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 would 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 CO_2e render the majority of Canada's coal-fired plants uneconomic.

Keywords: electricity; greenhouse gas emissions; linear programming; Canada; renewable energy; transmission

1. INTRODUCTION

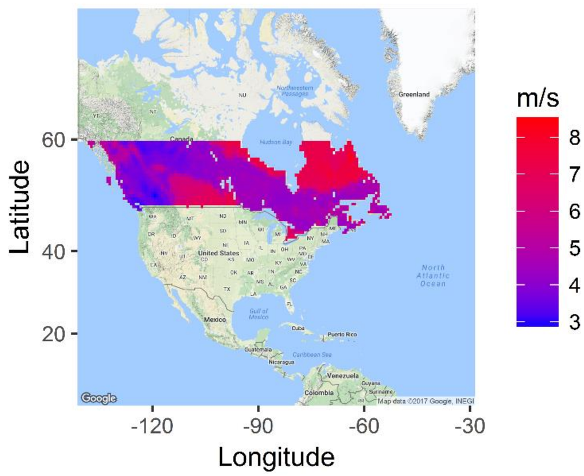
With the ratification of the Paris Agreement, the world has committed to "holding the increase in the global average temperature to well below 2 °C above pre-industrial levels" (UNFCCC, 2015: 2). By some estimates, meeting the 2 °C target will require global per capita greenhouse gas (GHG) emissions 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, 2016).

In this paper, we ask: how much will it cost to decarbonize the Canadian electricity system? Canada 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. Canadian fossil fuel electricity plants emitted 79 Megatonnes (Mt) CO_2e in 2015, which accounted for 10.9% of Canada's 722 Mt CO_2e GHG emissions total (Environment and Climate Change Canada, 2017).

In our analysis 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 photovoltaic installations can achieve

[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 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.

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.



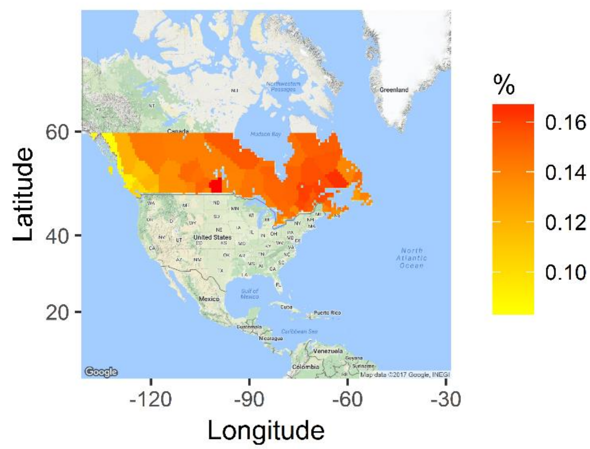


Figure 1a Wind Speed by MERRA Grid Cell **Figure 1b Solar Capacity Factors by MERRA Grid Cell**

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 whether it is beneficial to build new high-voltage transmission between Canadian provinces. 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.

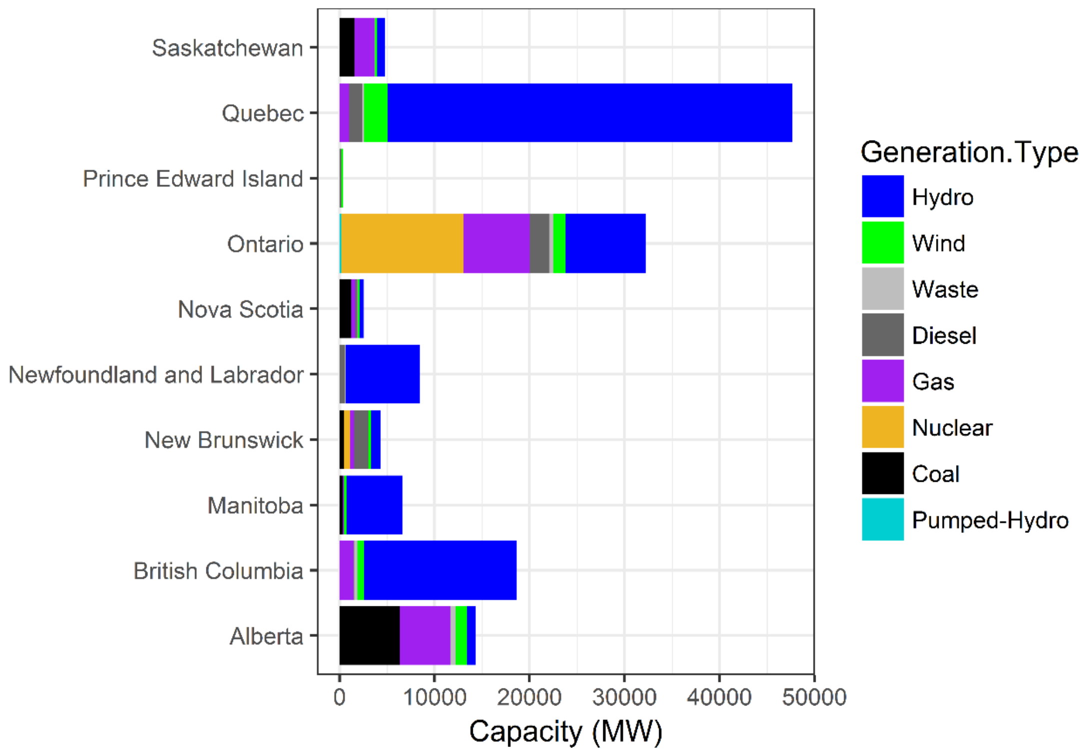


Figure 2 – Canadian Electricity Generation Capacity by Province[2]

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 TEFP (2016) study uses a proprietary version of the *North American Times Energy Model (NATEM)* to identify 11 scenarios for lowering GHG emissions in Canada. The NATEM model represents the electricity sector spatially at the provincial scale and temporally using 16 time-slices to represent the

[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.

variation of electricity demand (ESMIA, 2017). The TEFP (2016) concludes that decarbonizing the electricity sector is an important measure to facilitate GHG emissions reduction in Canada.

The GE (2016) study uses a “heuristic generation expansion planning approach” to understand the potential for integrating wind energy into the Canadian electricity system (p. 23). The GE (2016) study finds that it is technically feasible 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 GE (2016) study also identifies one potential set of transmission lines that could be built to aid wind energy integration. Our study uses an optimization approach to assess the value of constructing additional transmission links.

