The Cost of Decarbonizing the Canadian Electricity System

Brett Dolter [i]
Postdoctoral Research Fellow
Institute of the Environment
University of Ottawa

Nicholas Rivers
Associate Professor
Public and International Affairs
Institute of the Environment
University of Ottawa

i Corresponding Author: Brett Dolter, Institute of the Environment, University of Ottawa, 1 Stewart Street (301), Ottawa, ON K1N 6N5. Email: brett.dolter@gmail.com

The Cost of Decarbonizing the Canadian Electricity System

Abstract
Canada's electricity sector is predominantly low-carbon, but includes coal, natural gas, and diesel fuelled power plants. We use a new linear programming optimization model to identify least-cost pathways to decarbonize Canada's electricity sector. We co-optimize investments in new generation, storage and transmission capacity, and the hourly dispatch of available assets over the course of a year. Our model includes hourly wind speed data for 2281 locations in Canada, hourly solar irradiation data from 199 Canadian meteorological stations, hourly demand data for each province, and inter- and intra-provincial transmission line data. We model the capacity of hydropower plants to store potential energy and respond to variations in renewable energy output and demand. We find that new transmission connections between provinces and a substantial expansion of wind power in high wind locations such as southern Saskatchewan and Alberta could allow Canada to reduce electricity sector emissions at the lowest cost. We find that hydropower plants and inter-provincial trade can provide important balancing services that allow for greater integration of variable wind power. We test the impact of carbon pricing on Canada's optimal electricity system and find that prices of $80/tonne render Canada's coal-fired plants uneconomic.
Keywords: electricity; greenhouse gas emissions; linear programming; Canada; renewable energy; transmission

1. INTRODUCTION

"Clean up electricity. Electrify everything" (Roberts, 2016)

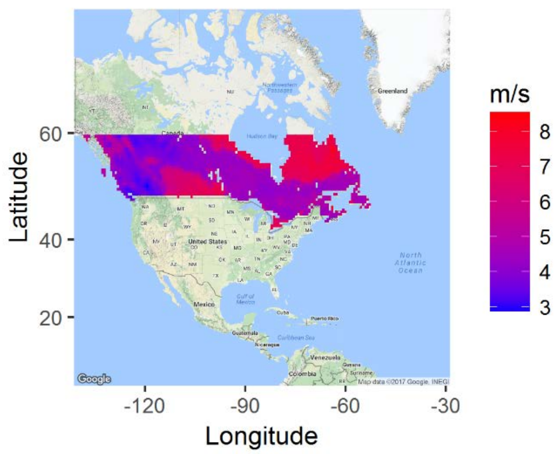
With the ratification of the Paris Agreement, the world has committed to "holding the increase in the global average temperature to well below 2 °C above pre-industrial levels" (UNFCCC, 2015: 2). By some estimates, meeting the 2 °C target will require global per capita greenhouse gas (GHG) emissions of 1.7 tonnes carbon dioxide equivalent (CO_2e) per person by 2050 (Bataille *et al.*, 2015). As context, Canada's per capita GHG emissions were 20.6 tonnes CO2e in 2014 (Environment and Climate Change Canada, 2016a). One prescription for achieving deep GHG emissions reductions is captured in the David Roberts (2016) quote above: decarbonize electricity, and "electrify everything", including transportation, heating, and industrial processes (Government of Canada, 2016a). This pathway represents a revolutionary transformation of our energy system, away from fossil fuels and towards low-carbon electricity.

In this paper, we ask: how much will it cost to decarbonize the electricity system? We use Canada as a case-study, recognizing that it starts from an advantageous position. In 2014, Canada generated 78.4% of its electricity using low-carbon technologies such as hydropower plants (60.3%), nuclear power plants (16.2%), and wind turbines (1.8%) (Statistics Canada, 2016 CANSIM 127-0007).[1] The remainder came largely from coal and natural gas power plants.

---

[1] Note that these Statistics Canada numbers are known to underestimate renewable energy production. For example, as of December 2016, the Independent Electricity System Operation (IESO) in the province of Ontario had 4,514 Megawatts (MW) of wind power capacity and 2,206 MW of solar power capacity under contract (IESO, 2016). By contrast, Statistics Canada (2016) CANSIM 127-0009 reports 2762 MW of wind capacity and 172 MW of solar capacity in Ontario for the year ending 2015. The discrepancy arises because Statistics Canada does not

We pay particular attention to the potential for Canada to develop wind and solar energy. Canada has several regions where annual average wind speeds at 50 meters (m) elevation reach 7 meters/second (m/s) or better, including the southern Plains of Alberta and Saskatchewan, southern Ontario, and northern Quebec (GMAO, 2016; see Figure 1a). Solar facilities can achieve annual capacity factors as high as 16% in sunny areas such as southeast Saskatchewan (MSC & NRC, 2010; Figure 1b). Canada is also the second largest hydropower producer in the world, behind only China and on par with Brazil (Natural Resources Canada, 2016). Canada's hydropower reservoirs can provide balancing services to allow higher integration of wind and solar onto the electricity grid.



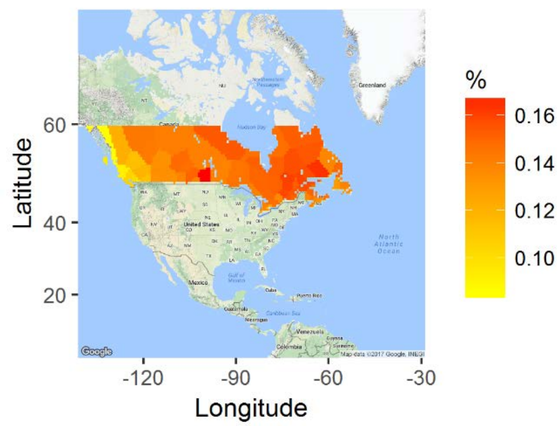


Figure 1a Wind Speed by MERRA Grid Cell **Figure 1b Solar Capacity Factors by MERRA Grid Cell**
Figure 1a Source: Global Modelling and Assimilation Office (GMAO) (2016); author's calculations. Figure 1b Source: Meteorological Service of Canada (MSC) and Natural Research Council (NRC) (2010a); author's calculations.

We also model the potential for high-voltage transmission lines to lower the cost of decarbonizing the Canadian electricity system. Canadian provinces have different electricity generation profiles (Figure 2). Hydropower plants are an important source of electricity generation in Quebec, Newfoundland and Labrador, Manitoba, and British Columbia. Provinces relying on coal and natural gas fired power plants include Saskatchewan, Nova Scotia, New Brunswick, and Alberta. Geographically, each of the fossil-fuel powered provinces is adjacent to a hydropower province. However, the existing transmission network allows only limited east-west inter-provincial electricity trade. We test whether strengthened transmission connections between provinces can lower the cost of reducing electricity sector GHG emissions in Canada.

survey facilities below a certain capacity threshold, and neither the IESO or Statistics Canada report generation from "embedded" wind and solar facilities connected to local distribution systems.

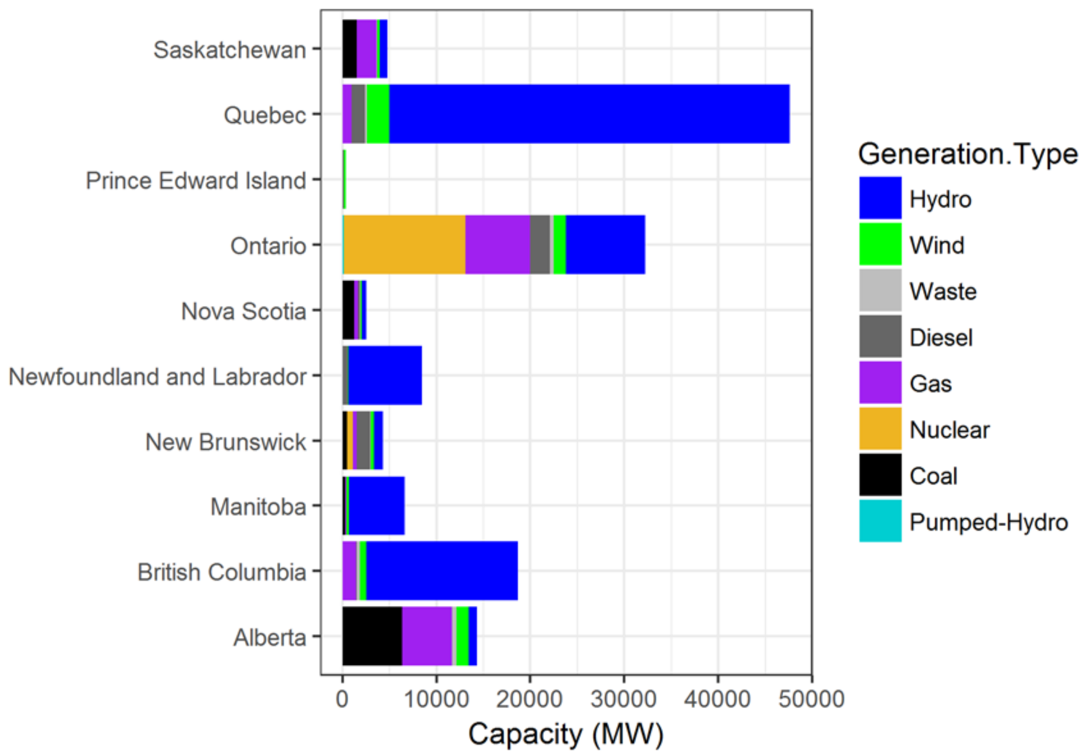


Figure 2 – Canadian Electricity Generation Capacity by Province[2]

Other recent studies of decarbonizing the Canadian electricity sector include the Trottier Energy Futures Project (TEFP, 2016), General Electric International (GE, 2016), and Ibanez and Zinaman (2015). The GE (2016) study finds that it is technically possible for wind energy to make up 35% of Canadian electricity generation. This is achieved by expanding wind power capacity to 65 Gigawatts (GW) in Canada with concentrations of 15 GW or more in Ontario, Quebec, and Alberta. In our results, we find similar potential for wind energy, but with a different provincial distribution of installations. The analysis by Ibanez and Zinaman (2015) jointly optimizes Canadian and United States (US) electricity futures. We model the interdependent nature of the Canadian and US electricity system by including hourly export data from Canadian provinces to the US.

Our contribution to the literature is threefold. First, we model the Canadian electricity system with much greater spatial and temporal resolution than previous studies. We include hourly demand data over the course of a year for each province, and hourly wind and solar capacity factor data for 2281 grid cells south of 60˚ latitude in Canada. We use this data to co-optimize investments in new generation with the hourly dispatch of available generation assets over the course of a year. This allows us to more realistically model the potential to integrate variable renewable energy sources like wind and solar onto the Canadian electricity system. In contrast, other studies typically model representative temporal snapshots of electrical grid operation, with lower resolution wind and solar data. We find that wind energy is a low-cost means of reducing GHG emissions and can supply 30-35% of electricity demand despite its variability. Our co-optimization approach is most similar to MacDonald *et al*. (2016) who

[2] This figures shows existing Canadian electricity capacity, minus expected retirements by 2025. Data is collected from various sources outlined in the Supplementary Information (SI) document that accompanies this paper.

evaluate the potential for greater renewable energy integration in the United States. MacDonald *et al*. (2016) find that increased investment in wind and solar power could allow the United States to reduce electricity sector GHG emissions by 80% below 1990 levels without increasing electricity costs. We find that investments in wind can achieve GHG reductions of 86.7% below 2025 reference scenario emissions and would increase electricity costs by $12 to $13/Megawatt-hour (MWh).

Second, we co-optimize investments in generation facilities with investments in transmission and storage technologies. Transmission lines and energy storage technologies can be thought of as substitute options for balancing the variability of renewable energy. We test which is most important in an optimized Canadian electricity system. We find that new inter-provincial transmission lines can reduce the cost of achieving a zero-carbon electricity system by 26% relative to scenarios where new inter-provincial transmission is not allowed. We also find that transmission lines obviate the need for energy storage in Canada. This finding mirrors MacDonald *et al*. (2016) who concluded that high-voltage direct current (HVDC) transmission lines allowed for high levels of renewable penetration without energy storage.

Third, we offer insights into the likely impact of proposed Canadian climate policies. The Canadian government has recently announced plans for a national carbon price that starts at $10/tonne carbon dioxide equivalent (CO_2e) and increases to $50/tonne by 2022 (Prime Minister of Canada, 2016). We consider the impact of carbon pricing on the optimal generation mix of the Canadian electricity sector. We find that, barring complementary policies, carbon prices must rise above $50/tonne to achieve significant decarbonization in Canada's electricity sector. We find that carbon prices of $80/tonne render Canada's remaining coal-fired plants uneconomical. We also find that some natural gas combined cycle capacity remains optimal even at carbon prices of $450/tonne. This means that complete decarbonization of the electricity sector is difficult to motivate using carbon pricing alone.

This paper proceeds as follows. In the next section, we describe our modelling approach and data sources. We then present the results of our analysis. In the final section, we discuss the policy implications of our results and conclude.

2. METHODOLOGY AND DATA

2.1 Model Design

We simulate the Canadian electricity system using a new a linear programming optimization model which co-optimizes the investment in new electricity generation, transmission, and storage facilities and the hourly dispatch of these facilities to meet electricity demand. A distinguishing feature of the model is the combination of high geographic and temporal resolution that is used, which is especially relevant for intermittent wind and solar technologies. We use this model to minimize the total annual cost of operating the Canadian electricity system, which includes annualized capital costs (CC), fixed operations and maintenance costs (FOM), variable operations and maintenance costs (VOM), fuel costs (FC), and carbon pricing costs (CP) (Equation 1).[3]

[3] In some of our scenarios, we motivate GHG emissions reductions by imposing a price on carbon dioxide emissions. Carbon pricing cost (CP) is a function of the electricity supplied by GHG emitting thermal generation technologies (tp) in each hour (h), the carbon price (cprice), the GHG content of fuel (fuel_CO2), and the fuel efficiency (η_{tp}) of each generation technology (Equation 2),

$$Total\ cost = CC + FC + FOM + VOM + CP.\ (Eq.1)$$

The model minimizes annual electricity system costs by selecting capital investments in electricity generation technologies, storage facilities, and transmission lines, as well as the hourly dispatch of available assets over the course of a year (8760 hours).

In this section, we provide a qualitative description of the model. A complete mathematical description of the model as well as the data used to parametrize the model is available in the Supplementary Information (SI).

2.2 Constraints

To give shape to the problem of planning Canada's electricity future, our model requires constraints. Important constraints include:

- Electricity supply must be equal to or greater than demand in each hour and balancing area;[4]
- Hourly dispatch from electricity generation assets must be less than or equal to installed capacity;
- Hourly electricity transmission between balancing areas must be less than or equal to transmission capacity;
- The density of wind installations in each grid cell must be less than 2 MW per kilometer-squared (km^2) (drawn from GE, 2016). We also exclude lakes and rivers from wind and solar development;
- The density of solar installations in each grid cell must be less than 31.3 MW per km^2 (drawn from Ong *et al.*, 2013).

We also include operational constraints to control the speed at which dispatchable generation facilities can ramp up and down, and set minimum and maximum annual capacity factors so that plants operate within a realistic range (Table 1). A full account of the constraints in our model is included in the SI.

2.3 Wind and Solar Energy Modelling

Our model includes hourly wind power capacity factor data for 2281 grid cells south of the 60th parallel

---

$$CP = \sum\nolimits_{h,tp} supply_{h,tp} \times cprice \times fuel\_CO2_{tp} \times 3.6 \times \frac{1}{\eta_{tp}}. \qquad (Eq.2)$$

There can be two interpretations of carbon pricing. When carbon pricing is used as a policy tool for achieving a GHG emission reduction objective, carbon pricing payments should be considered transfers from electricity utilities and consumers to government. From this perspective, the carbon pricing revenue is not lost, and should not be understood as an economic cost. However, there can be another interpretation. Carbon pricing is necessary to correct the market failure of carbon pollution and climate change. Economists and governments have attempted to put a value on the marginal damage caused by a tonne of GHG emissions emitted in a given year. In recent estimates, this "social cost of carbon" value ranges from \$10 to \$212 (2007 USD) per tonne of CO_2 with a mid-range value of \$46 (2007 USD) per tonne of CO_2 for emissions in 2025 (IWGSCGG, 2016). From this perspective, carbon pricing represents the external social cost of the electricity system, and, for carbon prices within this range, our optimization can be interpreted as minimizing social cost.

[4] Note that we do not model the requirement for surplus capacity to be maintained to provide backup in case of unexpected outages or increases in demand.

of latitude in Canada (each grid cell is one-half degree by two-thirds of a degree). We obtain hourly wind speed data from the *Modern-Era Retrospective analysis for Research and Applications* (MERRA) dataset (GMAO, 2016).[5] We translate this wind speed data into hourly capacity factors assuming a 3 MW wind turbine with 80-m hub height and 110-m rotor swept diameter (see Supplementary Information (SI) for details on construction of power curve). Hourly wind energy production in the model is the product of wind power capacity installed in a MERRA grid cell and the capacity factor in that grid cell and hour.

Our model also includes hourly solar capacity factor data for each MERRA grid cell. We first obtain solar irradiation, temperature and snowcover data for 199 meteorological stations south of 60˚ latitude from the *Canadian Weather for Energy Calculations* (CWEC) dataset (MSC & NRC, 2010). We then use this data to calculate hourly capacity factor values for each CWEC meteorological station (see SI for details). To match the spatial distribution of our wind data, we assign each MERRA grid cell the hourly solar capacity factor data of the nearest CWEC meteorological station. Like wind energy production, solar energy produced in each hour is the product of installed solar capacity in a given MERRA grid cell and the hourly capacity factor for that cell.

Wind and solar energy in our model is non-dispatchable. Rather, the model chooses the capacity of wind and solar power to build in each MERRA grid cell and a profile of annual electricity generation results based on hourly wind speeds and solar irradiation. The resulting renewable energy output varies over each hour according to the variability in wind and solar energy in each location and hour. It is important to note, however, that we do not model potential errors in forecasting wind and solar availability. In practice, an electricity system planner would face forecast errors when predicting wind and solar production and would schedule additional back-up capacity to be available when forecasts are incorrect. Because perfect foresight is built into our model, we likely under-estimate the dispatchable, balancing generation required to complement these variable renewables.

2.4 Hydroelectric Modelling

We do not allow investment in new hydropower capacity. Though Canada has additional hydropower potential, the costs of these projects are geography-specific and unknown to us. Existing hydropower plants are, however, an important part of hourly dispatch in our model.

We divide existing hydroelectricity into three types: run-of-river (30% of existing capacity), day-storage (35% of capacity), and month-storage (35% of capacity).[6] These three technologies differ in their ability

---

[5] MERRA grid cells vary in east-west width from 48.6 km at the 49th parallel to 37 km at the 60th parallel and have a north-south height of approximately 55.5 km.

[6] While we do not observe the proportion of hydro storage facilities by type directly, we believe our storage assumptions are reasonable. In British Columbia, BC Hydro (2016) reports that the utility has averaged 12,400 GWh of stored potential electricity in its system over the past ten years and had 17,800 GWh of system storage at the end of their 2015 fiscal year. Total hydroelectricity production in B.C. in 2014 was 57,572 GWh, meaning average system storage was equal to 21.5% of the annual total and the 2015 level was equal to 30.9% of total production (BC Hydro, 2016; Statistics Canada, 2016: CANSIM 127-0007). Hydro Quebec finished 2015 with 126,900 GWh of system storage, up from 103,700 GWh at the end of 2014 (Hydro Quebec, 2016). Total Hydro Quebec sales were 200,847 GWh in 2014 and 201,127 GWh in 2015, meaning system storage at the end of 2015 was equal to 63% of total sales (Hydro Quebec, 2016). These numbers indicate that both provinces have a large storage capacity and that intra-day and intra-month storage is substantial.

to store water for future electricity generation: run-of-river facilities cannot store water; day storage can store water over the course of a day; month-storage can store water over the course of a month.

