispatchable hydroelectric generators are modelled. If operational constraints of a certain installation are not known, they are modelled as fully dispatchable. Hydro plants can be ramped up or down quickly and thus were not modelled with any ramp constraints.

The levelised cost of hydro generation was obtained from BC Hydro's 2009-2010 Revenue Requirement Application (RRA) [37], which reports the annual generation from their heritage and non-heritage hydro assets, and the total cost spent maintaining and operating those assets. For 2009 and 2010, BC hydro predicts heritage hydro assets to generate power at an average cost of $6.9/MWh, and IPP assets to generate power at a cost of $66.5/MWh. Calculating a weighted average of these costs by the total annual generation from each type, the average levelised cost for hydro is found to be $16/MWh. In Ontario, the levelised cost of regulated hydro was reported as $5.5/MWh in 2009 [38], which confirms that the price of hydro power in Ontario is similar to that of heritage hydro in British Columbia. Since little information on the cost of hydro power was available for Alberta, the same variable and fixed hydro costs were assumed for all three jurisdictions. Note that all costs shown in this thesis are in 2009 CAD unless otherwise specified.

The emissions from hydro power are associated with the loss of CO_2e absorbing forest that occurs during flooding, and the resulting methane expulsion from the flooded vegetation. The emissions from a specific reservoir can vary due to the types of vegetation and topography of the area. While the emissions from tropical reservoirs can be quite high, with some installations releasing up to 400 kg-CO_2e/MWh, the emissions in mountainous and boreal regions are much lower. Taking the highest estimates of boreal reservoirs from [39] and [40], the lifecycle emissions were assumed to be 35 kg-CO_2e/MWh for purposes of this study. This assumption is confirmed by Weisser [41], who reported that lifecycle emissions from Finnish hydro installations were mostly attributed to flooded land mass, with an average GHG intensity of 30 kg-CO_2e/MWh.

3.2.2. Coal

Coal plants use large boilers to generate steam and drive turbines. Since these units use large thermal masses to generate steam, they are limited in how fast they can vary electricity generation levels. Fast ramping can accelerate wear on thermal components and increase lifetime cost [42], especially on older units [43]. Thus, ramping was conservatively constrained to around 0.6% of rated capacity per minute [43], which equates to a 3 hour ramp-up and ramp-down time.

The cost of coal generation can vary widely due to annual capacity factor (CF), availability, installed capacity, heat rate, and the price of coal. The Canadian Energy Research Institute (CERI) considered all of these factors in a detailed report on the cost of generation options for Ontario. The report found the base case Levelised Unit Electricity Cost (LUEC) to be $52/MWh. This value is used for coal plants in both Ontario and Alberta [44].

Coal generation is the most carbon-intensive generation modelled in this study at 975 kg-CO_2e/MWh [45]. Over 90% of this is due to combustion of the fuel, while the remaining 10% is due to the upstream mining and transportation related emissions.

3.2.3. Natural Gas

Natural gas (NG) can be used in a variety of different generation plants, most notably simple cycle and combined cycle plants. Combined cycle plants feature improved thermodynamic efficiency through the use of waste heat from the generator. The thermal efficiencies of typical simple cycle and combined cycle installations are around 39% and 45% respectively [45]. Since some of these generators use combustion directly to spin turbines, they can ramp output quickly, and can be used in peaking or load following applications. Since this study operates on an hourly time step, no ramping constraints were modelled for NG generation.

The levelised cost of NG generation is difficult to estimate, since the LUEC can vary widely based on the application of a specific generator. Baseload (or high capacity factor) steam generators are estimated to cost around $79/MWh in Ontario [44]; however, in peaking (i.e. low capacity factor) applications, the price per unit energy may be higher. BC Hydro's 2009-2010 RRA shows the Burrard NG plant (a rarely used peaking plant) generated power at an average LUEC of $115/MWh between 2007 and 2009. Since the NG generators modelled in this study may be either high capacity factor or peaking plants, an average levelised cost of $97/MWh is used in this study. Note that all combined cycle and simple cycle generators are aggregated together in the OPF model, since data describing specific installations in each jurisdiction are largely unavailable.

Like coal, NG plants have combustion emissions and upstream emissions related to fuel extraction and transport. Simple cycle plants are less efficient (burning more fuel), and have a lifecycle emissions intensity of 608 kg-CO_2e/MWh, while more efficient combined cycle plants have a lifecycle emissions intensity of 518 kg-CO_2e/MWh [45]. Upstream emissions account for about 20% of the total in each case. Since an exact capacity breakdown of simple and combined cycle plants is not available for any jurisdiction, an average lifecycle emissions value of 563 kg CO2/MWh is used. This assumption is supported by CERI, who estimate a lifecycle emissions rate of 548 kg-CO_2e/MWh for NG generation in Ontario [46].

3.2.4. Nuclear

Nuclear power generators use the controlled fission of uranium to release large amounts of thermal energy, which is used to heat water and generate steam. The reactors used in Canada are CANDU (CANadian Deuterium Uranium) reactors developed by the Atomic Energy of Canada Limited (AECL) in the 1960s. Though work is continuing on a new generation of CANDU plants, Advanced CANDU Reactors (ACR), this study will only consider the existing CANDU reactors. Like coal plants, nuclear plants use large thermal masses to generate steam, and variation of these thermal masses can accelerate wear on components. For this reason, the same 3 hour ramping limits that constrain coal generation were also applied to nuclear generation.

The cost of nuclear power can vary widely depending on application, location and technology. Ontario Power Generation publishes an annual report that details the revenues and costs associated with their Pickering and Darlington reactors, including the LUEC. While there have been ongoing upgrades and maintenance work on the reactors, the annual LUEC of nuclear power between 2007-2009 has remained fairly constant, with an average cost of $45/MWh [47,48,38]. Although the cost of nuclear power is higher than that of hydro power, current IESO practice places nuclear power ahead of hydro power in the Dispatch Priority for a variety of technical reasons [49]. To emulate this practice in the OPF, nuclear power is only permitted to dispatch down if transmission constraints require curtailment.

The emissions from nuclear power vary depending on how uranium is obtained, and also based on the level of enrichment [45]. CANDU reactors do not require enriched uranium to operate, and thus have low lifecycle GHGs. CERI broke down the lifecycle emissions of nuclear power in Canada, finding a total value of 1.8 kg-CO_2e/MWh, with over 85% of this attributed to upstream mining efforts [46].

3.2.5. Wind

Most wind farms employ the standard 3-blade upstream turbine design. While the technology is becoming mature, the inherent intermittency of wind still remains a large barrier to increased penetration of wind. Section 3.2.6 describes the modelling of wind power in more detail.

The levelised cost of wind power in Canada is difficult to establish, as few data on Canadian installations are publicly available. In 2005, the President of the Canadian Wind Energy Association (CanWEA) stated that levelised costs in Canada were around \$80/MWh (in 2005 CAD) and stated that costs were expected to decline by 3% per year [50]. Applying a 3% annual decrease to the 2005 cost and adjusting for inflation results in a levelised cost of \$76/MWh, in 2009 CAD.

The emissions due to wind power are a result of upstream energy and material use, but also due to land use, which can be significant when considering multiple wind farms. Hondo estimates that around 70% of emissions are related to the construction of the wind farm, while the remaining 30% are due to regular maintenance. The lifecycle emissions estimate for wind power emissions in a high production volume scenario is given as 20 kg-CO_2e/MWh [45].

Table 1: Summary of modelled generation types

Type	Levelised Cost [\$/MWh]	Lifecycle GHG Intensity [kg-CO_2e/MWh]	Operational Constraints
Hydro	16	35	• No ramping constraints
Coal	52	975	• 3 hours for full ramp up or ramp down
Gas	97	563	• No ramping constraints
Nuclear	45	1.8	• 3 hours for full ramp up or ramp down • Utility must-take all power produced unless transmission requires curtailment
Wind	76	20	• Utility must-take all power produced unless transmission requires curtailment

3.2.6. Wind Power Modelling

Wind power modelling is done using actual wind speed data, and a realistic turbine power curve from a manufacturer. For the purposes of the 168-hour planning period in this study, the wind speed profile is assumed to be perfectly forecasted. For simplicity, the same wind speed profile is used for each jurisdiction. Each turbine in the hypothetical wind farm is assumed to experience the exact same wind speed at the same time (i.e. ignoring spatial distribution).

The wind speed data used in this study is from a site monitoring study done on British Columbia's North Coast, an actual location for proposed wind development by the NaiKun Wind Energy Group [51,52]. The anemometer data are processed into hourly average wind speeds. The 168-hour profile used in this study was randomly selected and includes periods of low wind speed, and wind speeds above the turbine cut-off speed.

The turbine power curve assumed for each location in this study is that of the Siemens SWT-3.6-107 wind turbine, the same unit selected for the NaiKun project [52]. The turbine has an 80 m hub height, a 5 m/s cut-in speed, a 25 m/s cut-out speed, and is rated for 3.6 MW [53]. The power curve is shown in Figure 2.

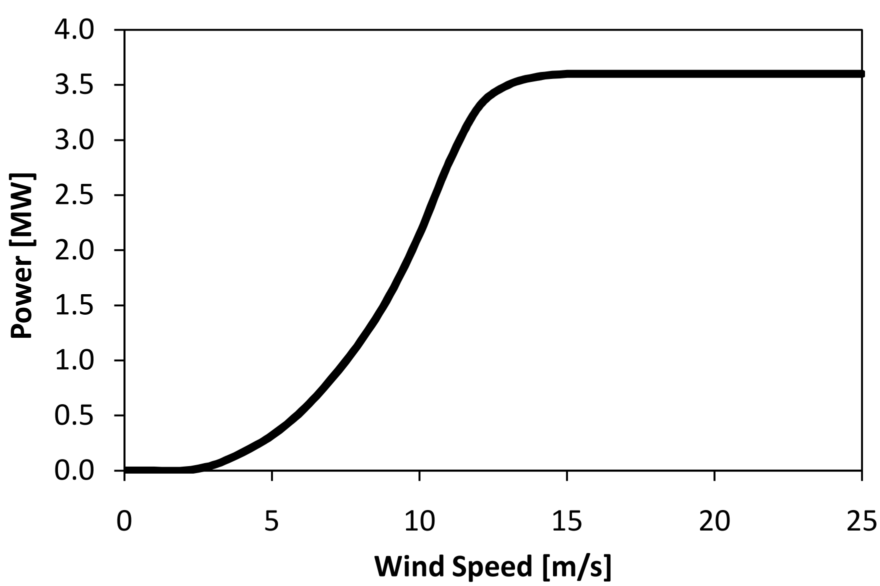

Figure 2: Siemens SWT-3.6-107 wind turbine power curve [53]

Since the wind speed was measured at a height of 30 m, and the hub height of the turbine is 80 m, a correction for wind speed due to hub height must be made. Lu et al. [54] use the following equation:

$$v_{hub} = v_{anemometer} \left(\frac{h_{hub}}{h_{anemometer}} \right)^{\alpha} \quad (8)$$

where v is the wind speed and h is the height in metres. The exponent α is a measure of the surface shear, and is determined by the local geography (water, grassland/pasture, heavy forest etc...). Without site specific data, a value of α=0.14 was used, as recommended by Johnson [55]. The resulting wind speed profile is shown in Figure 3. The capacity factor of the wind power profile (also shown in Figure 3) is 28%, similar to other onshore wind sites in the US and Europe [56].

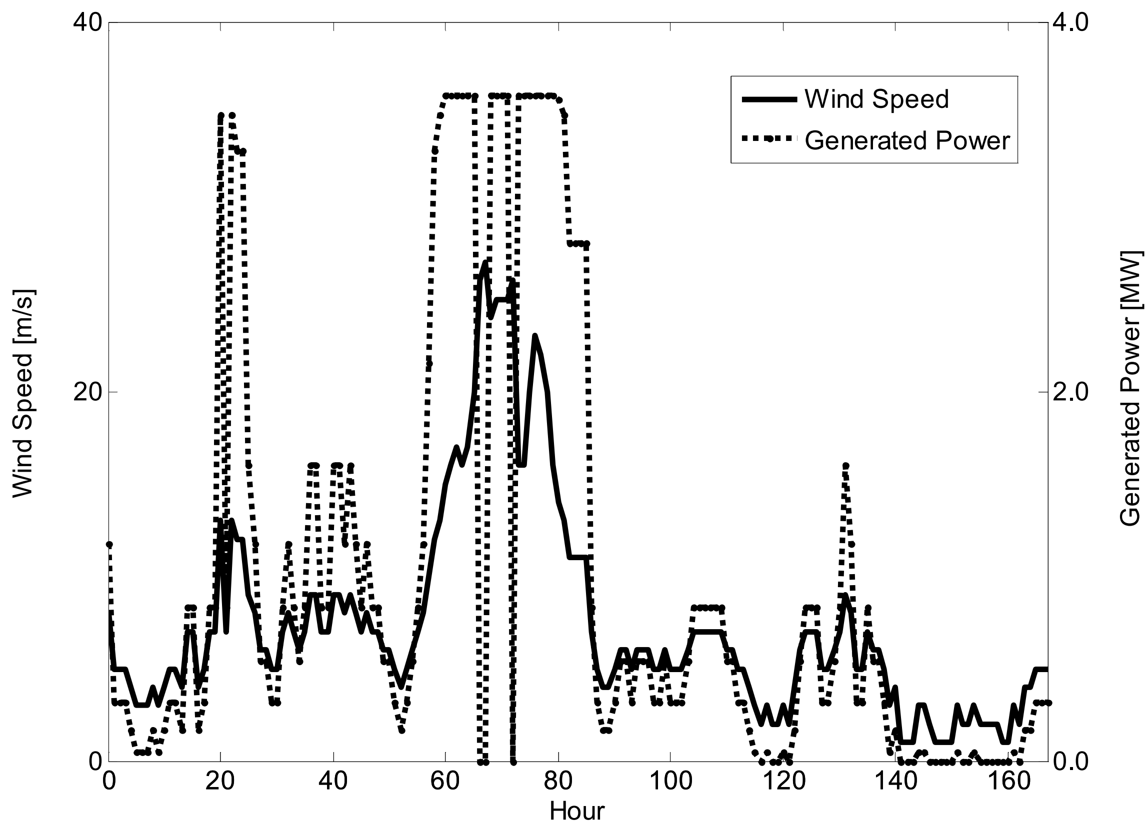

Figure 3: Wind speed and generated wind power – 168-hour profile

3.3. Operating Cost Breakdown

The levelised generation costs discussed in Section 3.2 represent the equivalent annual cost of constructing and operating a generation plant over its lifetime, amortized over expected annual generation at a real discount rate of 7% [57]. The three major components of the levelised cost are the capital costs, fixed operating and maintenance (O&M) costs, and variable O&M costs (including fuel). Capital costs include construction and financing costs, and are a function of plant capacity. Fixed O&M costs are also a function of plant capacity, and are not affected by generator output. Variable O&M costs include the cost of fuel, as well as maintenance costs incurred through plant operation. Since changes in generation dispatch schedule will affect only the variable expenses of a generator, it is necessary to break down the levelised cost of each generation type into its major components.

The US Energy Information Administration (EIA) publishes an Annual Energy Outlook which breaks down the levelised costs of newly constructed generation resources [57]. Since most of the generation sources modelled in this work have already been in operation for many years, only the proportional breakdowns of capital cost, fixed O&M and variable O&M costs are used in this work, as summarized in Table 2. Note that the breakdown for NG generation is an average of simple and combined cycle plants, as discussed previously in Section 3.2.3.

Table 2: Levelised cost breakdown by generation type [57]

Type	Capital Costs (%)	Fixed O&M (%)	Variable O&M (%)
Hydro	91	3	6
Coal	71	4	25
Gas	30	3	67
Nuclear	82	10	8
Wind	93	7	0

By substituting in the levelised costs from Table 1, the values for capital cost, fixed O&M and variable O&M can be expressed in $/MWh, as shown in Table 3. The EIA assumes typical capacity factors (CF) for each generation type and expresses the capital and fixed costs in $/MWh, to facilitate comparison with variable costs [57]. Since capital costs and fixed costs are not a function of plant output, these costs are converted back to $/MW-week, as discussed below.

Table 3: Equivalent levelised cost breakdown by generation type

Type	Capital Costs [$/MWh]	Fixed O&M [$/MWh]	Variable O&M [$/MWh]
Hydro	14.5	0.5	1.0
Coal	37.1	2.0	12.8
Gas	29.7	2.9	64.3
Nuclear	36.8	4.5	3.6
Wind	70.4	5.6	0.0

Using the typical capacity factors assumed by the EIA (shown in Table 4), the weekly capital and fixed costs can be calculated in $/MW-week for each generation type. For example, a 1000 MW coal plant with an 85% capacity factor will generate 142800 MWh per week. At an equivalent levelised capital cost of $37.1/MWh, the capital costs for that week total $5.3M, or $5303/MW-week. This calculation is repeated for all generation types, and for both capital and fixed O&M costs, with the final figures shown in Table 4.

Table 4: Cost breakdown by generation type

Type	EIA Assumed CF (%)	Weekly Capital Costs [$/MW]	Weekly Fixed O&M Costs [$/MW]	Variable O&M Costs [$/MWh]
Hydro	52	1254	42	1
Coal	85	5303	291	13
Gas	59	2588	229	64
Nuclear	90	5566	686	4
Wind	34	4021	320	0

Since the OPF model only calculates the plant output, the optimization only considers variable costs, as shown previously in Equation 2. Capital and fixed O&M costs are added to the model after the optimization. Note that as wind penetration increases, the fixed costs increase in proportion to installed wind capacity. The variable cost of power from each generation type is assumed to be constant at all generator loading levels, neglecting the effect of efficiency losses at low part loadings. This assumption is reviewed later in Section 7.2.

4. Jurisdictional Models

4.1. British Columbia Model

British Columbia's power generation mixture is characterized by a large share of hydroelectric power. The general layout of the bulk transmission grid is shown in Figure 4, with the locations of major generation and load modelled. The location and size of generation, location of demand, and other network considerations will be discussed in the following sections.

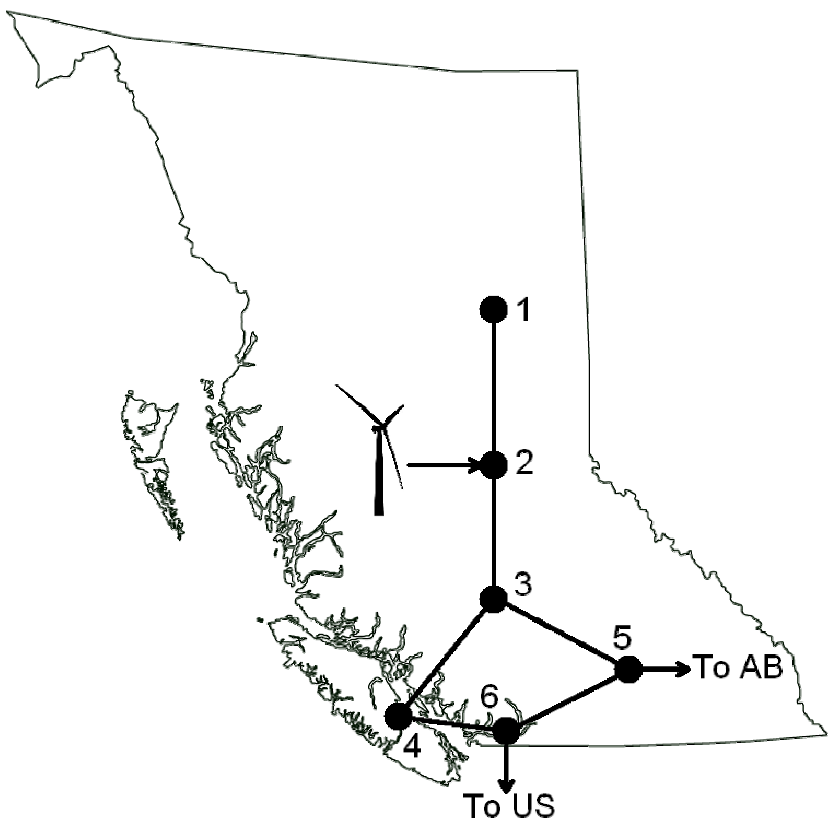

Figure 4: 6-bus model of British Columbia's power network

4.1.1. Generation

British Columbia's generation mixture is made up of over 85% hydro power [58]. The largest hydroelectric installations in British Columbia are found in the Peace and

Columbia regions. The Peace region contains the Williston and Dinosaur reservoirs, which feed the G.M. Shrum and Peace Canyon generating stations respectively. Total installed dispatchable capacity in the Peace region is 3424 MW. The Columbia River system, containing the Mica and Revelstoke dams, has a total installed dispatchable capacity of 5155 MW. Smaller hydroelectric installations are found in the Vancouver Island and Lower Mainland regions, with 238 MW and 1034 MW of capacity respectively, giving the province a total of 9851 MW of fully dispatchable hydroelectric power [59]. Statistics Canada reports the total installed nameplate power generation capacities in all Canadian provinces [58] and reports 12609 MW of hydro capacity in British Columbia. The discrepancy comes from the existence of Run-Of-River projects in the province, which generate power in accordance with the natural flow of rivers and streams, and do not have significant storage capacity. These installations are not fully dispatchable, and thus are not modelled in this study. Instead, RoR projects are assumed to be operated in conjunction with the large storage dams, such that any energy produced by RoR effectively allows water to be retained in the larger reservoirs for later use.

While British Columbia is predominantly hydro-powered, there is also 2223 MW of thermal generation capacity in the province [58]. The largest of these thermal plants is the Burrard NG-fired plant, rated at 950 MW, located near the Lower Mainland [59]. The remainder of the thermal generation capacity is backup power for industry or commercial buildings, or for combined heat and power in industrial applications. Since little information is available on these thermal IPP contracts and their locations, the entire 2223 MW of thermal capacity in British Columbia is assumed to be NG-fired, dispatchable, and is aggregated with the Burrard thermal plant.

Table 5: Summary of generation in British Columbia

Location	Bus	Type	Rating [MW]
Peace	1	Hydro	3424
Vancouver Island	4	Hydro	238
Columbia (Interior)	5	Hydro	5155
Lower Mainland	6	Hydro	1034
Burrard	6	Gas	2223
North Coast	2	Wind	0 – 10757

4.1.2. Demand

British Columbia is a winter peaking utility, with the highest load periods occurring between November to February, and a peak load of 10757 MW recorded in 2009. BC Hydro publishes annual hourly data on aggregate demand in British Columbia; however, there is no spatial resolution to these data. Therefore, demand is allocated to each bus based on population distribution, and is assumed to have the same load profile at each bus. Vancouver Island and the Interior each have about 20% of the provincial population, while the lower mainland has around 60% of the population [60]. The northern locations have small populations compared to the rest of the province (around ~1-3% of total), and thus are not modelled as significant sources of load. Figure 5 shows the annual aggregate demand profile in British Columbia, with the winter and summer demand periods used in this study highlighted.