The analysis by Ibanez and Zinaman (2015) jointly optimizes Canadian and United States (US) electricity futures using the NREL *Regional Energy Deployment System (ReEDs)* model. This is a useful approach since there are greater transmission connections north-south from Canada to the United States than there are east-west between provinces within Canada. We model the interdependent nature of the Canadian and US electricity system by including hourly export data from Canadian provinces to the US. This simplification means that we do not co-optimize investments in generation and transmission capacity between Canada and the United States. Instead we focus on actions Canada can take within its borders to decarbonize and optimize electricity supply. The NREL ReEDs model contains 47 wind and solar power resource regions within Canada and 17 time-slices to represent spatial and temporal variation in renewable energy supply and electricity demand (Ibanez and Zinaman, 2015).

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 (8760 hourly time steps), hourly wind resource data for 2281 grid cells south of 60˚ latitude in Canada, and hourly solar resource data for 199 meteorological stations south of 60˚ latitude. In contrast, the NATEM (TEFP, 2016) and ReEDS (Ibanez and Zinaman, 2015) models use representative temporal snapshots of electrical grid operation (called time-slices), and lower spatial resolution for their wind and solar data.

We use the high resolution spatial and temporal data to co-optimize investments in new generation with the hourly dispatch of available generation assets over the course of a year. The hourly wind and solar resource data in our model allows us to account for the variability of electricity supplied by renewable energy. Our co-optimization approach is most similar to MacDonald *et al*. (2016) who 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 wind energy is a low-cost means of reducing GHG emissions in Canada. At a carbon price of \$200/tCO_2, investments in wind can achieve GHG reductions of 83 - 87% below 2025 reference scenario emissions and would increase average electricity costs by \$12 to \$13/Megawatt-hour (MWh). In these low-carbon scenarios, wind energy meets 30-35% of electricity demand despite its variability.

Our second contribution to the literature is evaluating the desirability of investing 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. In a sensitivity analysis, we also find that if capital costs for HVDC transmission lines are much higher than expected, the optimal level of investment in transmission is decreased, and the optimal level of investment in energy storage is increased.

Third, we offer insights into the 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 CO_2e to achieve significant decarbonization in Canada's electricity sector. In our modelled scenarios, we find that carbon prices of $80/tonne CO_2e 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 CO_2e.

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 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 its high geographic and temporal resolution, 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]

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

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 and the data used to parametrize the model is available in the Supplementary Information (SI) document.

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]

[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),

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

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

- 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 include operational constraints to control the speed at which dispatchable generation facilities can ramp up and down.[5] We also set minimum and maximum annual capacity factors to ensure that generating capacity operates within an economically viable and technically feasible range (Table 1). Minimum capacity factors represent the economic reality that a plant will have to run for a minimum amount during a year to justify ongoing staffing and operation of the facility. Maximum capacity factors represent the technical constraint that plants will require shutdowns on occasion and do not operate at 100% capacity throughout the course of a year.[6] These constraints are required because we allow investment into generation capacity on a continuous scale and do not use an integer programming investment modelling approach or unit commitment dispatch modelling approach. A full account of the constraints in our model is included in the SI.

[5] Note that we do not model discrete electricity generation units and so all available capacity can ramp up and down at the same rate.

[6] Note that without minimum and capacity factors in our model, nuclear and combined cycle gas plants often register 100% capacity utilization. This unrealistic operating range allows the model to invest less in capacity and reduce total costs by 4.5 – 8% depending on the scenario.

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 of latitude in Canada (each grid cell is one-half degree by two-thirds of a degree). We obtain hourly wind speed data for 2014 from the *Modern-Era Retrospective analysis for Research and Applications* (MERRA) dataset (GMAO, 2016).[7] 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

[7] 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.

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 we do not require additional back-up reserves, 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 new 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).[8] These three technologies differ in their ability 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

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[8] While we do not observe the proportion of hydro storage facilities by type directly, we believe our storage assumptions are reasonable and in fact likely underestimate storage potential, especially the potential to store potential energy in reservoirs across seasons. 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.

electricity production by province and month.[9] 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 can 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 course of a month does not exceed the average hourly production multiplied by the number of hours in the month. All 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).

[9] The majority of our scenarios rely on historic electricity production data from 2014, but in our sensitivity analysis we also test the impact of low precipitation years on optimal system investment using data from 2010.