Hydroelectricity production varies seasonally in Canada. We use monthly historic hydroelectric production data from Statistics Canada (2016; CANSIM Table 127-0002) to estimate average hourly electricity production by province and month. Run-of-river facilities are non-dispatchable and produce a constant hourly amount of electricity that varies by month according to historical output. Day-storage hydro is able to store water and optimally allocate production over the course of 24 hours. Production at day-storage plants is constrained so that total electricity generated does not exceed the average hourly production multiplied by 24 hours. Similarly, month-storage can shift production over the course of a month, ramping up electricity production in times of peak demand, and holding back water during times of low demand. Month-storage hydro facilities are constrained so that total production over the courses of a month does not exceed the average hourly production multiplied by the number of hours in the month. All of the hydro facilities are also constrained to meet minimum flow requirements, and to ensure that production does not exceed installed capacity in any given hour.

2.5 Demand Data

Hourly electricity demand data is sourced from provincial electricity utilities (Figure 3a; see SI for sources). Electricity demand includes exports to the US from the electricity exporting provinces: British Columbia, Manitoba, Quebec, and New Brunswick (Figure 3b). It also includes imports from the US to British Columbia. Canada's domestic demand for electricity peaks in the winter (Figure 3a), freeing up capacity to export electricity to the US in the summer months (Figure 3b).

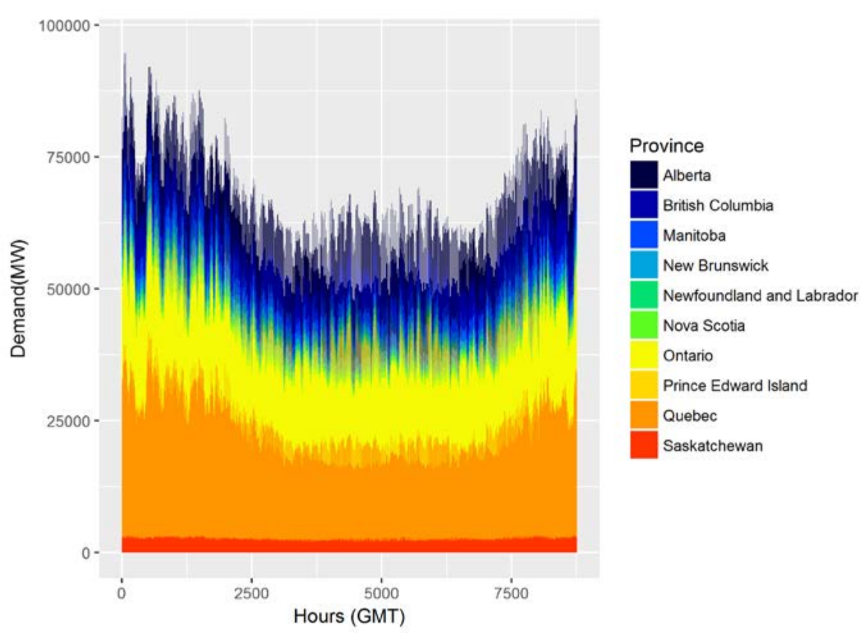


Figure 3a – Canadian Domestic Electricity Demand

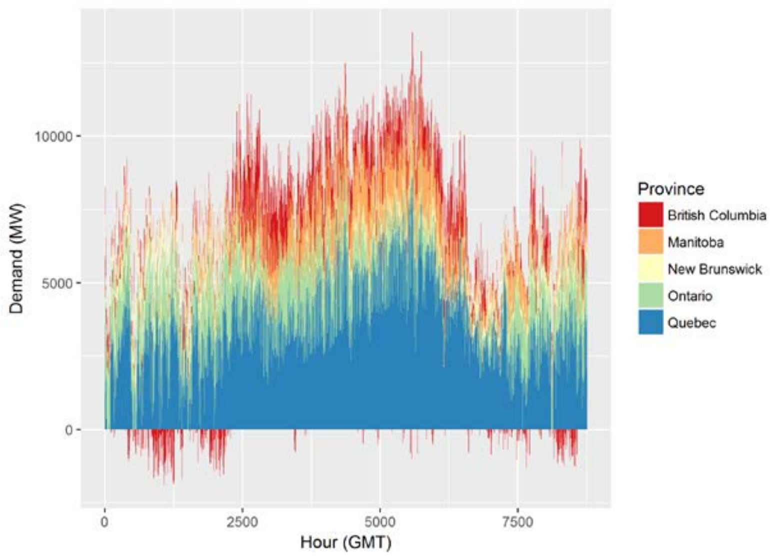


Figure 3b – Electricity Trade with the United States

We model Canadian electricity demand in 2025 by scaling electricity profiles for each province to match the 2025 electricity demand forecast presented in the General Electric study (GE, 2016, Section 4, p. 29). Scaling factors are a weighted average of forecast growth in annual energy (GWh) and forecast growth in peak demand (MW), each weighted equally. We assume zero growth of exports to the US. This is a conservative assumption based on the US Energy Information Administration (EIA)'s (2016) projection that electricity purchases from Canada will decline in the coming years.

We lack a detailed behavioural model of electricity consumption behaviour by electricity customers. For this reason, we do not model the potential for energy conservation actions that could lower electricity demand or demand response programs that could shift the timing of electricity demand. Instead, we focus on supply options for meeting a fixed level of electricity demand.

2.6 Generation Technologies and Cost Data

We model the potential for investment in the following generation technologies: coal-fired power plants, combined cycle natural gas-fired power plants, simple-cycle peaking natural gas-fired power plants, nuclear power plants, onshore wind power installations, and utility-scale solar power installations. Costs, fuel efficiency, and minimum and maximum annual capacity factors are drawn from Lazard (2015) and summarized in Table 1. Capital costs are amortized over 20 years for wind, solar, and natural gas combined cycle and peaking plants, and 25 years for all other generation technologies, storage facilities, and transmission lines.[7]

We include existing power plants in our model and account for planned retirements expected by 2025 and the completion of three hydroelectric projects currently under construction in Canada (the resulting 2025 provincial capacity figures are presented in Figure 2). We allow extant installations of diesel generators and waste power plants to be dispatched to meet hourly demand, but do not allow new

[7] We assume 20% debt-financing at 8% interest, and 80% equity financing at 12% interest.

investment in these technologies. For thermal generation technologies, we include fuel costs and model the GHG content of fuels (Table 2).

Technology	Capital Cost ($CAD/kw)	Amortization (yrs)	Annualized Capital Cost ($CAD/MW)	Efficiency (%)	Variable O&M ($/MWh)	Fixed O&M ($/MW/yr)	Capacity Factor (%)	
							Min.	Max.
Coal	$3,836	25	$440,647	39.0%	$4.48	$76,723	40%	93%
Diesel	$831	25	$95,474	39.0%	$19.18	$19,181	10%	95%
Natural Gas Combined Cycle	$1,471	20	$178,355	50.9%	$3.52	$7,480	40%	70%
Natural Gas Simple Cycle	$1,151	20	$139,582	28.0%	$7.80	$19,181	5%	20%
Nuclear	$8,695	25	$998,801	32.7%	$0.80	$172,626	40%	90%
Pumped Hydro	$2,500	25	$287,169	75.0%	-	$18,000	-	-
Solar	$1,790	20	$205,635	-	-	$14,705	-	-
Waste	NA	NA	NA	39.0%	$100.00	$100,000	40%	80%
Wind	$1,598	20	$193,864	-	-	$47,952	-	-

Table 1 – Cost and Operating Characteristics of Modelled Generation and Storage Technologies

Fuel	$ per GJ	tonnes CO_2e per GJ
Coal	1.80	0.090
Diesel	25.80	0.072
Natural Gas	4.91	0.051
Uranium	1.00	0.000

Table 2 –Cost and GHG Content of Fuels (various sources, see SI)

2.7 Storage Cost Data

New pumped-hydro facilities can be built to store potential energy and respond to variations in demand and variable renewable output. Cost and operating characteristics of pumped-hydro facilities are taken from TEFP (2016) and included in Table 1. We assume that storage facilities can provide eight hours of electricity generation at the nameplate capacity of the facility. We assume that 25% of energy is lost from pumping water to fill the storage facility.

2.8 Transmission Technologies and Cost Data

We divide Canada into balancing areas that largely coincide with provincial boundaries, except for Ontario, Quebec, and Newfoundland and Labrador, which are each divided into two north-south balancing areas. New high-voltage direct current (HVDC) electricity transmission can be built to connect balancing areas. We include existing transmission connections in our model with data drawn from TEFP (2016).

Cost data for new inter-balancing area transmission lines is taken from GE (2016) and is representative of a 345 kilovolt (kv) HVDC line with 1500 MW of transmission capacity (see Table 3). We assume a fixed transmission loss of 2% and a variable transmission loss of .003% per km for electricity transmitted between balancing areas. Inter-balancing area transmission losses and costs are calculated based on centroid-to-centroid distances between balancing areas.

Transmission Technology	Capital Cost ($Million CAD/km)	Annualized Capital Cost ($CAD/MW/km/yr)	Fixed O&M ($/MW/yr)
Double-circuit 345 kv HVDC	$2.4	$184	$10,860
Single-circuit 230 kv HVDC	$1.6	$557	-

Table 3 – Transmission Cost Assumptions (various sources, see SI)

We account for the cost of connecting new wind and solar installations to existing transmission lines. Transmission costs associated with new wind and solar installations are $557/MW/km/year, reflecting the cost characteristics of a single-circuit 230-kv HVDC line (Table 2; GE, 2016). Extant transmission line data is collected from DMTI (2016) and summarized in Figure 4.

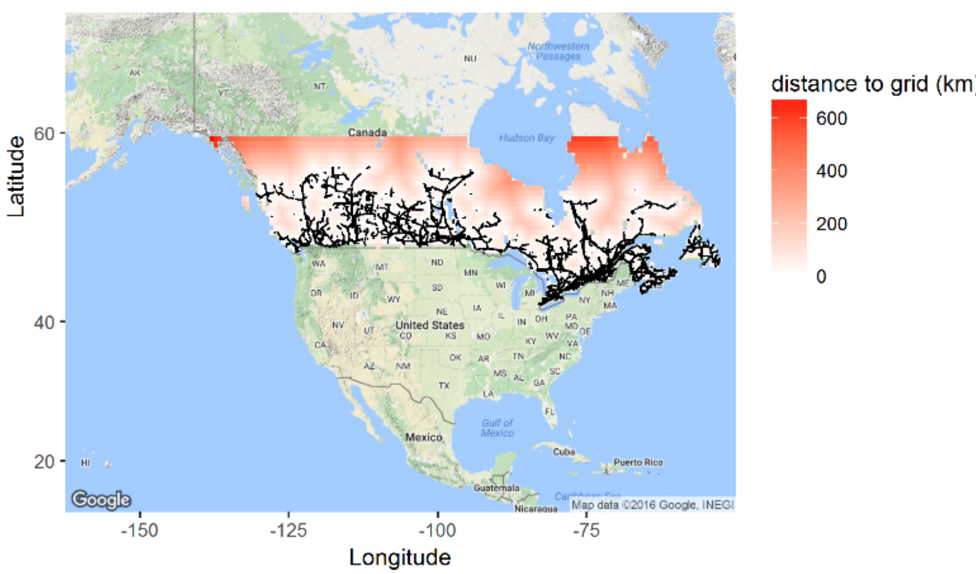


Figure 4 – Distance of MERRA Grid Cells to Existing Transmission Grid

(DMTI, 2016; author's calculations)[8]

2.9 Scenarios

We use our model to evaluate optimal electricity system configurations under different policy assumptions. All scenarios are run assuming forecast demand growth and scheduled capacity retirements for the year 2025. Because our model is a static, single-year model, we do not model the transition to the year 2025. Rather, we model the optimal system in 2025 based on our policy drivers: carbon pricing and emission reduction targets.

The Canadian government has announced their intentions for a national carbon price signal equivalent to $10/tonne in 2018, escalating to $50/tonne carbon dioxide equivalent (CO_2e) by 2022 (Prime Minister of Canada, 2016). We model carbon prices increasing in increments of $10/tonne CO_2e from $0 to $200 to understand the ability of carbon pricing to motivate the decarbonization of electricity in Canada. We model two variants of our carbon pricing scenarios; one variant in which new transmission capacity between provinces is allowed, and another variant in which no new inter-provincial transmission capacity is allowed (in this scenario intra-provincial transmission can still be built between the north and south balancing areas within Ontario, Quebec, and Newfoundland and Labrador).

We then evaluate the cost of achieving complete decarbonization by constraining GHG emissions to zero in the model. This complete decarbonization scenario is evaluated with and without new inter-provincial transmission.

3. RESULTS

3.1 Cost

Carbon pricing motivates GHG emission reductions by increasing the cost of releasing emissions. Investments that reduce emissions for less than the carbon price will be undertaken, while more expensive actions will not. As such, the carbon price in our model serves as a measure of the marginal cost of abatement (Figure 5). Evaluating increments of $10/tonne CO_2e, we find that significant emissions reductions occur at a threshold carbon price of $80/tonne CO_2e when coal-fired plants in Alberta are retired (Figure 5). After this large emissions reduction, the marginal abatement stepwise cost curves begin to increase more steeply indicating diminishing mitigation opportunities.

[8] Maps made using Google Map in R, open-source software described in Kahle and Wickham (2017).

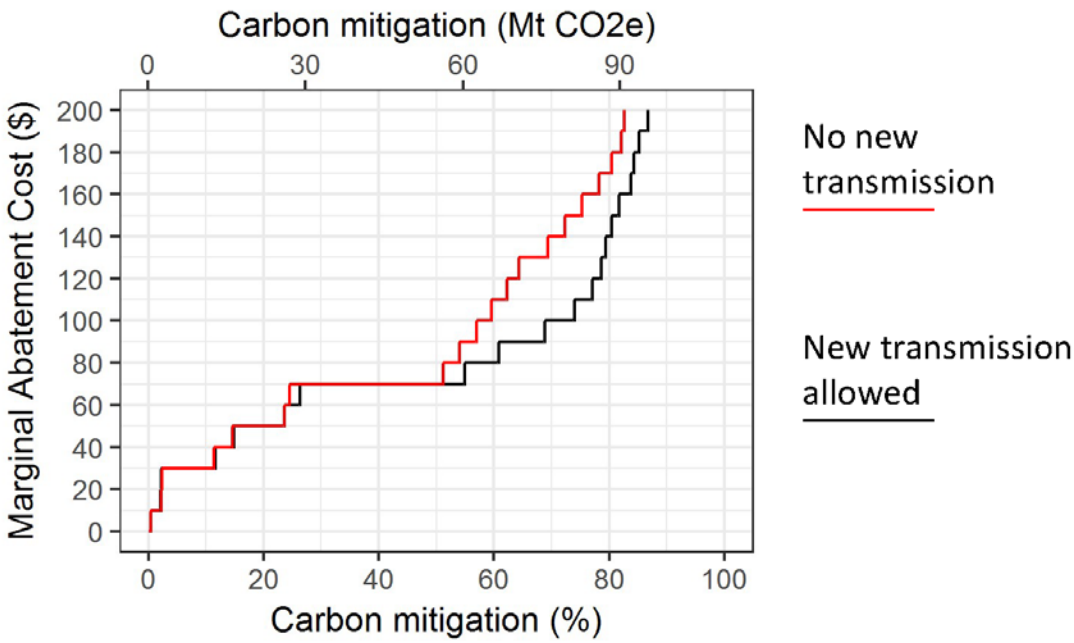
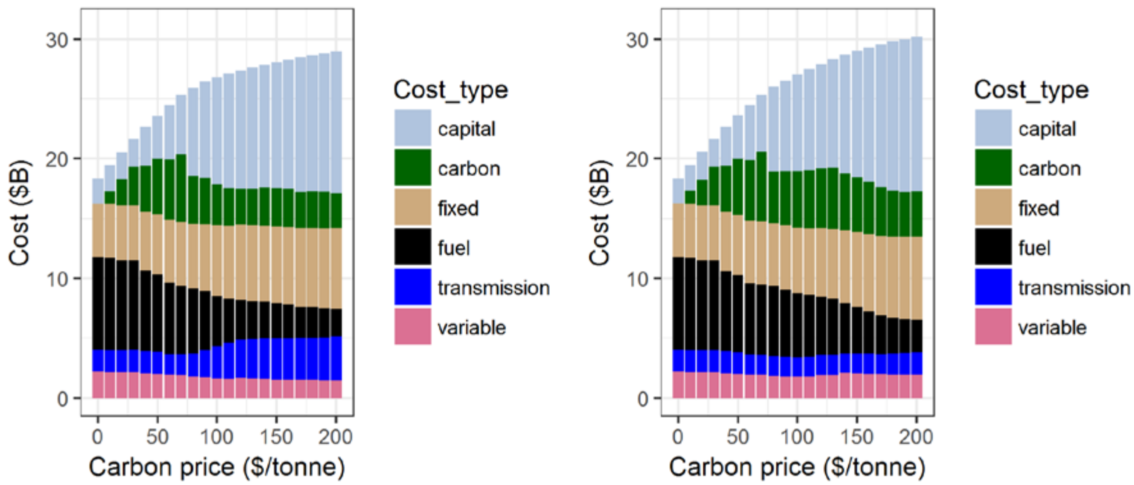


Figure 5 Marginal Abatement Stepwise Cost Curve (year = 2025)

The differences between the two stepwise curves after \$80/tonne CO_2e indicates that new inter-provincial transmission allows for greater GHG emissions reductions at a lower cost (Figure 5). GHG emissions in the reference scenarios are 110 Megatonnes (Mt) at a carbon price of \$0/tonne. At \$200/tonne CO_2e, electricity sector emissions have been reduced by 86.7% (95.3 Mt CO_2e) when transmission is allowed (the black line in Figure 4) and 82.7% (90.1 Mt of CO_2e) when no new transmission is allowed (the red line in Figure 4). Allowing transmission achieves an additional 5% (5.2 Mt CO_2e) of emissions reduction at a marginal abatement cost of \$200/tonne.

As carbon prices are increased, investments in new low-carbon generation substitute for the continued operation of thermal power stations. More money is invested in capital (light blue bars in Figure 6) and less is spent on fuel (black bars in Figure 6).[9] Expenditures on carbon pricing increase until the price reaches \$70/tonne CO_2e after which they decrease with the retirement of the Alberta coal-fired generation fleet. Carbon expenditures then remain roughly constant as emissions decline at a rate comparable to the increase of carbon prices. As mentioned above, these carbon expenditures are a transfer of funds from the electricity utility to government. For that reason, we do not include them in calculating the impact of emissions reductions on electricity costs below.

[9] Figure 6 is titled '*Incremental* Electricity Expenditure by Cost Category' because the figures do not display the complete costs of the Canadian electricity system. We do not account for payments on existing debt or administrative costs above operations and maintenance costs. The costs in Figure 6 a. and b. are limited to incremental capital costs for new generation, storage and transmission assets, and operational costs for all generation, storage and transmission assets.



a. New Transmission Allowed **b. No New Transmission**

Figure 6 Incremental Electricity Expenditure by Cost Category

Achieving emissions reductions will increase Canadian electricity costs (Figure 6 & 7). Reducing emissions by 86.7% (95.3 Mt) in the new transmission scenario would result in an additional annual cost of $7.7 billion (CAD 2015) relative to the reference scenario.[10] Averaged across all electricity production, this would increase electricity costs by $12.3/MWh. When transmission is not allowed, reducing emissions by 82% (90.1 Mt) would cost $8 billion (CAD 2015) and would add an average $12.8/MWh to the cost of electricity. In 2015, electricity rates for residential customers in Canada ranged from $82 to $178/MWh (Natural Resources Canada, 2016). If averaged across all customers, the emissions reductions would generate a 7-15% price increase for these customers. Relative impacts on industry would be greater. Industrial electricity rates in Canada range from $44 to $115/MWh (Natural Resources Canada, 2016). Average industrial rates could rise by 10-28%.