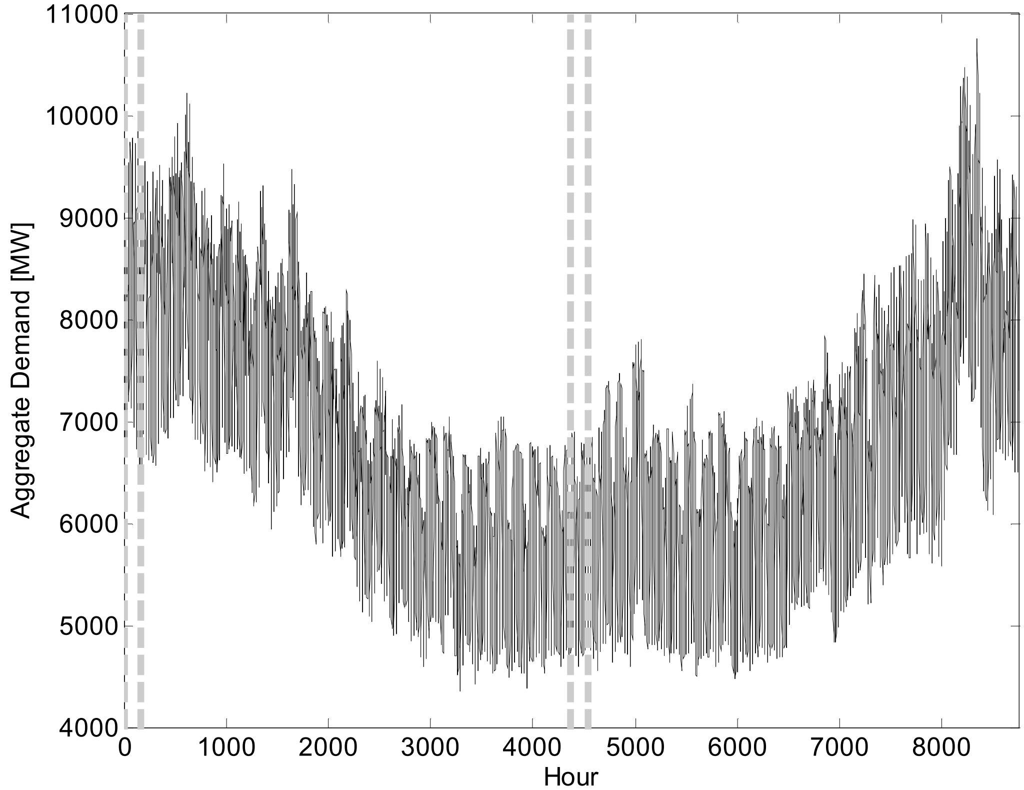

Figure 5: Annual aggregate demand profile - British Columbia

4.1.3. Location of PHEV Demand

PHEV demand is assumed to be located in the same proportions as non-PHEV load. Vancouver Island is assumed to have 20% of the PHEVs, the Lower Mainland has 60%, and the Interior region has the remaining 20%.

4.1.4. Transmission Constraints

Working limitations on the bulk transmission system are supplied by the British Columbia Transmission Corporation (recently re-amalgamated with BC Hydro), and will not be discussed here due to an existing non-disclosure agreement with the University of Victoria [36].

4.1.5. Location of Wind Power

The North Coast is a region of high wind power potential in British Columbia, and is the proposed location for the Naikun Offshore Wind Project. The project features 110 offshore turbines, each rated at 3.6 MW (396 MW total) [52]. For the purposes of this study, all wind power in British Columbia is assumed to be located in the North Coast area, and is to be connected to the bulk transmission system at bus #2. Wind penetration is expressed as a percentage of non-PHEV peak demand, and varies between 0-10757 MW in British Columbia.

4.1.6. Imports and Exports

Another major consideration in the British Columbia power grid relates to the energy trading done with Alberta and the United States. Generally speaking, British Columbia purchases low-cost baseload power from these jurisdictions during off-peak times, storing water for domestic use or export during high-value peak times. The 2009 average daily import/export profiles to these jurisdictions are shown in Figure 6, where negative exports imply an import to British Columbia [61].

Since this study will estimate the changes in dispatch due to wind and PHEV integration, the need for imports and exports in British Columbia may change significantly. However, the market dynamics involved in modelling this change are beyond the scope of this work. Thus, in order to represent the wheeling done in the British Columbia transmission system due to imports/exports, the average daily profiles were assumed to always take place. The Alberta intertie connects to the British Columbia system at the Columbia bus, and the United States intertie is modelled at the Lower Mainland bus.

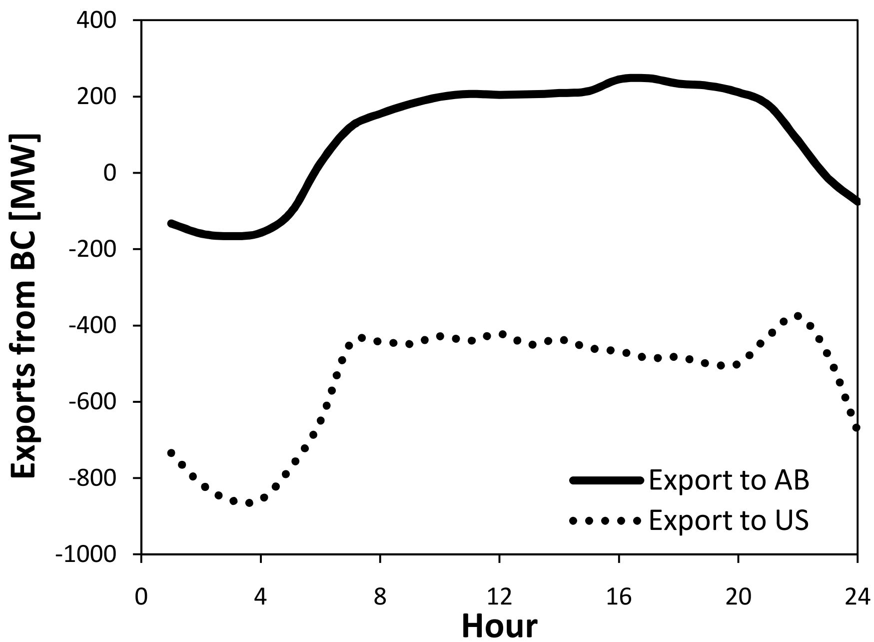

Figure 6: 2009 average daily export profiles to Alberta and the United States

4.2. Ontario Model

The Ontario transmission system model used in this thesis is based on the Independent Electric System Operator's (IESO) zonal model, shown in Figure 7. The IESO model defines 10 major load zones, major sources of generation, and inter-zonal power flows.

4.2.1. Generation

The IESO breaks down the total installed generation capacity in Ontario (35781 MW) by generation type, as shown in Figure 8. This capacity breakdown equates to roughly 11500 MW of nuclear power, 8600 MW of NG, 7800 MW of hydro power and 6400 MW of coal, with wind power constituting the remaining 4% of installed capacity. For consistency with the other jurisdictional models, the baseline generation system in Ontario is assumed to have zero wind capacity. Wind capacity is added as a percentage of non-PHEV peak demand, and is varied from 0-100% penetration.

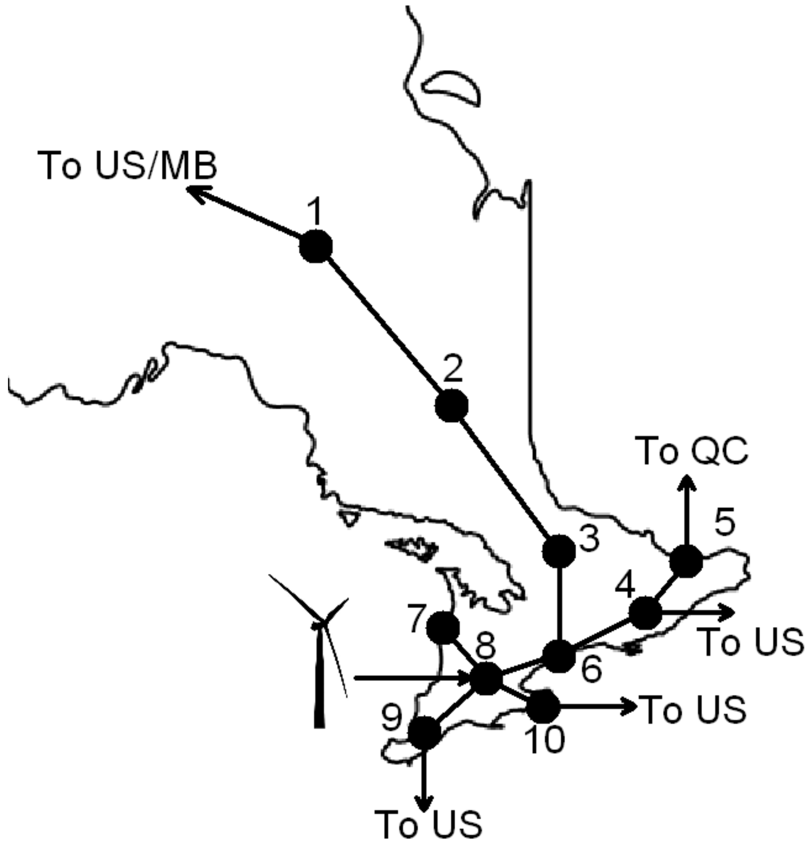

Figure 7: 10-bus model of Ontario's power network (adapted from [62])

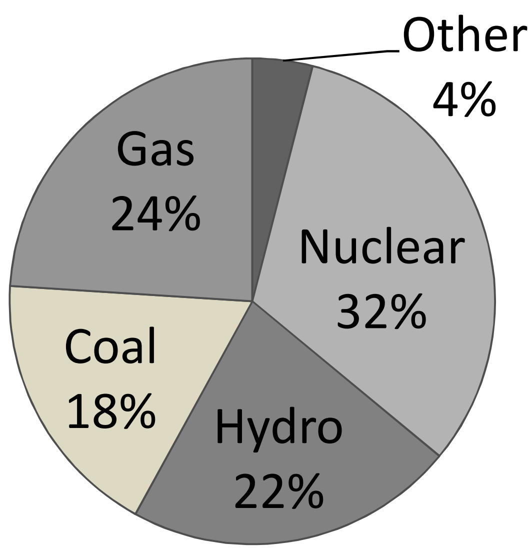

Figure 8: Breakdown of installed generation capacity in Ontario [63]

The IESO zonal model specifies the major generation sources in each zone. The locations of nuclear and coal-fired plants are known with certainty, since most of them are owned and operated by Ontario Power Generation (OPG). NG-fired plants are more numerous and not as easily located in the model. NG capacity was distributed based on publications from the Ontario Power Authority (OPA) and NG industry reports [64,65]. Aside from the large hydro operations described by the OPG, there are also many smaller hydro operations. In order to allocate the rest of the hydro power geographically, the OPG map of operations is used [66]. Since little information about the dispatchability of each hydro plant is available, it is assumed to be fully dispatchable for the one-week period of study in winter and summer. The final breakdown of generation at each bus is shown in Table 6.

Table 6: Breakdown of installed generation capacity in Ontario

Zone	Type	Rating [MW]
1	Hydro	754
1	Gas	420
1	Coal	517
2	Hydro	1476
3	Hydro	820
4	Hydro	2263
4	Gas	2566
5	Gas	420
6	Gas	2232
6	Nuclear	6631
7	Nuclear	4724
8	Gas	624
8	Coal	3640
8	Wind	0-24005
9	Gas	3055
9	Coal	1920
10	Hydro	2495
TOTAL		**34557**

The IESO reported that coal-fired plants operated at an average capacity factor of 18% in 2009, due to Ontario's desire to phase out coal-powered generation [67]. Therefore, to represent Ontario's desire to use coal in a limited peaking role (as explicitly stated in [68]), it is limited to a maximum capacity factor of 18% in this model.

4.2.2. Demand

Demand data are obtained from IESO archives, and are already separated by zone [69]. The zonal demands appear to be strongly correlated with population distribution, supporting the assumption made in the British Columbia model. The majority of the load occurs in the Toronto, Southwest and West zones, which account for over 65% of the total demand. Figure 9 shows the annual aggregate demand profile for Ontario, with the winter and summer demand periods used in this study highlighted. Peak demand in 2009 was 24005 MW.

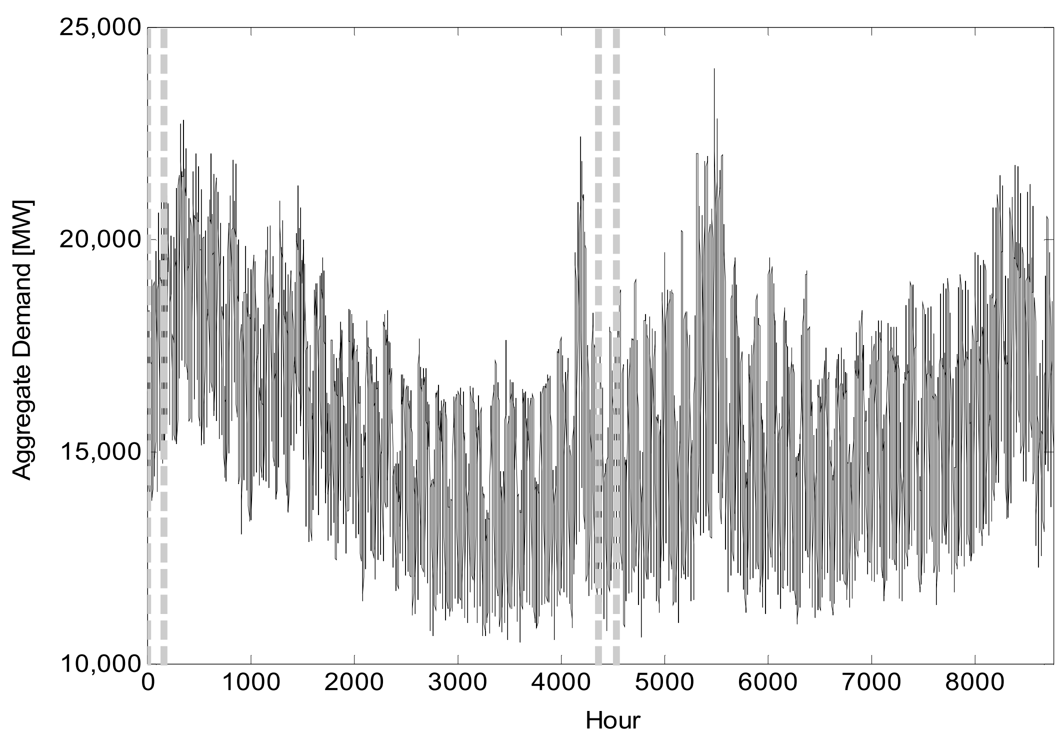

Figure 9: Annual aggregate demand profile - Ontario

4.2.3. Location of PHEV Demand

Since actual zonal data are available for Ontario, PHEVs are added to each region in the same proportions as non-PHEV demand.

4.2.4. Transmission

The limitations to inter-zonal flows are well described in [70] and are summarized in Table 7. In the event of varying or seasonal transmission limits, the most conservative limits are used. Note that some lines are modelled with no transmission limit, as flows expected in the indicated direction will not cause system concerns [70]. Upon inspection, power flow results confirm that no significant power transfer occurs in these directions.

Table 7: Inter-zonal transmission limits in Ontario

Originating Bus	Destination Bus	Flow Limit Towards Destination [MW]	Flow Limit Towards Origin [MW]
1	US/QC	415	-
1	2	325	350
2	3	1400	1900
3	6	1000	2000
4	6	No limit	No limit
4	5	1900	No limit
4	US	400	-
4	QC	470	-
5	QC	167	-
7	8	6224	No limit
6	8	No limit	5700
8	9	3500	1500
8	10	No limit	1950
9	US	2200	-
10	US	1950	-

4.2.5. Location of Wind Power

The IESO has published a map of existing wind installations in Ontario, and much of this wind power is installed on the shorelines of Lake Erie, Lake Huron and Lake Ontario [71]. It appears to be evenly distributed over the Southwest and Western regions (zones 8 and 9), likely due to the excellent wind regimes near the shorelines of the Great Lakes and relative proximity to existing transmission infrastructure. For the purposes of this study, it is assumed that all wind power injections occur at the transmission hub of bus 8, in the South Western region of the province. Wind penetration is expressed as a percentage of non-PHEV peak demand, and varies between 0-24005 MW of installed capacity.

4.2.6. Imports/Exports

Like British Columbia, Ontario has strong interconnections to its neighbouring power systems in Quebec, Manitoba and the United States. However, unlike British Columbia (where net imports made up almost 7% of domestic demand in 2009 [61]), Ontario is a net exporter of power. In 2009, Ontario's domestic demand was 138 TWh, while only 5 TWh was imported and 15 TWh was exported [63]. Since imports are not a significant source of generation, only exports are modelled for simplicity. Exports are modelled as power sinks at all major interties to the United States, Manitoba and Quebec, with the transfer limits described in [70]. Exports are modelled as zero-profit, to ensure power is not generated simply for export, and in effect only serve to alleviate transmission and ramping constraints aggravated by wind adoption.

4.3. Alberta Model

The Alberta grid model developed in this study uses information from the Alberta Electric System Operator (AESO) Long-Term Transmission System Plan [72], and the Reduced System Model verified in [73].

4.2.7. Generation

The defining characteristic of the Alberta power system is that its generation mixture is almost entirely dependent on fossil-fuel generation. The generation mixture is made up of 5667 MW of coal, 5111 MW of NG, 871 MW of hydro, and around 800 MW of wind and biomass, though biomass was not modelled in this thesis. For consistency with the other jurisdictional models, the baseline generation system in Alberta is assumed to have zero wind capacity. Wind capacity is added as a percentage of non-PHEV peak demand, and is varied from 0-100% penetration.

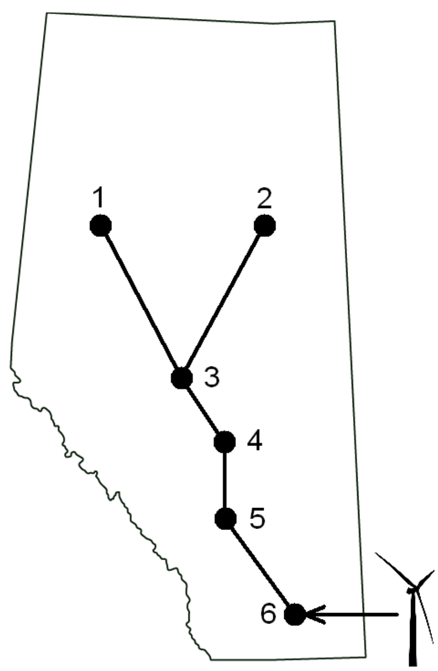

Figure 10: 6-bus model of Alberta's power network [72]

The AESO publishes hourly supply-demand summaries, with a list of generators participating in the market. A recent report from 2010 [74] is used to determine where each of the market participants are geographically located, in order to allocate generation to the regions shown in Figure 10. Generation is aggregated by type at each bus, and Table 8 summarizes the installed capacities by location, type and size.

Table 8: Location of generation in Alberta

Location	Bus	Type	Rating [MW]
Northwest	1	Coal	143
Northwest	1	Gas	720
Northeast	2	Gas	2150
Edmonton	3	Coal	4104
Edmonton	3	Gas	633
Central	4	Hydro	470
Central	4	Gas	803
Central	4	Coal	1420
Calgary	5	Hydro	319
Calgary	5	Gas	576
South (Pincher Creek)	6	Hydro	82
South (Pincher Creek)	6	Gas	303
South (Pincher Creek)	6	Wind	0-10235

4.3.1. Demand

Hourly aggregate demand data was obtained from IESO records, with a 2009 peak load of 10235MW [74]. Alberta is a winter peaking utility, but has larger relative summer loads than British Columbia. Also, Alberta has high share of industrial load, totalling 56% of energy demand [73]. Thus, demand is not allocated by population in Alberta, and is instead allocated based on regional peak loads. The AESO's Long Term Plan contains regional peak demands from 2006 [72], which are then used to estimate the percentage of total load in each region, as summarized in Table 9.

Table 9: Geographic distribution of loads in Alberta

Location	Bus	2006 Winter Peak Demand	Share of Total Load [%]
Northwest	1	1134	11.7
Northeast	2	2040	21.0
Edmonton	3	2155	22.3
Central (Red Deer)	4	1929	19.9
Calgary	5	1515	15.6
South (Pincher Creek)	6	909	9.5

In regions with large shares of industrial load such as the northeast (due primarily to oil sands operations), the load shapes are unknown. Without this information, the loads in all regions are assumed to follow the aggregate demand profile. Figure 11 shows this annual aggregate demand profile, with the winter and summer periods used in this study highlighted.

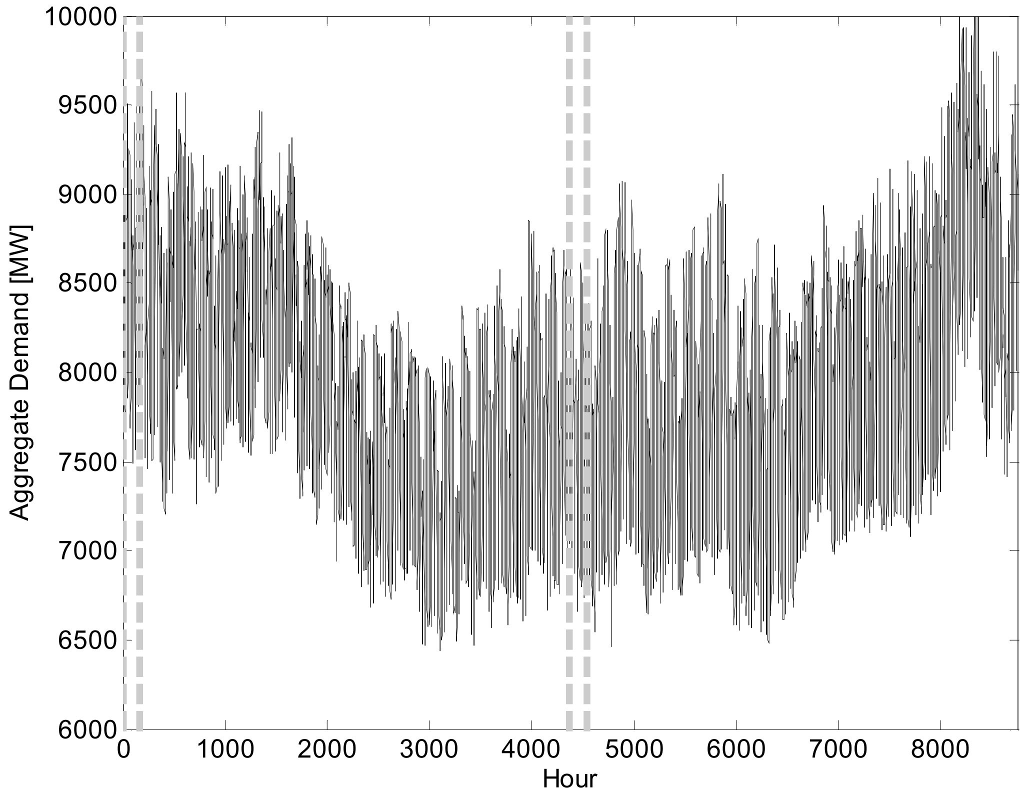

Figure 11: Annual aggregate demand profile - Alberta

4.3.2. Location of PHEV Demand

Alberta PHEV distribution is roughly based on population, as in the British Columbia and Ontario models. The majority of PHEV load is concentrated in the urban centres of Edmonton and Calgary, accounting for about 35% and 40% of the provincial total respectively. The Central region, including Red Deer, Banff and Jasper, accounts for

15% of the PHEV demand, while the South region, including Lethbridge and Medicine Hat, accounts for the remaining 10% [75].

4.3.3. Transmission

The transmission constraints for the Alberta system are derived from [73] and AESO Operating Policies and Procedures [76]. As in British Columbia, the predominant power flows in Alberta are in the north-south direction. The major flows in Alberta are from coal generators near Edmonton towards the Northwest and Central regions, from NG generation in the Northeast towards Edmonton, and from wind power in the South towards Calgary [73]. Transmission for new wind power in the south is a concern for the AESO. The AESO's 10-year transmission plan addresses this need through 6 major transmission upgrades. The Alberta Utilities Commission (AUC) expects up to 2700 MW of new wind to be connected by 2017 [77], in addition to the 629 MW of wind power already operating in the region. Thus, transmission requirements out of the South Region are expected to be higher than 3000 MW, which is used as a conservative flow limit estimate. All transmission flow limits modelled in this study are shown in Table 10.

Table 10: Interregional transmission limits in Alberta

Originating Bus	Destination Bus	Flow Limit Towards Destination [MW]	Flow Limit Towards Origin [MW]
1	3	600	600
2	3	600	300
3	4	2050	2050
4	5	2050	2050
5	6	3000	3000

4.3.4. Location of Wind Power

The South region of Alberta already contains around 800 MW of wind power capacity. For this reason, all new wind capacity in Alberta is assumed to be installed in the South region.