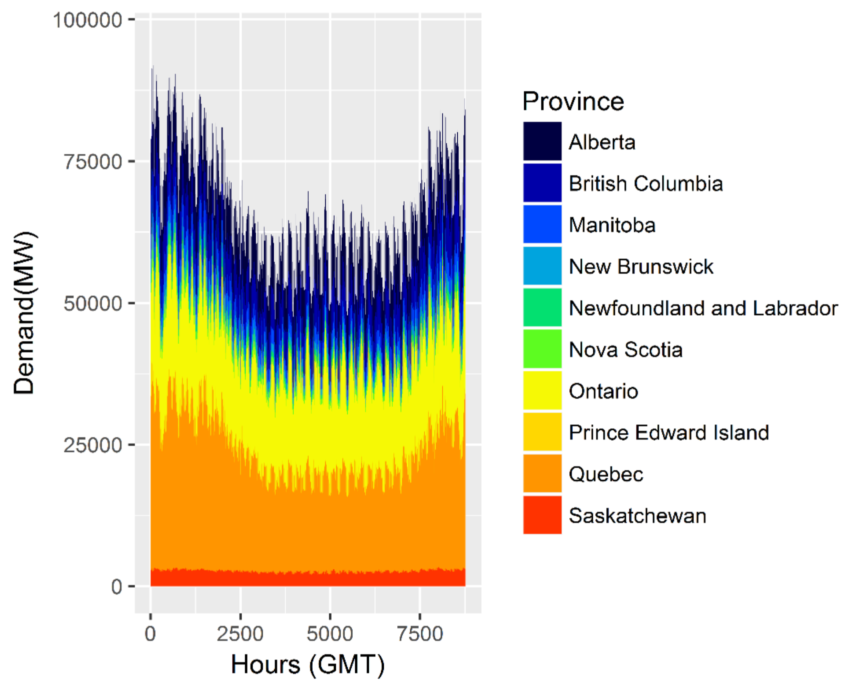


Figure 3a – Canadian Domestic Electricity Demand

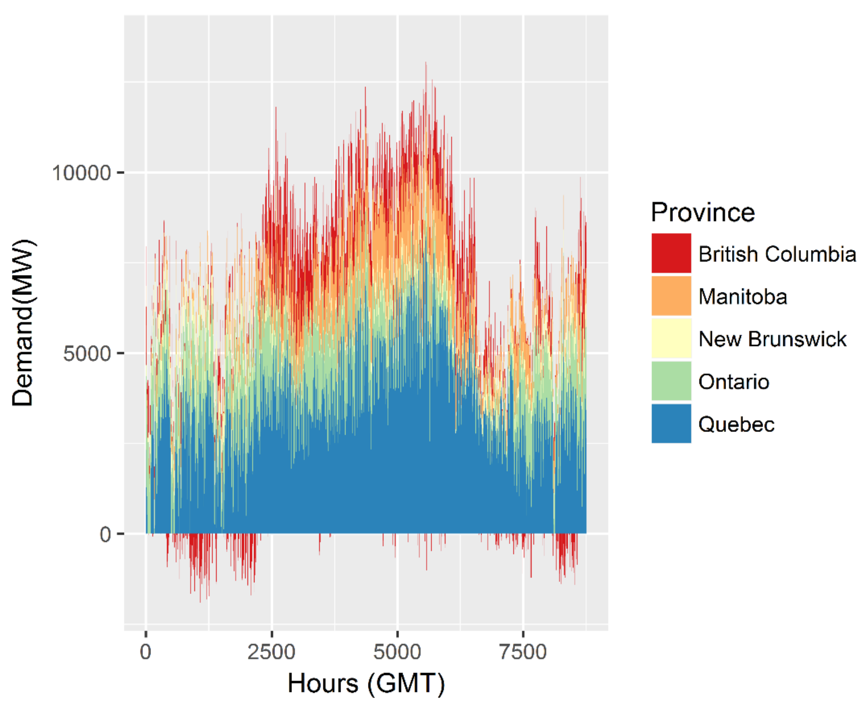


Figure 3b – Electricity Trade with the United States

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 and do not allow demand to respond to electricity price.

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.[10]

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

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

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

Technology	Capital Cost ($CAD/kw)	Life	Annualized Capital Cost ($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	CO2e tonnes 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 amortized capital cost 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.

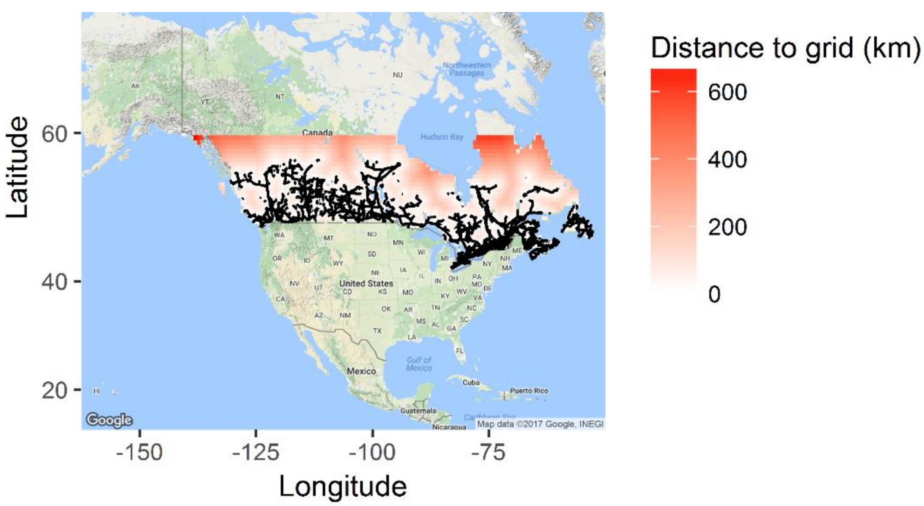


Figure 4 – Distance of MERRA Grid Cells to Existing Transmission Grid

(DMTI, 2016; author's calculations)[11]

2.9 Calculating the Correlation Between Net Electricity Demand and Electricity Supply

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.

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

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).

2.10 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.

Lastly, we conduct a sensitivity analysis where we vary natural gas prices, vary the capital cost of building new transmission lines, and restrict hydroelectric generation to represent a low-precipitation year.

2.11 Model Limitations

Our modelling approach has the following limitations. First, we do not model plant investment in terms of discrete units. This means the optimization model selects investment levels in each technology and region on a continuous scale. For electricity technologies like wind turbines that can be built in increments of 1-3 Megawatts (MW) this is likely not a large concern. For technologies like nuclear power plants that must be built at minimum capacity values of 300-1000 MW, and transmission lines that are built at discrete capacities, this is a simplification of investment opportunities. The need to build units larger than selected by our optimization model would increase the cost of these technologies in our model.

Second, because we do not model discrete generations units, we do not use a unit commitment approach to dispatch available generation assets. In a unit commitment approach, dispatch occurs in two stages. In stage one, the model selects the level at which a dispatchable plant can operate in a future time-period. Wind and solar forecasts influence the required unit commitments. In stage two, units are dispatched at the required level given contemporaneous demand and renewable energy supply. Additional reserve generation capacity is required as a safeguard to ensure that supply can meet demand if demand exceeds expectations or renewable energy supply differs from the forecast. We do not require additional reserve capacity. We also assume that all installed capacity can ramp up and down concurrently (subject to ramp rate constraints). Both the lack of reserve requirements and the ability of plants to ramp concurrently mean our model likely underestimates the cost of responding to the variability of demand and renewable energy.

Third, we do not model intra-provincial electricity distribution in detail and our model does not consider power flow and frequency regulation (Dowds *et al.*, 2015; Clack *et al*., 2017). Technologies like flywheels may be necessary to manage frequency regulation, especially in the face of higher integration of variable renewables. Our modelling results are best interpreted as accounting for the resource adequacy of wind and solar generation and the cost of providing back-up generation capacity that can respond to the variability of renewable generation (Dowds *et al.*, 2015). Accounting for frequency regulation would likely increase total cost in our model.