[10] The impact to average electricity costs does not include carbon pricing costs. We treat carbon pricing revenues as a transfer, not an economic cost.

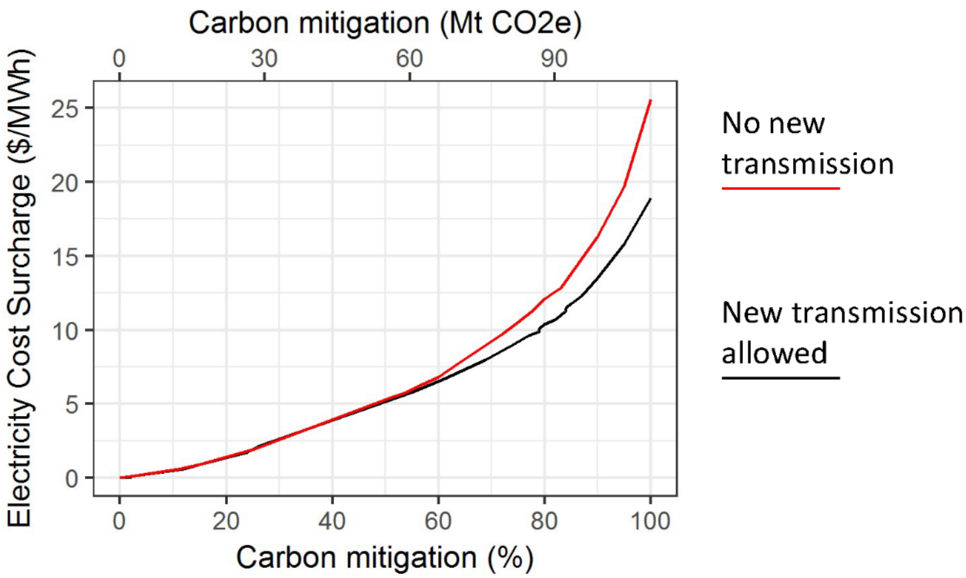
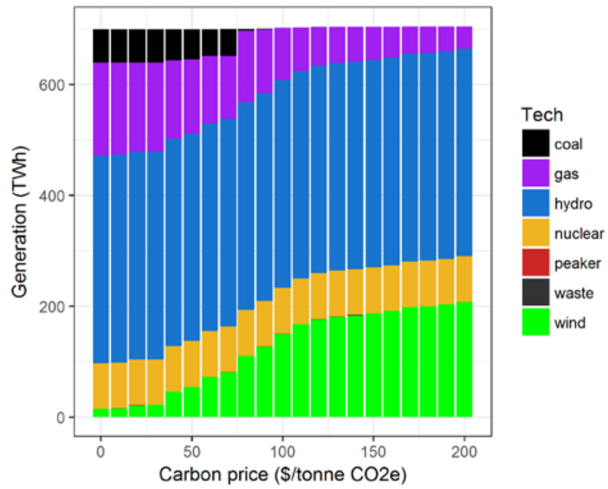


Figure 7 Electricity Price Impacts (year = 2025)

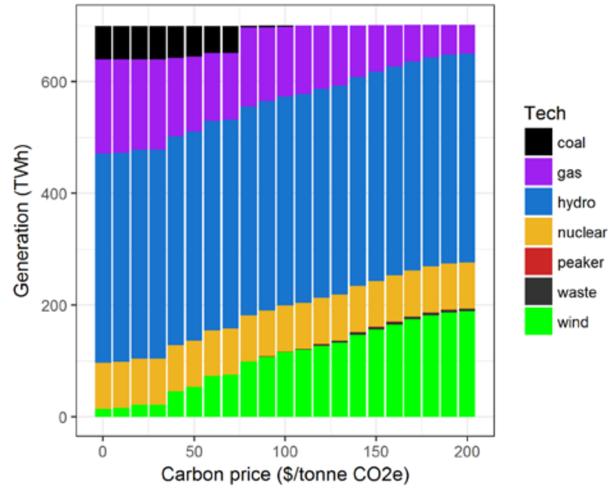
As Figure 5 indicated, a carbon price of $200/tonne CO_2e is not enough to motivate a complete decarbonization of the Canadian electricity sector. Even with carbon prices of $450/tonne, some GHG emissions remain in our optimized scenarios. To understand the cost of completely decarbonizing Canadian electricity we run scenarios where GHG emissions are constrained to equal zero. These scenarios result in an additional annual cost of $11.8 billion (CAD 2015) relative to the reference scenario when transmission is allowed, and $16 billion when transmission is not allowed. These costs in turn translate into average electricity cost increases of $18.9/MWh with new transmission and $26.4/MWh when new inter-provincial transmission is not allowed (Figure 7). In these scenarios, the benefits of allowing transmission become clear. New inter-provincial transmission can reduce the cost of completely decarbonizing the Canadian electricity system by $4.2 billion/year; 26% below the costs of decarbonization without new inter-provincial transmission.

3.2 Generation Mix

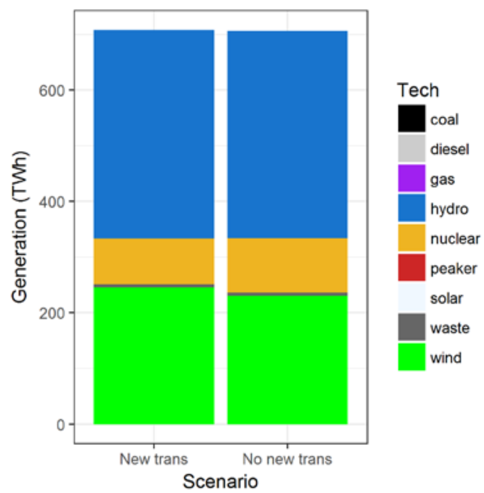
The optimal composition of Canada's generation mix shifts as carbon prices increase. Investments in wind power offer a low cost means of reducing emissions and are increasingly attractive at higher carbon prices (Figure 8). At $200/tonne CO_2e, wind composes nearly 30% of the optimal generation mix. In the 100% decarbonization scenarios, wind represents 35% of generation when new transmission is allowed, and 33% when it is not allowed (Figure 8c). These levels of wind penetration are comparable to the 35% of generation that GE (2016) found to be technically possible.



a. New transmission allowed



b. No new transmission



c. Zero Emissions

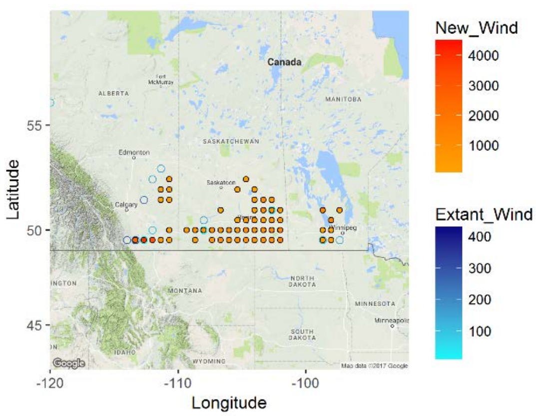
Figure 8 Annual Canadian Electricity Generation by Carbon Price Scenario

As mentioned above, it is optimal to retire coal plants in Alberta once carbon prices reach $80/tonne CO_2e. Combined cycle natural gas plants become a smaller portion of the optimal generation mix as the carbon price increases, except for a spike at $80/tonne CO_2e when they substitute for retired coal plants. Interestingly, natural gas combined cycle plants remain part of the optimal mix even at carbon prices of $200/tonne CO_2e. Though the levelized cost of electricity generated from a combined cycle natural gas plant exceeds that of wind power at carbon prices of only $12/tonne CO_2e, there is significant value to the dispatchable nature of natural gas plants that is not captured by measures of levelized cost.

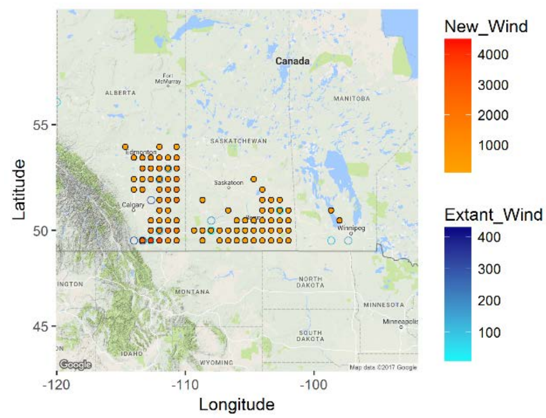
Due to their high cost relative to wind power and natural gas plants, utility-scale solar facilities and new nuclear facilities are not part of the optimal mix at carbon prices of $200/tonne. They are also not part of the optimal 100% decarbonization mix when transmission is allowed. Only when new transmission is not allowed and complete decarbonisation of the electricity system is modeled, are new nuclear facilities part of the optimal mix. In that instance, they are built in British Columbia (1600 MW), New Brunswick (900 MW), and Nova Scotia (910 MW). Solar also makes an appearance in the 100% decarbonization scenario when new transmission is not allowed; 100 MW of New Brunswick solar is optimal in that scenario. These results indicate that further cost improvements are necessary if either nuclear or solar are to offer a cost-effective means of reducing GHG emissions in Canada.

3.3 Geographic Dispersion of Wind Facilities

The model finds that new wind facilities are optimally located in southern Alberta, Saskatchewan and Manitoba (Figures 9a and 9b), southern Ontario (Figure 9c and 9d) and locations along the east coast (Figure 9e and 9f). The availability of new inter-provincial transmission lines changes the geographic dispersion of wind facilities. When new transmission is allowed, it is optimal to overbuild wind power capacity in Saskatchewan and export electricity to Alberta (Figure 9a).[11] Without new transmission, the model locates additional wind capacity in Alberta (Figure 9b). This finding contrasts with the GE (2016) study which concluded "there is no significant incentive to transport wind energy from slightly better wind locations over long distances (likely requiring new transmission facilities) when wind resources of almost equal quality are located closer to the provincial load centers where the energy would be used" (p. 18 of Section 1). Unlike the GE (2016) approach, we co-optimize the construction of generation and transmission assets. Using this approach, it appears there may be benefits to building wind power in the best sites and exporting to neighbouring markets.[12]



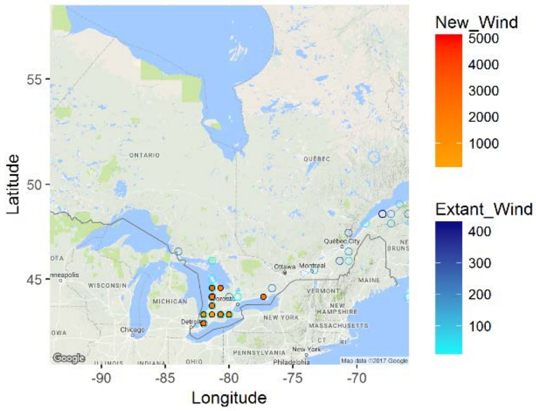
a. New Transmission Allowed



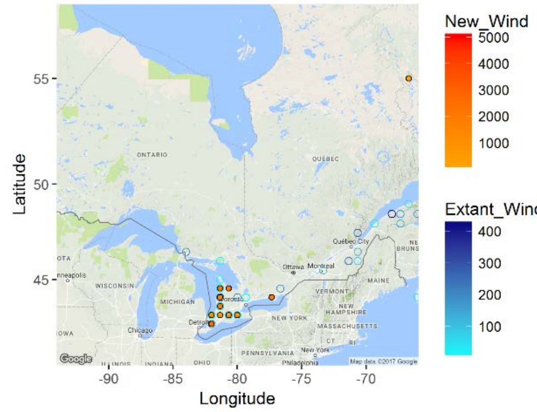
b. No New Transmission

[11] In the $200/tonne CO2e scenario, it is optimal to build 27.6 GW of wind capacity Saskatchewan when transmission is allowed and 6 GW when transmission is not allowed. Conversely, it is optimal to build 12.6 GW of wind capacity in Alberta when new transmission is allowed and 38.4 GW when no new transmission is possible. These levels of wind penetration are technically possible, but may not be socially acceptable (*e.g.* Höltinger *et al*., 2016; Jäger, 2016). We assume that wind power spacing requires 1 km^2 per 2 MW of wind capacity. In the 200/tonne CO_2e scenario, wind power would impact 13,794 km^2 of land in Saskatchewan. Much of southern Saskatchewan consists of cropland and pasture. More work is required to understand the degree to which wind turbines and agriculture are complementary, and the acceptability of building wind power in rural communities.

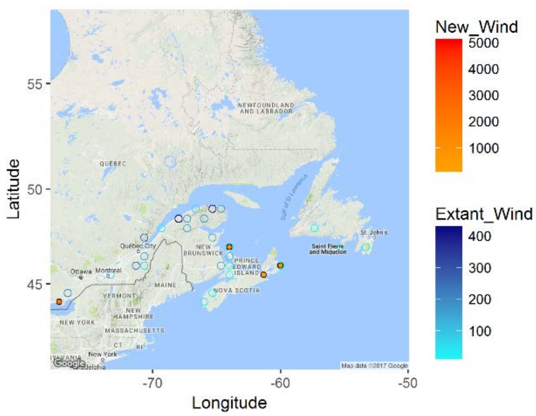
[12] Note that the GE (2016) study also constrains wind to a maximum penetration of 50% of electricity generation in any one province. We do not constrain the penetration of wind in this manner.



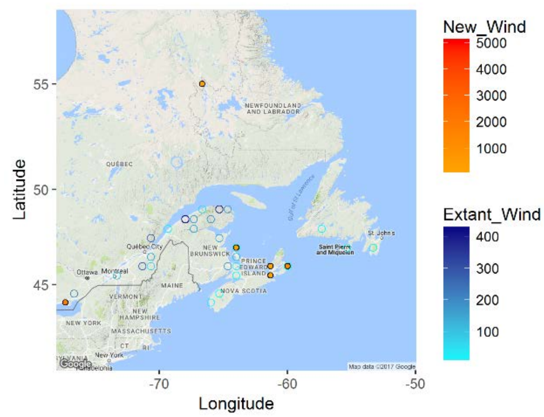
c. New Transmission Allowed



d. No New Transmission



e. New Transmission Allowed



f. No New Transmission

Figure 9 Optimal Wind Power Locations at $200/tonne CO_2e[13]

3.4 Transmission

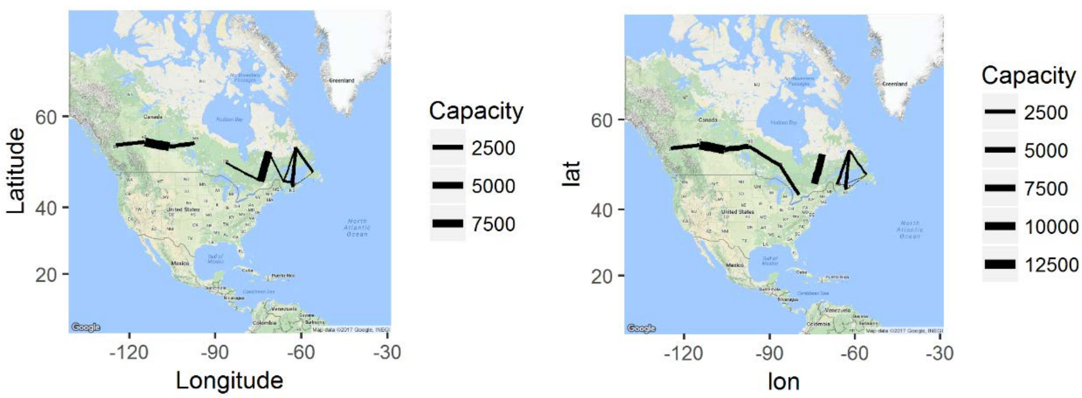
When allowed in our model, it is optimal to build new inter-provincial transmission in three main places.[14] First, the model recommends building transmission links between hydro-producing Labrador and neighbouring power markets on the east coast of Canada (Figure 10 and Table 4). This optimized east coast transmission network shows the desirability of the 'Maritime Link' transmission project currently under construction to connect Labrador's hydroelectric assets to the neighbouring island province of Nova Scotia via the island of Newfoundland (Emera, 2017). Our results also suggest a greater role for wind energy exports from Prince Edward Island. Second, it is optimal to build between northern

---

[13] Maps made using Google Map in R, open-source software described in Kahle and Wickham (2017).

[14] In all our scenarios, intra-provincial transmission is built between northern Quebec and southern Quebec to enhance electricity exports from the hydropower plants in the north to southern markets. New *intra*-provincial transmission is permitted in the model even when no new *inter*-provincial transmission is not.

Ontario and southern Quebec. Interestingly, transmission between Quebec and southern Ontario is not selected by the model. This may be due to our assumption of costless continuation of Ontario's nuclear fleet. Ontario's nuclear plants must be refurbished in the coming years. Further analysis is required to understand whether imports of hydroelectric energy from Quebec would offer a more cost-effective option for Ontario than nuclear refurbishment. Lastly, the model recommends enhanced connections between the four western provinces. This "western interconnect" project has been discussed in Canadian policy circles in the past (Christensen and McLeod, 2016; CAE, 2012). Our results suggest that a transmission line stretching from Manitoba to British Columbia has merit at \$200/tonne CO_2e (Figure 10a). An extension of the "western interconnect" to north and south Ontario is optimal in our zero emissions scenario (Figure 10b).



a. \$200/tonne CO_2e **b. Zero Emissions**

Figure 10 Optimal Transmission Connections at \$200/tonne CO_2e

Exporting Province	Importing Province	MW
Alberta	British Columbia	1700
Saskatchewan	Alberta	9552
Manitoba	Saskatchewan	1858
Ontario (north)	Quebec (south)	459
Quebec (north)	Quebec (south)	7167
Quebec (north)	New Brunswick	356
Newfoundland and Labrador (south)	Nova Scotia	48
Newfoundland and Labrador (north)	New Brunswick	340
Newfoundland and Labrador (north)	Newfoundland and Labrador (south)	759
Newfoundland and Labrador (north)	Nova Scotia	954
Newfoundland and Labrador (north)	Prince Edward Island	440
Prince Edward Island	New Brunswick	437
Prince Edward Island	Nova Scotia	549

Table 4 – Inter-Provincial HVDC Transmission Connections built at \$200/tonne CO_2e

Our modelling shows that new transmission connections obviate the need to build energy storage facilities. When new inter-provincial transmission is allowed, storage is not selected at carbon prices of $10-200/tonne CO_2e, and only a 28 MW storage unit in Saskatchewan is part of the optimal mix in the zero emissions scenario. When new inter-provincial transmission is not possible, it is optimal to build storage capacity in Alberta at carbon prices of $160-200/tonne CO_2e, and 6475 MW of storage across Canada in the zero emissions scenario. Most of the storage selected in the zero emissions scenario is located in Alberta (5177 MW), with the remaining located in Saskatchewan (682 MW), Nova Scotia (482 MW), Prince Edward Island (106 MW), and New Brunswick (28 MW). Without enhanced transmission links to neighbouring provinces, storage is required to balance the variability of wind (see below).