4.3.5. Imports/Exports

Interties to neighbouring jurisdictions are not modelled in this study. The intertie to Saskatchewan is weak, and is effectively limited to about 50 MW in most hours [73]. The intertie to British Columbia is stronger, with an operational limit of 300-500 MW; however, the average daily imports from British Columbia occur mostly during peak hours (see Figure 6) as the marginal source of power during that time. Since no generation outages or transmission contingencies are modelled in this work, there is sufficient capacity to meet all demand within Alberta during peak times, and thus imports are assumed not to be required. In reality, system outages and reserve requirements drive the need for imports; however, this level of detail is beyond the scope of this work.

5. Plug-In Hybrid Electric Vehicles

In 2008, cars and light trucks accounted for about 12% of all Canadian GHG emissions [78]. Electrified transportation, including the use of PHEVs, has been identified as a potential avenue for reducing greenhouse gas emissions from passenger vehicles [2]. However, the environmental impacts of these vehicles are highly dependent on the type of generation used to supply electricity to the vehicles. As the energy demand from electric vehicles becomes significant, changes in load shape due to the addition of PHEVs could change the generation dispatch schedule, potentially increasing or reducing the environmental benefit of replacing gasoline with electricity. Current PHEV technology, PHEV economics, and the formulation of charging profiles for use in the OPF models will be discussed in the following sections.

5.1. Vehicle Description

Hybrid electric vehicles (HEVs), such as the Toyota Prius, are currently the most commercially successful vehicles to integrate electric power into the drive train. These vehicles use a small battery (around 1.3 kWh [79], charged by the engine) to optimize the operation of the internal combustion engine (ICE), thereby achieving fuel consumption improvements over conventional vehicles (CVs). PHEVs are poised to be the next mainstream electric vehicle technology, and will feature a larger onboard battery which can be recharged from the grid. This large battery will permit driving in all-electric mode, increasing gasoline displacement compared to both CVs and HEVs.

PHEVs can operate in a Charge Depleting/Charge Sustaining mode (CD/CS), or in a blended mode. The CD mode allows all-electric operation until the battery reaches a certain minimum charge level, upon which time the Charge Sustaining (CS) mode begins and the gasoline motor turns on to power the vehicle. The blended mode is characterized by simultaneous use of both energy sources. Vehicles that use a CD/CS operating strategy are also referred to as Extended Range Electric Vehicles (EREV) [80].

For the purpose of this study, a mid-size sedan is considered as the base vehicle type, and is assumed to represent the average car in Canada. Also, since the CD/CS operation mode maximizes the amount of driving done on electricity, operation in this mode is assumed for this study.

The relevant technical specifications assumed for the average vehicle in this study are based on the Chevrolet Volt, set to be the first commercially available PHEV, and are summarized in Table 11 [81]. The nominal battery size represents the total energy capacity of the battery; however, during actual operation the depth of discharge may be limited to avoid premature degradation of the battery. It has been estimated that a PHEV battery will experience over 4000 deep cycles in the vehicle lifetime, and should thus be limited to a 50% depth of discharge [82]. The charge rates shown in Table 11 are continuous ratings for 120 V and 240 V outlets respectively. While the 240 V charger may become popular with increased PHEV penetration, most of the readily available outlets in a home are 120 V, and thus 2.0 kW is the assumed charge rate for this study [80].

Table 11: PHEV specifications [81]

All–Electric Range [km]	Battery Size [kWh] (nominal)	Charge Rate [kW]
64	16 (Li-Ion)	2.0-9.6

The fuel consumption value used in this work is an average value of several different studies, all of which consider midsize sedan vehicle types, as summarized in Table 12. Note that all values are given for PHEVs with a 64 km All-Electric Range (AER) and fuel consumption values for blended operation modes are not used. The fuel consumption of a Chevrolet Malibu is used as a proxy for the equivalent CV fuel consumption of the Chevy Volt. The CS Mode fuel consumption for the Chevrolet Volt is not yet an official fuel consumption figure, but has previously been quoted as a pre-production goal [83].

Table 12: Fuel efficiency for mid-size sedan CV and PHEV

Reference	CV Fuel Consumption [L/100km]	CD Mode [Wh/km]	CS Mode [L/100km]
van Vliet [84]	6.0	119	4.3
Shiau [85]	8.3	111	4.7
Chevrolet Volt [81]	8.6	125	4.7
Campanari [86]	-	150	-
Samaras [29]	8.0	200	5.0
Argonne National Lab [87]	8.5	-	5.1
AVERAGE	**7.9**	**141**	**4.8**

5.2. Driving Patterns

The two most significant driving habits considered when developing a charging profile are the time at which drivers take trips and the length of trips. The latter is addressed by the Canadian Vehicle Survey, which publishes thorough annual statistics on driving habits in each province.

Table 13 shows some of the relevant statistics taken from the Canadian Vehicle Survey. The total number of cars in each region is roughly 55% of the total light duty fleet (up to 4.5 tonnes), as per [88]. The remainder of the light duty market is made up mostly of vans, SUVs and pickup trucks. Since the vehicle assumptions described above apply only to a mid-size sedan, these larger vehicle types are not included in this study. Daily vehicle-kilometres for cars are calculated from Canadian Vehicle Survey statistics [88].

Table 13: Relevant statistics from the Canadian Vehicle Survey

Location	Total number of cars	Daily Vehicle-Kilometres [km]
Alberta	1419694	44.2
British Columbia	1421124	35.3
Ontario	3941759	44.6

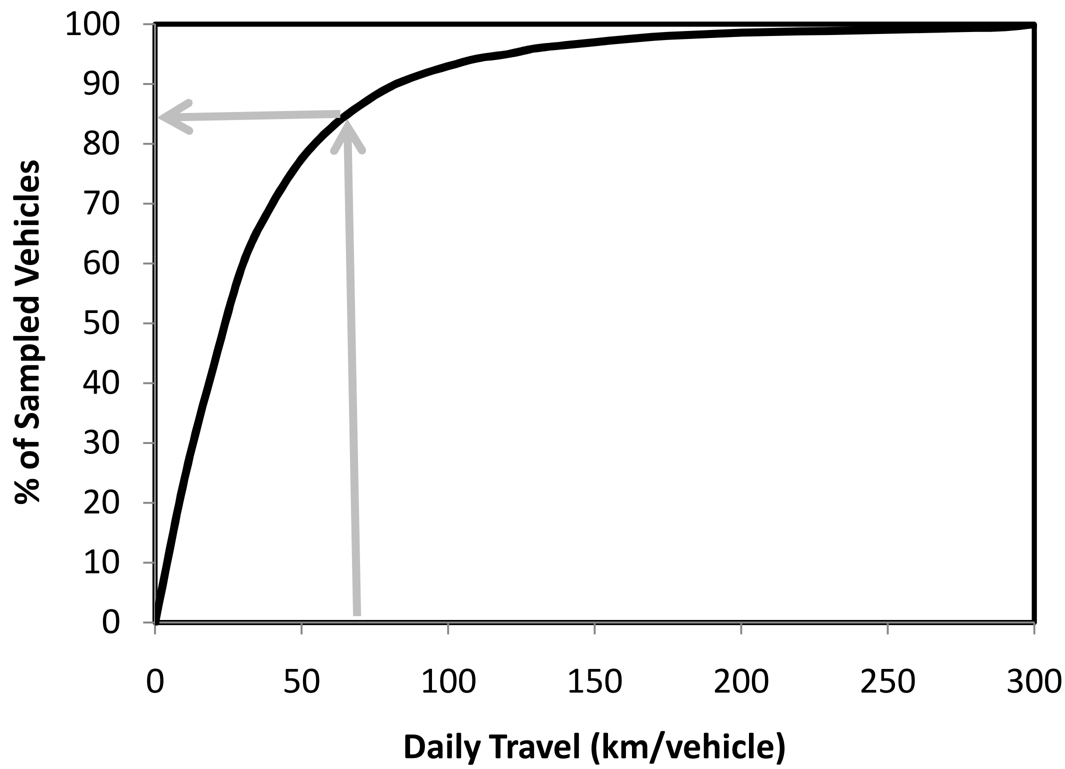

Figure 12: Assumed distribution of daily driving distances in Canada (adapted from [89])

In order to determine how much PHEV driving would be done in CD and CS mode for a 64 km AER, a statistical distribution of average daily trip length is used. These data are not available for Canadian jurisdictions, but are available for the US through the National Household Transportation Survey [89]. Figure 12 shows the distribution of trip length in the United States, with a mean distance of 42 miles per day. This distribution shape is also confirmed by a GPS-monitored driving survey conducted in St. Louis, which shows that the average daily vehicle-mile distribution is almost identical to the NHTS chart [90]. The Canadian average daily vehicle travel is 42 km per day, much less than the US average of 42 miles per day [88]. Since no equivalent distribution is available for Canadian driving habits, the US distribution shape is assumed to be given in daily kilometres instead of miles.

From the trip length distribution shown in Figure 12, it is assumed that about 85% of daily travel is done entirely on electricity, while the remaining 15% of travel is done on gasoline. This is referred to as the Utility Factor (UF) method (UF=0.85 here), and is standard practice for estimating actual fuel displacement by a PHEV fleet [91,92]. Note that while the average daily travel in each province varies slightly from the 42 km Canadian average, scaling the cumulative distribution curve to match the actual provincial average does not result in a significant change to the Utility Factor, and thus an average daily trip length of 42 km was assumed for all jurisdictions.

5.3. Economic Assumptions

The economics of PHEVs will be a strong determinant of their future success in the marketplace. The main economic factors are the extra cost of a PHEV relative to an equivalent CV, savings from avoided gasoline, and the cost of electricity. Purchase incentives and tax breaks for PHEV buyers are not considered in this study since they do not change the cost of the vehicle, only who pays for it.

The extra cost of a PHEV is attributed to the battery, generator and other electrical drive components. A thorough analysis of PHEV and CV costs was completed by van

Vliet et al. [84], and considered battery size, production volumes and drive train architecture. The findings for a mid-size sedan, after correcting for currency and taxes, are summarized in Table 14.

Table 14: Cost comparison - CV vs. PHEV

Component	CV	PHEV
Vehicle Platform	18158	18158
Electrical Drive	-	5147
ICE/generator	4382	5674
Battery	-	8878
Total	**22540**	**37857**

The cost of the PHEV upgrade can be expressed as a per-kWh premium. With a 16 kWh battery, the PHEV premium is found to be $957/kWh. This estimate compares well to the findings of other studies, namely $1000/kWh [93] and Markel 1117 $/kWh [94]. Using these capital costs, the weekly cost of owning a PHEV instead of a CV is then calculated.

The weekly cost of the PHEV premium is estimated by amortizing the capital cost over the lifetime of the vehicle, as done previously in [79,95,96]. For the purposes of this study, the average lifetime of a vehicle in Canada is assumed to be 14 years, according to [97]. Using a 5% discount rate, the equivalent annual cost of the PHEV premium is calculated to be $1547. Scaling this annual cost by a factor of 168/8760, the weekly cost of the PHEV premium is found to be $29.67. Battery replacement costs are not considered.

The next major parameter involved in PHEV economics is the actual fuel displacement. As shown in Section 5.2, a fleet average PHEV with a 64 km AER can drive 85% of its total travel on electricity, with the remaining 15% done on gasoline. Using the vehicle-kilometre statistics and fuel consumption figures shown in Sections 5.1

and 5.2, the actual daily fleet average fuel displacement is calculated, with results shown in Table 15.

Table 15: Daily fuel requirements for each vehicle type

Vehicle Type	Distance on gas [km]	Gas Used [L]	Distance on Electricity [km]	Electricity Used [kWh]
CV	42	3.32	0	0
PHEV	6.3	0.31	35.7	5.03

Assuming a gasoline price of $1/L, the weekly gasoline savings due to PHEV ownership totals $21.07. This shows that, even before adding the cost of electricity purchase (captured through the OPF in this study), PHEVs are not an economic choice at the current capital and gasoline prices. Thus, any CO_2e reductions from this technology will come at a cost of more than $8.60 per week. Again, no carbon credits or purchase incentives are included in this analysis.

The cost of electricity is not a strong determinant of PHEV economics when compared to PHEV capital costs or the price of gasoline. For example, considering a high electricity price of $120/MWh, the weekly cost of charging a fleet average PHEV is only $4.23, five times smaller than the savings from gasoline displacement. Considering a more realistic price of $60/MWh for electricity in Canada, the weekly cost of charging a PHEV is only $2.11.

5.4. Load Modelling

In order to accurately assess the impacts a fleet of PHEVs may have on a power network, representative models of the electricity demand from a PHEV fleet are required. To model the PHEV demand profile, daily energy requirements and plug-in times are first assessed.

As shown in Table 15, a fleet average PHEV consumes 5.03 kWh of electricity per day. However, since charging stations have inherent inefficiencies, the grid is required to deliver slightly more than 5.03 kWh per vehicle. Assuming an average charging efficiency of 88% [98], the total daily grid load from each vehicle is 5.72 kWh.

The three scenarios investigated in this work are uncontrolled charging, off-peak charging, and optimally dispatched charging. The timing of trips is important in PHEV impact modelling, and the St. Louis GPS study referenced earlier has been used to develop hourly charging profiles [99]. Using vehicle characteristics similar to the ones used in this thesis, the authors in [99] develop a charging profile (shown in Figure 13) intended to represent a fleet of vehicles plugging in after the evening commute. This profile assumes that drivers do not have any incentive to charge at off-peak times, and do not consider any of the impacts that their vehicles have on the grid. This scenario is termed the "uncontrolled" charging profile in this work, and serves as a bounding worst case for passive PHEV integration.

The off-peak charging scenario assumes that vehicles charge during the periods of lowest demand each day. This is also known as a "valley-filling" method. Figure 14 shows how uncontrolled charging and off-peak charging modify the daily utility load profile. An arbitrary Ontario load profile is shown, with a 100% market penetration of PHEVs. Off-peak charging does not increase peak load requirements on the grid, and enables increased use of surplus baseload power, making it the bounding best case for passive PHEV integration. This charging profile is developed by iteratively adding small amounts of PHEV load (during the lowest load hours of each day) until the total daily energy required by a given number of PHEVs has been achieved.

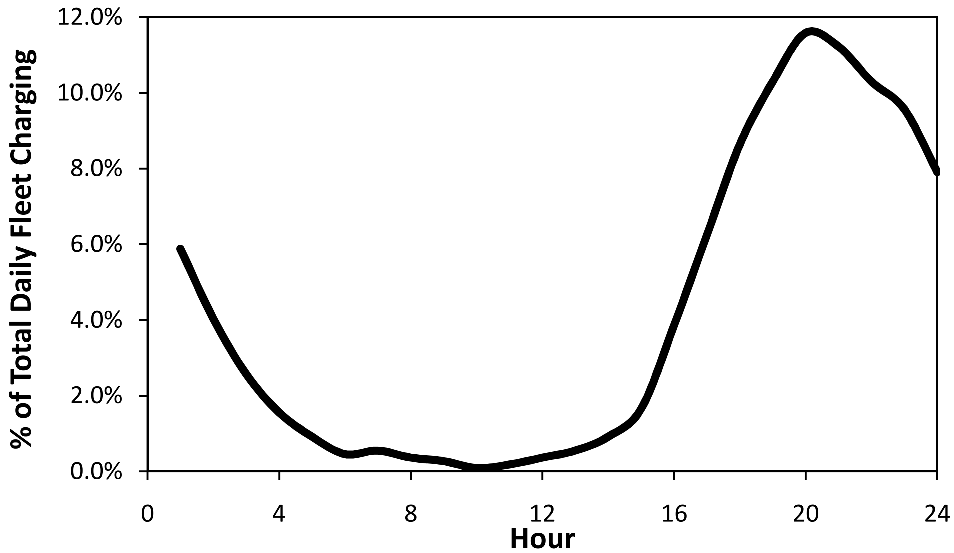

Figure 13: Daily PHEV charging profile - uncontrolled charging scenario

The optimal charging scenario modelled in this work takes advantage of the fact that vehicles are idle for 96% of the time [9], and assumes that charging infrastructure is widespread enough that each vehicle is plugged in if stationary. While stationary, PHEVs represent a large dispatchable load that could be used by a utility to mitigate the intermittency of renewable generation. For example, 100% market penetration of PHEVs in Ontario represents almost 4 million PHEVs (each with 2 kW charge capacity) and about 8.0 GW of dispatchable load. Similarly, British Columbia and Alberta each have about 4.0 GW of dispatchable load at 100% PHEV adoption. If this PHEV load was dispatchable, a utility could allocate PHEV load in a way that minimizes overall generation cost. For the purposes of the optimal PHEV dispatch scenario, PHEV load is assumed to be fully dispatchable at all times of the day, with the constraint that each vehicle's energy requirement of 5.72 kWh per vehicle per day be satisfied. This scenario is intended to represent the best possible case of active PHEV integration, where PHEV charging is fully controlled by the utility.

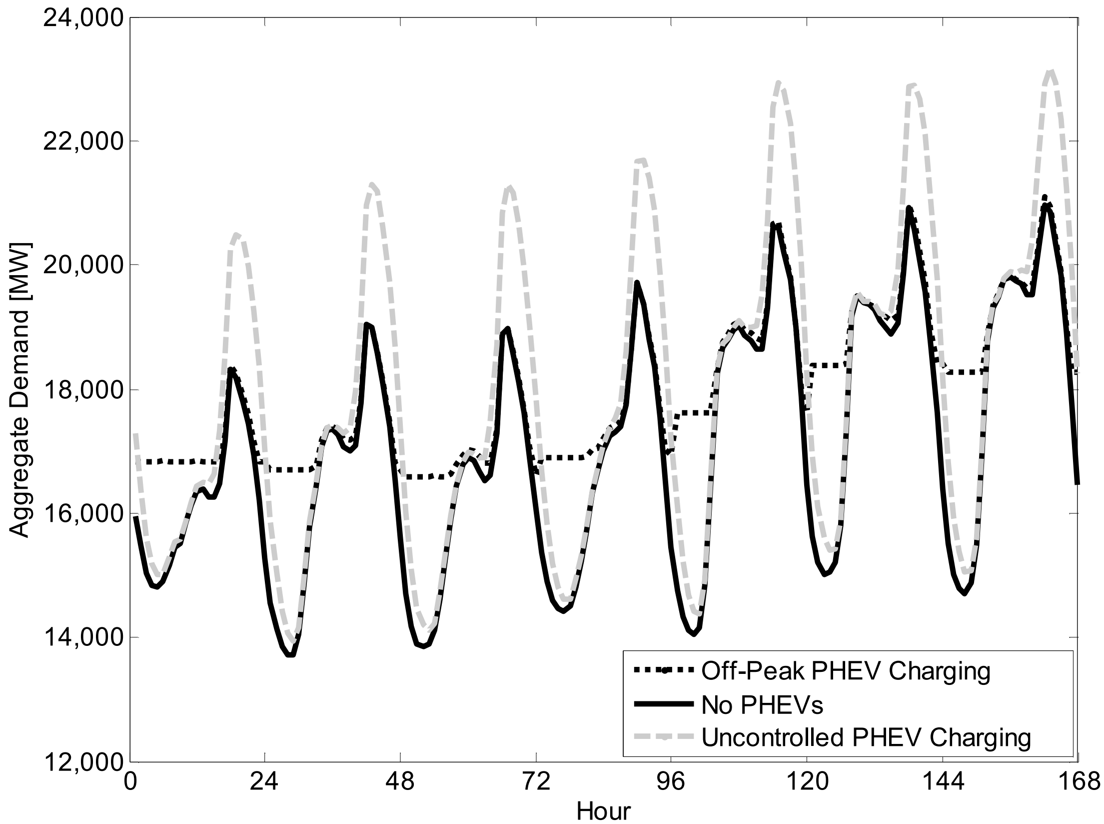

Figure 14: Addition of uncontrolled and off-peak PHEV charging to utility load

To capture PHEV demand in the OPF formulation, two additional constraints are added. The energy constraint (Equation 8) ensures that a fleet average of 5.72 kWh is delivered to each vehicle every day. The power constraint (Equation 9) ensures that the PHEV charging load in any given hour does not exceed the total dispatchable demand discussed in the previous paragraph.

$$\sum_{t=1}^{24} (V_{i,t,D} \times 1 \text{ hr}) = 5.72 \text{ kWh} \times N_{\mathrm{i}} \tag{8}$$

$$\forall\, i = 1,2, \dots, \#\text{ busses} \;\&\; D = 1,2, \dots 7 \text{ days},$$

$$V_{i,t} \leq N_{\mathrm{i,t}} \times 0.002 \text{ MW } \forall\, i = 1,2, \dots, \text{\# busses } \&\ t = 1,2, \dots T, \tag{9}$$

where *V* refers to the PHEV load, and *N* is the number of PHEVs assumed to be charging at bus *i* and time *t*.

6. Results and Discussion

The changes in costs and emissions related to the adoption of PHEVs and wind power in three Canadian jurisdictions are presented in this section. Results are shown for PHEV penetrations of 0-100% of the local car fleet in each jurisdiction. Wind penetrations are shown as a percentage of the peak non-PHEV load in each jurisdiction. For simplicity, all costs and emissions related to power generation, as investigated through the OPF, are termed "grid-related". The costs and emissions related to PHEV purchase price and gasoline displacement are termed "road-related". Costs and emissions are calculated by running the OPF model for the baseline scenario in each jurisdiction, then repeating for various levels of PHEV and/or wind penetration.

First, the changes in grid-related generation cost due to PHEV and wind adoption are shown for each region in Section 6.1. Then, the resulting changes in grid-related emissions are examined in Section 6.2. Finally, the grid-related cost and emission changes are combined with the road-related values discussed in Section 5, and an overall emissions reduction cost is calculated, in \$/t-CO_2e. This metric is first compared across all PHEV charging scenarios in Section 6.3.1, then for each jurisdiction in Section 6.3.2. Finally, a seasonal comparison will be shown in Section 6.3.3. Recall that all changes in cost and emissions are measured from the baseline systems described in Section 4, which are assumed to initially contain no PHEVs or wind capacity. For the sake of clarity, the effects of wind and PHEVs will be explained separately in Sections 6.1 to 6.3, while the effects of PHEV and wind interaction will be discussed in Section 6.4.

6.1. Generation Cost

This section discusses the impacts of PHEV and wind power adoption on the average cost of power. The results in this section are shown for the winter demand profile from each jurisdiction.

6.1.1. British Columbia

The average cost of power in British Columbia is sensitive to the addition of wind, but insensitive to the addition of PHEVs, as shown in Figure 15. As wind power is introduced into the system, large wind injections displace mostly hydro power, since wind is defined as “must take”. However, because the variable cost for both hydro and wind power are low, the cost increases seen in Figure 15 are largely the result of the fixed costs (capital and O&M) associated with new wind capacity. Note that the baseline cost of power agrees well with the cost of power (weighted average between heritage assets and IPP contracts) published in BC Hydro’s RRA [37].

At approximately 40% wind penetration, transmission constraints begin forcing wind curtailment. This is not evident in Figure 15 because the variable cost savings from displacing hydro with wind are insignificant in comparison to the additional fixed costs from wind capacity.

The effects of PHEV addition are subtle compared to the effects of wind addition simply because PHEV load represents only a small portion of overall demand. As PHEV load is added, only the variable expenses of generation increase. In most hours, the PHEV load is met with hydro generation at low variable cost. Thus, at higher PHEV penetrations, the hydro assets operate at higher capacity factors, driving down the average cost of electricity.