Lastly, we assume that electricity demand is fixed at initial forecast levels. In effect, this means we assume perfectly inelastic electricity demand. While it is beyond the scope of our current analysis, allowing for price-responsive demand would have two impacts on our results. First, efforts to respond to higher prices would reduce the welfare of electricity consumers. We do not conduct a welfare analysis in this paper. Second, given a consistent carbon pricing signal throughout the economy, these efforts would lead to greater GHG emissions at any given carbon pricing level, increasing the effectiveness of carbon pricing.

Despite these limitations, we believe our results offer insights into the scale of electricity decarbonization costs, the role that renewables like wind and solar can play in decarbonizing electricity, the value of building new transmission and storage assets to balance the variability of renewables, and the effectiveness of carbon pricing in Canada.

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).[12] 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).[13] After this large emissions reduction, the marginal abatement stepwise cost curves begin to increase more steeply indicating diminishing mitigation opportunities.

[12] As noted, we do not model the price-elasticity of electricity demand. This means our marginal abatement costs represent upper-end cost estimates.
[13] The province of Alberta has introduced legislation to retire coal-fired electricity generation capacity by 2030 (Alberta Government, 2017). In our model this policy is equivalent to a \$70-80/tCO_2 carbon price.

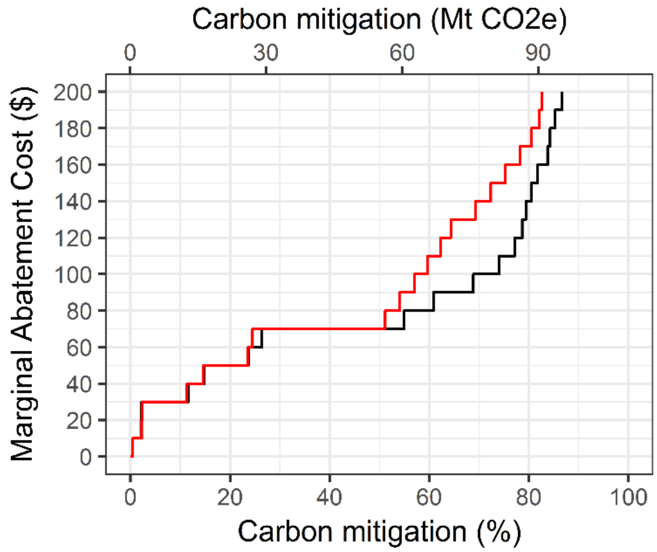


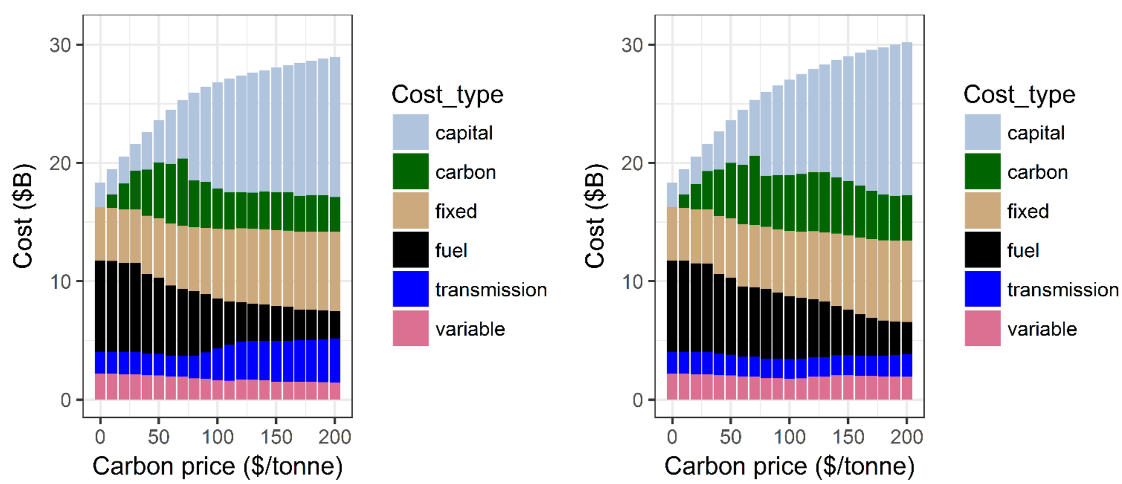
Figure 5 Marginal Abatement Stepwise Cost Curve (year = 2025)

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 CO_2e. 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 CO_2e.

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).[14] Expenditures on carbon pricing increase until the price

[14] 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.

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. These carbon expenditures are a transfer of funds from the electricity utility to government and that revenue can be recycled in ways that compensate the electricity utility or electricity customers, offsetting competitiveness impacts and limiting welfare impacts. For that reason, we do not include carbon costs in calculating the impact of emissions reductions on electricity costs below.[15]



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.[16] Averaged across all electricity production,

[15] Note that the Canadian federal government has committed to provinces that all carbon revenue stays within the jurisdiction in which it was raised.
[16] The impact to average electricity costs excludes carbon pricing costs..

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%.

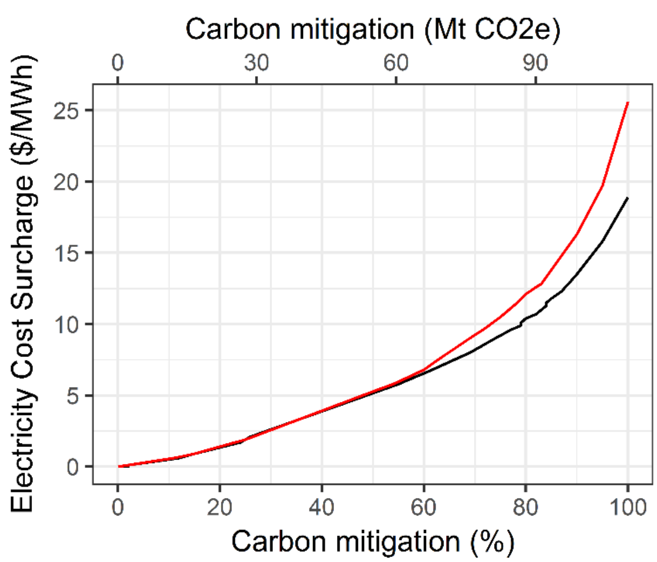
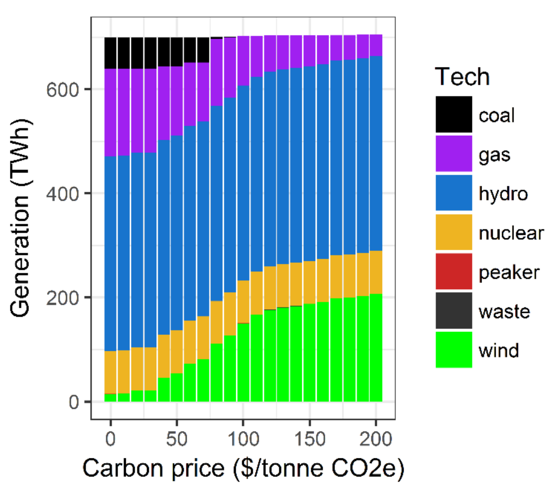