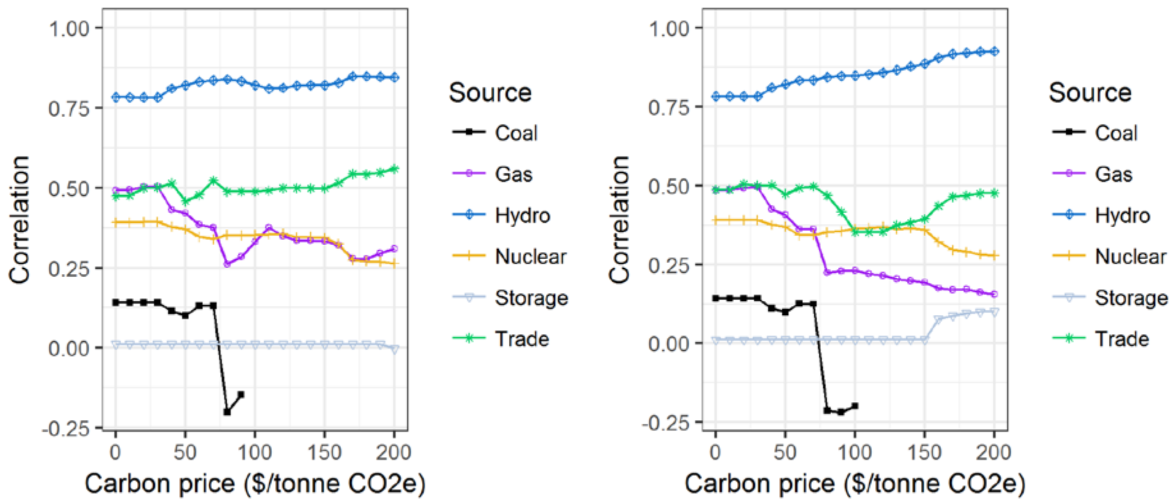
3.5 Balancing the Variability of Wind

The variability of wind requires a dispatchable supply of balancing energy. This energy can be supplied by domestic electricity generation, imports from neighbouring jurisdictions, or energy storage facilities. We calculate the sample Pearson correlation coefficient between net electricity demand (x) and the electricity supplied by various supply options (y_s) to understand which are most important for balancing wind output,

$$r_s = \frac{\sum_{h=1}^{8760}(x_h - \bar{x})(y_{s,h} - \bar{y}_s)}{\sqrt{\sum_{h=1}^{8760}(x_h - \bar{x})^2}\sqrt{\sum_{h=1}^{8760}(y_{s,h} - \bar{y}_s)^2}}. \qquad (Eq. 3)$$

Net electricity demand (x) refers to the electricity load that remains after accounting for the variable production of renewables like wind and solar. It is equal to Canadian domestic demand, plus exports to the United States, minus wind energy generation (and minus solar energy generation when solar is present).

Figure 11a and 11b display the resulting correlations between net demand and six supply options at the national scale for our carbon pricing scenarios. We find that hydropower facilities provide the dominant method of balancing the variability net demand across all carbon pricing scenarios. Second to hydro is trade, which plays an increasing role in balancing net demand when new transmission is allowed. Natural gas facilities also correlate positively with net demand, but their importance declines as carbon prices increase and gas plants are retired and used less frequently. The correlation between net demand and nuclear power output declines in higher wind integration scenarios. Nuclear power plants are constrained by slow ramp rates which make them less able to respond to the variability of net demand. Energy storage plays a role in balancing net demand when new transmission is not allowed. Storage plays a balancing role in the $160-200 /tonne CO_2e scenarios (Figure 11b). These results highlight the potential for Canada's hydroelectric assets to enable a much higher penetration of wind energy. They also highlight the value of transmission, and the limited role required of energy storage, to balance the variability of wind.



a. New transmission allowed **b. No new transmission**

Figure 11 Correlation Between Net Demand and Supply Options

4. CONCLUSIONS AND POLICY IMPLICATIONS

The Government of Canada has set a 2030 goal of reducing GHG emissions to 30% below 2005 levels. Reductions in the electricity sector can contribute to meeting this target. We find that least-cost emissions reductions within Canada's electricity sector are achieved by expanding Canada's wind power capacity. Canada can use its strong wind resources to generate electricity, and can use existing hydropower assets and enhanced electricity trade between provinces to balance the variability of wind. This shift towards wind power can be motivated by carbon pricing. Building on carbon pricing efforts by British Columbia, Quebec, Ontario, and Alberta, the Canadian government announced a national carbon price that will begin at $10/tonne CO_2e in 2018 and rise to $50/tonne by 2022 (Prime Minister of Canada, 2016). We find that a $50/tonne carbon price could decrease greenhouse gas emissions in the electricity sector by 20-21 % below Canada's 2005 electricity sector emissions (Environment and Climate Change Canada, 2016). If the electricity sector is to contribute proportionately to Canada's 2030 goal – without complementary emission reduction policies in the electricity sector – Canada's carbon price must continue to rise beyond 2022.

The Canadian government has introduced regulations that impact Canada's coal-fired power plants. In 2012, the Canadian government introduced regulations requiring coal-fired facilities to achieve a performance standard of 420 tonnes CO2e / Gigawatt-hour (GWh) when they reach the end of their 50-year useful life (CEPA, 2012). This standard can be achieved by retiring coal plants or equipping units with carbon capture and storage technology. In 2016, the Canadian government announced plans to tighten those regulations to ensure that all plants meet the performance standard by 2030 (Government of Canada, 2016b). The accelerated coal phase-out offers a substitute for higher carbon prices. Our modelling suggests that retiring coal and replacing it with lower-carbon generation sources like wind power and natural gas facilities has an implied marginal abatement cost of between $70-80/tonne CO_2e and reduces GHG emissions to 54-58% below 2005 levels. The coal phase-out increases total electricity system costs by $3.4-3.6 billion/year (CAD 2015), which, averaged across demand equals $5.4-5.8/MWh.

To achieve the reductions outlined in *Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy* (Government of Canada, 2016a), Canada must contemplate complete decarbonization of the electricity sector. In this instance, policies beyond carbon pricing are likely required. Beyond $80/tonne CO_2e, the marginal abatement stepwise cost curve increases steeply. Each $10/tonne increase of the carbon price motivates the retirement of additional natural gas capacity, but natural gas capacity is not fully retired even at very high carbon pricing levels of $450/tonne. This is because, despite a higher levelized cost, natural gas provides valuable balancing services. A natural gas phase-out would help lower electricity sector emissions to zero, but would require additional investment in low-carbon generation, new transmission lines, and energy storage facilities if new inter-provincial transmission is not possible. Achieving complete decarbonization by 2025 would add another $8.2-12.6 billion (CAD 2015) to annual costs, bringing total annual costs to $11.8-16 billion (CAD 2015) above the reference scenario. Building inter-provincial HVDC transmission connections promises to reduce the cost to the lower end of that range, saving $4.2 billion (CAD 2015) or 26% of the high-cost scenario. By mid-century, improvements in the cost of generation, transmission, and storage technologies could also help to reduce the cost of decarbonization.

Our modelling demonstrates there is value to building new inter-provincial HVDC transmission lines. As the Canadian Academy of Engineering (CAE) writes, "The main obstacle (to new inter-provincial transmission) remains the political will to commit to such an objective, and to craft a workable financial architecture which spreads both risk and return on investment among all stakeholders" (2016: 73). Canada's federal structure means that the Canadian government could play an important coordinating role. The moment for coordination may have arrived. The Canadian government has signalled its willingness to fund new inter-provincial transmission projects (Government of Canada, 2016b), and our research shows that these projects can help Canada to meet its GHG emission reduction goals at a lower cost to Canadians.

Acknowledgements
The authors would like to acknowledge helpful comments from discussant Randall Wigle and other participants at the Canadian Resource and Environmental Economics (CREE) conference in Banff 2016. The authors would also like to thank Philippe Kabore (University of Ottawa) for his research assistance.

Funding Support
Dolter acknowledges the funding received from the Social Science and Humanities Research Council Postdoctoral Fellowships Program. Rivers acknowledges the funding received from the Social Science and Humanities Research Council Canada Research Chairs Program.

References

Bataille, Chris, David Sawyer, and Noel Melton (2015) *Pathways to Deep Decarbonization in Canada*. Deep Decarbonization Project. Available on-line at: http://deepdecarbonization.org/wp-content/uploads/2015/09/DDPP_CAN.pdf. Last accessed December 20, 2016.

BC Hydro (2016) *Revenue Requirements Application Fiscal 2017 to Fiscal 2019*. Vancouver, BC: BC Hydro. Available on-line at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf. Last accessed September 27, 2016.

Canadian Association of Engineering (CAE) (2012) Canadian Academy of Engineering (2012) Canada: Winning as a Sustainable Energy Superpower – Volume II – The Details. Available on-line at: https://www.cae-acg.ca/canada-winning-as-a-sustainable-energy-superpower/. Last accessed January 11, 2017.

CEPA (Canadian Environmental Protection Act): Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (2012) *Canada Gazette Part II*, 146:19. Retrieved from: http://www.gazette.gc.ca/rp-pr/p2/2012/2012-09-12/html/sor-dors167-eng.html. Last accessed January 11, 2017.

Christensen, Naomi and Trevor McLeod (2016) *Power Up: The Hydro Option*. Canada West Foundation. Available on-line at: http://cwf.ca/research/publications/power-up-the-hydro-option/.

DMTI Spatial (2016) "Transmission Line Lines" Available on-line at: http://geo.scholarsportal.info/#r/details/_uri@=2731396105. Last accessed November 25, 2016.

Emera (2017) "Maritime Link." Available on-line at: http://www.emeranl.com/en/home/themaritimelink/overview.aspx. Last accessed January 11, 2017.

Energy Information Administration (EIA) (2016) "Electric Power Projections by Electricity Market Module Region." *Annual Energy Outlook, 2016*. Available on-line at: http://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2016&cases=ref2016&sourcekey=0. Last accessed November 28, 2016.

Environment and Climate Change Canada (2016a) "Greenhouse Gas Emissions per Person and per Unit Gross Domestic Product." Available on-line at: https://www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=79BA5699-1. Last accessed December 20, 2016.

Environment and Climate Change Canada (2016b) "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada - Executive Summary." Available on-line at: https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1#ghgemissions. Last accessed January 11, 2017.

General Electric International Inc. (GE) (2016) *Pan-Canadian Wind Integration Study*. Published by the Canadian Wind Energy Association (CANWEA). Available on-line at: http://canwea.ca/wind-energy/wind-integration-study/. Last accessed September 15, 2016.

Global Modelling and Assimilation Office (GMAO) (2016) *Modern-Era Retrospective analysis for Research and Applications (MERRA)*. NASA/GSFC, Greenbelt, MD, USA, NASA Goddard Earth Sciences Data and Information Services Center (GES DISC). Available on-line at: http://disc.sci.gsfc.nasa.gov/mdisc/data-holdings. Last updated February 2016.

Government of Canada (2016a) *Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy*. Submitted to the United Nations Framework Convention on Climate Change. Available on-line at: http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf. Last accessed December 15, 2016.

Government of Canada (2016b) "The Government of Canada accelerates investments in clean electricity." *News Release*. Available on-line at: http://news.gc.ca/web/article-en.do?nid=1157989&wbdisable=true. Last accessed January 11, 2017.

Hydro Quebec (2016) *2015 Annual Report*. Available on-line at: http://www.hydroquebec.com/publications/en/docs/annual-report/annual-report.pdf. Last accessed September 27, 2016.

Höltinger, Stefan, Boris Salak, Thomas Schauppenlehner, Patrick Scherhaufer, Johannes Schmidt (2016) "Austria's wind energy potential – A participatory modeling approach to assess socio-political and market acceptance." *Energy Policy*. 98, pp. 49-61. DOI: 10.1016/j.enpol.2016.08.010.

Ibanez, Eduardo and Owen Zinaman (2016) "Modeling the integrated expansion of the Canadian and US power sectors." *The Electricity Journal*. 29, pp. 71-80. DOI: 10.1016/j.tej.2015.12.003.

Interagency Working Group on Social Cost of Greenhouse Gases, United States Government (IWGSCGG) (2016) *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866*. Available on-line at: https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

Jäger, Tobias, Russell McKenna, Wolf Fichtner (2016) "The feasible onshore wind energy potential in Baden-Württemberg: A bottom-up methodology considering socio-economic constraints." *Renewable Energy*. 96, pp. 662-675. DOI: 10.1016/j.renene.2016.05.013.

Kahle, D. and H. Wickham (2017). "ggmap: Spatial Visualization with ggplot2." *The R Journal*. 5:1, pp. 144-161. http://journal.r-project.org/archive/2013-1/kahle-wickham.pdf.

Lazard (2015) *Levelized Cost of Energy Analysis – Version 9.0*. Available on-line at: https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-90/. Last accessed: September 1, 2016.

MacDonald, Alexander E., Christopher T.M. Clack, Anneliese Alexander, Adam Dunbar, James Wilczak, and Yuanfu Xie (2016), "Future cost-competitive electricity systems and their impact on US CO2 emissions." *Nature Climate Change*. January 25, 2016, DOI: 10.1038/NCLIMATE2921.

Meteorological Service of Canada (MSC) and Natural Research Council (NRC) (2010) *Canadian Weather for Energy Calculations (CWEC Files).* Available online at: http://climate.weather.gc.ca/prods_servs/engineering_e.html. Last accessed September 6, 2016.

National Energy Board (2016) *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040*. Calgary, AB: National Energy Board. Available on-line at: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html#s3. Last accessed September 27, 2016.

Natural Resources Canada (2016) *Energy Fact Book 2016-17*. Available on-line at: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/EnergyFactBook_2016_17_En.pdf. Last accessed January 16, 2017.

Ong, Sean, Clinton Campbell, Paul Denholm, Robert Margolis, and Garvin Heath (2013) *Land-Use Requirements for Solar Power Plants in the United States*. Boulder, CO: National Renewable Energy Laboratory. Available on-line at: http://www.nrel.gov/docs/fy13osti/56290.pdf. Last accessed September 20, 2016.

Prime Minister of Canada (2016) "Prime Minister Trudeau delivers a speech on pricing carbon pollution." http://pm.gc.ca/eng/news/2016/10/03/prime-minister-trudeau-delivers-speech-pricing-carbon-pollution. Last accessed December 24, 2016.

Roberts, David (2016) "The key to tackling climate change: electrify everything." *Vox*. Available on-line at: http://www.vox.com/2016/9/19/12938086/electrify-everything. Last accessed January 16, 2017.

Statistics Canada (2016) *Assorted CANSIM Tables*. Available on-line at: http://www5.statcan.gc.ca/cansim/home-accueil?lang=eng. Last accessed December 20, 2016.

Trottier Energy Futures Project (TEFP) (2016) *Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions*. The Canadian Academy of Engineering and the Trottier Family Foundation.

United Nations Framework Convention on Climate Change (UNFCCC) (2015) *Paris Agreement*. Available on-line at: http://unfccc.int/paris_agreement/items/9485.php. Last accessed December 20, 2016.

Canadian Renewable Integration

Model Documentation

Introduction

We use a new linear programming optimization model to evaluate alternative strategies for investing in and operating the Canadian electricity sector. The model combines a simulation of investments in electricity generation and transmission capacity with an hourly dispatch model. As its objective function, the model minimizes total annual cost. Decision variables include investment in new electricity generation, storage and transmission capacity, retirement of existing capacity, and hourly dispatch of available technologies to meet electricity demand over the course of a full year.

Model Notation

The notation used in documenting the model is given in Tables 1 to 4. Specifically, Table 1 introduces the notation used to index model variables and parameters, Table 2 describes the endogenous variables in the model, Table 3 describes the exogenous parameters (data) used in the model, and Table 4 summarizes the decision variables.

Symbol	Definition
h	Hours in the year (1:8760)
d	Days in the year (1:365)
m	Months in the year (1:12)
p	Electric generating plant types (on-shore wind, solar photovoltaic, nuclear, coal, natural gas, waste, diesel, hydroelectric (further divided into run-of-river, large capacity storage hydro, small capacity storage hydro, and pumped storage hydro))
$tp(p)$	Thermal electric generating plant types (coal, diesel, natural gas, nuclear, waste)
$rp(p)$	Non-dispatchable renewable generating plant types (on-shore wind, solar photovoltaic)
$hp(p)$	Hydroelectric generating plant types (run-of-river, large capacity storage hydro, small capacity storage hydro, pumped storage hydro)
ap,apa	All provinces (10 provinces, excluding territories)
aba,$abba$	All balancing areas
l	Grid locations

Table 1: Notation for sets defined in the model. Brackets indicate that one set is a subset of another. For example x(y) indicates that x is a subset of the set y.

Symbol	Definition
totalcost	Total cost of supplying electricity for one year
fuelcost	Annual total fuel cost for thermal electricity generation plants
capitalcost	Annual capital cost for all new generation plants
varcost	Variable operations and maintenance cost for all electricity generation plants
fixcost	Fixed operations and maintenance cost for all electricity generation plants
carbon(*ap*,*aba*)	Annual carbon dioxide emissions for balancing area *aba* and province *ap* expressed in megatonnes (Mt) carbon dioxide equivalent (CO_2e)

Table 2: Notation for endogenous variables defined in the model

Symbol	Definition
fuelprice(*tp*)	Price of fuel in dollars per GJ for plant type *tp*
fuel_CO_2(*tp*)	Carbon dioxide content of fuel in kilograms (kg) CO_2e/Gigajoule (GJ)
η(*tp*)	Efficiency of thermal plant *tp* (electrical output per unit of thermal input)
capital_cost(*p*)	Annualized capital cost for electricity plant type *p*
variable_o_m(*p*)	Variable operations and maintenance cost per megawatt-hour (MWh) electricity generated for plant type *p*
fixed_o_m(*p*)	Annual fixed operations and maintenance cost per megawatt (MW) installed capacity per year for plant type *p*
store_cost	Annualized capital cost for new pumped hydroelectric storage capacity
trans_cost	Annualized capital cost for constructing new high voltage transmission capacity, in dollars per MW-kilometer (km)
intra_ba_transcost	Annualized capital cost for constructing transmission to connect new wind and solar facility with existing transmission grid, in dollars per MW-km of capacity
distance(*aba*,*ap*,*abba*,*apa*)	Distance in km between centroid of balancing area *aba* in province *ap* to balancing area *abba* in province *apa*
distance_to_grid(*gl*)	Distance in km between centroid of MERRA grid cell and nearest transmission line
trans_loss(*aba*,*ap*,*abba*,*apa*)	Share of electricity lost in transmitting from balancing area *aba* in province *ap* to balancing area *appa* in province *apa*
capacity_factor(*h*,*l*,*rp*)	Capacity factor for a renewable plant of type *rp* built at location *l* in hour *h*
extant_renew_capacity(*l*,*rp*)	Extant renewable electricity generating capacity in location *l* by plant type *rp*
ba_pump_hydro_capacity (*aba*,*ap*)	Extant pumped hydro storage capacity in balancing area *aba* and province *ap*
demand_us(*h*,*aba*,*ap*)	Demand for electricity exports to the United States by hour *h* in each balancing area *aba* and province *ap*
demand(*h*,*aba*,*ap*)	Electricity demand by hour *h* in each balancing area *aba* and province *ap*

Table 3: Notation for exogenous parameters defined in the model

Symbol	Definition
supply(*h*,*aba*,*ap*,*tp*)	Supply of electricity (MWh) in hour *h* in balancing area *aba* in province *ap* by plant type *tp*
windout(*h*,*aba*,*ap*,*wind*)	Wind electricity (MWh) generated in hour *h* in balancing area aba and province ap
pumpenergy(*h*,*aba*,*ap*)	Stored potential energy in pumped hydroelectric storage facilities in hour *h* in balancing area *aba* in province *ap*
pumpout(*h*,*aba*,*ap*)	Stored potential energy released and used to meet demand in hour *h* balancing area *aba* and province *ap*
pumpin(*h*,*aba*,*ap*)	Electricity used to increase stored potential energy of pumped hydroelectric storage in hour *h* balancing area *aba* and province *ap*
daystoragehydroout(*h*,*aba*,*ap*)	Hydroelectric output in hour *h*, balancing area *aba* and province *ap* from facilities that are capable of storing potential energy over the course of 24 hours
monthstoragehydroout(*h*,*aba*,*ap*)	Hydroelectric output in hour *h*, balancing area *aba* and province *ap* from facilities that are capable of storing potential energy over the course of a month
transmission(*h*,*aba*,*ap*,*abba*,*apa*)	Transmission of electricity from balancing area *aba* in province *ap* to balancing area *abba* in province *apa*
gen_capacity(*aba*,*ap*,*tp*)	New electricity generating capacity in balancing area *aba* in province *ap* by plant type *tp*
renew_gen_capacity(*l*,*rp*)	New electricity generating capacity in location *l* by plant type *rp*
capacity_storage(*aba*,*ap*)	New pumped hydro storage capacity in balancing area *aba* and province *ap*.
retirements(*aba*,*ap*,*p)*	Extant electricity generation retired in balancing area *aba* in province *ap* by plant type *p*
capacity_transmission (*aba*,*ap*,*abba*,*apa*)	Transmission capacity in MW from exporting balancing area *aba* in province *ap* to importing balancing area *abba* in province *apa*

Table 4: Notation for decision variables defined in the model

Abbreviation	Definition
GJ	Gigajoule
GHG	Greenhouse gas
km	Kilometer
kv	Kilovolt
MW	Megawatt
MWh	Megawatt-hour
O&M	Operations and maintenance
$CAD	Canadian 2015 dollars
$USD	United States 2015 dollars

Table 5: Common units and abbreviations used in this document.