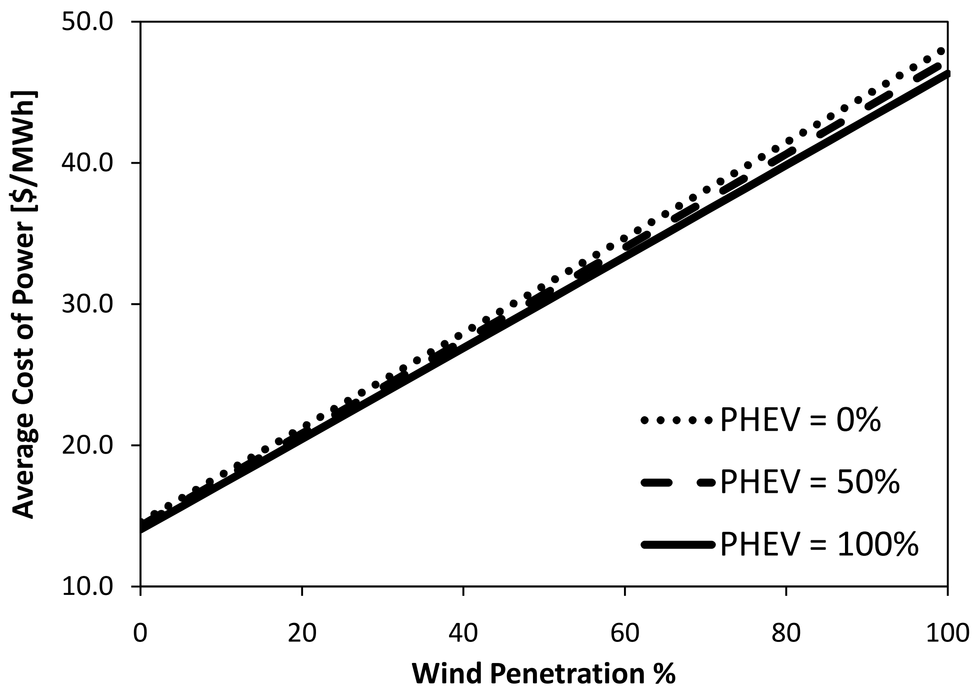

Figure 15: Average cost of power - British Columbia (off-peak PHEV charging)

Figure 15 only shows the results from the off-peak charging scenario, but the results in the uncontrolled and optimal charging scenarios are similar. While uncontrolled charging is met with more peaking NG generation than in the other two scenarios, the total amount of energy delivered by NG is small compared to the total amount of energy delivered through hydro generation; therefore, the average price of power is essentially the same for all scenarios. The off-peak and optimal scenarios have identical costs, as the marginal source of generation (hydro power) for PHEV load is the same in both cases.

6.1.2. Ontario

The average cost of power in Ontario changes drastically due to the introduction of wind, but is less sensitive to the addition of PHEVs, as seen in Figure 16. Similar to results shown for British Columbia, the change in average cost in Ontario is driven largely by the fixed costs of new wind capacity.

At low penetrations, wind displaces proportionally more NG generation than at higher wind penetrations, where it displaces proportionally more hydro, coal and nuclear (as detailed in Appendix A.1). Since the variable cost of NG is higher than coal, hydro or nuclear, increases in the average cost of power are less significant at low wind penetrations.

Similar to British Columbia, wind curtailment begins at around 40% wind penetration. At this wind penetration, most of the displaced power is hydro. Since the variable cost of hydro generation is low, wind curtailment does not significantly decrease overall variable expenses, and thus the high fixed cost of wind increases the average price of power.

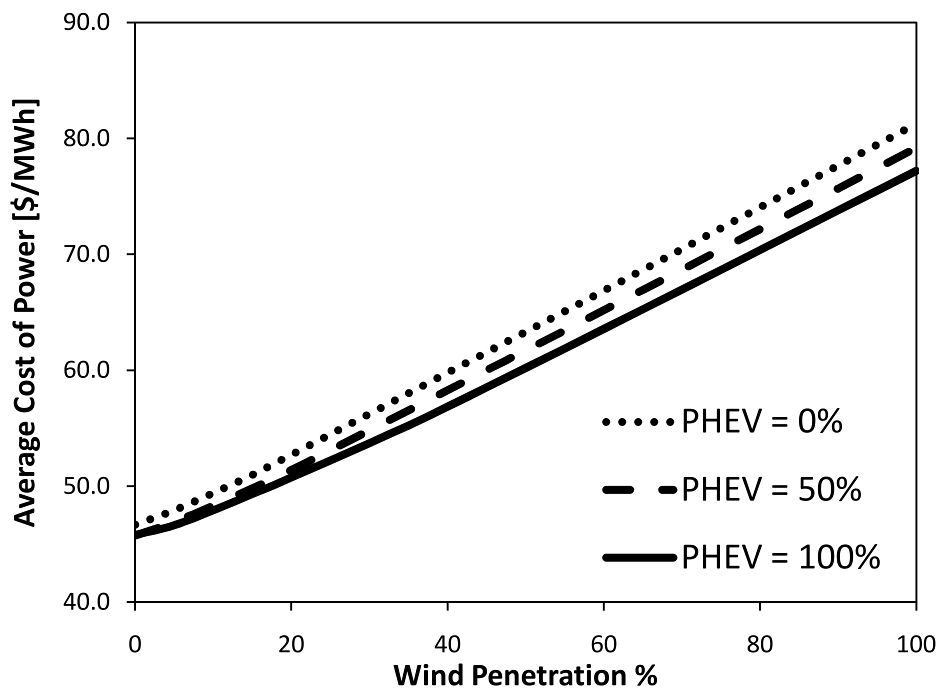

Figure 16: Average cost of power – Ontario (off-peak PHEV charging)

The effect of PHEVs on the average cost of power is subtle compared to the effect of wind addition because PHEVs represent only a small portion of total demand. Figure 16 shows that as PHEV penetration increases, the average cost of power decreases. This is due to the fact that some generators must operate at slightly higher capacity factors to meet increased demand from PHEVs, which drives down the average cost of power from those plants.

The average cost of power is very similar for all three charging scenarios, again because the additional PHEV load is small compared to the non-PHEV demand. Figure 16 shows only the results for the off-peak charging scenario. Uncontrolled charging has slightly higher average costs than off-peak and optimal charging due to increased use of peaking NG and coal plants; however, the average cost never differs by more than $1.5/MWh.

6.1.3. Alberta

The average cost of power in Alberta is fairly insensitive to the addition of PHEVs, but reacts quite drastically to the addition of wind, as shown in Figure 17. The average cost of power in Alberta is strongly influenced by the fixed costs of new wind capacity.

In Alberta, wind power displaces mostly NG and coal power, as detailed in Appendix A.2. Since the variable costs of these plants are considerably higher than the variable costs of hydro and nuclear, wind power allows for significant reduction in variable expenses, partially offsetting the fixed expenses of new wind capacity. For this reason, increases in the average cost of power due to wind additions are smaller in Alberta than in Ontario and British Columbia. Also, small wind additions allow proportionally more NG generation to be displaced, which slows average cost increases at low wind penetrations.

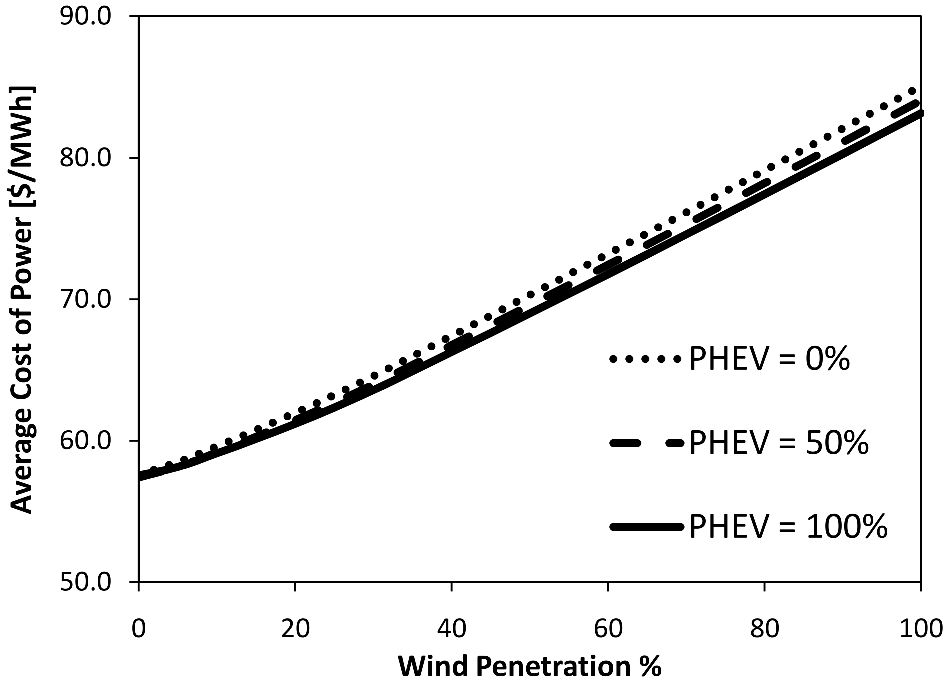

Figure 17: Average cost of power – Alberta (off-peak PHEV charging)

The addition of PHEVs generally decreases average cost, as seen previously in British Columbia and Ontario. Again, this is because some plants operate at higher capacity factors to meet the PHEV load, which drives down the average cost of power from those plants. Once again, the overall effect of PHEVs on the average cost of power is quite subtle, since PHEV demand makes up such a small share of overall demand (roughly 5%).

In Alberta, the average cost of power is almost identical for all three charging scenarios. This is because NG is the marginal source of generation at almost all hours of the day. Thus, very little benefit is acquired from charging PHEVs at off-peak or high wind hours, since that marginal load is usually met with NG in both cases. Figure 17 is shown for the off-peak charging scenario, but the results are almost identical for the uncontrolled and optimal charging scenarios.

6.2. Generation Emissions

This section discusses the impacts of PHEV and wind power adoption on the emissions intensity of power generation. The results in this section are shown for the winter demand profile for each jurisdiction.

6.2.1. British Columbia

While average grid-related emissions in British Columbia are already quite low, both wind and PHEV adoption have an effect on the average emissions intensity of power generation. Figure 18 shows the emissions intensity curves for the uncontrolled charging scenario. Wind adoption reduces emissions at all penetration levels, since wind power is modelled as slightly less GHG-intense than hydro power. These emissions reductions are small compared to other provinces because the environmental benefit of substituting wind power for hydro power is quite small. Note that emissions reductions begin to slow down near 40% wind penetration, as curtailment begins limiting wind power injections.

The effects of PHEV integration are quite obvious in British Columbia, as shown in Figure 18. Clearly, uncontrolled PHEV charging has the potential to increase the emissions intensity of power generation. This is because uncontrolled PHEV charging must be met with peaking NG generation, which is over 15 times more GHG-intense than hydro generation, and even small amounts of NG generation can drive up the average emissions intensity of power quite quickly. The off-peak and optimal charging scenarios use only hydro generation to met marginal PHEV load, and thus average emissions do not increase with PHEV adoption. The emissions intensities in these two scenarios are essentially identical to the ‘PHEV = 0%’ curve shown in Figure 18, at all PHEV penetrations.

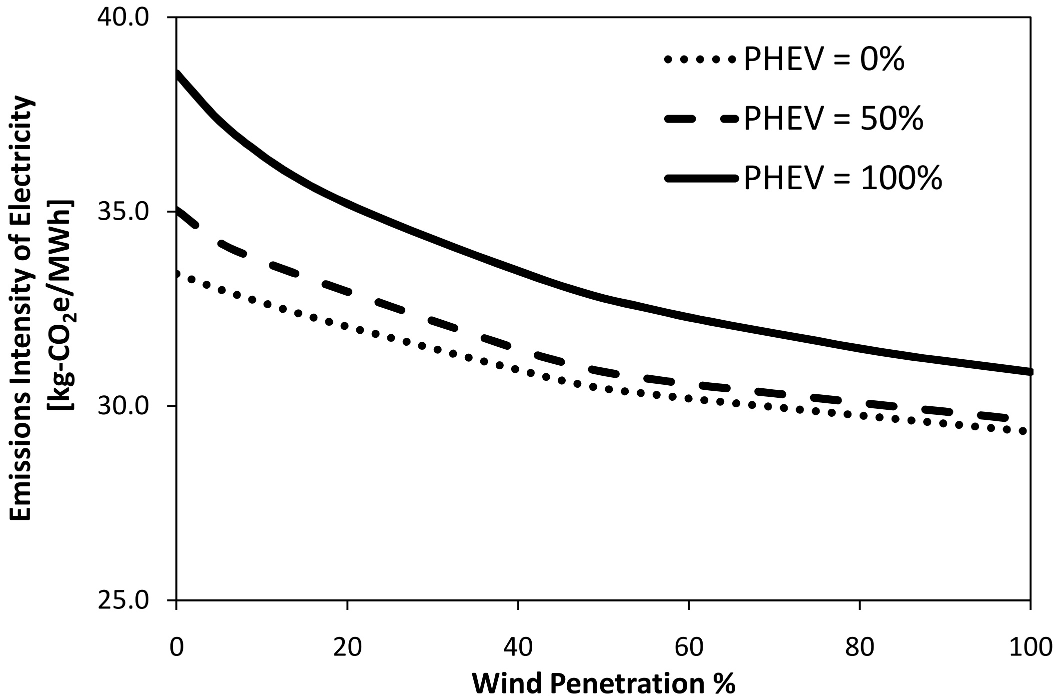

Figure 18: Average emissions intensity of electricity - British Columbia (uncontrolled PHEV charging)

6.2.2. Ontario

Grid-related emissions in Ontario are sensitive to the addition of wind and PHEVs. The impact of wind is dictated by the generation type it displaces, while the grid-related impacts of PHEVs are dictated by the marginal generation source during charging. Figure 19 and Figure 20 illustrate the effects of wind and PHEV addition for off-peak and uncontrolled charging scenarios, respectively. In both charging scenarios, emissions decrease across all wind penetrations. Emissions reductions are quite drastic at low wind penetrations, since large portions of NG generation are displaced. As wind penetration increases, proportionally more hydro and nuclear power are displaced (with small environmental benefit), and wind curtailment begins, both slowing emissions reductions. Appendix A.1 shows the breakdown of displaced generation in more detail. Wind curtailment beginning around 40% wind penetration also slows emissions reductions. Note that full wind adoption reduces the emissions intensity of power by around 30 kg-$CO2_e$/MWh in Ontario, in comparison to the 5 kg-$CO2_e$/MWh reductions seen in British Columbia.

The charging scenario has a noticeable impact on emissions intensity as well. Figure 19 shows that, for off-peak charging, emissions increase only slightly below 50% PHEV penetration, and increase considerably afterwards. This result is characteristic to the Ontario system, which has surplus nuclear and hydro capacity during off-peak hours. Off-peak charging (up to 50% PHEVs) takes advantage of the underused capacity, resulting in near constant emissions. After 50% PHEV penetration has been reached, the surplus nuclear and hydro capacity has been exhausted, making coal and NG generation the marginal sources at that point, increasing emissions. Uncontrolled charging increases emissions faster than off-peak charging, since NG generation must be used to meet charging during peak hours at all PHEV penetrations. Results for the optimal charging scenario are very similar to the off-peak scenario shown in Figure 19.

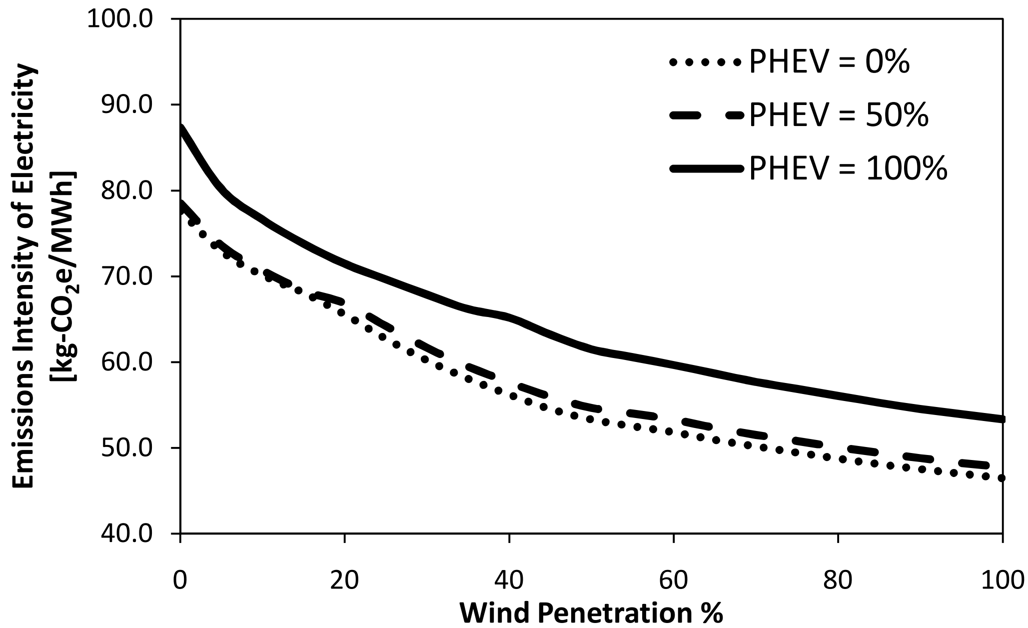

Figure 19: Average emissions intensity of electricity - Ontario (off-peak PHEV charging)

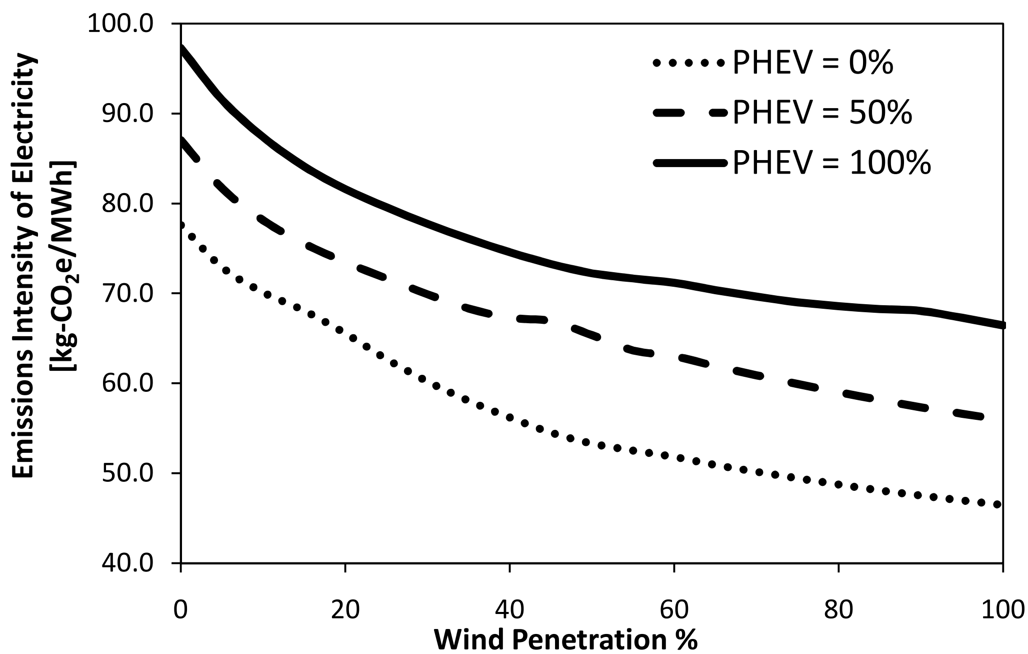

Figure 20: Average emissions intensity of electricity - Ontario (uncontrolled PHEV charging)

6.2.3. Alberta

Figure 21 shows the behaviour of average emissions in Alberta. Wind penetration has a significant effect on emissions, since fossil-fuel generation is always displaced when wind power is injected into the Alberta power grid. Emissions reductions are steep up to roughly 30% wind penetration, as no wind curtailments occur before this point. Above 30% penetration, wind curtailment due to transmission constraints slows emissions reductions. The makeup of displaced generation changes as wind penetration increases, with proportionally more coal displaced as wind penetration grows (as detailed in Appendix A.2). This would imply that emissions reductions should accelerate with increasing wind, since coal is more GHG intense than NG. However, the effect of this change is small compared to the effects of wind power curtailment, and thus emissions reductions still slow above 30% wind penetration. Note that full wind adoption reduces the emissions intensity of power by over 140 kg-CO_2e/MWh in Alberta, far more than the 5 kg- CO_2e/MWh and 30 kg- CO_2e/MWh reductions seen in British Columbia and Ontario, respectively.

All three charging scenarios have nearly identical emissions intensities, but only the off-peak scenario is shown in Figure 21. Below wind penetrations of 30% (i.e. before curtailment begins), all marginal PHEV load is met with NG generation. Since the emissions intensity of NG generation is lower than the grid-average, average emissions decrease with PHEV addition. Above 30% wind penetration, wind power displaces large portions of NG and coal. This coal capacity is then used to charge PHEVs (since it is cheaper), which serves to increase the average emissions intensity of power.

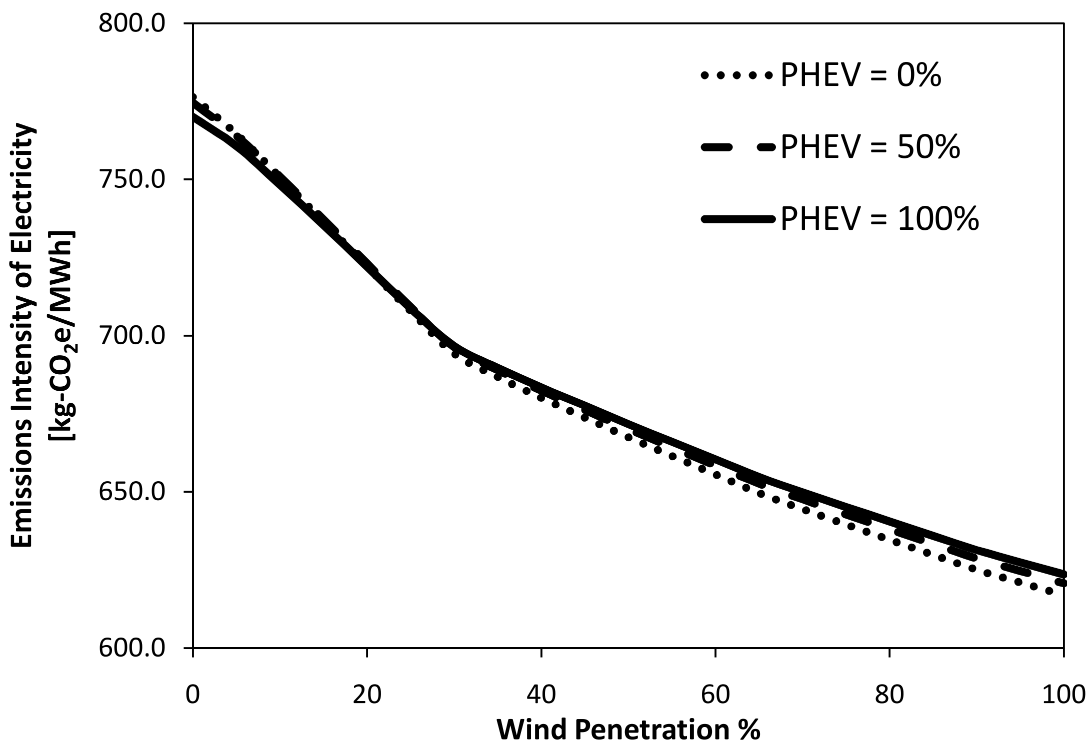

Figure 21: Average emissions intensity – Alberta (off-peak PHEV charging)

6.3. Cost of Emissions Reductions

Now that the changes in grid-related generation costs and emissions have been discussed, the road-related costs and emissions from PHEVs are added to assess the full impacts on the energy system. For simplicity, all results shown in this section are for the off-peak charging scenario in the respective jurisdiction.