Figure 7 Electricity Cost Impacts (year = 2025)

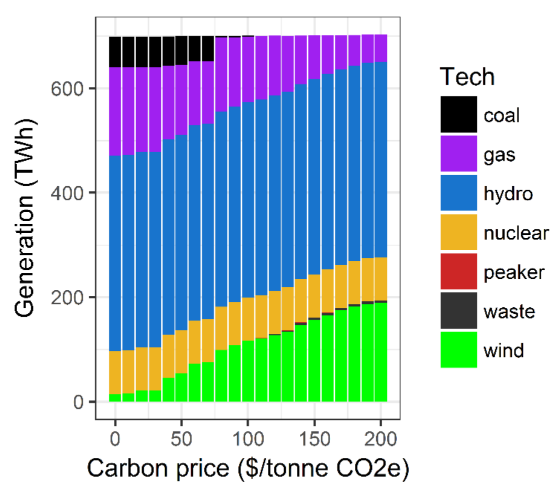
As Figure 5 indicated, a carbon price of $200/tonne CO_2e is not enough to motivate a complete decarbonization of the Canadian electricity sector in our model. Even with carbon prices of $450/tonne CO_2e, some GHG emissions remain in our optimized scenarios. To understand the cost of completely decarbonizing 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 are clear. New inter-provincial transmission reduces the cost of completely decarbonizing the Canadian electricity system by $4.2 billion/year in our modelled scenarios; 26% below the costs of decarbonization without new inter-provincial transmission.

3.2 Generation Mix

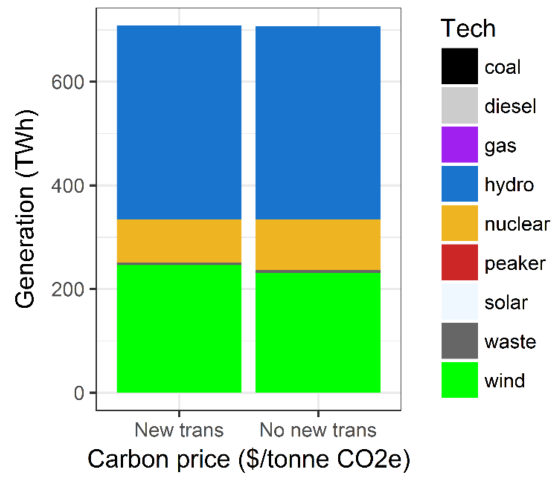
The optimal composition of Canada's generation mix shifts as carbon prices increase. Investments in wind power offer a low cost means of reducing emissions and are increasingly attractive at higher carbon prices (Figure 8). At $200/tonne CO_2e, wind composes nearly 30% of the optimal generation mix. 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.

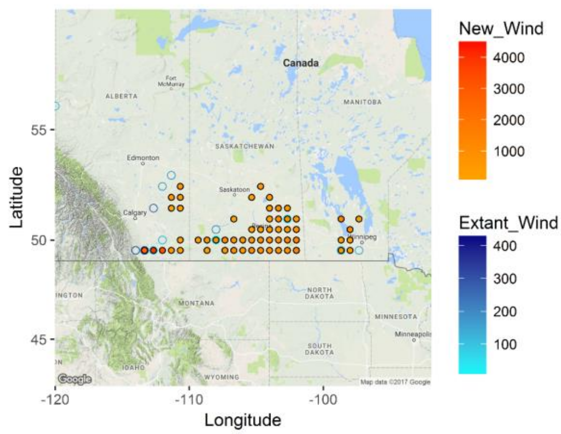
Due to their high cost relative to wind power and natural gas plants, utility-scale solar facilities and new nuclear facilities are not part of the optimal mix at carbon prices of $200/tonne CO_2e. They are also not part of the optimal 100% decarbonization mix when transmission is allowed. Only when new transmission is not allowed and complete decarbonization 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). Similarly, a small investment of 100 MW of solar in New Brunswick is optimal in the 100% decarbonization scenario when new transmission is not allowed. 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

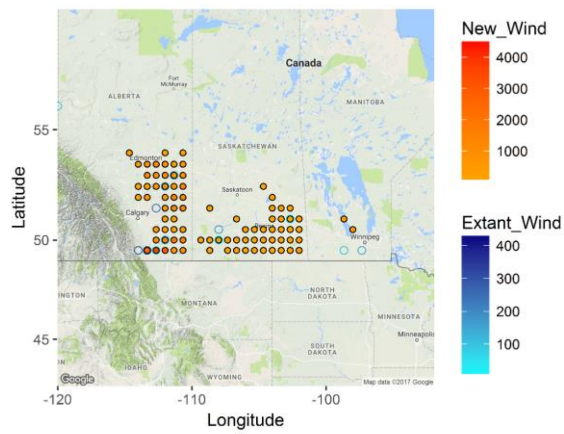
The model finds that new wind facilities are optimally located in southern Alberta, Saskatchewan and Manitoba (Figures 9a and 9b), southern Ontario (Figure 9c and 9d) and locations along the east coast (Figure 9e and 9f). The availability of new inter-provincial transmission lines changes the geographic 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).[17] 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

[17] 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 social acceptability of building wind power in rural communities.