Spatial and temporal resolution

Electricity is a unique commodity because the ability to store electricity is limited. As a result, the supply of electricity must match the demand for electricity, both at all times and at all locations. Our model is defined with a high degree of spatial and temporal resolution to accurately capture the heterogeneity in supply and demand for electricity that occurs across time and space.

To model the temporal variation in the supply and demand for electricity, we resolve the electricity market at hourly intervals. This allows us to ensure that supply adequately meets demand over a relatively short time interval. We model the operation of the electricity system over the course of an entire year to accommodate seasonal variation in both demand and supply of electricity. Importantly, our model does not consider uncertainty, and so the grid operator is presumed to know the availability of electrical generators, wind and solar output, and the electric load ahead of time.

To model the spatial variation in the supply and demand for electricity, we divide the modeled area (Canada) into small grid cells measuring two-thirds of a degree in longitude and one-half of a degree in latitude. Expressed in distance terms, these grid cells measure approximately 43 km by 55 km.[1] To limit computational resource requirements, we only consider locations south of 60˚ latitude in Canada. After excluding areas over water, we are left with 2,281 grid cells, shown grouped by province in Figure 1.

[1] The distance between two meridians of longitude at the 49th parallel of latitude is approximately 73 km. The distance between two meridians of longitude at the 60th parallel is 55.6 km. The width of cells in this study thus varies from 48.6 km at the 49th parallel to 37 km at the 60th parallel. The distance between parallels of latitude ranges between 110.5 km at the equator to 111.7 at the poles. The height of grid cells is thus fairly consistent at approximately 55.5 km.

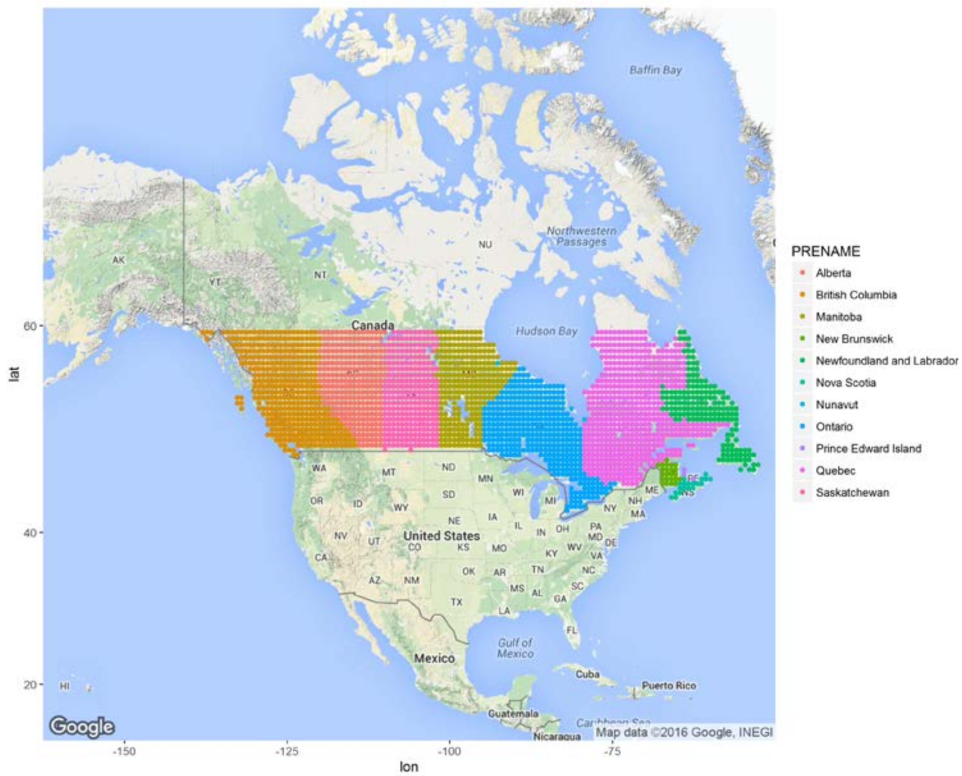


Figure 1 - Model Coordinates

In theory, it would be possible to operate the entire model at the resolution of these grid cells, which we call *locations (l)*. However, we do not yet have complete data on the spatial distribution of electricity demand. As a result, we model the site-specific generation of renewable energy at the scale of these grid cells, but model the overall balance of supply and demand for electricity and the geographic transmission of electricity at a lower geographic resolution. Specifically, we define *balancing areas (aba)*, which are aggregations of grid locations, as the primary geographic unit in the model. In our model, balancing areas are defined using provincial boundaries. Each province corresponds to a single balancing area, except for Ontario, Quebec, and Newfoundland and Labrador where the northern and southern portions of the provinces are modelled as independent balancing areas. We explicitly model the transmission of electricity between balancing areas. Within balancing areas, we model the cost of building new wind or solar capacity to include the cost of intra-balancing area connections to the existing electricity transmission network.

Model equations

Objective function

The model is a linear programming model that has the objective of minimizing the total cost of delivering electricity over the course of a year. The objective function for the model is:

$$Min. total\ cost = capitalcost + fuelcost + fixcost + varcost. \quad (1)$$

Capital cost represents the cost associated with building new generation, storage, and transmission capacity:

$$\begin{aligned} capitalcost = & \sum\nolimits_{aba,ap,tp} gen\_capacity_{aba,ap,tp} \times capital\_cost_{tp} \\ & + \sum\nolimits_{l,aba,ap,rp} renew\_gen\_capacity_{l,aba,ap,tp} \times capital\_cost_{l,rp} \\ & + \sum\nolimits_{aba,ap} capacity\_storage_{aba,ap} \times store_{cost} \\ & + \sum\nolimits_{aba,ap,abba,apa} distance_{aba,ap,abba,apa} \\ & \times capacity\_transmission_{aba,ap,abba,apa} \times trans\_cost. \quad (2) \end{aligned}$$

Notice that the capital cost associated with new renewable generating capacity is indexed by location (l) and renewable technology (rp). With balancing areas set at the provincial level, intra-balancing area transmission costs can be substantial. This becomes an issue when the model is deciding where to build wind and solar facilities. We calculate the distance of each grid cell location to the nearest electricity transmission line. This means that the capital cost of a wind or solar facility is:

$$\begin{aligned} & capital\ cost_{l,rp} \\ & \quad = capitalcost_{rp} + (distance\_to\_grid_{l} * intra\_ba\_transcost). \quad (3) \end{aligned}$$

The variable *fuelcost* is the total cost of fuel used by thermal plants for generating electricity throughout the year. It includes both the cost of purchasing the fuel and the cost of carbon pricing. Carbon pricing costs are incurred when the policy variable *ctax*, which stands for carbon tax, takes a value greater than zero. *Fuelcost* is determined by summing the fuel demand for each thermal generator over each location and hour, and then multiplying by the unit cost of fuel, which is the expression contained in the large brackets. Note that the factor 3.6 converts fuel costs from \$/GJ to \$/MWh:

$$fuelcost = \sum_{h,aba,ap,tp} supply_{h,aba,ap,tp} \times \left(\left(fuelprice_{tp} + \left(ctax \times fuel\_CO2_{tp} \right) \right) \times 3.6 \times \frac{1}{\eta_{tp}} \right). \qquad (4)$$

The variable *fixcost* refers to fixed operations and maintenance (O&M) expenditures. There are fixed O&M costs associated with each generation technology. These costs are expressed in \$/MW of capacity.

$$fixcost = \sum_{l,aba,ap,p} \Big(\big(extant\_capacity_{aba,ap,tp} + extant\_renew\_capacity_{l,aba,ap,rp} - retirements_{aba,ap,p} + gen\_capacity_{aba,ap,tp} + renew\_gen\_capacity_{l,aba,ap,rp} \big) \times fixed\_o\_m_{p} \Big). \qquad (5)$$

The variable *varcost* refers to variable O&M expenditures. All generation technologies except for wind and solar incur O&M costs per unit of electricity generated. These costs are expressed in \$/MWh per year.

$$varcost = \sum_{h,aba,ap,p} supply_{h,aba,ap,p} \times variable\_o\_m_{p}. \qquad (6)$$

The model chooses the value of the decision variables $gen\_capacity_{aba,ap,tp}$, $renew\_gen\_capacity_{l,aba,ap,rp}$, $retirements_{aba,ap,p}$, $capacity\_transmission_{aba,ap,abba,apa}$, and $capacity\_storage_{aba,ap}$ to obtain an optimal mix of generation, transmission and storage assets. Simultaneously it chooses how to dispatch available assets using $supply_{h,aba,ap,tp}$, $transmission_{h,aba,ap,abba,apa}$, $pump\_out_{h,aba,ap}$, $pump\_in_{h,aba,ap}$, $daystoragehydroout_{h,aba,ap}$, and $monthstoragehydroout_{h,aba,ap}$. The resulting values minimize the total cost of electricity, as per (1).

Constraints

Without constraints, the solution to the model in (1) is trivial. Constraints are imposed to ensure that the generation portfolio chosen by the model meets demand, operates according to physical laws, and meets any policy constraints.

Renewable Generation Constraints

The first constraints relate to renewable power generation. We specify wind and solar generation capacity at the grid location level (*l*) and aggregate to the balancing area (*aba*) level:

$$gen\_capacity_{aba,ap,rp} = \sum\nolimits_{l\in[ap,aba]} renew\_gen\_capacity_{l,rp} \quad \forall ap, aba. \quad (7)$$

Hourly electricity generated by wind and solar generation facilities is a function of hourly, location-specific wind speed and solar capacity factor data.

$$\begin{aligned} solarout_{h,aba,ap} \\ &= \sum_{l\in[aba,ap]} capacity\_factor_{h,l,solar} \\ &\times \left(renew\_gen\_capacity_{l,solar} \right. \\ &+ \left. extant\_renew\_capacity_{l,solar}\right) \ \forall h, ap, aba. \quad (8) \end{aligned}$$

$$
\begin{aligned}
windout_{h,aba,ap} &= \sum_{l \in [aba,ap]} capacity\_factor_{h,l,wind} \\
&\times \left(renew\_gen\_capacity_{l,wind}\right. \\
&+ \left. extant\_renew\_capacity_{l,wind}\right) \ \forall h, ap, aba. \quad (9)
\end{aligned}
$$

The implication of Equations (8 & 9) is that the hourly wind and solar generation is not a choice variable. Instead, hourly available generation is based on the wind and solar resource availability at each point in time and space (expressed as a capacity factor). This non-dispatchable character of wind and solar resources is critical to considering how they can act as part of the overall electrical system.

Supply and Demand Constraints

A supply and demand constraint ensures that the supply of electricity in each hour adequately meets demand for electricity in that balancing area:

$$
\begin{aligned}
\sum_{p} supply_{h,aba,ap,p} &\geq \ demand_{h,aba,ap} + demand\_us_{h,aba,ap} \\
&+ \ transmission_{h,aba,ap,abba,apa} \\
&- \ (1 - \ trans_{loss_{abba,app,aba,ap}}) \\
&\times transmission_{h,abba,app,aba,ap} \quad \forall h, aba, ap. \qquad (10)
\end{aligned}
$$

The equation says that the supply of electricity in a balancing area must be equal or greater than the demand for electricity in that balancing area, net of electricity trade. In practice, electricity supply and demand must be equal. The inequality assumes costless curtailment of excess electricity supply. Transmission losses (expressed as a share of electricity transmission) are accounted for on the import side of electricity trade. This means that when a balancing area exports an amount of electricity equal to

$transmission_{h,abba,app,aba,ap}$, the importing balancing area *aba* receives the amount of electricity net of transmission losses:

$$(1 - \ trans\_loss_{abba,app,aba,ap}) \times transmission_{h,abba,app,aba,ap}.$$

Thermal Capacity Constraints

Generation of electricity from thermal power plants cannot exceed installed capacity:

$$supply_{h,aba,ap,tp} \leq \ gen\ capacity_{aba,ap,tp} + \ extant\ therm\ capacity_{aba,ap,tp} - retirement_{aba,ap,tp} \quad \forall h, aba, ap, tp. \qquad (11)$$

In a similar manner, the transmission of electricity between two balancing areas cannot exceed the installed transmission capacity:

$$transmission_{h,aba,ap,abba,apa} \leq \ extant\ trans\ capacity_{aba,ap,abba,apa} \quad \forall h, aba, ap, abba, apa. \qquad (12)$$

We also model annual capacity factor constraints for thermal power plants. A capacity factor measures the proportion of electricity generated by a power plant relative to the maximum annual production of the plant. It is expressed as a percentage. We calculate annual capacity factor as follows:

$$Capacity\ factor_{aba,ap,tp} = \frac{\sum_h supply_{h,aba,ap,tp}}{\left(gen\ capacity_{aba,ap,tp} + \ extant\ therm\ capacity_{aba,ap,tp} - \ retirement_{aba,ap,tp}\right) \times 8760}. \qquad (13)$$

The number 8760 refers to the number of hours in a year. We model annual capacity factor constraints as follows:

$$Capacity\ factor_{aba,ap,tp} \leq Maximum\ Capacity\ factor_{tp} \quad (14)$$

$$Capacity\ factor_{aba,ap,tp} \geq Minimum\ Capacity\ factor_{tp} \quad (15).$$

The maximum and minimum capacity factors we use in our model are drawn from Lazard (2015) and are summarized in Table 6 below.

Technology	Minimum	Maximum
Coal	40%	93%
Diesel	10%	95%
Natural Gas Combined Cycle	40%	70%
Natural Gas Peaking Plant	5%	20%
Nuclear	40%	90%
Waste	40%	80%

Table 6 - Minimum and Maximum Annual Capacity Factors

Hydroelectric Generation

We employ a series of constraints to model the operation of existing hydroelectric generating stations. It is important to note that we only consider the operation of *existing* hydroelectric stations, and do not model the potential expansion of hydroelectric generating assets.[2] This is primarily because the development cost and operating characteristics of hydroelectric stations are heavily dependent on the local site and hydroelectric resource. We do not possess detailed cost and operations data for potential sites. Nevertheless, hydroelectric generation constitutes the majority of installed generation in Canada today, and so realistically modeling dispatch from this resource is critical to considering the operation of the electric network.

We consider four types of hydroelectric stations: pumped storage hydro, run-of-river hydro, hydro with small storage reservoir, and hydro with large storage reservoir. Each is modeled in a distinct manner.

[2] Note that we do include hydroelectric assets currently under construction: Keeyask in Manitoba (695 MW), Muskrat Falls in Newfoundland & Labrador (824 MW), and Site C in British Columbia (1100 MW)

Pumped Storage Hydro

For pumped storage hydro, an electric pump is employed, which allows water to be pumped up into a storage reservoir when there is excess electricity supply. There is one existing pumped hydro facility in Canada, at Niagara Falls (another is currently being built in Ontario). The variable *ba_pump_hydro_capacity* expresses the nameplate capacity of the Niagara Falls pumped hydro storage facility in megawatts (MW). The nameplate capacity is the rate at which a pumped hydro facility can produce electricity when running at full capacity. The variable *capacity_storage* refers to new storage built by the model.

Each facility can store a limited amount of potential energy. The variable *pumpenergy* refers to the amount of potential energy that can be stored in a pumped hydro reservoir, measured in megawatt-hours (MWh). The maximum value of *pumpenergy* that can be stored by the pumped hydro storage facilities in each balancing area is the product of built capacity (*ba_pump_hydro_capacity* + *capacity_storage*) and the variable *pump_hours* which refers to the number of hours the facility can run at full capacity before being drained completely of potential energy:

$$pumpenergy_{aba,ap} \\ \leq (ba\_pump\_hydro\_capacity_{aba,apa} \\ + capacity\_storage_{aba,ap}) \times pump\_hours \quad (13)$$

We use an equation of motion to model the amount of energy stored in the pumped hydro reservoir at any given hour:

$$pumpenergy_{h+1,ap,aba} \\ = pumpenergy_{h,ap,aba} - pumpout_{h,ap,aba} \\ + pumpin_{h,ap,aba} \times \eta_{pump} \; \forall h, ap, ab, \qquad (14)$$

where *pump_energy* is the storage level, *pumpout* is the amount of energy made available to meet demand in hour *h*, *pumpin* is the amount of electricity used to replenish the storage reservoir, and η_{pump} reflects the full-cycle efficiency penalty associated with operating the pump storage system. In addition to this constraint governing the storage of energy in the reservoir, we model two additional constraints for pump storage systems:

$$pumpin_{h,ap,aba} \times \eta_{pump} \leq ba\_pump\_hydro\_capacity_{aba,apa} + capacity\_storage_{aba,ap} \quad \forall ap, aba \quad (15)$$

$$pumpout_{h,ap,aba} \leq ba\_pump\_hydro\_capacity_{aba,apa} + capacity\_storage_{aba,ap} \quad \forall h, ap, aba. \quad (16)$$

The first sets a limit on the rate at which potential energy can be added to the pumped hydro facility, and the second sets a limit on the amount of electricity that can be generated at any given time from the pumped hydro facility. We parameterize pumped hydro with an efficiency value of $\eta_{pump} = .75$, and a storage value of $pump\_hours = 8$.

Run-of-River Hydroelectric

Run-of-river hydroelectric facilities cannot store electricity and instead generate electricity according to streamflow availability. As a surrogate for streamflow data, we use historic monthly hydroelectric generation data to calculate average hourly hydro electricity production by province (see Table 7). We then model run-of-river hydro production as equal to this hourly average in each province and month.

Reservoir Hydroelectric

For hydro facilities with reservoir storage, we must model the decision of whether to release water through the generator or to accumulate water in the reservoir. The amount of water that can be accumulated in the reservoir is contingent on the size of the reservoir. For simplicity, we model reservoirs of two sizes: small and large. We assume that small reservoirs are large enough to allow the facility to optimize generation over the course of a day. We assume that large reservoirs are large enough to allow the facility to optimize generation over the course of a month.

We express these constraints as follows:

$$\sum_{h \in d} day\ storage\ hydro\ out_{h,ap,aba} \leq historic\ small\ hydro\ output_{d,ap,aba} \quad \forall d, ap, aba \quad (17)$$

$$\sum_{h \in m} month\ storage\ hydro\ out_{h,ap,aba} \leq historic\ large\ hydro\ output_{m,ap,aba} \quad \forall m, ap, aba. \quad (18)$$

For each type of reservoir hydro generator, we impose minimum flow constraints. These constraints are designed to ensure that the reservoir is operated according to ecological, recreational, or other constraints:

$$day\ storage\ hydro\ out_{h,ap,aba} \geq minflow\ small\ hydro_{ap,aba} \quad \forall h, ap, aba \quad (19)$$

$$month\ storage\ hydro\ out_{h,ap,aba} \geq minflow\ large\ hydro_{ap,aba} \quad \forall h, ap, aba. \quad (20)$$

On a system-wide basis, we set minimum flow at 10% of total hydroelectric capacity. Minimum flow by hydro type is then allocated relative to the proportional size of each type of hydroelectric asset. We assume 30% of facilities are run-of-river, 35% are day-storage hydro, and 35% are month-storage hydro.