Recall from Section 5.3 that the costs of PHEVs are mainly related to capital cost and gasoline savings. The amortised one-week cost of PHEV ownership is estimated to be \$29.67 more than the weekly ownership cost of a CV. This ownership cost is partially offset by \$21.07 of weekly gasoline savings, while the additional electricity cost is captured through the OPF. Thus, the weekly road-related cost of a PHEV is assumed to be \$8.60 per vehicle. The avoided gasoline usage for each week is found to be 21.1 L, and assuming an emissions intensity of 2.97 kg-CO_2e/L of gasoline [29], avoided emissions amount to 62.6 kg-CO_2e per vehicle for the study period.

The road-related costs and avoided emissions from PHEVs are added to the grid-related results of the OPF in proportion to the penetration of vehicles in the local market. For example, a 50% PHEV penetration Ontario represents 1918140 conversions from CV to PHEV, resulting in a total weekly additional cost of about \$16.5M, and 120000 tonnes CO_2e of avoided emissions from gasoline displacement. Once these road-related costs are added to the OPF results, the total change in system cost and emissions from the baseline scenarios (no wind or PHEVs) are calculated as shown in Equations 10 and 11:

$$\Delta C_{x,y} = C_{x,y} - C_{Baseline} \qquad (10)$$

$$\Delta E_{x,y} = E_{x,y} - E_{Baseline} \qquad (11)$$

where $C_{x,y}$ and $E_{x,y}$ are the total system cost and emissions, at PHEV penetration x and wind penetration y. These data are then used to calculate the cost of CO_2e reductions, $A_{x,y}$, at each combination of PHEV penetration and wind penetration, as shown in Equation 12:

$$A_{x,y} = -\frac{\Delta C_{x,y}}{\Delta E_{x,y}} \qquad (12)$$

Figure 22 and Figure 23 are shown in order to compare the grid-related costs and emissions to the road-related costs and emissions for the off-peak charging scenario in Ontario. Figure 22 compares the grid-related and road-related cost changes, and is shown for 100% PHEV penetration. If 100% of the vehicle fleet in Ontario (about 3.9M vehicles) converts to PHEVs, the total cost change would be about \$34M. The grid-related costs in Ontario were previously discussed in Section 6.1.2, but are expressed here as an absolute value (\$M) instead of a unit cost (\$/MWh).

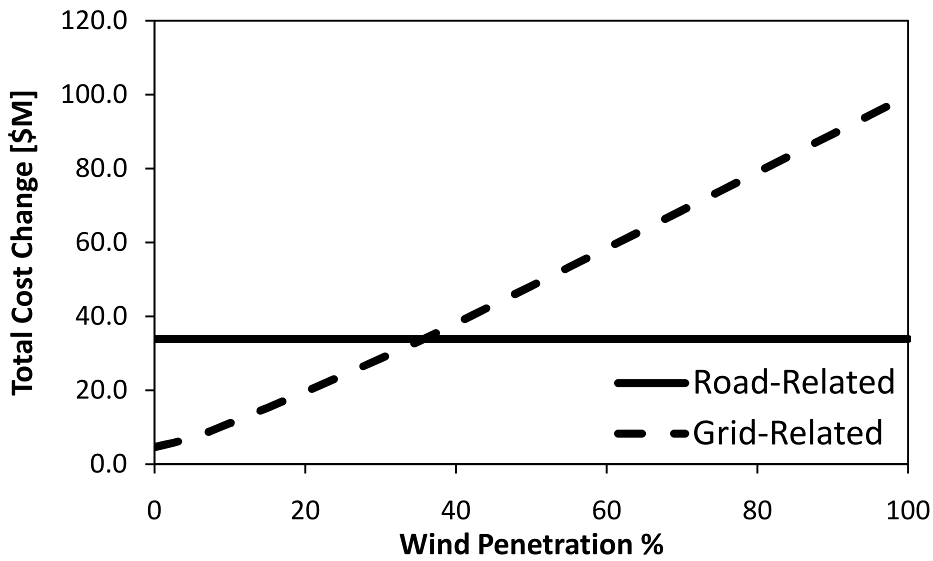

Figure 22: Grid-related and road-related cost changes – Ontario (PHEV = 100%)

The grid-related and road-related emissions reductions are compared in a similar manner, as shown in Figure 23, for 100% PHEV penetration. If the entire vehicle fleet in Ontario converts to PHEVs, 246 kt-CO_2e would be avoided per week. The grid-related emissions reductions were previously discussed in Section 6.2.2, but are converted to absolute units here.

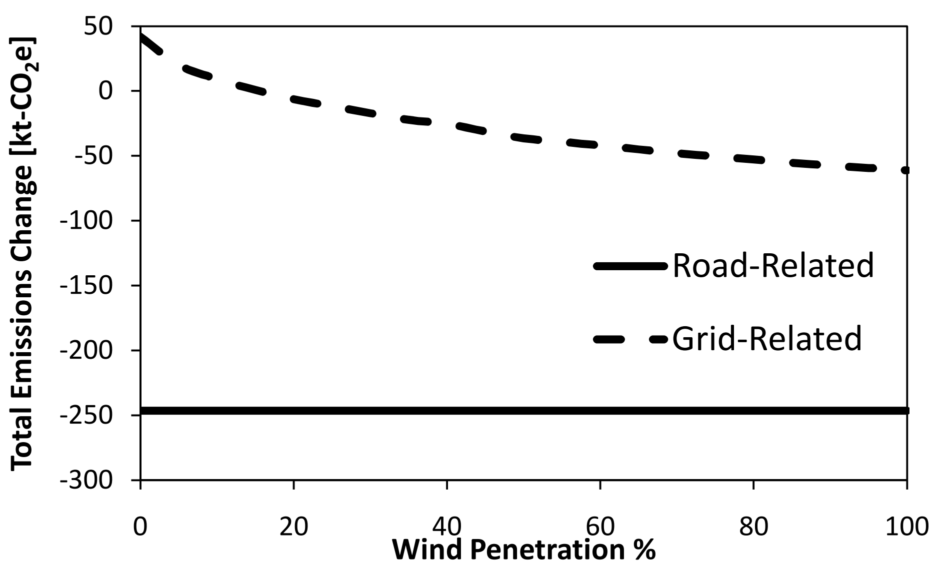

Figure 23: Grid-related and road-related emission changes – Ontario (PHEV=100%)

With Equations 10 and 11 calculated for all penetrations of wind and PHEVs, the CO_2e reduction cost is calculated (using Equation 12) for each charging scenario, jurisdiction, and season, as presented in Sections 6.3.1, 6.3.2, and 6.3.3 respectively.

6.3.1. Charging Scenario Comparison

The GHG reduction costs for British Columbia are shown for the uncontrolled and off-peak charging scenarios, as presented in Figure 24. GHG costs for the optimal charging scenario are only slightly lower than for the off-peak charging scenario, and are omitted from Figure 24 for clarity. As expected, the GHG costs at 0% PHEV penetration are the same for both charging scenarios. The most obvious conclusion drawn from Figure 24 is that GHG costs in British Columbia are extremely high at a PHEV penetration of 0%. This is because the cost of adding wind power to the British Columbia system is very high, while providing very little environmental benefit over hydro power. Figure 25 removes the high cost data points from Figure 24, in order to better highlight the differences between charging scenarios at higher PHEV penetrations. As PHEVs are introduced, significant environmental benefit is acquired through the use of hydro power for charging, and thus GHG costs decrease at higher PHEV penetrations.

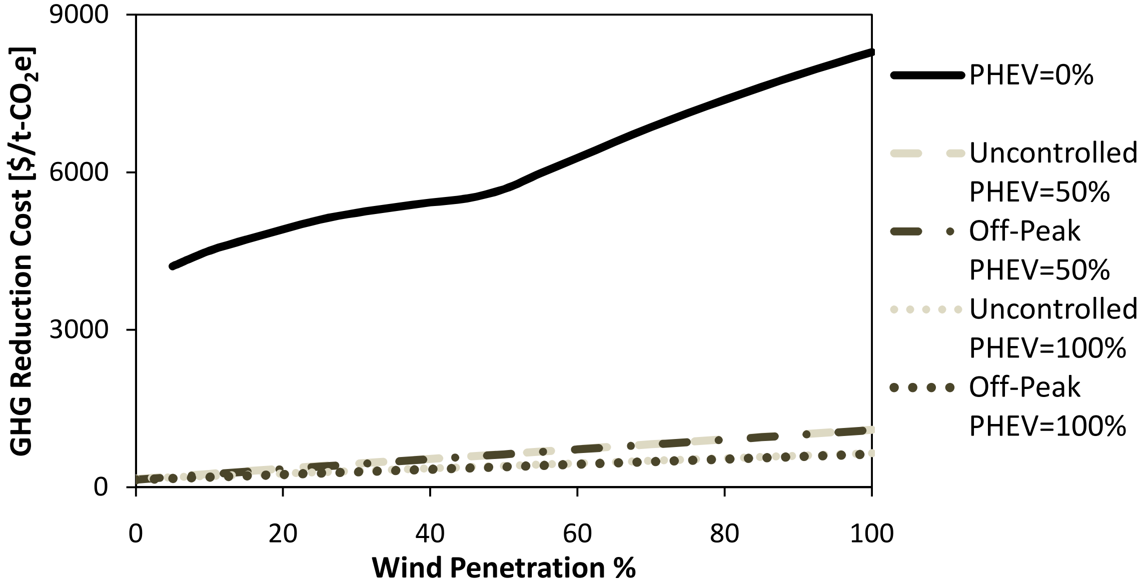

Figure 24: CO_2e reduction cost for British Columbia - charging scenario comparison

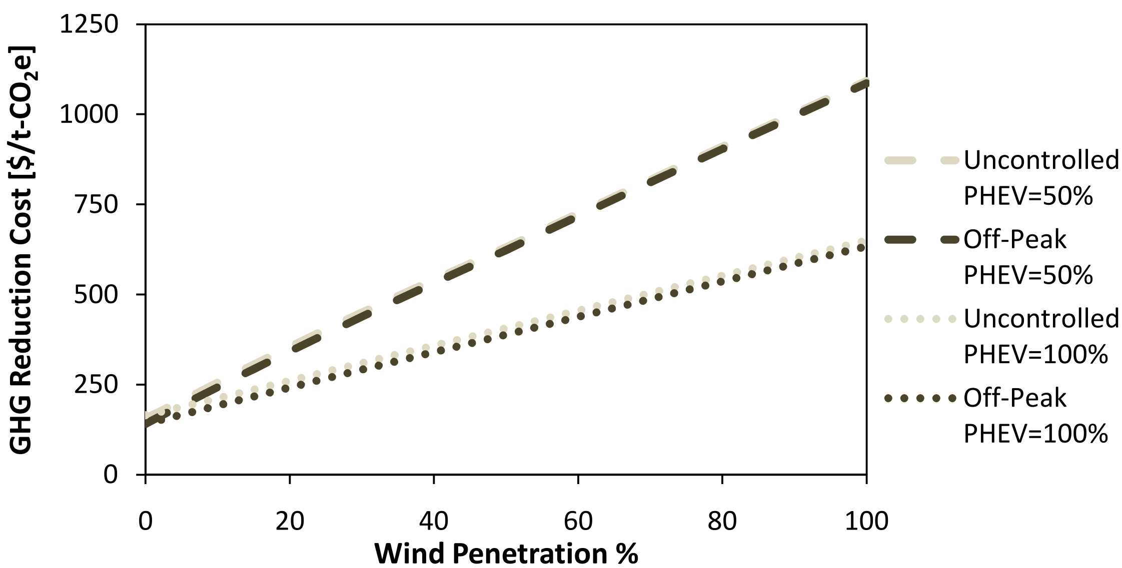

Figure 25: CO_2e reduction cost for British Columbia - charging scenario comparison (area of interest)

In the uncontrolled scenario, a larger portion of the additional PHEV load is met through NG generation, which decreases the environmental benefit of substituting gasoline for electricity while also increasing total cost. Thus, the GHG reduction costs are up to \$25/t-CO_2e higher for the uncontrolled charging scenario compared to the off-peak and optimal charging scenarios, where PHEV load is met entirely by low cost and clean hydro power.

Figure 26 shows the CO_2e reduction costs for different charging scenarios in Ontario. Again, the GHG costs for the optimal charging scenario are very similar to the off-peak scenario, and thus have been omitted for clarity. As seen in British Columbia, GHG costs are much higher at low PHEV penetrations because the environmental benefit of substituting wind power over (mostly) hydro and nuclear power is small, while the cost increase is large.

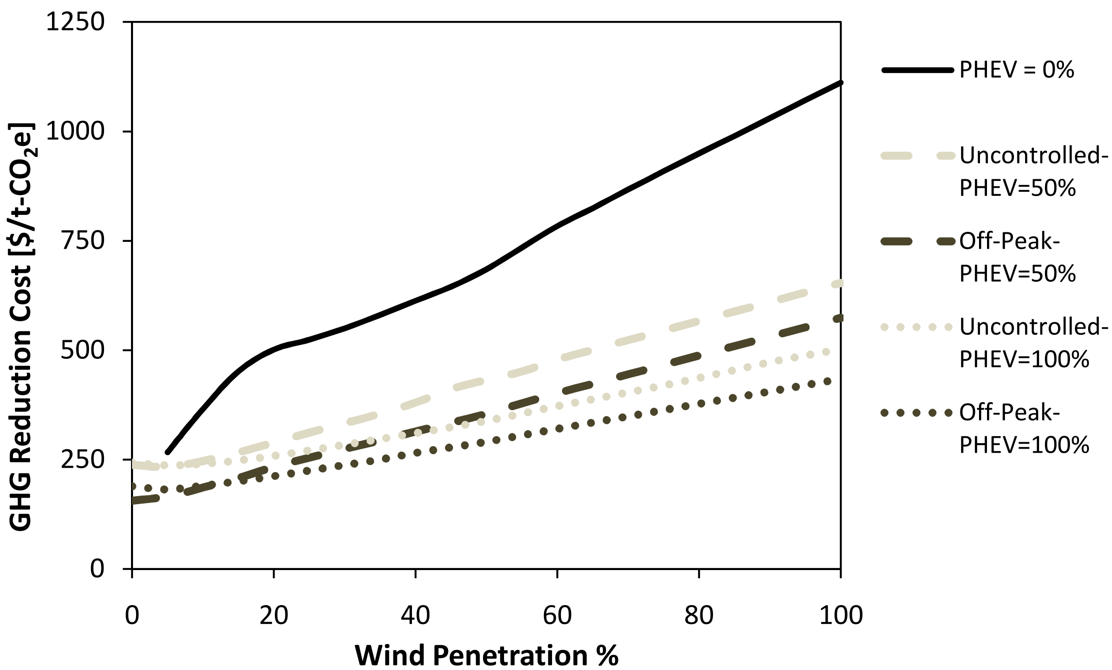

Figure 26: CO_2e reduction cost for Ontario - charging scenario comparison

The PHEV charging scenario affects GHG costs by changing the marginal generation type used to meet PHEV charging demand. In uncontrolled scenarios, PHEVs are met with coal and NG generation, which is expensive and relatively GHG-intense. The emissions savings from gasoline displacement are diluted by meeting PHEV demand with fossil-fuel generation. This makes the cost of CO_2e reduction up to \$80/t-CO_2e higher in the uncontrolled charging scenario when compared to the off-peak charging scenario.

The off-peak and optimal charging scenarios are similar to each other, the result of increased use of surplus baseload power during off-peak times. Since baseload power in Ontario (hydro and nuclear) is cheap and clean, CO_2e reduction costs are lower in these charging scenarios. The fact that off-peak and optimal charging costs are similar suggests that most of the benefit gained by optimally allocating PHEV charging comes from using the surplus baseload during off-peak times, rather than the synchronization of charging with periods of high wind output.

The emissions reductions in Alberta are proportionally different than in Ontario. As shown in Figure 27, the changes in grid-related emissions make up a larger fraction of total emissions change, in contrast to the results from Ontario (shown in Figure 23). This difference is due to the fact that displacing coal and NG power with wind power (Alberta) results in larger emissions reductions than displacing nuclear and hydro power with wind power (Ontario). Also, the environmental benefit of substituting gasoline for coal-fired electricity in a vehicle is smaller than substituting gasoline for hydro or nuclear power. After combining the changes in costs and emissions, CO_2e reduction costs were calculated (again using Equation 12) for each charging scenario in Alberta, with the results shown in Figure 28.

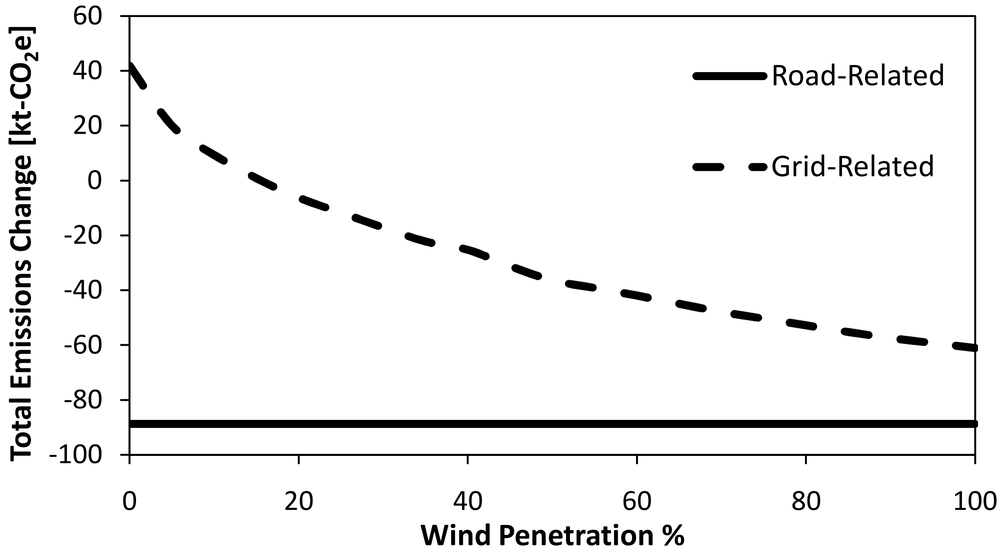

Figure 27: Grid-related and road-related emissions changes – Alberta (PHEV=100%)

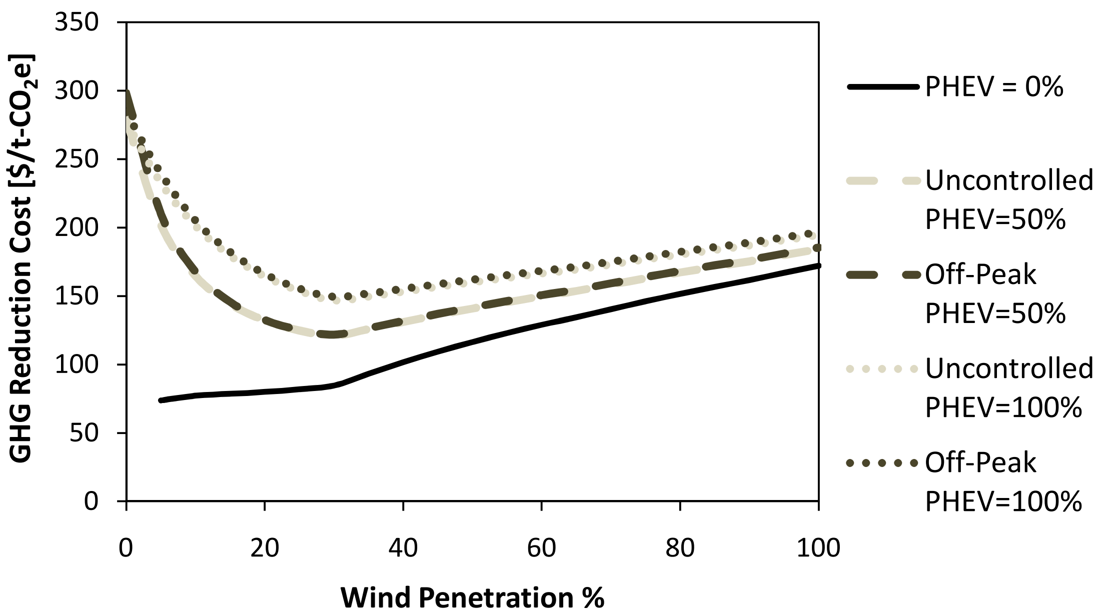

Figure 28: CO_2e reduction cost for Alberta - charging scenario comparison

Figure 28 shows little difference in GHG reduction cost between charging scenarios in Alberta. While PHEV demand is largely met with NG in both charging scenarios, off-peak charging is met with more coal power than uncontrolled charging. Intuitively, one would expect the cost of GHG reductions to be lower in off-peak scenarios, due to increased use of cheap baseload coal power; however, the environmental benefit of substituting gasoline use for coal-generated electricity is substantially smaller than if NG had displaced gasoline instead. While the uncontrolled charging scenario costs more due to increased NG use, the lower emissions from NG (relative to coal) results in more environmental benefit from PHEVs. Thus, the trade-off between cost and emissions between each generation type almost balance out, resulting in similar GHG reduction costs for all charging scenarios.

Also seen in Figure 28 are sharp initial reductions in GHG costs, as wind power displaces large amounts of NG without curtailment. At 30% penetration, wind curtailment begins increasing the cost of wind power (since capacity factor is being constrained by transmission limitations), which increases GHG costs.

6.3.2. Jurisdictional Comparison

The cost of GHG reductions are also compared across each jurisdiction. For this comparison, only the winter/off-peak charging scenarios are shown. The previous section showed some of the modest changes in GHG reduction costs induced by various charging scenarios; however, this section illustrates that the jurisdiction into which PHEVs and wind are integrated has a much stronger effect on GHG reduction costs. In the following section, the major differences between jurisdictional GHG costs are explained.