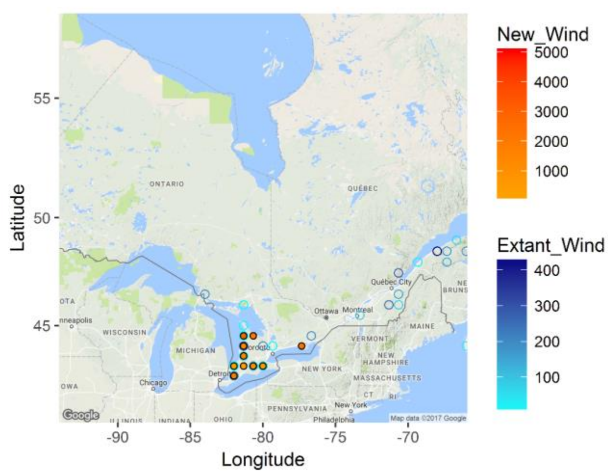
transmission assets. Using this approach, it appears there may be benefits to building wind power in the best sites and exporting electricity to neighbouring markets.[18]



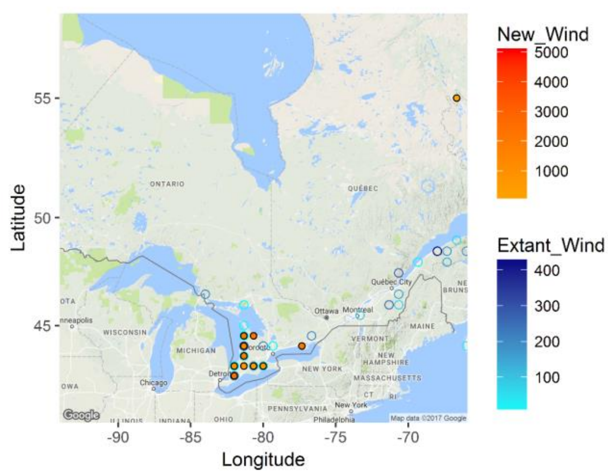
a. New Transmission Allowed



b. No New Transmission

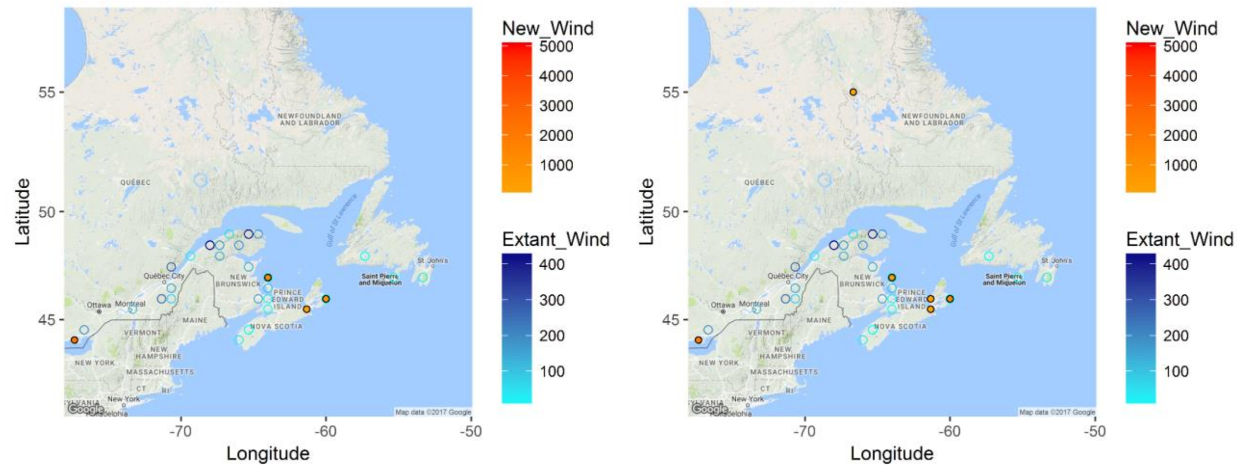


c. New Transmission Allowed



d. No New Transmission

[18] 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.



e. New Transmission Allowed

f. No New Transmission

Figure 9 Optimal Wind Power Locations at \$200/tonne CO_2e[19]

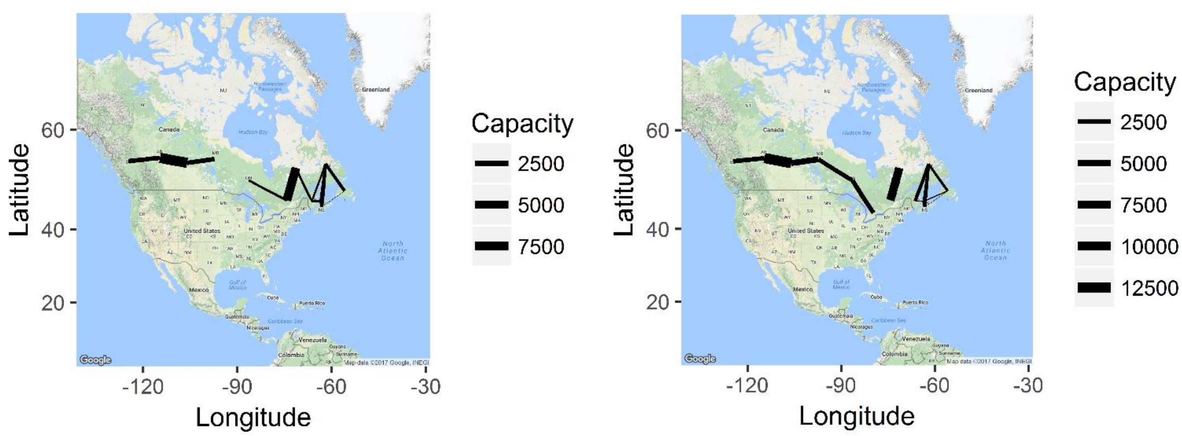
3.4 Transmission

When allowed in our model, it is optimal to build new inter-provincial transmission in three main places.[20] First, it is optimal to build 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 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.