For each type of storage hydro generator, we impose the usual capacity constraints, which ensure that the amount of electricity generated at any point in time does not exceed the installed capacity of the generator:

$$day\ storage\ hydro\ out_{h,ap,aba} \leq small\ hydro\ capacity_{ap,aba} \quad \forall h, ap, aba \quad (21)$$

$$month\ storage\ hydro\ out_{h,ap,aba} \leq large\ hydro\ capacity_{ap,aba} \quad \forall h, ap, aba. \quad (22)$$

Ramping Constraints

We impose ramping constraints on thermal generation units. These ramping constraints control the rate at which a grid operator ran increase or decrease the output of electricity from hour to hour:

$$\begin{aligned} supply_{h+1,ap,aba,tp} &\leq supply_{h,ap,aba,tp} \\ &+ \left(extant\ therm\ capacity_{ap,aba,tp} + capacity\ therm_{ap,aba,tp}\right) \\ &\times ramp\ rate_{tp} \quad \forall h, ap, aba, tp \quad (23) \end{aligned}$$

$$\begin{aligned} supply_{h+1,ap,aba,tp} &\geq supply_{h,ap,aba,tp} \\ &- \left(extant\ therm\ capacity_{ap,aba,tp} + capacity\ therm_{ap,aba,tp}\right) \\ &\times ramp\ rate_{tp} \quad \forall h, ap, aba, tp. \quad (24) \end{aligned}$$

We assume identical ramp rate constraints for up-ramping (the first expression) and down-ramping (the second expression). Ramp rate constraints are parameterized as outlined in Table 7.

Technology	Ramp Rate
Coal	10.0%
Diesel	25.0%
Natural Gas Combined Cycle	25.0%
Natural Gas Peaking Plant	100.0%
Nuclear	1.0%

Waste	0.1%

Table 7 - Ramp Rate Constraints

Siting Constraints

We impose constraints to limit the amount of wind and solar power capacity that can be installed in any grid cell. We limit installed wind capacity to a maximum of 2 MW per km^2. This is the same as the assumption made in General Electric (2016) study and close to the assumption made in MacDonald *et al*., 2016 (2.4 MW per km^2). We limit solar density to 31.28 MW per km^2, a figure derived from the Ong *et al*. (2013) finding that the total area used by large solar installations is typically 7.9 acres/MW. We also exclude any locations that are offshore or on lakes, as offshore turbines are currently considered less economically viable, and siting turbines in lakes is often not possible due to concerns about views, recreation, or wildlife disturbance. These constraints create a measure of the maximum renewable capacity (*max renew capacity*) that can be installed in any given grid cell *l*. We express this constraint as:

$$renew\ gen\ capacity_{l,rp} \leq max\ renew\ capacity_{l,rp} \quad \forall l, rp. \quad (25)$$

Policy Constraints

Finally, we impose policy constraints of various forms, depending on the model application. For example, we can impose constraints on the maximum emissions of carbon dioxide (or other pollutants), minimum (or maximum) penetration of certain types of electricity generating capacity, maximum penetration of transmission capacity, etc. We do not detail these constraints here, since they differ according to the simulation being considered.

Data

Renewable Resource Data - Wind

We obtain data on hourly wind speed for each location in the model from *The Modern Era Retrospective-analysis for Research and Applications* (MERRA) data set produced by NASA's Goddard Earth Sciences Data Information and Services Center (GMAO, 2016). The data are model-generated and estimate hourly wind speed and direction at various elevations at a grid with cells measuring two-thirds of a degree in longitude and one-half of a degree in latitude resolution. We obtain data corresponding to a 50-m elevation above the Earth's surface for all grid cells over land in Canada.

For each grid cell location and each hour, we estimate power production from a hypothetical wind turbine based on wind speed. We base wind power estimates on a 3 MW wind turbine with 80-m hub height and 110-m rotor swept diameter. We extrapolate from the 50-m hub height in our data to the 80-m hub height of our hypothetical turbine using a power law with an exponent of 1/7 (Peterson and Hennessey Jr, 1978).

We assume that the cut-in wind speed for the turbine is 3 m/s, the rated wind speed is 14 m/s, and the cut-out wind speed is 25 m/s. This gives rise to a wind power generation profile as shown in Figure 2 for a 3 MW turbine.[3]

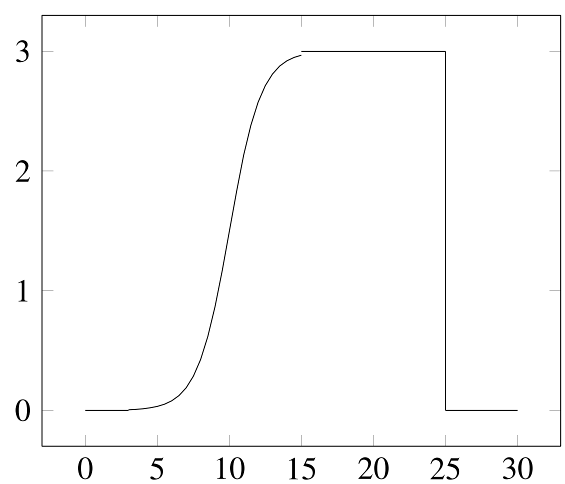


Figure 2 - Power curve for 3 MW simulated wind turbine

[3] For wind speeds, v, between the cut-in wind speed (v^{cut-in}) and the rated wind speed (v^{rated}), we assume generated power is determined by $P = \frac{P^{rated}}{1+exp-k(v-(v^{cut-in}+v^{rated})/2)}$, where k = 0.9 is a parameter that governs the shape of the power curve.

Based on the simulated power curve, we then calculate a capacity factor for each hour in each grid location, which is the estimated power output divided by the rated power output.

Figure 3 is an illustration of the wind resource in Canada based on the data described above. As noted above, we exclude locations north of 60˚ latitude.

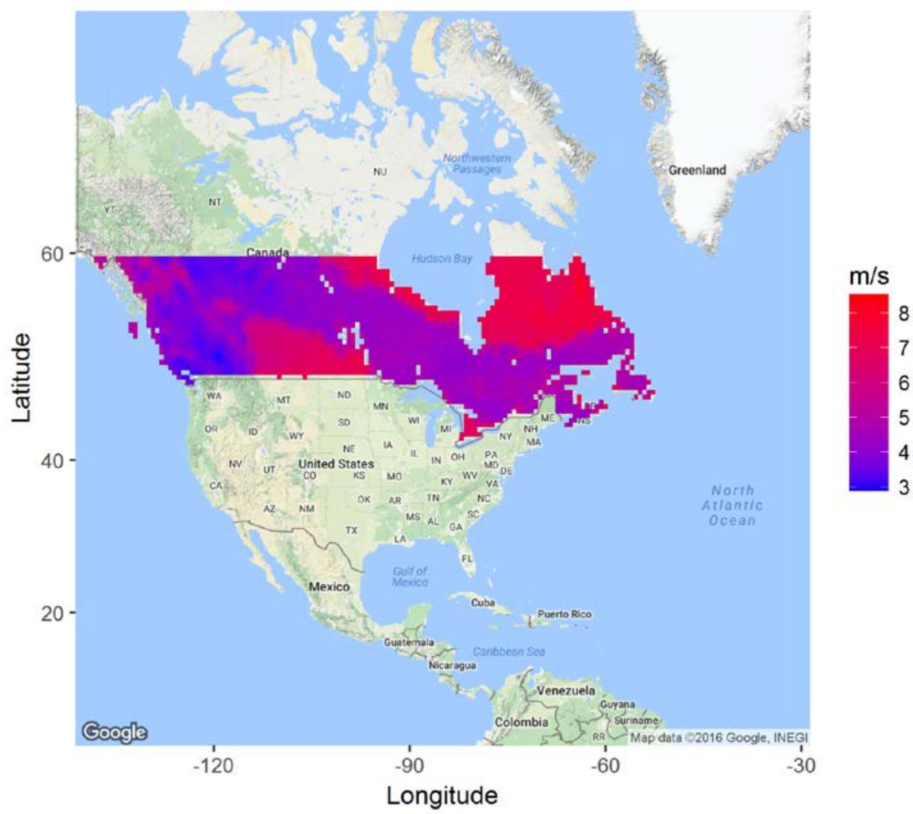


Figure 3 – Annual Mean Hourly Wind Speed by Grid Cell (meters/second)

Source: Global Modelling and Assimilation Office (GMAO) (2016).

Calculations by Nicholas Rivers and Brett Dolter.

Renewable Resource Data - Solar

We obtain data on hourly solar radiation from Environment Canada's Canadian Energy Year for Energy Calculation (CWEC) dataset (MSC & NRC, 2010a). The CWEC dataset is based on 30 years of climate data collected by weather monitoring stations, and represents climatological data using a 'Typical Meteorological Year' (TMY) based on historical data. The advantage of the CWEC data is that it contains no missing observations, since is imputes TMY data based on a large number of past observations (including both measured data and model simulations). The CWECS data is available at 235 Canadian locations. We impute the solar radiation at all grid locations by matching each grid location with the closest CWECS station.

We convert solar irradiation data for each site to potential hourly solar capacity factors using the approach outlined by Masters (2004). This conversion first requires that we calculate the position of the sun relative to the location of a theoretical solar installation. We assume that installed solar panels are fixed (they do not track the sun) and are installed facing directly south to maximize annual solar exposure. We assume solar panels are tilted (Σ) at an angle equal to the latitude of the site. Using latitude and longitude data for each CWECS site we then use the conversion process outlined in Appendix A to calculate the level of solar irradiance striking a solar collector face in each hour. These irradiance values are used to generate hourly capacity factors for potential solar installations. The solar capacity factors represent the potential solar electricity output per hour per kilowatt of installed solar capacity. Figure 4 presents a map of our solar data. Grid cells are those used by the MERRA wind data.

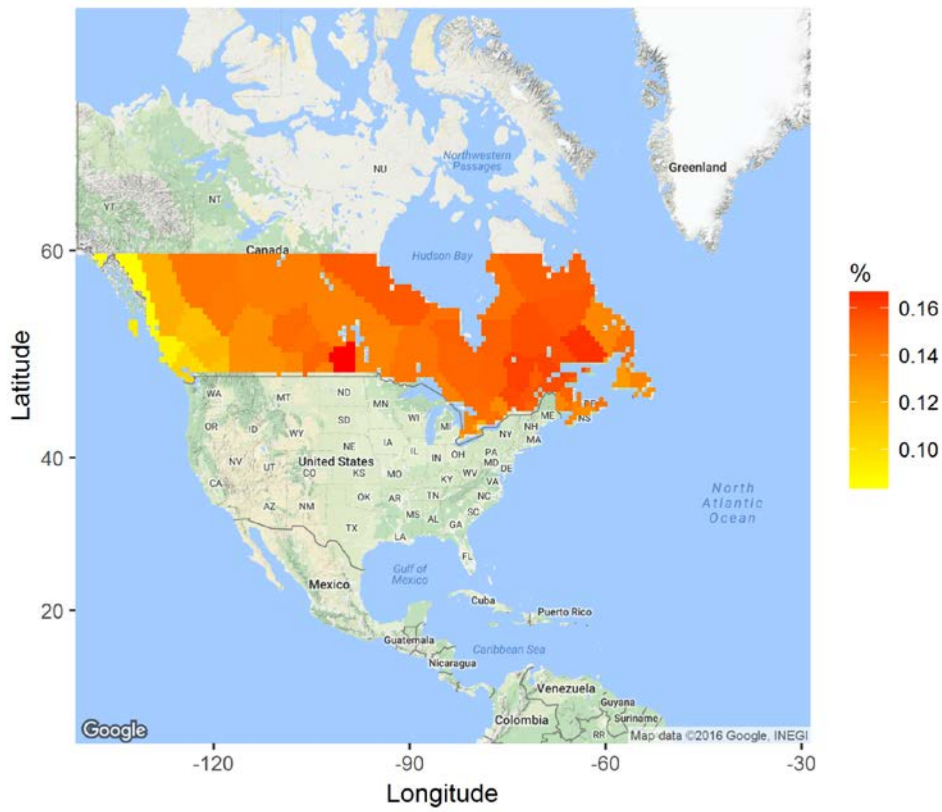


Figure 4 – Average Annual Solar Capacity Factors by MERRA Grid Cell

Source: Meteorological Service of Canada (MSC) and Natural Research Council (NRC) (2010a). Calculations by Brett Dolter and Nicholas Rivers.

Renewable Resource Data – Hydro

We obtain monthly hydroelectric generation from each province from Statistics Canada's (2016) CANSIM Table 127-0002. We use this monthly generation data to calculate an hourly average for each month and province pair (Table 8). Variations from the monthly average are represented by storage within the system. As noted above, we model four types of hydroelectric facilities: run-of-river facilities which cannot store water and potential power; hydro facilities adjacent to small-capacity reservoirs that have the capacity to store water over the course of a day; hydro facilities adjacent to large-capacity reservoirs that have the capacity to store water over the course of a month; and pumped hydro-electric facilities that can fill a storage reservoir using excess electricity.

We do not directly observe what proportion of total hydroelectric output is from run-of-river, small capacity storage, and large capacity storage hydroelectric systems. Thus, we cannot estimate the parameter $\theta_{hp,ap,aba}$, which is the proportion of historic hydroelectric output in balancing area *aba* of province *ap* from hydroelectric technology *hp*. Instead, we assume that run-of-river facilities compose 30% of hydroelectric capacity, and that of the remaining 70% capacity, half (35% of the total) can store water over the course of a day, and half (35% of the total) can store water over the course of a month.

We believe our storage assumptions are reasonable. In British Columbia, BC Hydro (2016) reports that the utility has averaged 12,400 GWh of stored potential electricity in its system over the past ten years and had 17,800 GWh of system storage at the end of their 2015 fiscal year. Total hydroelectricity production in B.C. in 2014 was 57,572 GWh, meaning average system storage was equal to 21.5% of the annual total and the 2015 level was equal to 30.9% of total production (BC Hydro, 2016a; Statistics Canada, 2016: CANSIM 127-0007). Hydro Quebec finished 2015 with 126,900 GWh of system storage, up from 103,700 GWh at the end of 2014 (Hydro Quebec, 2016). Total Hydro Quebec sales were 200,847 GWh in 2014 and 201,127 GWh in 2015, meaning system storage at the end of 2015 was equal to 63% of total sales (Hydro Quebec, 2016). These numbers indicate that both provinces have a large storage capacity and that intra-day and intra-month storage is substantial.

Province	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AB	183	167	185	184	264	381	365	272	199	212	183	231
BC	7,655	7,961	6,429	5,714	5,356	5,272	5,689	5,836	5,548	5,125	6,514	7,087
MB	3,944	3,921	3,953	3,832	3,638	4,094	4,269	4,304	3,785	3,037	4,083	4,256
NB	370	224	134	461	683	369	278	205	127	275	410	473
NL	6,074	5,812	6,139	4,190	3,450	2,632	2,948	2,670	3,039	3,640	5,552	6,012
NS	167	169	140	176	149	86	53	48	73	76	145	206
ON	4,407	4,597	3,976	4,244	4,724	4,391	4,076	3,915	4,152	3,976	4,349	4,664
QC	29,354	29,008	26,732	22,551	19,268	19,838	19,632	20,691	19,207	18,754	22,648	26,286
SK	477	432	440	553	703	735	679	559	451	474	415	437

Table 8 - Average Hourly Hydroelectric Production by Month and Province, 2014

Source: Statistics Canada (2016) CANSIM 127-0002; author's calculations

Extant Electricity Generation

We include existing electricity generation capacity by balancing area *aba* and province *ap*. Data is compiled from a variety of sources: NRCAN *Atlas of Canada* (Open Canada, 2016; NRCAN, 2016), the Commission for Environmental Co-operation's *North American Power Plant Air Emissions* (2016), the Global Energy Observatory (2010), and Wikipedia's *List of generating stations in Canada* (2016). The model includes eight plant types, five of which are thermal plants fuelled by natural gas, coal, nuclear, waste, or diesel, and three of which are powered by renewable energy: hydro, wind, and solar. Plants are identified by type, capacity (in Megawatts) and are linked to the model's spatial grid cells using location data (latitude and longitude) found using the above sources as well as DMTI (2016).

Capital Costs for Electricity Generation

Capital costs for thermal generation technologies are based on an average of the high and low 'Total Capital Cost' numbers in Lazard (2015) (Table 9). Capital costs for wind and solar are based on the low 'Total Capital Cost' numbers in Lazard (2015), which reflects an assumption that cost improvements will continue to 2025.[4] Capital costs are annualized by amortizing for a period of 25 years for all thermal technologies, except natural gas combined cycle and peaking plants which are amortized over 20 years. Wind and solar are amortized over 20 years. For all technologies, we assume 20% debt financing at 8% interest and 80% equity financing at 12% interest. Capital costs for pumped hydroelectric storage come from Trottier (2016), which reports a cost of $2500/kilowatt installed. The operating efficiencies of thermal plants refer to the efficiency of converting fuel energy to electricity and are taken from Lazard (2015). Pumped Hydro efficiency refers to the round-trip efficiency; an output/input energy ratio. Our cost and efficiency assumptions are summarized in Table 9. Note that we do not allow additional investment in 'waste' thermal facilities or hydroelectric facilities (aside from pumped hydro storage).

[4] Barbose and Gelen (2016) provide data on the rapid cost improvements of solar photovoltaics.

Technology	Capital Cost ($CAD/kw)	Amortization	Annualized Capital Cost ($CAD/MW)	Efficiency (%)
Coal	$3,836	25	$440,647	39.0%
Diesel	$831	25	$95,474	39.0%
Natural Gas Combined Cycle	$1,471	25	$178,355	50.9%
Nuclear	$8,695	25	$998,801	32.7%
Pumped Hydro	$2,500	25	$287,169	75.0%
Solar (Utility-scale)	$1,790	20	$205,635	-
Wind	$1,598	20	$193,864	-

Table 9: Capital Cost and Operating Efficiency Assumptions

Fuel Prices

The price of natural gas in 2025 is taken from the Reference Case of the National Energy Board's *Canada's Energy Future 2016* (NEB, 2016) and is converted from 2010 to 2015 $CAD using a CPI multiplier of 1.09.[5] We assume a coal price of $26/tonne in 2025 based on Westmoreland Coal's revenue per tonne lignite coal, which was $23 (CAD)/tonne in 2014, and an assumed price growth rate of 1.15%/year (Westmoreland, 2015; Westmoreland, 2014). To convert to $/GJ we assume coal energy content of 14.4 GJ/tonne, which is representative of the lignite coal burned in Saskatchewan (NEB, 2015). A uranium fuel price of $.85 (USD)/MMBtu is taken from Lazard (2015). This price is converted to $CAD/GJ using an exchange rate of 1.3444 (Bank of Canada, 2016) and an engineering conversion of 1.0551 GJ per MMBtu. We assume a diesel price of $1.00/litre (CAD 2015) and energy content of 38.68 GJ/m^3 (NEB, 2015). Table 10 summarizes the resulting fuel prices.

Fuel	$/GJ	kg CO2e/GJ
Natural Gas	4.91	51
Coal	1.81	90
Uranium	1.08	0
Diesel	25.85	72

[5] CPI based on Statistics Canada (2016) *CANSIM 326-0021*. Available on-line at: http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ46a-eng.htm.

Table 10 - Fuel Prices in 2025 ($2015 CAD) and GHG Intensities of Fuels

Fuel Greenhouse Gas Emissions Intensities

The GHG intensities of fossil fuels are derived from Environment Canada (2014, pp. 183-187) and summarized in Table 10. The GHG intensity of coal is calculated by taking the average GHG intensity expressed in kg CO_2e/GJ for four types of coal: Saskatchewan lignite (101 kg CO_2e/GJ), Alberta bituminous (80 kg CO_2e/GJ), Alberta sub-bituminous (93 kg CO_2e/GJ), and New Brunswick bituminous (84 kg CO_2e/GJ) (Environment Canada, 2014; author's calculations). The GHG intensity of natural gas is taken by calculating the average GHG intensity of marketable natural gas in three regions: Saskatchewan (49.5 kg CO_2e/GJ), Ontario (51.1 kg CO_2e/GJ), and Alberta (52.14 kg CO_2e/GJ) (Environment Canada, 2014; author's calculations). The GHG intensity of diesel is found by converting the GHG intensity in g CO_2e/L to kg CO_2e/GJ (Environment Canada, 2014; author's calculations).