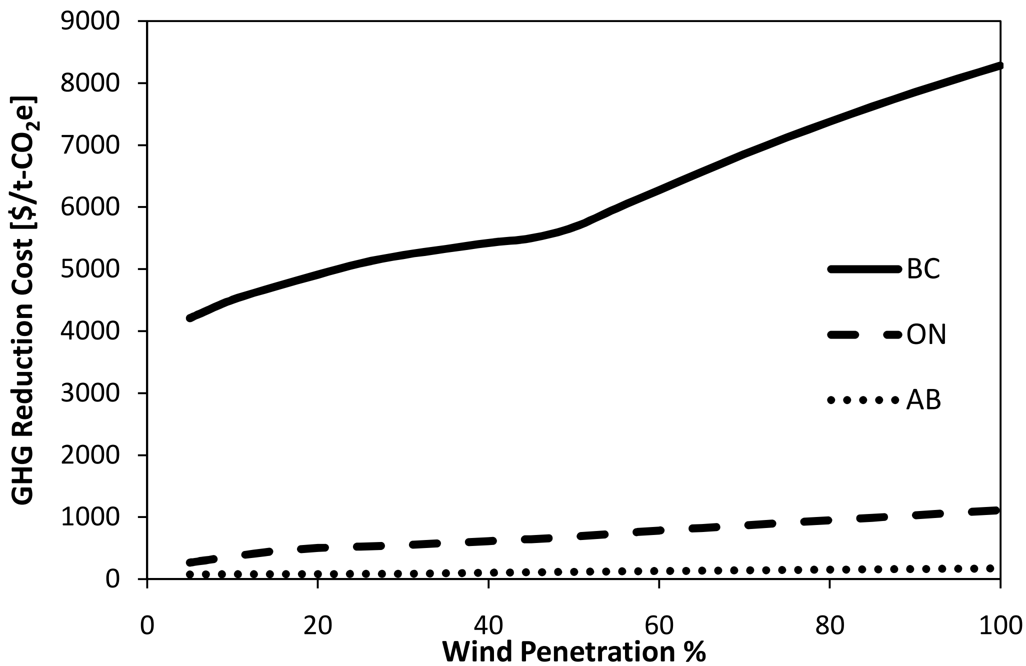

Figure 29: Jurisdictional comparison of GHG costs – PHEV = 0%

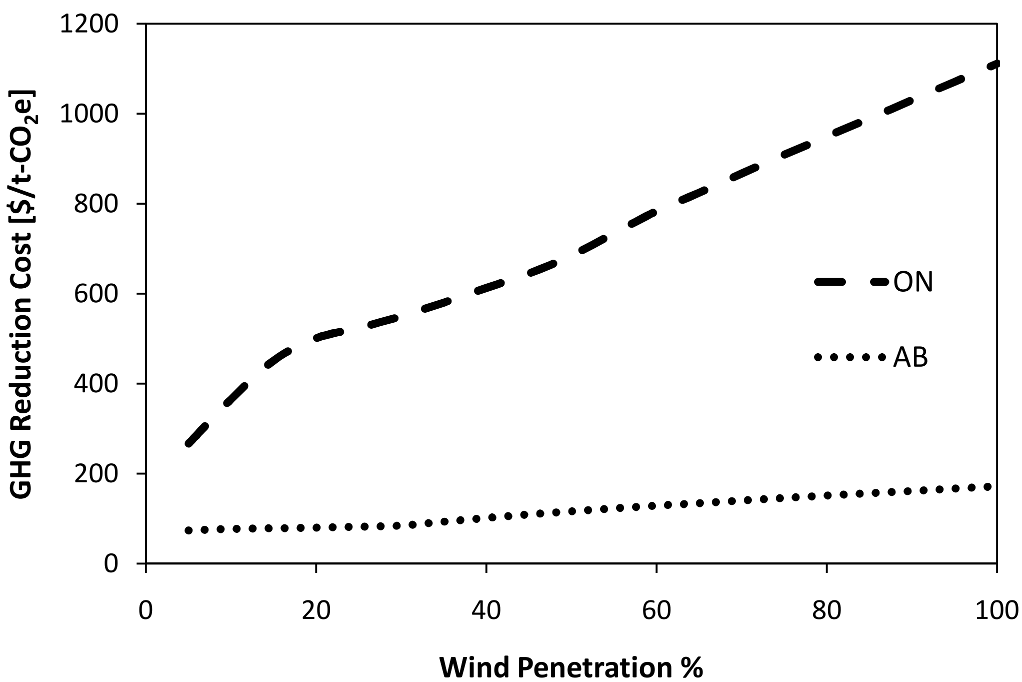

Figure 30: Jurisdictional comparison of GHG costs - PHEV = 0% (BC results removed)

There are several major trends worth highlighting in Figure 29, Figure 30, Figure 31 and Figure 32. Most apparent is the high cost of GHG reductions in British Columbia due to wind integration. This is an intuitive result since wind has limited environmental benefit over hydro power, but is over five times more expensive (in terms of levelised cost). Thus, GHG reductions through wind power alone in British Columbia are expensive. In Alberta, the converse is true. Wind power is cleaner than coal and NG, with a smaller cost premium; thus GHG costs are relatively low (\$74-\$172/t-CO_2e with no PHEVs). The cost of GHG reductions via wind power in Ontario are lower than the prices in British Columbia but higher than Alberta, since its generation mixture has more fossil fuels than British Columbia, but less than Alberta.

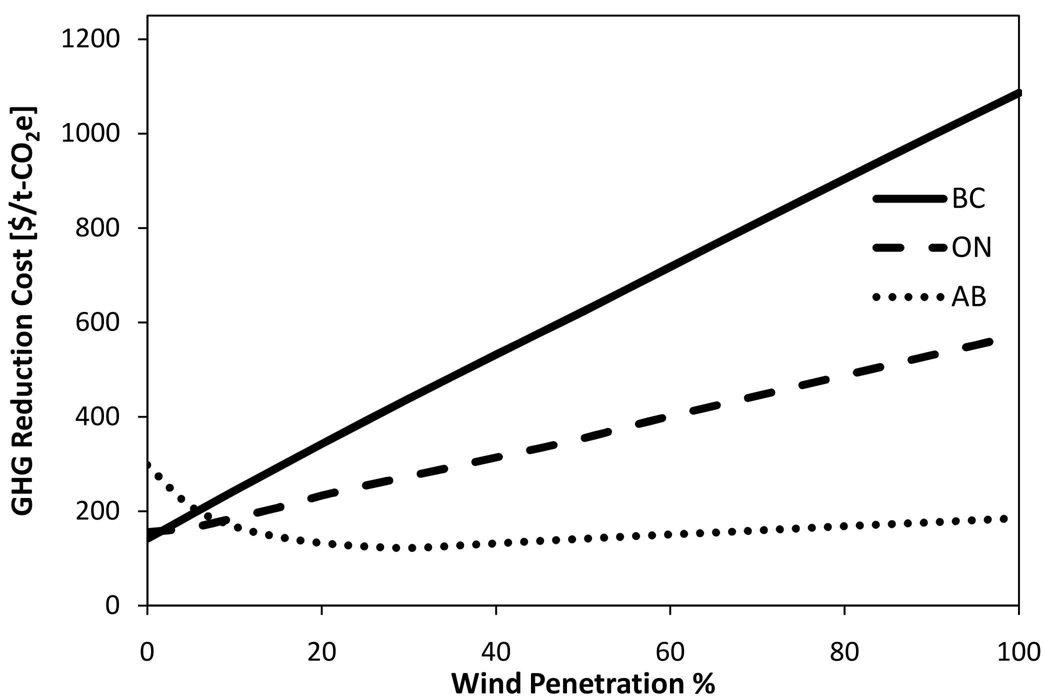

Figure 31: Jurisdictional comparison of GHG costs – PHEV = 50%

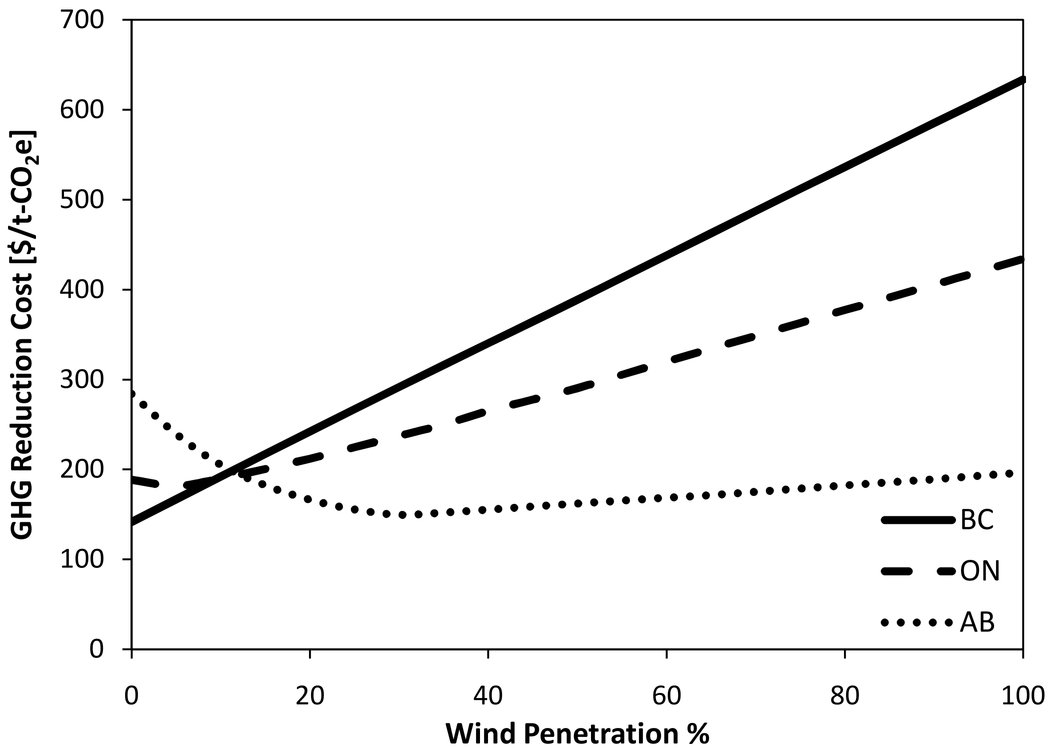

Figure 32: Jurisdictional comparison of GHG costs – PHEV = 100%

The cost of PHEV-only adoption is highest in Alberta. This is because the substitution of gasoline with coal or NG-fired electricity has less environmental benefit than the substitution of gasoline with hydro or nuclear power. Thus, PHEVs reduce emissions less in Alberta, resulting in the highest GHG reduction costs. The cost of GHG reductions through PHEVs (with no wind) is lowest in British Columbia because the generation mixture is dominated by clean hydro power, which is used to power off-peak PHEVs. The cost of GHG reductions via PHEV adoption is also fairly low in Ontario, though slightly higher than British Columbia.

6.3.3. Seasonal Comparison

As discussed in earlier sections, the aggregate non-PHEV demand profile varies throughout the year. In the higher-load winter periods, more generation is needed on top of the baseload generation sources. In Ontario, these additions are usually more expensive generation types like NG and coal. In the summer, these fossil fuel generation types are used less, and thus the CO_2e reduction costs from PHEV and wind addition may vary by season. What follows here is an illustration of the differences between winter and summer CO_2e reduction costs in Ontario, for the off-peak charging scenario.

When comparing the summer scenario to the winter scenario, as shown in Figure 33, Figure 34 and Figure 35, it is clear that wind power is a much more expensive CO_2e reduction in the summer than in the winter. Since the lower summer demand profile allows for nuclear and hydro to make up a larger share of generation, the overall generation mix in Ontario is cleaner and cheaper in the summer than in the winter. Because the average generation mixture is cleaner and cheaper in the summer, the environmental benefit of adopting wind power diminishes while the total system cost rises. Conversely, a cleaner mixture in the summer gives PHEVs more environmental benefit for the same cost, decreasing GHG costs.

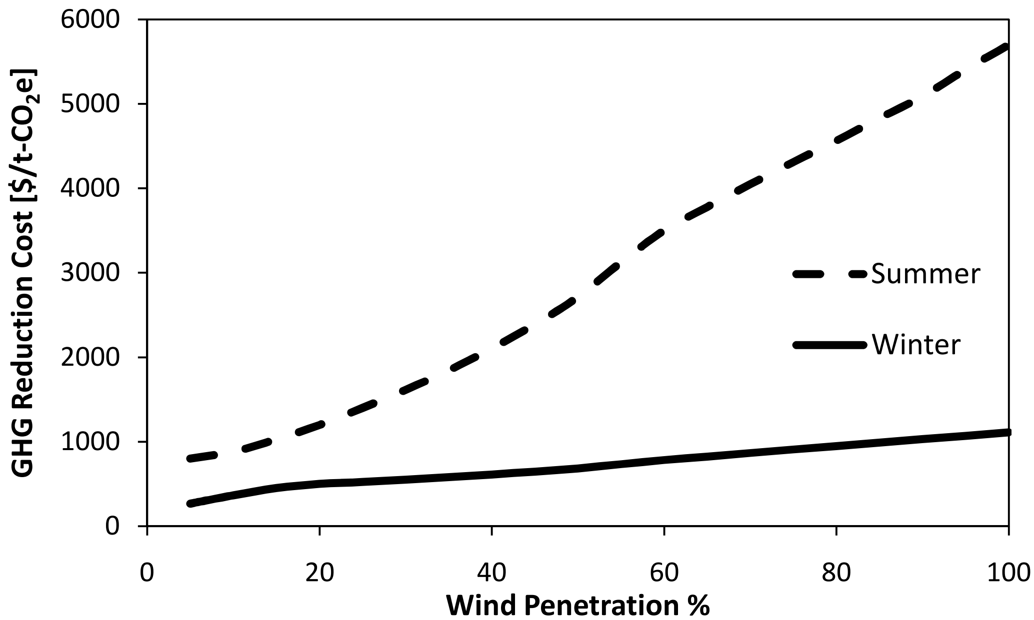

Figure 33: Seasonal comparison of GHG costs in Ontario – PHEV = 0%

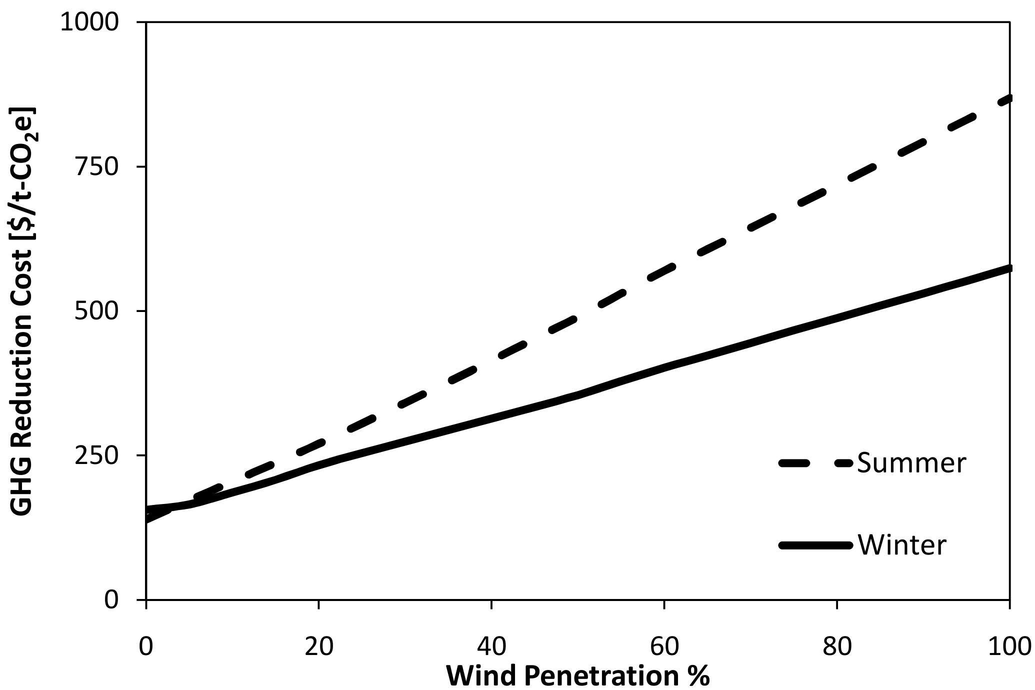

Figure 34: Seasonal comparison of GHG costs in Ontario – PHEV = 50%

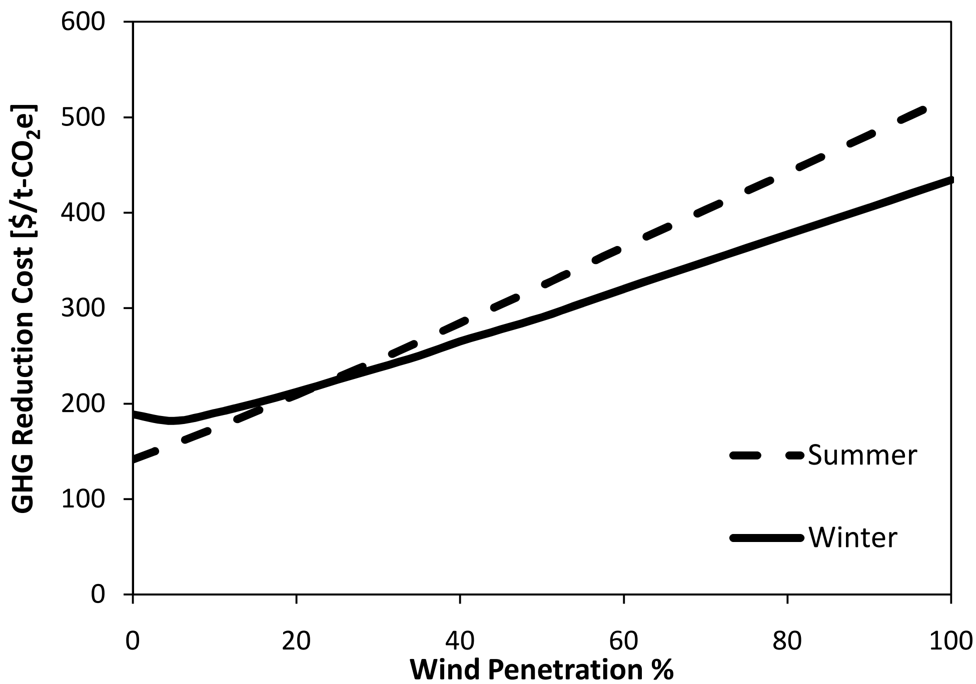

Figure 35: Seasonal comparison of GHG costs in Ontario – PHEV = 100%

Similar analyses were performed for Alberta and British Columbia, but little change was seen between summer and winter CO_2e costs. In Alberta, the overall summer energy demand is only about 10% lower than the winter energy demand, in part due to the province's relatively limited use of electric space heaters [100]. Since there are only two major types of generation, the dispatch schedule does not change significantly between summer and winter, and thus CO_2e costs are essentially constant between seasons.

In British Columbia, the summer demand profile is about 30% lower than the winter profile. However since there is only one major type of generation, the dispatch schedule does not change significantly either. The cost of replacing hydro with wind for CO_2e reductions remains high in British Columbia, and PHEV costs remain relatively low due to the large environmental benefit from gasoline displacement.

6.4. PHEV and Wind Interaction

Up to this point, the cost of PHEV and wind-powered GHG reductions have been discussed separately, but these technologies have complementary benefits. In general, changes in costs and emissions due to wind are dictated by what conventional generation types are displaced, and in what proportions. The makeup of the displaced power, when compared against the cost and GHG intensity of wind power, determine the changes in grid-related costs and emissions. For PHEVs, the costs are determined mostly through the purchase cost and gasoline displacement, although the electricity cost can be significant, especially in Alberta where the PHEV load is frequently met by expensive NG. The change in emissions due to PHEV adoption are driven by the marginal generation during charging times, which dictates the environmental benefit of substituting electricity for gasoline. The interaction between wind and PHEVs occurs as wind power injections change the marginal generation during PHEV charging times.

When more wind comes online, it has the opportunity to displace expensive fossil fuel generation and free up cheap, clean baseload power for PHEV charging. If PHEVs charge only at peak times, more baseload power remains displaced or underused in off-peak times. Since uncontrolled charging occurs during a 4-hour period of the day, and off-peak charging occurs over roughly 10 hours per day, wind power is less likely to make contributions during peak charging times, and thus uncontrolled PHEVs provide less benefit to wind than off-peak PHEVs.

In Ontario and British Columbia, large wind power injections during off-peak times displace cheap hydro or nuclear, which drives up average cost with limited environmental benefit. If PHEVs charge during off-peak times, less curtailment of cheap baseload power (or forced export of wind) occurs as wind is injected. Thus PHEVs provide benefit to wind power by enabling less curtailment of cheap, clean baseload power. For example, at 50% PHEV penetration in Ontario (winter scenario), increasing wind from 50% to 100% increases GHG cost by \$219/t-CO_2e, as shown in Figure 34. At 100% PHEV penetration, increasing wind from 50% to 100% only increases cost by \$143/t-CO_2e, due to increased use of surplus baseload power.

In Alberta, PHEVs do not provide any benefit to wind power. This is because wind power reduces GHG emissions at a relatively low cost in Alberta, while PHEVs reduce CO_2e at a higher cost, as shown earlier in Figure 28. Any addition of PHEVs increases overall CO_2e costs. However, the addition of wind to the system helps slow the GHG cost increases due to PHEV addition. For example, at 50% wind power, increasing PHEVs from 50% to 100% penetration increases GHG costs by \$20/t-CO_2e (as shown in Figure 28). However at 100% wind penetration, increasing PHEVs from 0-100% increases cost by only \$11/t-CO2e. This is simply because higher wind penetrations make the generation mixture cleaner, and thus PHEVs acquire more environmental benefit from gasoline displacement.

The optimal charging scenario does not offer many improvements over the off-peak charging scenario in any jurisdiction. This is because most of the benefits gained by optimal charging occur through the increased use of baseload power during overnight periods. If no wind power is present, optimal charging is identical to off-peak charging in terms of costs and emissions. Optimal charging only improves upon off-peak charging if baseload generation would have otherwise been displaced during peak hours by large wind injections. Since large, on-peak wind injections are infrequent, the off-peak and optimal charging scenarios yield similar GHG reduction costs.

7. Review of Major Assumptions

This section reviews some of the major assumptions made in this work. First, a sensitivity analysis is performed for GHG costs with respect to changes in generation and PHEV costs. Then, the impact of neglecting changes in generation efficiency at part loads is investigated.

7.1. Generation and PHEV Cost Assumptions

The CO_2e reduction costs reported in Section 6 are based on economic assumptions made for the cost of power generation, the cost of PHEV ownership, and the cost of gasoline. As such, it is prudent to assess the sensitivity of the results to changes in the cost of generation and the cost of PHEVs. Since the GHG impacts of each generation technology are well established values, no sensitivity studies are performed on these parameters.

In order to assess the sensitivity of grid-related costs on CO_2e cost, the levelised cost of each generation type (see Table 3) is independently varied by up to ±20%. To assess the sensitivity of GHG costs to road-related costs, the PHEV purchase price and the price of gasoline are independently varied by up to ±20%. The following plots illustrate the effect of changing the levelised cost of each generation type. All results shown here are for the Ontario winter/off-peak charging scenario with 100% PHEV penetration.

Figure 36 shows the sensitivity of GHG reduction costs to the cost of wind power. Since wind is defined as "must take", variations in wind cost do not induce any changes in dispatch schedule. As expected, increasing the cost of wind power increases the cost of GHG reductions, and vice versa.

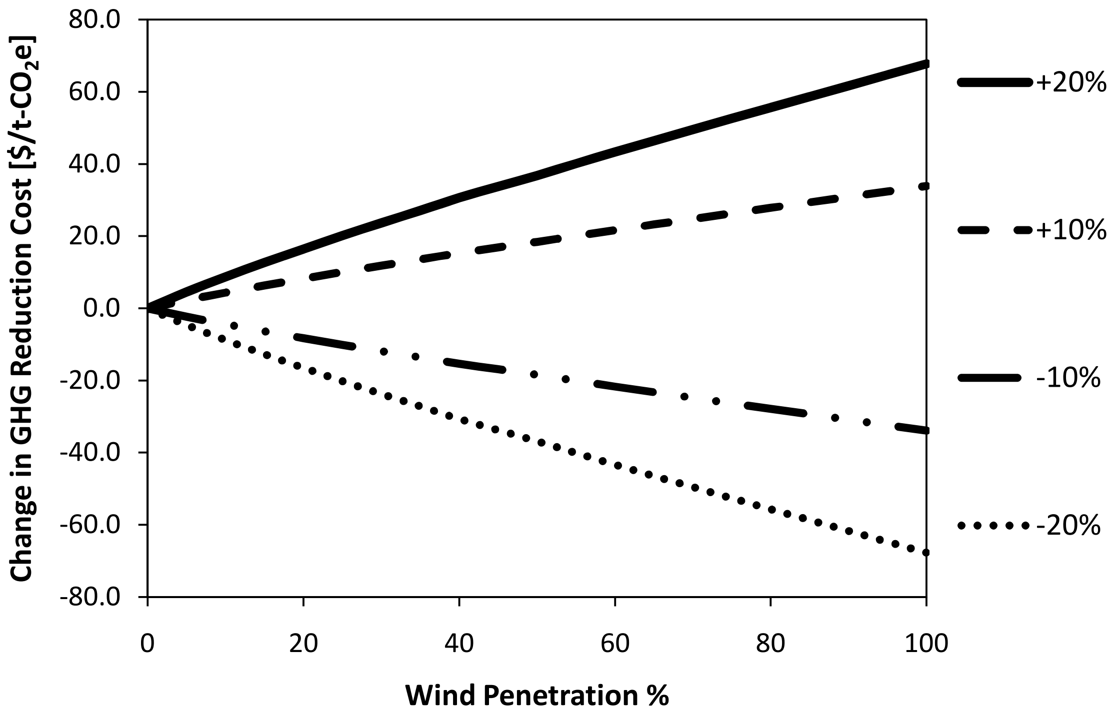

Figure 36: Sensitivity of CO_2e reduction cost to changes in wind price

Variations in the cost of nuclear power do not cause significant changes in GHG reduction costs, especially at low wind penetrations, as shown in Figure 37. This is because nuclear power is defined as "must take" to match IESO practice, and thus small wind injections displace hydro rather than nuclear power. At wind penetrations above 40%, GHG costs become slightly sensitive to nuclear power cost, since nuclear power displacement begins at this point (shown in Appendix A.1). However, because only the low variable cost of nuclear power affects the cost of GHG reductions, sensitivities are low. It is worth noting that increases in the cost of nuclear power cause decreases in CO_2e costs as wind is introduced. As nuclear becomes more expensive, the cost differential between nuclear and wind becomes smaller, thus the premium paid for wind over nuclear is smaller, and CO_2e costs decrease.