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

[20] 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'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, it is optimal to enhance transmission 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

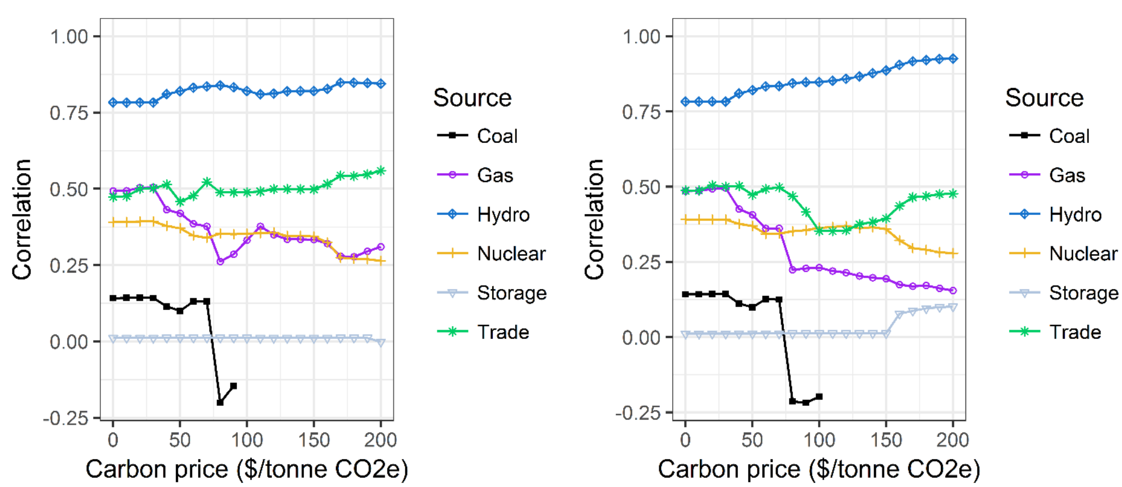
Exporting Province	Importing Province	MW
Alberta	British Columbia	1700
Saskatchewan	Alberta	9552
Manitoba	Saskatchewan	1858
Ontario (north)	Quebec (south)	459
Quebec (north)	Quebec (south)	7167
Quebec (north)	New Brunswick	356
Newfoundland and Labrador (south)	Nova Scotia	48
Newfoundland and Labrador (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 sample Pearson correlation coefficient between net electricity demand and the electricity supplied by various supply options identifies which supply options balance supply and demand in the face of variable wind output. Figure 11a and 11b display the correlation 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 balancing role in the $160-200/tonne CO_2e scenarios when new transmission is not allowed (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.

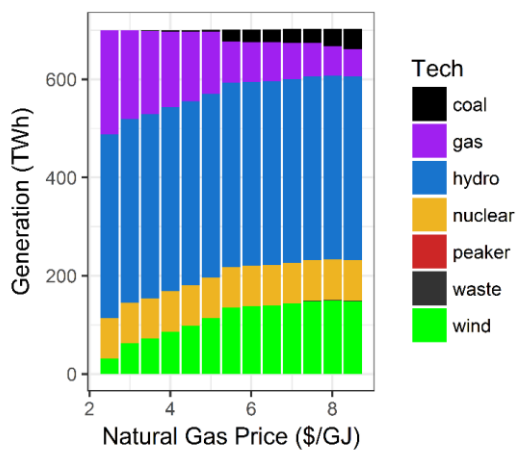


a. New transmission allowed **b. No new transmission**

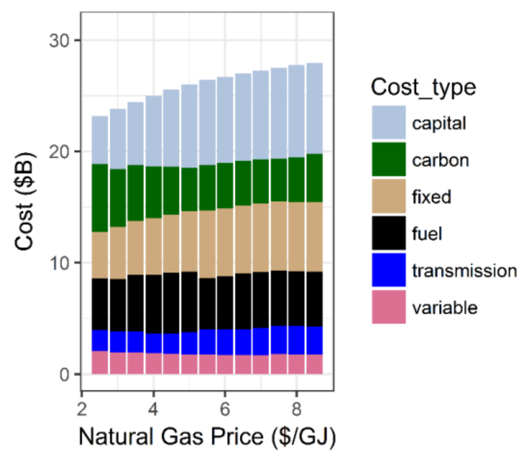
Figure 11 Correlation Between Net Demand and Supply Options

3.6.1 Sensitivity Analysis – Natural Gas

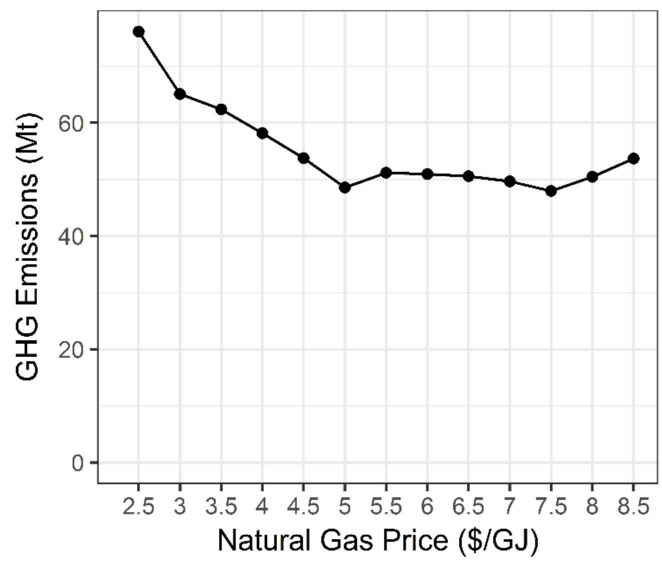
The scenarios above assume a natural gas price of \$4.91/GJ. Annual average natural gas prices have varied between \$2.52 and \$8.69 USD/GJ within the past ten years (EIA, 2017). Figures 12a, 12b, and 12c summarize how the optimal generation mix (12a), resulting GHG emissions (12b), and annual costs (12c) vary in response to natural gas prices ranging from \$2 to \$8.50 CAD/GJ. In these scenarios, we assume a carbon price of \$80/tonne CO_2e. This is the carbon price that would be achieved in 2025 if the Canadian government escalates the carbon price by \$10/year beginning in 2018.



a. Optimal Generation Mix



b. Greenhouse Gas Emissions



c. Annual Costs

Figure 12 Natural Gas Sensitivity Analysis

Figure 12b shows that GHG emissions are highest in the low natural gas price scenarios where natural gas generation crowds out investments in wind energy (Figure 12a). GHG emissions remain around 50 Mt in scenarios with natural gas prices of $5/GJ to $7.5/GJ. Emissions are again higher at prices of $8/GJ and $8.5/GJ. In these high-priced natural gas scenarios, the fuel cost penalty for natural gas outweighs the carbon penalty on coal, and coal-fired generation crowds out natural gas generation. Annual costs uniformly increase as natural gas prices increase (Figure 12c). Most of the increasing cost comes from increasing investments into new wind power capacity. Optimal capital investments in wind increase costs by $1 billion/year at a natural gas price of $2/GJ and $8 billion/year at a natural gas price of $8.50/GJ.