Operations and Maintenance Costs

Fixed and variable operations and maintenance (O&M) costs are taken from Lazard (2015), except for hydroelectric O&M costs taken from EIA (2016a). O&M costs are summarized in Table 11. Values are converted from USD $2015 to CAD $2015 using an exchange rate of 1.2787, which was the 2015 average exchange rate for Canada (Bank of Canada, 2016b).

Technology	Variable O&M ($US 2015)		Fixed O&M ($US 2015)		Variable O&M ($CAD 2015)	Fixed O&M ($CAD 2015)	Fixed O&M ($CAD 2015)	Source
	$/MWh		$/kw-yr		$/MWh	$/kw-yr	$/MW-yr	
	Low	High	Low	High	Mean	Mean	Mean	
Coal	2.0	5.0	40.0	80.0	4.48	76.72	76,723	Lazard (2015)
Natural gas combined cycle	3.5	2.0	6.2	5.5	3.52	7.48	7,480	Lazard (2015)
Natural gas simple cycle (peaking)	4.7	7.5	5.0	25.0	7.80	19.18	19,181	Lazard (2015)
Small Modular Nuclear Reactor	0.5	0.8	135.0	135.0	0.80	172.63	172,626	Lazard (2015)
Nuclear	0.5	0.8	135.0	135.0	0.80	172.63	172,626	Lazard (2015)
Wind Onshore			35.0	40.0		47.95	47,952	Lazard (2015)
Solar - Utility Thin Film			13.0	10.0		14.71	14,705	Lazard (2015)
Diesel	15.0	15.0	15.0	15.0	19.18	19.18	19,181	Lazard (2015)
Hydro	2.6	2.6	14.7	14.7	3.35	18.80	18,797	EIA (2016)

Table 11 - Operations and Maintenance Costs

Extant Electricity Transmission

To calculate the cost of constructing intra-balancing area transmission connections for new wind and solar facilities we require data on extant transmission lines. We obtain transmission line data from DMTI (2015). The DMTI (2015) *CanMap Content Suite* provides Canada-wide transmission line data in the GIS layer ‘TransmissionLinesLine.’ We remove telephone lines from the dataset and are left with the transmission lines shown in Figure 5 below. The shade of the MERRA grid cells indicate the distance of each grid cell from extant transmission.

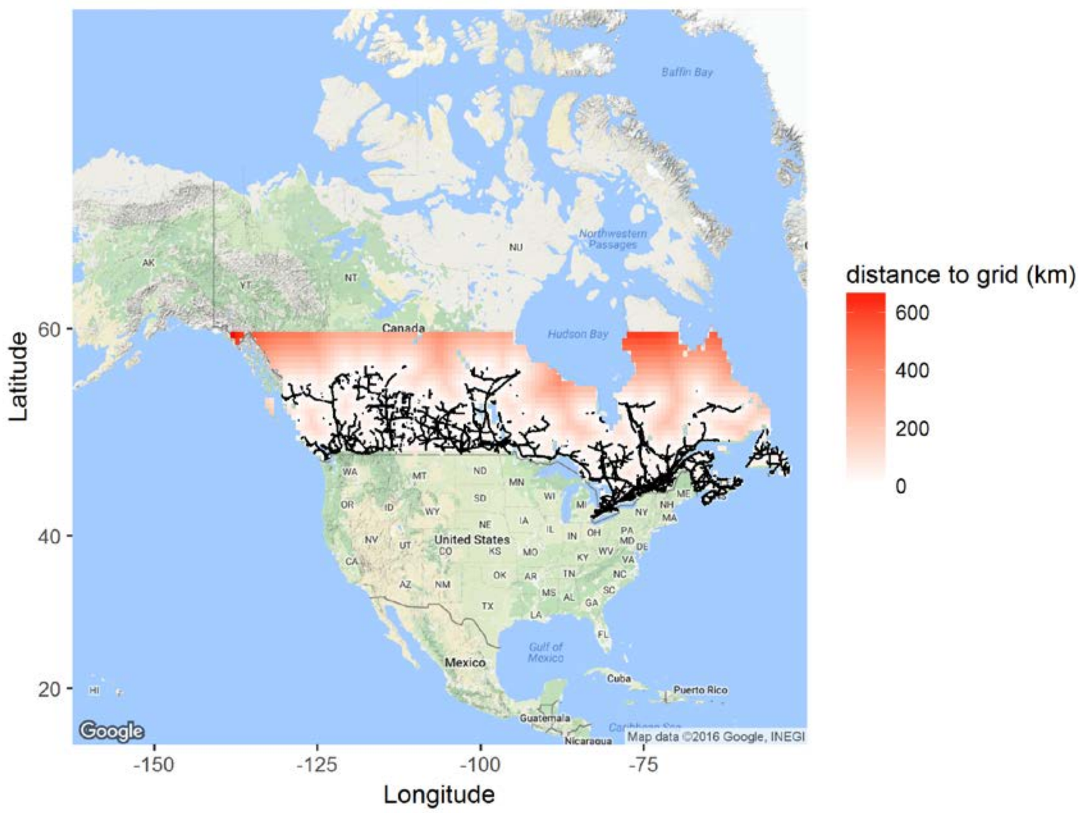


Figure 5 – Extant Transmission and MERRA Grid Cell Distance to Grid (km)

Extant Inter-Provincial Transmission Connections

Extant inter-provincial electricity transmission connections are taken from the Trottier Energy Futures Project (2016: 103) and summarized in Table 12.

Exporting region to destination	Installed capacity in 2011 (GW)	Exporting region to destination	Installed capacity in 2011 (GW)
AB to BC	1.00	NS to NB	0.35
AB to SK	0.08	PE to NB	0.22
BC to AB	1.20	ON to MB	0.28
MB to ON	0.34	ON to QC	1.98
MB to SK	0.15	QC to NB	1.03
NB to NS	0.30	QC to NL	0.00
NB to PE	0.22	QC to ON	2.38
NB to QC	0.79	SK to AB	0.15
NL to QC	5.15	SK to MB	0.05

Table 12 - Extant Electricity Transmission Links

Transmission Costs and Operating Losses

The General Electric (2016) study provides costs for high-voltage transmission lines. We base our inter-balancing area transmission costs on the cost to build a double circuit 345 kilovolt line (kv). At a cost of $2.4 Million CAD/kilometer, a maximum capacity of 1500 MW, and amortized over 25 years in the same manner as the capital costs, we calculate that new transmission will cost $184/MW/km/yr.[6] For inter-provincial transmission we assume transmission losses independent of distance to be 2% of transmitted electricity. We assume variable transmission losses per kilometer travelled to be .00003/km.

We base our intra-balancing area transmission costs on the cost to build a single circuit 230 kv transmission line. A 230 kv transmission line costs $1.6 million CAD/yr and has a maximum transmission capacity of 330 MW (GE, 2016). Amortized over 25 years the 230 kv line will cost $557/MW/km/yr.

Domestic Electricity Demand

Table 13 outlines the source of hourly domestic electricity demand data by province.

[6] Note that this cost is in line with the cost of Bipole III being built in Manitoba. That 2000 MW transmission line is estimated to cost $4.9 billion and run a distance of 1384 km (CBC, 2016). When amortized over 25 years and translated into annual costs, Bipole III will cost $203/MW/km/yr.

Domestic demand data is collected from provincial electricity utilities. Lacking data for Newfoundland and Labrador we use the load shape of New Brunswick scaled by relative proportions of provincial ‘Energy use, final demand of primary electricity’ from Statistics Canada (2016) CANSIM 128-0017. Figure 6 presents the domestic demand data.

Province	Source for Demand Data	Year
Alberta	AESO (2016)	2014
British Columbia	BC Hydro (2016b; 2016c)	2015
Manitoba	Manitoba Hydro (2016)	2014
New Brunswick	New Brunswick Power (2016)	2014
Newfoundland and Labrador	New Brunswick Load Shape	2015
Nova Scotia	Nova Scotia Power (2016)	2015
Ontario	IESO (2016a)	2014
Prince Edward Island	Maritime Electric (2016)	2015
Québec	Hydro Quebec (2016)	2014
Saskatchewan	SaskPower (2016)	2014

Table 13: Electricity Demand Data Sources

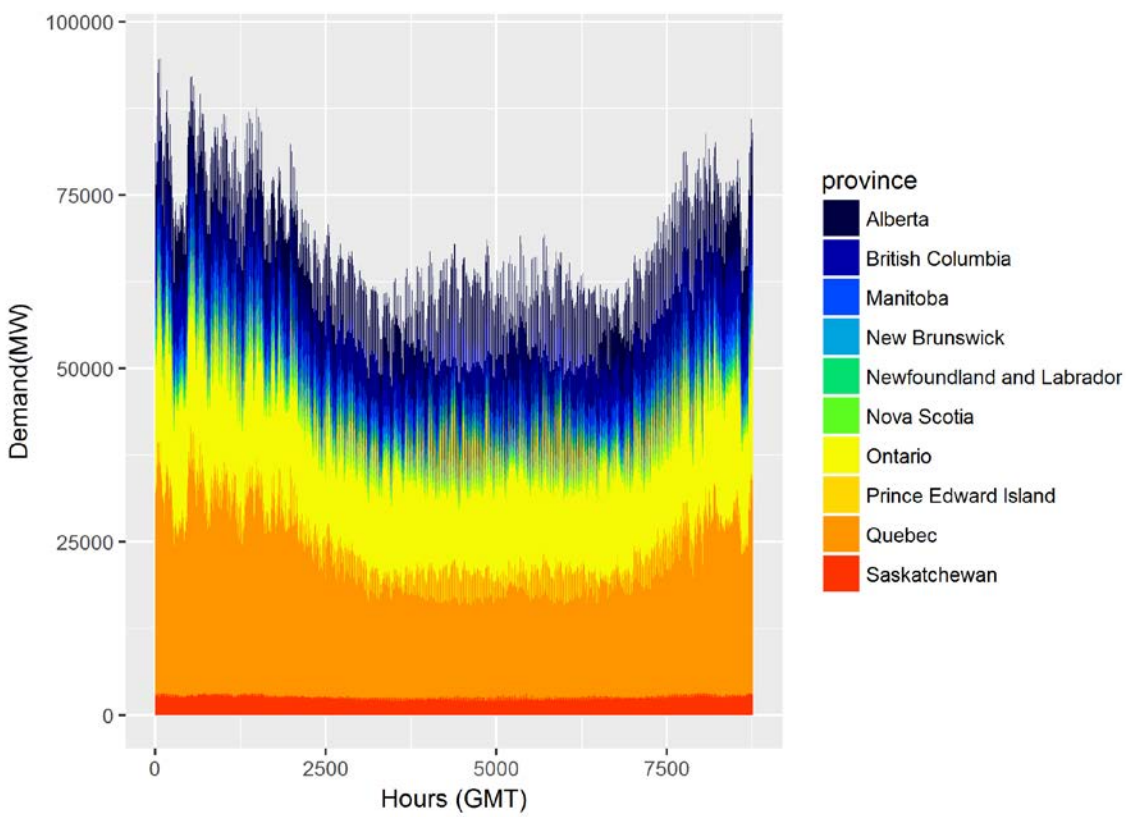


Figure 6 – Total Canadian Electricity Demand (MW)

We project electricity demand out to 2025 by scaling the hourly load data summarized in Table 13 and Figure 6 using annual growth factors calculated from the 2025 electricity demand forecast presented in General Electric (2016, Section 4, p. 29). Scaling factors are a weighted average of growth in annual energy (GWh) and growth in peak demand (MW), each weighted equally. The resulting annual growth rates are summarized in Table 14. Note that we assume demand growth for electricity in Newfoundland and Labrador will be positive and equal to demand growth for Nova Scotia.

Province	**Annual Growth Rates**
Alberta	3.19%
British Columbia	0.66%
Manitoba	1.09%
New Brunswick	-0.50%
Newfoundland and Labrador	0.46%
Nova Scotia	0.46%
Ontario	-0.67%
Prince Edward Island	-1.50%
Québec	0.52%
Saskatchewan	2.02%

Table 14 - Electricity Demand Growth Rates by Province

United States' Electricity Demand

Canada exports significant amounts of electricity to the United States (Table 15). Most of the net exports come from five provinces: Quebec, Manitoba, Ontario, New Brunswick, and, in some years, British Columbia. We account for exports to the US at an hourly scale in two ways. First, we collect hourly export data for British Columbia (BC Hydro, 2016c), New Brunswick (New Brunswick Power, 2016), and Ontario (IESO, 2016b). Second, we infer hourly exports from Manitoba and Quebec by comparing hourly domestic demand with hourly total production (Manitoba Hydro, 2016; Hydro Quebec, 2016). Hydro Quebec provided us with hourly production data that did not include production from their Churchill Falls facility in Newfoundland & Labrador. We add the

Churchill Falls facility to Hydro Quebec's production data assuming a constant rate of production and a capacity factor of 73.6%.

Year	Canada	NS	NB	QC	ON	MB	SK	AB	BC
2010	25702	-207	193	14504	7563	8775	-288	-208	-4630
2011	36555	-141	499	19436	9238	9206	-211	-863	-609
2012	46977	-9	187	23954	13168	7529	-47	-810	3005
2013	50876		3457	29002	8267	9531	-271	-377	1267
2014	47335		3757	28020	7828		-181	-56	-90

Table 15 Annual Net Exports to the United States, GWh (CANSIM 127-0008)

After creating hourly export vectors for the five exporting provinces, we add hourly domestic demand and exports to check that total demand in any given hour does not exceed peak domestic demand. In cases where it does, exports are reduced so that the total is equal to peak domestic demand. This correction assumes that utilities will not export power when local demand is peaking. This was most important to ensure we did not create false peaks in the synthetic export data we created for Manitoba and Quebec.

Figure 7 presents hourly demand for exports to the United States (US). As can be seen, exports increase during the summer months. This helps the US meet its peak electric load, which occurs when demand for cooling is high. It is a complement to Canadian demand, which generally peaks during the winter months when demand for heating is high. Note that British Columbia (BC) engages in a strategy of arbitrage, buying power from the United States when demand is low and prices are cheap, and selling power back to the United States at peak demand times. We keep imports of electricity to BC in the model to account for this arbitrage strategy. Imports are indicated when the red shaded area drops below the x-axis in Figure 7.

In the reference scenario of their 2016 *Annual Energy Outlook*, the EIA (2016b) project that US demand for Canadian electricity will decline into the future. We make the conservative assumption that current export levels will remain constant in future years.

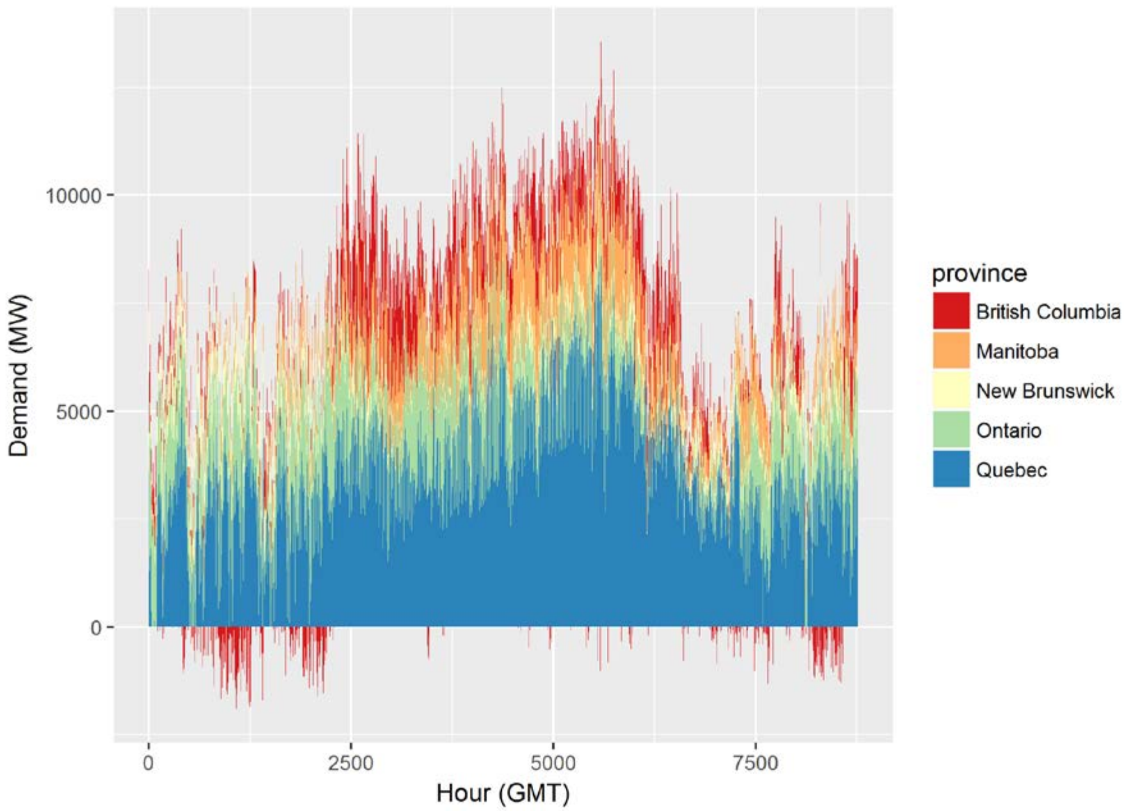


Figure 7 –Electricity Exports to the United States (MW)

References

Alberta Electricity System Operator (AESO) (2016) "Hourly load data for years 2005 to 2015." *Data Requests*. Available on-line at: https://www.aeso.ca/market/market-and-system-reporting/data-requests/. Last accessed September 1, 2016.

Bank of Canada (2016a) *USD Exchange Rate*. Available on-line at: http://www.bankofcanada.ca/rates/exchange/. Data accessed November 22, 2016.

Bank of Canada (2016b) *Average Annual USD Exchange Rate*. Available on-line at: http://www.bankofcanada.ca/rates/exchange/annual-average-exchange-rates/. Last accessed September 6, 2016.

Barbose, Galen and Naïm Darghouth (2016) *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States*. Lawrence Berkeley National Laboratory and SunShot U.S. Department of Energy. Available on-line at: https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report_0.pdf. Last accessed: September 16, 2016.

BC Hydro (2016a) *Revenue Requirements Application Fiscal 2017 to Fiscal 2019*. Vancouver, BC: BC Hydro. Available on-line at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf. Last accessed September 27, 2016.

BC Hydro (2016b) "2015 Balancing Authority Load Jan-Dec." *Historical Transmission Data.* Available on-line at: https://www.bchydro.com/energy-in-bc/our_system/transmission/transmission-system/balancing-authority-load-data/historical-transmission-data.html. Last accessed September 1, 2016.

BC Hydro (2016c) “Net Actual Flow.” *Historical Transmission Data*. Available on-line at: https://www.bchydro.com/energy-in-bc/our_system/transmission/transmission-system/actual-flow-data/historical-data.html. Last accessed November 25, 2016.

CBC (2016) “Bipole III route a mistake that can’t be changed, Manitoba Hydro board says.” *CBC News Online*. Available on-line at: http://www.cbc.ca/news/canada/manitoba/bipole-iii-route-manitoba-hydro-mistake-1.3772444. Last accessed November 25, 2016.

Commission for Environmental Co-operation (2016) *North American Power Plant Air Emissions*. Available on-line at: http://www2.cec.org/site/PPE/content/greenhouse-gases-ghg. Last accessed: September 27, 2016.

DMTI Spatial (2016) “Transmission Line Lines” Available on-line at: http://geo.scholarsportal.info/#r/details/_uri@=2731396105. Last accessed November 25, 2016.