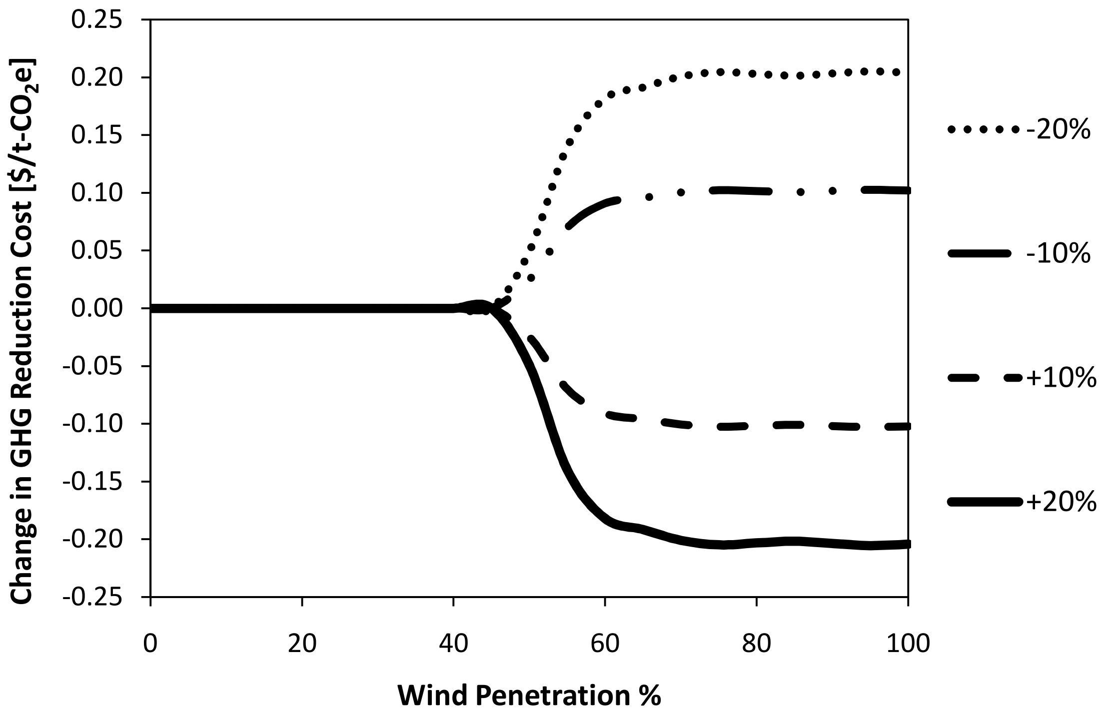

Figure 37: Sensitivity of CO_2e reduction costs to changes in nuclear cost

The sensitivity of GHG cost with respect to hydro power cost is shown in Figure 38. As wind power is introduced, it displaces hydro power. Since wind power displacement only affects the variable expenses of hydro generators ($1/MWh), the overall effect on GHG cost is small. At low wind penetration, increases in hydro cost cause increases in GHG costs, since the surplus hydro power used for PHEV charging is more expensive. However, as wind capacity is added, the variable cost savings achieved by displacing hydro with wind become more significant, and GHG costs start to decrease. As was the case with nuclear power, increases in hydro cost cause decreases in GHG cost, since the premium for wind power over hydro power is smaller.

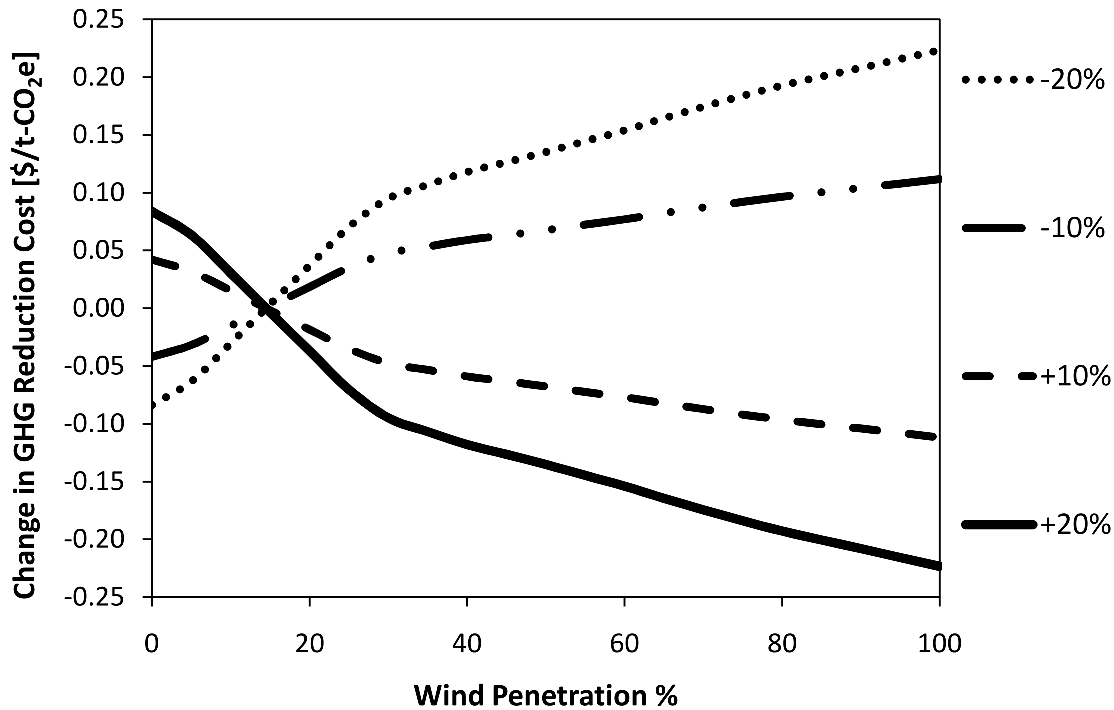

Figure 38: Sensitivity of CO_2e reduction cost to changes in hydro cost

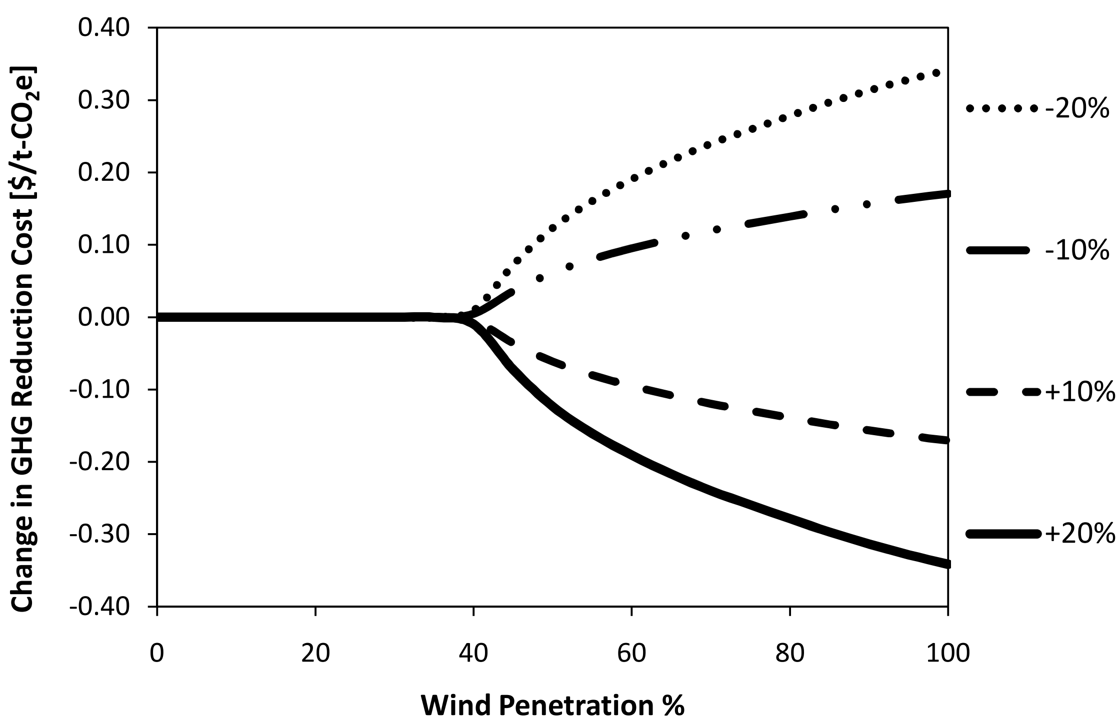

Figure 39: Sensitivity of CO_2e reduction cost to changes in coal cost

The cost of coal power affects GHG costs in a manner similar to nuclear power, evident by comparing Figure 37 and Figure 39. The cost of coal does not affect GHG costs below 40% wind penetration, due to the fact that coal is used in a peaking role in Ontario. Off-peak wind injections displace hydro or nuclear power, while on-peak wind injections displace more expensive peaking generation (NG) before displacing coal. When on-peak wind injections become significant (around 40% wind), coal displacement begins (as seen in Appendix A.1), with the same inverse effect on GHG costs as hydro and nuclear power.

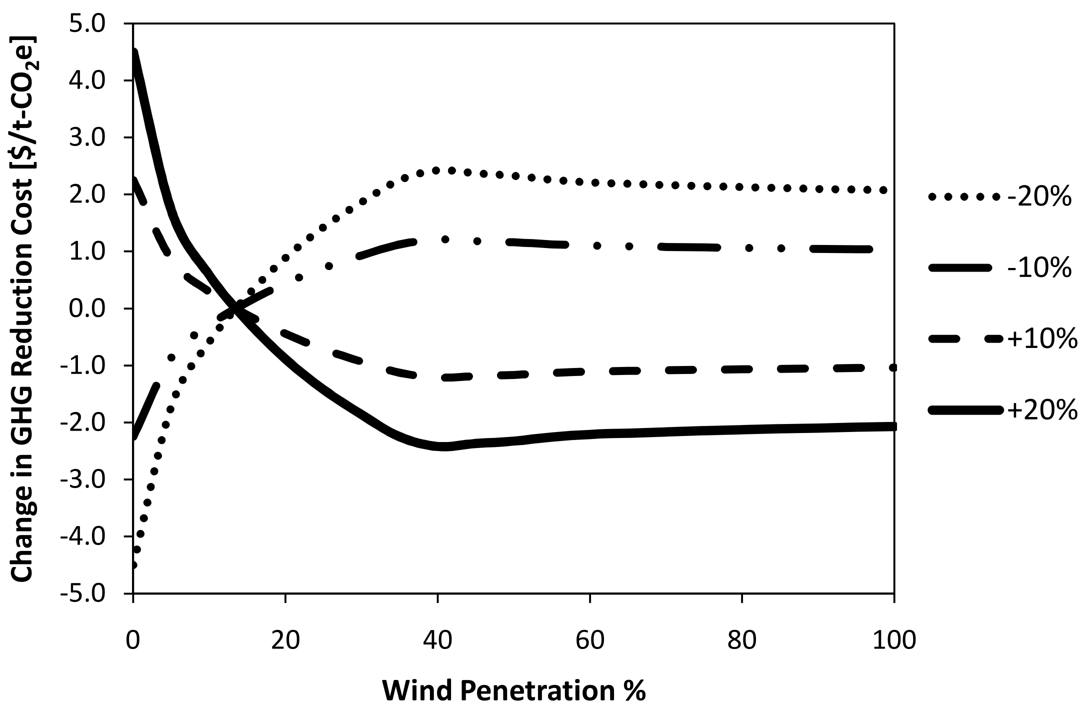

Figure 40: Sensitivity of CO2e reduction cost to changes in NG cost

NG has higher variable costs than any other form of generation, and thus CO_2e costs are generally more sensitive to NG cost than any other conventional form of generation, as shown in Figure 40. Changes in the cost of NG and hydro generation create similar effects on GHG costs, though slightly different in magnitude. At low wind penetration, increases in NG cost cause increases in GHG costs, since PHEVs use some NG for charging. As wind is added, the effects of substituting NG with wind become more significant, and costs start to decrease. Since the levelised cost associated with wind is higher than the variable cost of NG, increases in NG cost cause decreases in GHG costs as the premium for wind power over NG power is smaller.

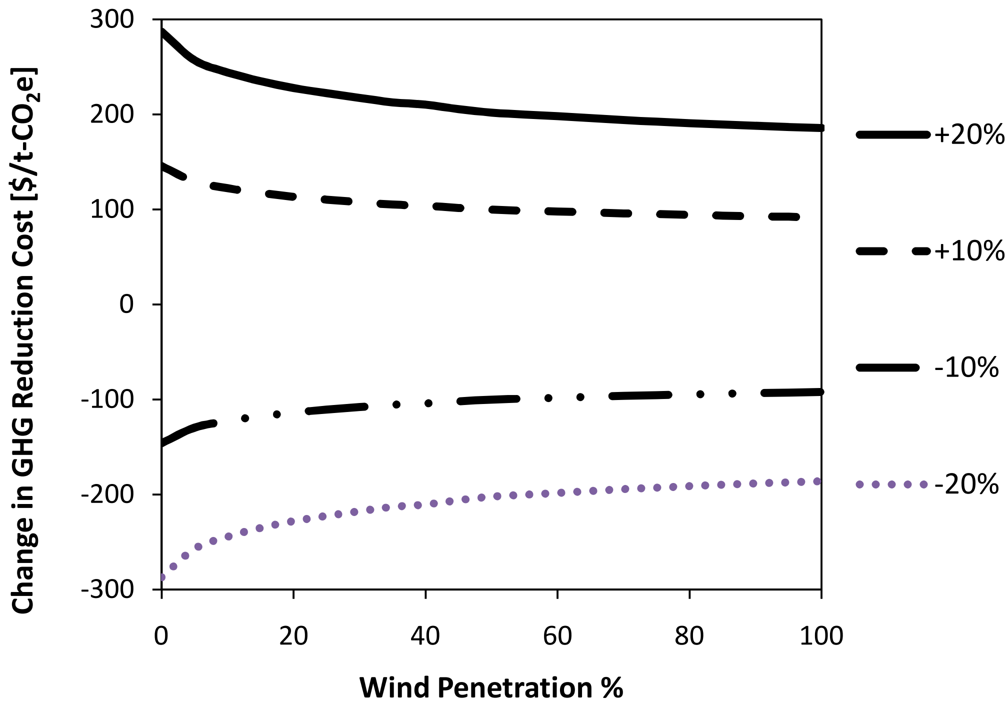

Figure 41: Sensitivity of CO_2e reduction cost to changes in PHEV purchase price

In Section 5.3, the economics of PHEVs were separated into two major components: purchase price and gasoline savings. Figure 41 shows the effect of varying the purchase cost of the vehicle by up to ±20%. At low wind penetrations, the road-related costs of the PHEVs dominate the grid-related costs, and thus the CO_2e costs are more sensitive to PHEV price in this region. As more wind is introduced, the grid-related costs become more significant, and the sensitivity to PHEV purchase price decreases. Clearly, the initial cost of the PHEV is a strong determinant of GHG reduction cost.

Also, the discount rate used to assess the cost of capital associated with vehicle purchase can have an effect on GHG costs. If the discount rate discussed in Section 5.3 is increased from 5% to 10%, the equivalent weekly PHEV ownership cost would be \$39.88. This cost increase is roughly equivalent to increasing the PHEV purchase cost by 14%; therefore, the sensitivity of GHG costs to a 5% increase in discount rate would fall between the '+10%' and '+20%' curves shown in Figure 41.

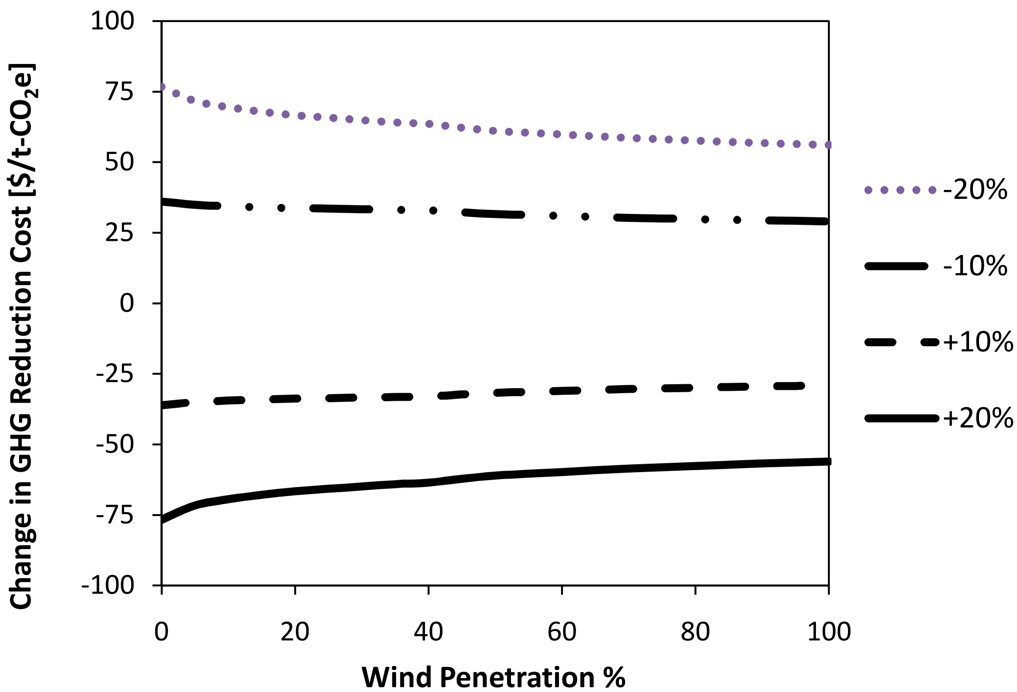

Figure 42: Sensitivity of CO_2e reduction cost to changes in gasoline price

Similar to the purchase price, the price of gasoline has a strong influence on the cost of GHG reductions, as shown in Figure 42. As the price of gasoline increases, the economic benefit of PHEV adoption increases, reducing the CO_2e reduction cost. At higher wind penetrations, the changes in grid-related costs and emissions become more significant, and overall sensitivity to gasoline cost decreases. Clearly, the price of gasoline is a stronger determinant of CO_2e costs than grid-related considerations.

7.2. Constant Variable Cost Assumption

The operating costs of generation were discussed previously in Section 3.3. The variable O&M costs, including fuel, were assumed to remain constant across all part-loading levels. This assumption neglects the fact that the net efficiency of a power generation plant changes depending on part loading [101,102]. Typically, efficiency drops as the plant loading drops. By assuming that variable costs are constant irrespective of part load, the effects of efficiency loss are not captured. What follows here is a brief assessment of the inaccuracies associated with this assumption, for each generation type.

Wind power is the only generation type that has efficiency explicitly included in the model. This was done through a turbine power curve (see Figure 2), which captures the change of turbine efficiency with varying wind speed.

The variable cost of nuclear power is a small fraction of the levelised cost, as shown in Table 2. The equivalent variable O&M cost equates to about $4/MWh and includes the cost of fuel. If the thermal plant efficiency curve from [101] is assumed to apply to the CANDU plant, then net efficiency is 45% at full loading and 40% at 25% part load. Assuming a fuel price of $4/MWh, the effect of efficiency on fuel cost (from 25% part loading to full loading) is about $0.5/MWh, representing a change in fuel price of about 13%. Referring to the results of Section 7.1, specifically Figure 37, it was shown that a ±20% change in the variable cost of nuclear resulted in a change of less than \$1/t-CO_2e in GHG reduction cost. Thus, the constant marginal cost assumption for nuclear power appears to be a reasonable one.

Like nuclear, the variable cost of hydro power is low, only $1/MWh. Examining a turbine curve for a Francis hydraulic turbine, it can be seen that turbine efficiency ranges from 0% to 90% across all part loadings [103]. This means that the variable cost of hydro power could vary significantly at low part loading. However, when the average capacity factor for hydro power is calculated across various wind and PHEV penetrations (shown in Figure 43), it can be seen that hydro plants operate at over 60% of rated capacity on average. Examining the part loading curve from [103], it can be seen that the efficiency of a single turbine at 60% part loading is roughly 75%, translating to an average efficiency change of 20%, which was already shown to have limited effect on GHG cost in Figure 38. Additionally, each hydro plant consists of multiple turbines which can be dispatched individually. Thus, even though a plant may be dispatched to 60% of its total rated capacity, the desired power output could be achieved by running some turbines near their peak efficiency points and shutting some turbines down, with minimal effect on overall plant efficiency.

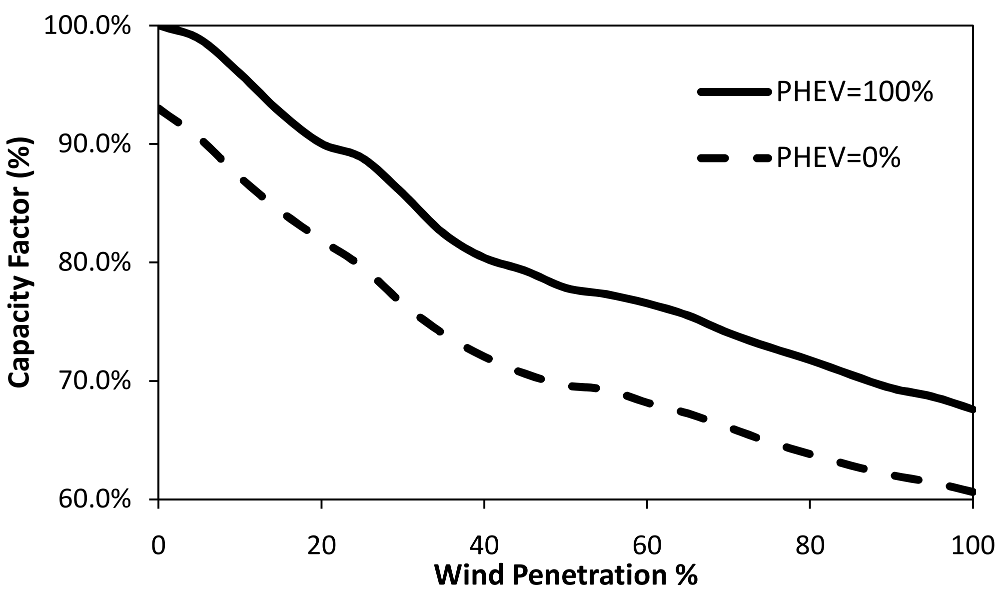

Figure 43: Average capacity factor for hydro - Ontario (off-peak PHEV charging)

Coal generation experiences changes in net efficiency across part loadings, as shown in [101]. With a variable cost of \$13/MWh, fuel costs are not particularly high for coal plants. Using the efficiency curve given in [101], it can be seen that efficiency is about 40% at 25% part load, and about 45% at full loading. If \$13/MWh is assumed to be the fuel cost at peak efficiency, then the fuel cost at 25% loading equates to \$14.6/MWh, a 13% increase. The effect of a ±20% change in variable cost is assessed in Section 7.1, specifically Figure 39, and shows less than 0.1% change in GHG reduction costs with a 20% change in the cost of coal.

NG generation has the highest variable cost of all generation types, and also the widest range of operating efficiencies. Smeers et al. [102] show that the efficiency of a simple cycle NG turbine can range from about 25% near zero load, up to 39% at full load. This change in efficiency could increase the assumed variable cost of \$64/MWh up to \$85/MWh, a 33% increase. To assess the potential effects of this, a sensitivity study is performed with a ±33% change in NG cost, as shown in Figure 44. A 33% change in the cost of NG results in less than \$8/t-CO_2e change in cost of GHG reductions. This low sensitivity to NG cost further supports the constant marginal cost assumption.