3.6.2 Sensitivity Analysis – Transmission Costs

The scenarios presented above assume an amortized capital cost of $184/MW/km/year for HVDC transmission lines. To test the robustness of our results we vary transmission capital costs between $100 and $600/MW/km/year. In these scenarios we constrain greenhouse gas emissions to be zero, which represents full decarbonization of the electricity system. As Figure 13 demonstrates, transmission and energy storage are clear substitutes in our model. As HVDC transmission capital costs rise, investments in transmission decline and investments in storage increase. Investments in wind also increase in the high-cost transmission scenarios. With less transmission capacity, wind must be built closer to load and at less optimal wind sites, requiring more wind to be built in aggregate. More wind is also necessary because there is an energy penalty for using storage.

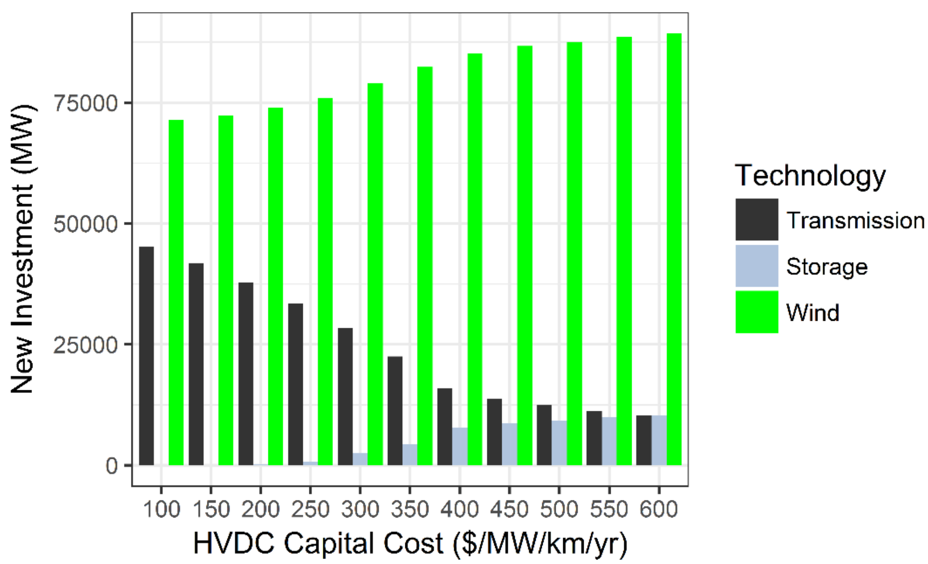


Figure 13 Transmission Cost Sensitivity Analysis

Annual costs range from $28 billion/year when HVDC lines cost $100/MW/km/year scenario, to $36 billion/year when HVDC costs are $600/MW/km/year. Of interest, it is optimal to build new transmission lines throughout the country even at HVDC capital costs of $600/MW/km/year. For example, even in this high-cost scenario, our model recommends a 450 MW connection from Manitoba to Saskatchewan, a 1300 MW connection from Saskatchewan to Alberta, and a 2100 MW connection from Alberta to British Columbia.

3.6.3 Sensitivity Analysis – Low Hydroelectric Years

In the scenarios above we model the availability of hydroelectric generation based on 2014 data when total hydroelectric electricity generation in Canada was 375 Terrawatt-hours (TWh) (Statistics Canada, 2016, CANSIM Table 127-0002). During years with low precipitation, hydroelectric output can fall. To understand the impact of low hydroelectric availability on our optimal electricity mix, we ran carbon pricing scenarios with hydroelectric generation data from 2010, when hydroelectric output was only 347 TWh. With less hydroelectric generation, more investment must be made in new generation capacity and costs increase by 6.6% - 8.1%. The contribution of hydroelectricity drops from 53.5% of total generation to 49.6% of the total. In low carbon price scenarios, this supply gap is made up by combined cycle and peaking gas plants. When carbon pricing is introduced, investments in wind power increases to make up for the loss of hydroelectric generation, and wind generation expands from 29.5% to 34% of supply at a carbon price of $200/tonne CO_2e. A useful way to prepare for low-hydro years may be to overbuild wind capacity and seek opportunities for greater exports to the United States during wet years.

4. CONCLUSION 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.

A 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 CO_2e 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, 2017).[21] If Canada is to significantly decarbonize the electricity sector by 2030, 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 in our model even at very high carbon pricing levels of

[21] Note that reductions would be deeper had we modelled price-responsive electricity demand.

\$450/tonne CO_2e. 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, if new inter-provincial transmission is not possible or is cost-prohibitive, energy storage facilities. Achieving complete decarbonization by 2025 adds another \$8.2-12.6 billion (CAD 2015) to annual costs in our modelled scenarios, increasing total annual costs by \$11.8 billion over the reference scenario when it is possible to build new inter-provincial HVDC transmission connections, and by \$16 billion (CAD 2015) if it is not possible to build new inter-provincial HVDC transmission links. This means that the availability of new transmission could reduce decarbonization costs by \$4.2 billion (CAD 2015) or 26%. If HVDC capital costs exceed \$184/MW/km/year, complete decarbonization is more expensive. At HVDC capital costs of \$600/MW/km/year, total annual costs increase by \$17.5 billion (CAD 2015), nearly doubling the \$18.3 billion (CAD 2015) annual cost of the reference scenario. Even in these high HVDC cost scenarios, it remains optimal to build new transmission lines throughout Canada.

Our modelling demonstrates there is value to building new inter-provincial 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 may help Canada to meet its GHG emission reduction goals at a lower cost to Canadians. To validate these findings, we suggest the need for additional modelling that would include detailed intra-province transmission and distribution networks, electricity demand and renewable energy supply detail at the sub-hourly level, and the exploration of integer programming and unit commitment approaches to electricity modelling.

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