DMTI Spatial (2015) “Power plants points” Available on-line at: http://geo.scholarsportal.info/#r/details/_uri@=1305460747. Last accessed September 27, 2016.

Energy Information Administration (EIA) (2016a) “Table 8.2 Cost and performance characteristics of new central station electricity generating technologies.” *Annual Energy Outlook, 2016*. Available on-line at: https://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf. Last accessed: November 25, 2016.

Energy Information Administration (EIA) (2016b) “Electric Power Projections by Electricity Market Module Region.” *Annual Energy Outlook, 2016*. Available on-line at: http://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2016&cases=ref2016&sourcekey=0. Last accessed November 28, 2016.

Environment Canada (2014) *National Inventory 1990-2012, Part 2, Annex 8*. Government of Canada. Available on-line at: http://publications.gc.ca/collections/collection_2014/ec/En81-4-2012-2-eng.pdf. Last accessed November 25, 2016.

General Electric International Inc. (2016) *Pan-Canadian Wind Integration Study*. Published by the Canadian Wind Energy Association (CANWEA). Available on-line at: http://canwea.ca/wind-energy/wind-integration-study/. Last accessed September 15, 2016.

Global Energy Observatory (2010) “Nuclear in Canada.” Available on-line at: http://GlobalEnergyObservatory.org/. Last accessed September 27, 2016.

Global Modelling and Assimilation Office (GMAO) (2016) *Modern-Era Retrospective analysis for Research and Applications (MERRA).* NASA/GSFC, Greenbelt, MD, USA, NASA Goddard Earth Sciences Data and Information Services Center (GES DISC). Available on-line at: http://disc.sci.gsfc.nasa.gov/mdisc/data-holdings. Last updated February 2016.

Hellman, Hannu-Pekka, Matti Koivisto and Matti Lehtonen (2014) “Photovoltaic Power Generation Hourly Modelling.” *Proceedings of the 2014 15th International Scientific Conference on Electric Power Engineering (EPE).* IEEE. DOI: 10.1109/EPE.2014.6839426.

Hydro Quebec (2016) *Hourly Electricity Demand and Production*. Data provided October 2016.

Hydro Quebec (2016) *2015 Annual Report*. Available on-line at: http://www.hydroquebec.com/publications/en/docs/annual-report/annual-report.pdf. Last accessed September 27, 2016.

Independent Electricity System Operator (IESO) (2016a) "Hourly Ontario and Market Demands, 2002-2014." *IESO Historical Reports (2002-present)*. Available on-line at: http://www.ieso.ca/Pages/Power-Data/Data-Directory.aspx. Last accessed September 1, 2016.

Independent Electricity System Operator (IESO) (2016b) "Import Export Schedule, 2002-2015." *IESO Historical Reports (2002-present)*. Available on-line at: http://www.ieso.ca/Pages/Power-Data/Data-Directory.aspx. Last accessed November 25, 2016.

Lazard (2015) *Levelized Cost of Energy Analysis – Version 9.0*. Available on-line at: https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-90/. Last accessed: September 1, 2016.

MacDonald, Alexander E., Christopher T.M. Clack, Anneliese Alexander, Adam Dunbar, James Wilczak, and Yuanfu Xie (2016), "Future cost-competitive electricity systems and their impact on US CO2 emissions." *Nature Climate Change*. January 25, 2016, DOI: 10.1038/NCLIMATE2921.

Manitoba Hydro (2016) *Hourly Electricity Demand and Production*. Data provided October 2016.

Maritime Electric (2016) *Hourly Electricity Demand for PEI*. Data provided November 2016.

Masters, Gilbert (2004) *Renewable and Efficient Electric Power Systems*. John Wiley & Sons: Hoboken, New Jersey.

Mattei, M, G. Notton, C. Cristofari, M. Muselli, P. Poggi (2006) "Calculation of the polycrystalline PV module temperature using a simple method of energy balance." *Renewable Energy*. 31, pp. 553-567. DOI: 10.1016/j.renene.2005.03.010.

Meteorological Service of Canada (MSC) and Natural Research Council (NRC) (2010a) *Canadian Weather for Energy Calculations (CWEC Files).* Available online at: http://climate.weather.gc.ca/prods_servs/engineering_e.html. Last accessed September 6, 2016.

Meteorological Service of Canada (MSC) and Natural Research Council (NRC) (2010b) *Canadian Weather for Energy Calculations (CWEC Files) Updated User Manual.* Available online at: http://climate.weather.gc.ca/prods_servs/engineering_e.html. Last accessed September 6, 2016.

National Energy Board (2016) *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040*. Calgary, AB: National Energy Board. Available on-line at: https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html#s3. Last accessed September 27, 2016.

National Energy Board (2015) *Energy Conversion Tables*. Available on-line at: http://www.neb-one.gc.ca/nrg/tl/cnvrsntbl/cnvrsntbl-eng.html#s2ss_auto1. Last accessed November 25, 2016.

New Brunswick Power (2016) *System Information Archive*. Data available on-line at: https://tso.nbpower.com/Public/en/system_information_archive.aspx. Last accessed September 1, 2016.

Nova Scotia Power (2016) "Hourly Total Net Nova Scotia Load." *Open Access Same-Time Information System*. Available on-line at: http://oasis.nspower.ca/en/home/oasis/monthly-reports/hourly-total-net-nova-scotia-load.aspx. Last accessed September 1, 2016.

NRCAN (2016) "Map of Clean Energy Resources and Projects (CERP) in Canada," in *The Atlas of Canada – Clean Energy Resources and Projects (CERP).* Available on-line at: http://atlas.gc.ca/cerp-rpep/en/. Last accessed September 27, 2016.

Ong, Sean, Clinton Campbell, Paul Denholm, Robert Margolis, and Garvin Heath (2013) *Land-Use Requirements for Solar Power Plants in the United States*. Boulder, CO: National Renewable Energy Laboratory. Available on-line at: http://www.nrel.gov/docs/fy13osti/56290.pdf. Last accessed September 20, 2016.

Open Canada (2016) "Renewable Energy Power Plants, 1 MW or larger" in *NRCAN Canada Atlas*. Available on-line at: https://goo.gl/9EXT87. Last accessed September 27, 2016.

Peterson, Ernest W and Joseph P Hennessey Jr (1978) "On the use of power laws for estimates of wind power potential." *Journal of Applied Meteorology*. 17:3, pp. 390–394.

SaskPower (2016) *2014-2015 Hourly Electricity Demand*. Data provided November 2016.

Statistics Canada (2016) *CANSIM Tables 127-0002, 127-0007, 127-0009, 127-0010, 127-0017, and 326-0021*. Available on-line at: http://www5.statcan.gc.ca/cansim/home-accueil?lang=eng.

Susdesign (2016) *Declination*. Accessed on-line at: http://www.susdesign.com/popups/sunangle/declination.php.

Trottier Energy Futures Project (2016) *Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions*. The Canadian Academy of Engineering and the Trottier Family Foundation.

U.S. Naval Observatory (USNO) (2015) “Azimuth Angle”
Available on-line at: aa.usno.navy.mil/data/docs/AltAz.php, Last accessed September 6, 2016.

Westmoreland Coal (2015) *Westmoreland First Quarter Results*. Englewood, CO: Westmoreland Coal Company. Available on-line at: http://westmoreland.com/2015/04/westmoreland-reports-first-quarter-2015-results/. Last accessed November 25, 2016.

Westmoreland Coal (2014) *Westmoreland Annual Report*. Englewood, CO: Westmoreland Coal Company. Available on-line at: http://westmoreland.com/wp-content/uploads/2014/05/2014-Proxy-and-Annual-Report-Color-Version-FINAL.pdf. Last accessed November 25, 2016.

Wikipedia (2016) *List of generating stations in Canada*. Available on-line at: https://en.wikipedia.org/wiki/List_of_generating_stations_in_Canada. Last accessed: September 27, 2016.

Appendix A – Solar Capacity Factor Calculations

A.1 Solar Calculation Notation

Table A.1 introduces the notation used in the solar equation calculations and defines key parameters.

Symbol	Definition
θ	Incidence angle between sun and solar collector face
δ	Solar declination: “the angle formed between the plane of the equator and a line drawn from the center of the sun to the center of the earth is called the solar declination” (Masters, 2004: 392)
n	Day number
H	Hour angle: “the number of degrees that the earth must rotate before the sun will be directly over your local meridian (line of longitude)” (Masters, 2004: 396)
βn	Altitude Angle: “the angle between the sun and the local horizon directly beneath the sun.” (Masters, 2004: 394)
L	Latitude of site location
Φ_s	Azimuth angle “Azimuth is the angle along the horizon, with zero degrees corresponding to North, and increasing in a clockwise fashion. Thus, 90 degrees is East, 180 degrees is South, and 270 degrees is West. Using these two angles, one can describe the apparent position of an object (such as the Sun at a given time).” (USNO, 2015)
Σ	Tilt of the solar panel
I_b	Direct-beam radiation (normal to the rays) measured by CWECS variable DNI – Direct normal irradiance (kJ/m^2), which indicates the “radiant energy received by a pyranometer directly from the sun during the hour.” (MSC and NRC, 2010b)
I_{bc}	The direct-beam radiation that strikes the solar collector (kJ/m^2)

I_{dh}	Diffuse horizontal radiation (normal to the rays) measured by CWECS variable DHI – Diffuse horizontal irradiance (kJ/m^2), which indicates the "radiant energy received on a horizontal surface by a pyranometer indirectly from the sky during the hour." (MSC and NRC, 2010b)
I_{dc}	Diffuse horizontal radiation that strikes the solar collector (kJ/m2)
I_{rc}	Reflected-beam radiation that strikes the solar collector (kJ/m^2)
$IkWh/m^2$	Total irradiation striking the solar collector measured in kWh/m^2
T_c	Solar cell temperature
T_a	Ambient dry-bulb temperature (provided by CWECS)
T_{noct}	Normal operating cell temperature
τ	Temperature correction factor
γ	Solar cell power temperature coefficient (e.g. .45 %/°C for Mitsubishi Diamond Pro)
T_{stc}	Temperature at Standard Test Conditions (STC) (25°C)
CF_{dc}	Temperature adjusted DC hourly solar capacity factor
Cd_{ac}	AC hourly solar capacity factors.

Table A1: Notation for solar calculations

A.2 Solar Position Calculations

The level of solar irradiation received by a solar panel depends on the intensity of solar irradiation striking the site and the angle of the solar collector relative to the sun. We have assumed a fixed-mount solar panel facing directly south and calculate the position of the sun relative to this panel position.

Equation A1 calculates **solar declination** (δ): "the angle formed between the plane of the equator and a line drawn from the center of the sun to the center of the earth" (Masters, 2004: 392). This angle changes throughout the course of the year as the earth rotates around the sun,

$$\delta = 23.45\, sin\left[\frac{360}{365} * (284 + day)\right] \quad \text{(A1)}$$

(SusDesign, 2016).

Equation A2 calculates the **hour angle** (H): "the number of degrees that the earth must rotate before the sun will be directly over your local meridian (line of longitude)" (Masters, 2004: 396). The hour angle changes over the course of the day and is equal to zero when the sun is directly overhead of the site,

$$H = \left(\frac{15°}{\text{hour}}\right) * (\text{hours before solar noon}) \quad \text{(A2)}$$

(Masters, 2004: 396).

The next two equations are key in locating the sun in the sky in any given hour (see Figure 5 below). Equation A3 calculates the **altitude angle** (β): "the angle between the sun and the local horizon directly beneath the sun" (Masters, 2004: 394),

$$\sin\beta = \cos L \cos\delta \cos H + \sin L \sin\delta \quad \text{(A3)}$$

(Masters, 2004: 396).

Equation A4 calculates the **azimuth angle of the sun** (ϕ_s), which measures the angle of the sun "along the horizon" (USNO, 2015). When calculating the solar azimuth angle in the northern hemisphere due south has a value of zero. As well, "by convention, the azimuth angle is positive in the morning with the sun in the east and negative in the afternoon with the sun in the west" (Masters, 2004: 395),

$$\sin\phi_s = \frac{\cos\delta \cos H}{\cos\beta} \quad \text{(A4)}$$

(Masters, 2004: 396).

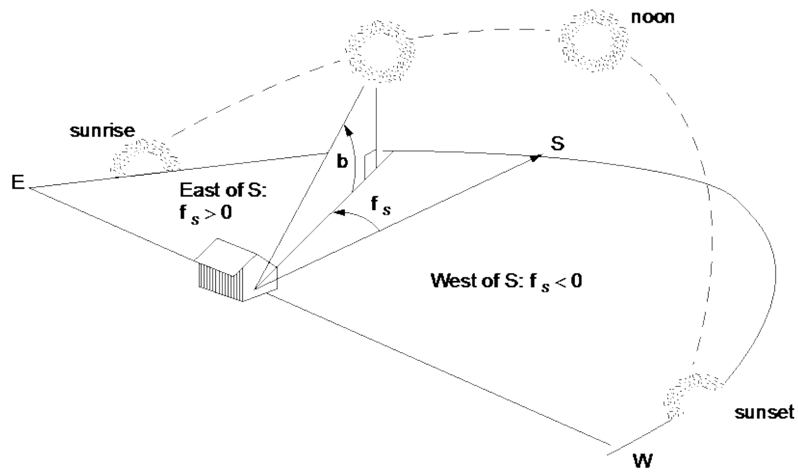


Figure 7.10 The sun's position can be described by its altitude angle β and its azimuth angle φ_S. By convention, the azimuth angle is considered to be positive before solar noon.

Figure A1: Altitude and Azimuth Angles Locate the Sun in the Sky

(Masters, 2004: 396)

A.3 Solar Irradiance on the Collector

Using the hourly and site-specific values calculated for ϕ_s and β it is possible to use equation A5 to calculate the angle of incidence (θ), which refers to the angle θ "between a line drawn normal to the collector face and the incoming beam radiation" (Masters, 2004: 414),

$$\cos\theta = \cos\beta\cos(\phi_s - \phi_c)\sin\Sigma + \sin\beta\cos\Sigma \quad \text{(A5)}$$

(Masters, 2004: 414).

The azimuth of the collector (ϕ_c) is zero when it faces directly south as we have assumed. We set the tilt of the solar panel (Σ) equal to the latitude of the CWECS site.

We then use the cosine of the angle of incidence to translate direct-beam irradiation data, measured by the CWECS variable DNI (direct normal irradiation) (I_b), into the direct-beam radiation striking the face of the solar collector,

$$I_{bc} = I_b\cos\theta \quad \text{(A6)}$$

(Masters, 2004: 414).

Additional solar irradiation reaching the solar collector comes from diffuse-beam radiation (I_{dh}) and reflected beam radiation (I_{rc}). Diffuse-beam radiation (I_{dh}) is solar irradiation "scattered from atmospheric particles and moisture" or "reflected by clouds" (Masters, 2004: 415). I_{dh} is measured by Environment Canada as Direct Horizontal Irradiance (DHI) (kj/m^2). On a cloudy day this diffuse-beam radiation may be the main source of irradiation striking a solar collector. The level of diffuse-beam irradiation striking a solar collector is a function of the level of diffuse-beam irradiation in that hour (I_{dh}) and the amount of sky the collector "sees", which is dependent on the tilt of the solar collector (Σ),

$$I_{dc} = I_{dh} * \left(\frac{1+\cos\Sigma}{2}\right) \quad \text{(A7)}$$

(Masters, 2004: 716).

When the tilt of the panel is zero, the collector can "see" the entire sky and the level of diffuse-beam irradiation striking a solar collector (I_{dc}) is equal to the level of diffuse-beam irradiation in that hour (I_{dh}).

Lastly, irradiation can be reflected off nearby surfaces and onto the solar collector. Reflected-beam radiation striking a solar collector (I_{rc}) is a function of ground reflectance (ρ) and both direct-beam irradiation (I_b) and diffuse-horizontal irradiation (I_{dh}),

$$I_{rc} = \rho * (I_b + I_{dh}) * \left(\frac{1+\cos\Sigma}{2}\right) \quad \text{(A8)}$$

(Masters, 2004: 417).

Masters (2004) writes that "estimates of ground reflectance range from about 0.8 for fresh snow to about 0.1 for a bituminous-and-gravel roof, with a typical default value for ordinary ground or grass taken to be about 0.2" (p. 417). We assume a reflectance value of .2 as a default and a reflectance value of .6 when snow is present (indicated by the CWECS variable ‘Snow’).

The total irradiation striking the solar collector (I_{tot}) (kj/m^2) is the sum of direct, diffuse, and reflected irradiation striking the solar collector,

$$I_{total} = I_{bc} + I_{dc} + I_{rc} \quad \text{(A9)}$$

A.4 Solar Capacity Factors

The irradiation measure in equation A9 can be converted to kWh/m^2 by dividing by 3600,

$$I_{kWh/m^2} = I_{total}/3600 \quad \text{(A10).}$$

Total irradiation striking the solar collector measured in kWh/m^2 (I_{kWh/m^2}) creates a number that is equal to the direct current (DC) capacity factor of the solar collector. This is so because solar panels are rated under standard test conditions of 1000 Watts/m^2 solar irradiation striking the collector. This means that a 1-kilowatt (kW_{dc}) solar installation will produce power at its rated capacity of 1 kW_{dc} when solar irradiation is equal to standard test conditions of 1000 Watts/m^2. If these conditions persist over the course of one hour, then the solar panel will have generated 1 kilowatt-hour (kWh) of electricity. We assume a linear relationship between solar irradiation striking the solar collector and electricity output measured in DC; if a 1 kW_{dc} solar collector is struck by .8 kWh/m^2 of solar irradiation over the course of an hour than it will have generated .8 kWh of electricity.

A.5 Electricity Conversion Corrections

Two further steps are required to estimate electricity supplied to the grid by solar panels. First, it is necessary to correct for temperature. Solar panels are rated at standard test conditions (STC) of 1000 Watts/m^2 solar irradiation striking the collector at a temperature of 25°C. Solar cells work more efficiently at temperatures below 25°C and less efficiently at temperatures above 25°C. We calculate the temperature of the solar cell in each hour using equation A11,

$$T_c = T_a + (T_{NOCT} - 20°\text{C}) * \frac{I_{kWh/m^2}}{.8\ kW/m^2} \text{ (A11)}$$

Where,

T_c = solar cell temperature

T_a = ambient dry-bulb temperature (provided by CWECS)

T_{NOCT} = Normal operating cell temperature

(Hellman *et al*, 2014: 2; Mattei *et al*., 2006).

We assign a value of 46°C to the parameter T_{NOCT}, which is based on the specifications of the Mitsubishi Diamond Pro 265W solar collector.

Using the temperature of the solar cell T_c we calculate a temperature correction factor (τ) in each hour using equation A12,

$$\tau = 1 - \gamma\ (T_c - T_{stc}) \text{ (A12)}$$

Where,

γ = solar cell power temperature coefficient (*e.g.* .45 %/°C for Mitsubishi Diamond Pro)

T_{stc} = Temperature at Standard Test Conditions (STC) (25°C).

(Hellman *et al.*, 2014: 2)

We assign a value of .45 %/°C to the parameter T_{NOCT}, which is based on the specifications of the Mitsubishi Diamond Pro 265W solar collector.

The temperature adjusted DC hourly capacity factor CF_{DC} for solar facilities at a given location is found by multiplying the irradiation striking the solar collector by the temperature correction factor (τ),

$$CF_{DC} = I_{kWh/m^2} * \tau \quad \text{(A13).}$$

The amount of solar electricity generated by a panel in direct current (DC) is greater than the amount of electricity a solar panel delivers to an electricity grid. Electricity is lost as solar electricity is converted from DC to AC using an inverter. Theoretical capacity factors may also be greater than realized capacity factors due to dirt and debris on the solar panel. For this reason, we multiply the DC capacity factor by 85% to account for inverter and other losses,

$$CF_{AC} = CF_{DC} * .85 \quad \text{(A14).}$$

We then use the resulting AC hourly solar capacity factors (CF_{AC}) as exogenous parameters in the optimization model.