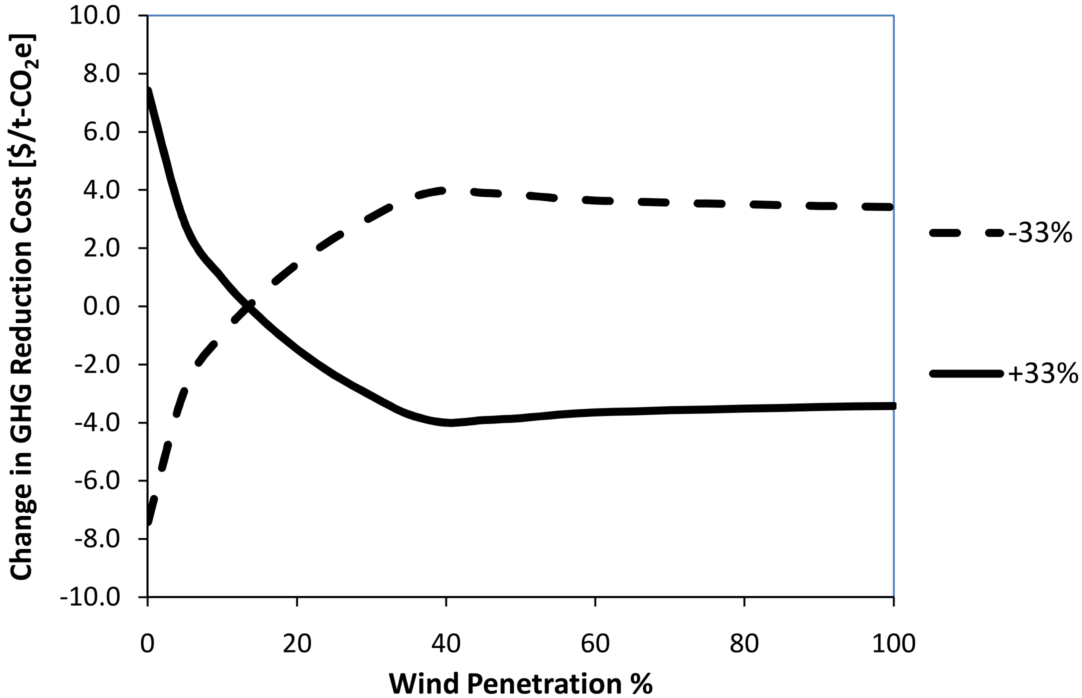

Figure 44: Sensitivity of CO_2e reduction cost to inclusion of NG plant efficiency

8. Conclusions

This work has described a method of quantifying the cost of GHG reductions using wind power and PHEVs. An OPF model was used to assess the changes in generation dispatch resulting from the addition of wind power and PHEVs to several Canadian provincial electricity networks. The model solved a one-week planning period with an hourly time resolution, using a linear power flow formulation. Generation cost and emissions data were extracted from the model for various levels of PHEV and wind penetration.

Three Canadian jurisdictions were investigated in this work, namely British Columbia, Ontario and Alberta. British Columbia features a hydro-dominated generation mixture, which is clean and cheap. Ontario has the most diverse generation mixture, including hydro, nuclear, coal and NG. Costs and emissions are slightly higher in Ontario than in British Columbia. Alberta features a fossil fuel dominated mixture with the highest GHG emissions and costs. Public domain data were used to formulate power network models for each jurisdiction, with transmission constraints in each region. These transmission network models added operational constraints to the generation dispatch schedules found by the OPF models, since spatial distributions of load and generation were considered.

In order to accurately compare the CO_2e reduction costs from wind and PHEVs, the PHEV purchase price and gasoline savings were accounted for. The total purchase price of a PHEV was estimated at $37857, compared to $22540 for a conventional ICE vehicle. When amortized over the lifetime of the vehicle, the equivalent weekly premium cost of PHEV ownership equated to $29.67. The economic benefit of PHEVs comes from gasoline displacement. Using transportation statistics, weekly gasoline savings were estimated to be $21.07 for a fleet average PHEV with a 64 km AER, assuming a $1/L gasoline price. The electric load placed on a utility from a fleet of PHEVs was also estimated using transportation data. Three fleet charging scenarios were investigated: uncontrolled charging, off-peak charging and optimal charging. These three scenarios serve as bounding cases for the best and worst likely scenarios of passive PHEV integration, and the best possible scenario of active PHEV integration respectively.

Once the overall changes in cost and emissions were determined for various degrees of PHEV and wind penetration, GHG reduction costs were then calculated. The results obtained for CO_2e reduction costs were compared across each charging scenario, jurisdiction and season.

8.1. Charging Scenario Comparison

Results show that the uncontrolled charging scenario was associated with the highest CO_2e reduction costs in Ontario and British Columbia. In Ontario, GHG cost differences between uncontrolled and off-peak charging were attributed to the use of NG and coal power to meet uncontrolled charging demand, while hydro and nuclear power were used for off-peak charging. In British Columbia, the uncontrolled scenario was more expensive than the off-peak/optimal scenarios because of increased use of NG. In Alberta, the uncontrolled, off-peak and optimal scenarios were nearly identical. Uncontrolled charging uses more NG than the off-peak or optimal scenarios (which use comparatively more coal); however, NG is cleaner than coal and more expensive as well. Thus, the emissions/cost trade-off between coal and NG almost balances, thus little difference was seen between charging scenarios in Alberta. It is also worth noting that the off-peak and optimal charging scenarios were similar in all jurisdictions. This suggests that most of the benefit offered by optimal charging is owed to the increased use of surplus baseload power, rather than synchronization of wind power and PHEV charging.

8.2. Jurisdictional Comparison

Results for the jurisdictional comparison were shown in Figure 29, Figure 31 and Figure 32, and showed that the local generation mixture was a strong driver of GHG reduction cost. In British Columbia and Ontario, the CO_2e reduction costs via wind power adoption were high. This was largely due to the limited environmental benefit of wind over the nuclear and hydro baseload mixtures. Thus, the large premium paid for wind power over hydro or nuclear does little to reduce emissions, and thus CO_2e costs are high. In Alberta, CO_2e reductions via wind power are much cheaper, since wind is closer in price to coal and NG, and also much cleaner.

The cost of CO_2e reductions via PHEVs were highest in Alberta, since the dirty generation mixture offers the least environmental benefit over gasoline in vehicles. Thus PHEVs do little to reduce emissions in Alberta, making CO_2e costs high for PHEVs alone. In Ontario and British Columbia, the costs are lower than in Alberta due to the cleaner generation mixtures and larger environmental benefit gained by substituting gasoline for nuclear or hydro generated electricity.

8.3. Seasonal Comparison

Ontario was the only jurisdiction to show significant change in CO_2e costs from seasonal effects. In Ontario, summer demand is generally lower than winter, with the exception of the brief air conditioning period. Lower demand means that hydro power and nuclear power make up a larger share of generation. Since displacing hydro and nuclear with wind power has little environmental benefit, the cost of CO_2e is higher during the summer compared to the winter, as shown in Figure 33.

British Columbia and Alberta do not exhibit any significant seasonal changes in CO_2e cost. In Alberta, the modelled summer and winter periods differ by only 10% in total energy demand. Since there are also only two major sources of generation, there is limited change in dispatch schedule between the two seasons, and thus limited change in CO_2e costs. British Columbia's demand varies by almost 30% between summer and winter, however hydro power dominates the mixture in both seasons, thus costs and emissions remain essentially constant as well.

8.4. PHEV and Wind Interaction

The interaction between PHEVs and wind power is characterized by the type of power generation displaced by wind power, and the marginal generation source during hours of PHEV charging. Clearly, wind power has the ability to change the marginal generation source for PHEV charging, especially at large wind penetrations. In Ontario and British Columbia, large wind injections sometimes displace large amounts of hydro or nuclear power. When PHEVs are added, it reduces the amount of curtailed baseload power, driving down the cost of CO_2e reduction. Thus, in Ontario and British Columbia, PHEV adoption facilitates wind adoption. In Alberta, wind adoption benefits PHEVs by cleaning up the generation mixture, and permitting more CO_2e reduction through gasoline displacement, slowing down CO_2e cost increases due to PHEVs. In this sense, wind power adoption facilitates PHEV adoption in Alberta.

8.5. Review of Major Assumptions

The sensitivity of the GHG cost calculations to changes in generation and PHEV costs were investigated. It was found that CO_2e costs are most sensitive to the price of wind power, since it directly displaces a mixture of conventional generation types. Of the traditional generation types, CO_2e costs are most sensitive to NG usage due to the high variable cost of NG, although this sensitivity is still low compared to wind. Hydro, coal and nuclear are all found to have similar sensitivities, with a variation of ±20% in generation cost resulting in less than \$1/t-CO_2e variation in CO_2e costs for all PHEV and wind penetrations. A ±20% variation in the cost of PHEV purchase and gasoline was found to cause changes in CO_2e cost of \$287/t-CO_2e% and \$77/t-CO_2e respectively.

The effect of neglecting the part load efficiency of generation was shown to be minimal for all generation types. A net efficiency curve for a thermal plant was used to estimate the changes in variable cost associated with running at lower efficiencies. This curve revealed that nuclear and coal plants will experience a 13% increase in fuel cost due to part load efficiency losses, but this increase was shown to have insignificant effect on GHG costs. A similar procedure was carried out for NG plants, resulting in a 33% change in fuel cost. A sensitivity study was carried out at this higher fuel cost, with an effect of less than \$8/t-CO_2e on the cost of GHG reductions. Hydro generation experiences the largest change in efficiency at part loading; however, examination of the average hydro capacity factor showed that hydro plants run at over 60% capacity factor during the study period. An average part load of 60% results in an average efficiency loss (and fuel cost increase) of 20%, which was previously shown to have limited effect on GHG costs.

9. Recommendations

This study considers a static electrical demand profile and instantaneous wind adoption, with wind power displacing conventional generation. In reality, load growth is expected to occur in all jurisdictions, requiring an expansion of the energy supply. The economics of wind power will be different when considering it as a marginal energy supply option rather than a replacement for existing energy supply. Wind power may be competitive with other new sources of generation in certain jurisdictions, depending on system requirements.

The impacts of large wind penetration on the import/export markets of Canadian provinces could significantly affect normal power system operation. As is currently seen in Denmark, where wind capacity exceeds 20% of total installed capacity, exports to neighbouring countries are frequently required during periods of high wind output [104]. However, modelling changes in electricity import/export markets is complex and beyond the scope of this work.

This study does not consider the effects that wind or PHEVs may have on ancillary service markets. Since wind power can suddenly decrease unexpectedly, spinning reserves must be available to ensure system reliability. At low wind penetrations, this additional reserve cost is low, but at large wind penetrations, significant amounts of standby generation (or storage) may be needed [27]. The economics of PHEVs may improve when considering their ability to quickly start or stop charging, which could be used to provide dispatchable load services to the grid operator. It has been suggested that PHEVs may supply high-value grid services like regulation or spinning reserves, in the form of dispatchable load or Vehicle-to-Grid power [9]. If the ancillary service opportunities for PHEVs were considered in this study, results could be quite different.

The economics of PHEVs could change when considering different vehicle specifications. If the average PHEV had a smaller battery, the cost premium over a CV would be smaller, while potentially still offering significant gasoline displacement. This could dramatically change GHG costs via PHEV adoption. Other vehicle technologies, such as hydrogen fuel cell or natural gas powered vehicles, could also have significantly different costs and GHG reduction potentials and therefore should be investigated.

Finally, this study could also be extended to a variety of different renewable energy technologies, like solar or wave power. Solar power has a distinctly different daily profile than wind power, and this may affect the large-scale power system quite differently. This would be especially true if comparing the CO_2e costs of off-peak and daytime PHEV charging scenarios, in the context of high penetration solar power.

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Appendix - Breakdown of Displaced Generation

This section presents a breakdown of generation displaced by the introduction of wind power. The results for British Columbia will not be shown here, as wind injections almost always displace hydro generation. The results for Ontario and Alberta are more interesting and are discussed in detail below.

A.1. Ontario

As wind is added to the Ontario power system, generation types are displaced based on cost and transmission considerations. Figure 45 and Figure 46 both illustrate the makeup of power displaced by wind integration, for the off-peak charging scenario with PHEV=0% and PHEV=100% adoption rates.

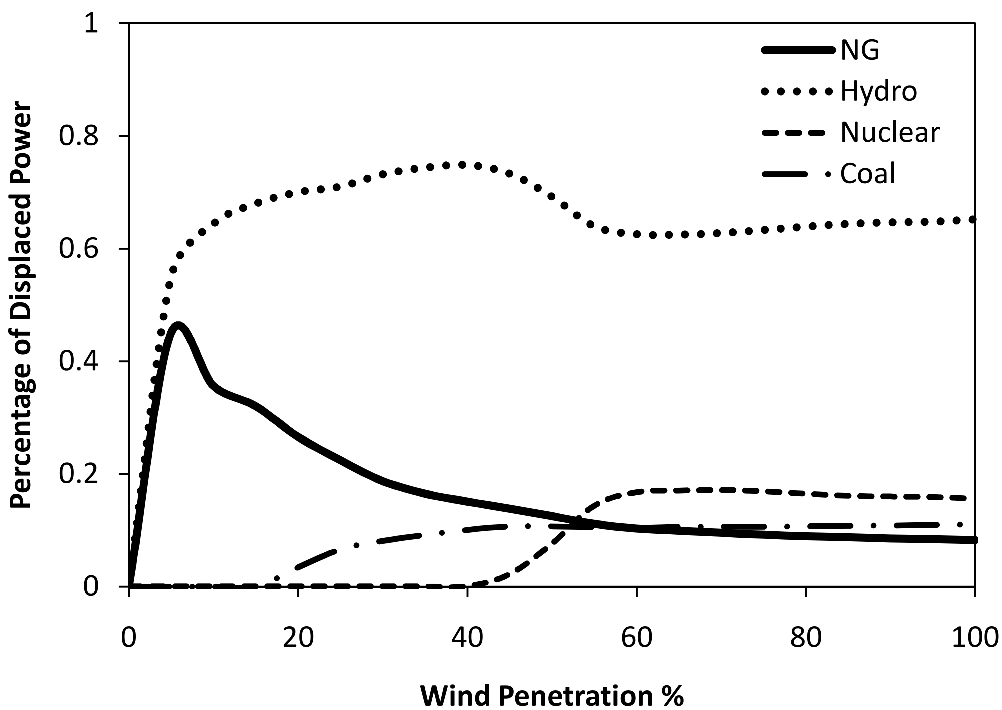

Figure 45: Makeup of displaced generation in Ontario – (Off-peak PHEV = 0%)

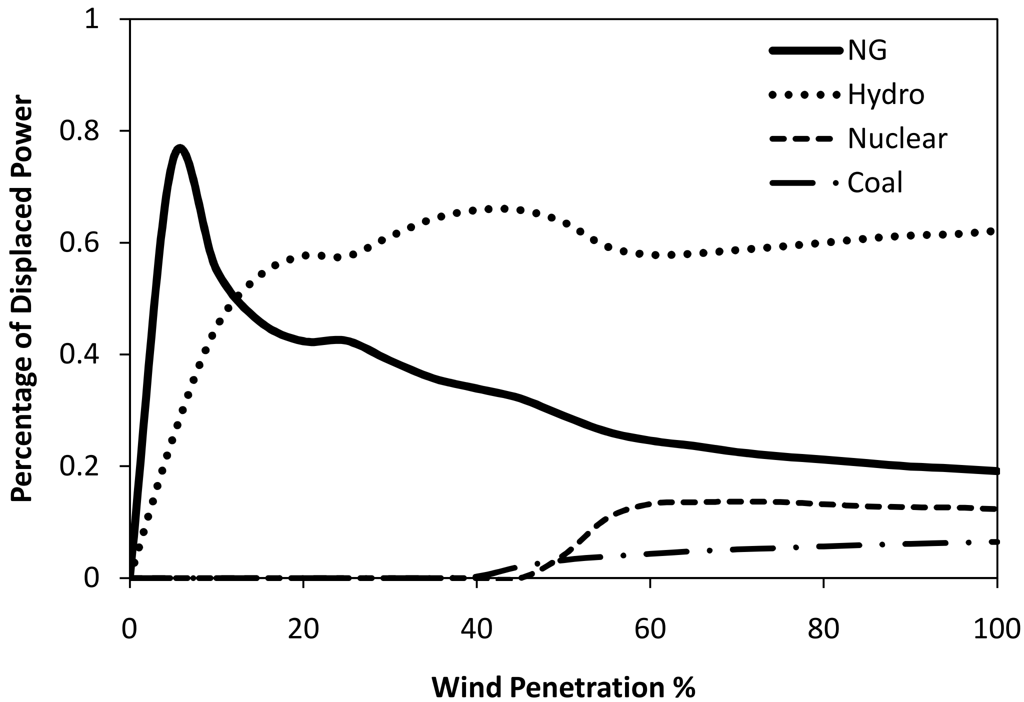

Figure 46: Makeup of displaced generation in Ontario – (Off-peak PHEV = 100%)

The first trend worth pointing out in both figures is that NG intially makes up a large percentage of the displaced generation, but becomes smaller as wind penetration grows. As wind injections increase, proportionally more hydro and nuclear are displaced, which has the effect of slowing emissions reductions and further increasing GHG costs. Note that for the zero-PHEV scenario, hydro and nuclear make up a larger percentage of the displaced generation than for the PHEV=100% scenario. As PHEV load is added in the off-peak hours, wind injections during this time will displace less hydro and nuclear power. Thus, for the PHEV=100%, NG and coal power make up a larger fraction of displaced power.

Note that hydro displacement occurs before coal displacement, even though coal power is more expensive than hydro. This is because coal power is used in a peaking role in Ontario. If wind injections occur in off-peak times, then hydro power is the first generation type to be displaced. If wind injections occur during on-peak hours, NG generation is displaced first. At wind penetrations above 40%, almost all possible NG displacement has already taken place, and thus coal displacement begins at this point.

A.2. Alberta

Results for Alberta are similar to the results shown for Ontario, as shown in Figure 47 and Figure 48. Initially, NG generation is displaced in large proportions, while proportionally more coal is displaced as wind is increased. Note that hydro is displaced in small proportions. This is due to the transmission limitation out of the South region, forcing curtailment of the small hydro installation (82 MW) to accomodate “must-take” wind.

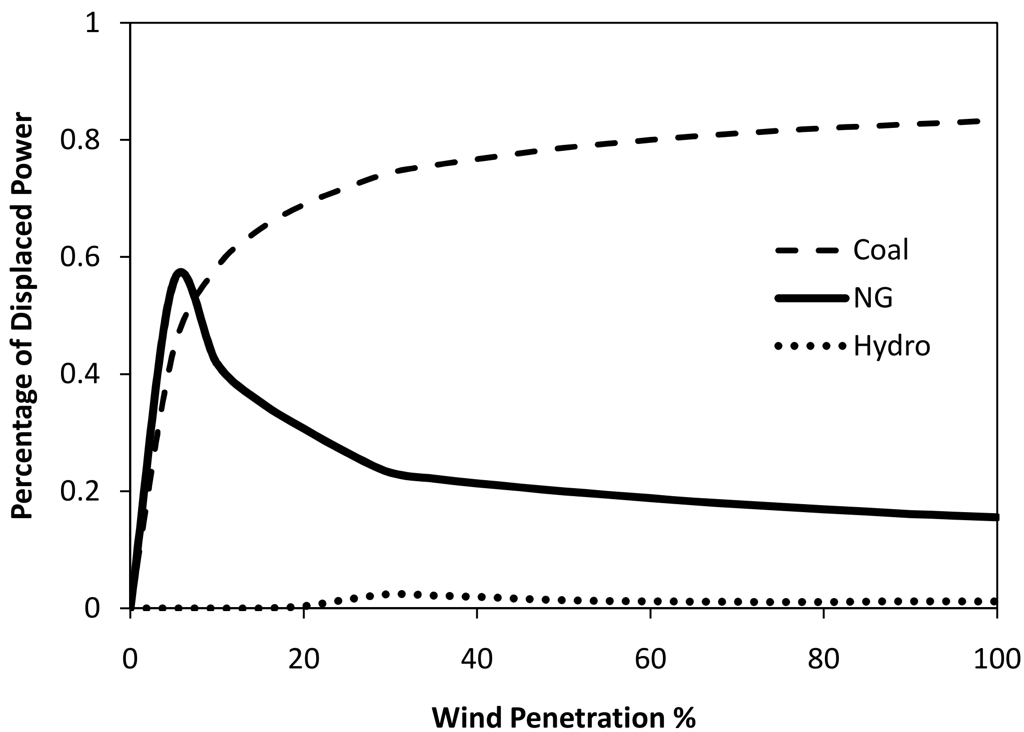

Figure 47: Makeup of displaced generation in Alberta – (Off-peak PHEV = 0%)

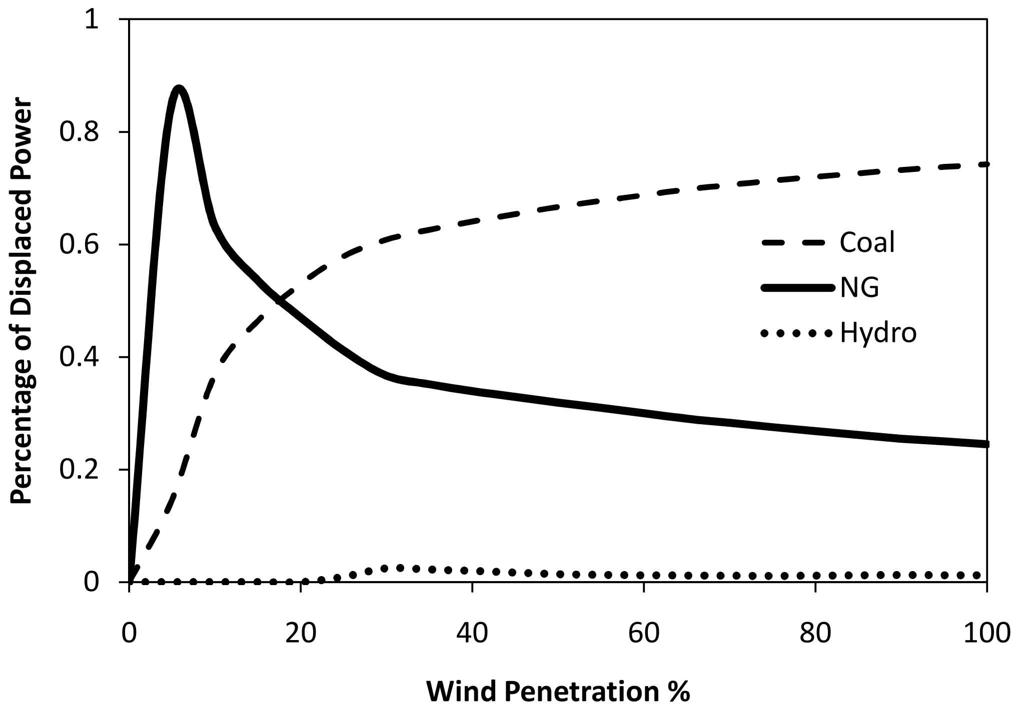

Figure 48: Makeup of displaced generation in Alberta – (Off-peak PHEV = 100%)

Even though NG is more expensive than coal, proportionally more coal power is displaced than NG. There are two major reasons for this. Since coal is cheaper, it is dispatched in a baseload role, and therefore makes up a majority of the power delivered during any given hour. This means that large wind injections displace proportionally more coal than NG. Second, transmission requirements force the dispatch of NG generation in several regions, particularily the northwest and northeast. Since wind power cannot displace the NG in these regions it instead forces curtailment of large coal plants in the Edmonton and Central regions. Note that more coal power is curtailed in the PHEV=0% scenario. Since off-peak charging is met with more coal generation than on-peak charging, less curtailment of baseload coal occurs as PHEV penetration increases.