Integrated Canada-U.S. Power Sector Modeling with the Regional Energy Deployment System (ReEDS)

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NATIONAL RENEWABLE ENERGY LABORATORY

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Prepared under Task No. IGIN.2900

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Abstract

The electric power system in North America is linked between the United States and Canada. Canada has historically been a net exporter of electricity to the United States. The extent to which this remains true will depend on the future evolution of power markets, technology deployment, and policies. To evaluate these and related questions, we modify the Regional Energy Deployment System (ReEDS) model to include an explicit representation of the grid-connected power system in Canada to the continental United States. ReEDS is unique among long-term capacity expansion models for its high spatial resolution and statistical treatment of the impact of variable renewable generation on capacity planning and dispatch. These unique traits are extended to new Canadian regions.

We present example scenario results using the fully integrated Canada-U.S. version of ReEDS to demonstrate model capabilities. Two scenarios are examined: a no-new-policy reference scenario and a clean electricity standard (CES) scenario where 80% of all electricity generation in the United States and Canada must come from clean sources by 2035. Under the assumptions used, the preliminary scenario analysis demonstrates that without any new energy policies, growth in fossil generation will continue in both the United States and Canada. For the CES scenario, a mix of renewable, nuclear, and carbon capture and sequestration technologies are deployed and result in about 70% reduction of carbon dioxide emissions in 2050, as compared to the reference scenario. Growth in wind capacity is particularly significant in Canada, reaching 46 GW of installed capacity by 2050. We also evaluate changes in electricity and fossil fuel prices in the two scenarios.

The newly developed integrated Canada-U.S. ReEDS model can be used to analyze the dynamics of electricity transfers and other grid services between the two countries under different scenarios. Annual electricity transfers in the reference scenario remain largely constant over time and are small compared to total generation. However, instantaneous power transfers can be larger. Under the CES scenario, we find greater energy transfers between the two countries. Additionally, we find that seasonal differences in peak electricity demand between load centers in Canada and the United States allow sharing of firm capacity between the two countries.

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1 Introduction

The Canadian and U.S. power systems are electrically linked. In the West, British Columbia and Alberta are connected through Washington State and Idaho and are part of the Western Electric Coordinating Council (WECC) Interconnect. Saskatchewan and Manitoba are connected to North Dakota and Minnesota. Ontario has strong ties to Michigan and New York. In the East, Quebec has DC inter-ties to New York and Vermont. Maine is closely connected to New Brunswick. These connections allowed for exports of 43.8 TWh of Canadian electricity to the United States in 2010 and imports of 18.5 TWh (U.S. EIA 2010). The amount and direction of electricity transfer between the United States and Canada may change in the future, especially with greater deployment of clean electricity and renewable technologies. For example, abundant Canadian dispatchable hydropower resources can complement variable generation from wind and solar. However, the degree to which these and other technology pathways are complementary is uncertain.

To better understand the possible future interactions between the Canadian and U.S. electric systems, we have extended a capacity expansion model of the United States to include the Canadian bulk power system. The effort is part of the Canada and U.S. Clean Energy Dialogue (CED) Action Plan.[1] The CED Action Plan was formulated to facilitate joint analysis of international clean energy scenarios. This report documents the model development effort conducted under the CED Action Plan at the National Renewable Energy Laboratory (NREL). We relied on data and assistance from a range of Canadian organizations, including Natural Resource Canada (NRCan), National Energy Board (NEB), and Simon Fraser University. Many of the input datasets also came from provincial governments and utilities.

NREL's Regional Energy Deployment System (ReEDS) model was identified and chosen as the model to be used in this cross-border collaboration and analysis tool-building effort.[2] ReEDS is a capacity expansion model of the U.S. electric sector.[3] It is unique among capacity expansion models in its high geographic resolution and statistical treatment of variable renewable resource technologies—solar and wind. However, Canada was not originally endogenously modeled in ReEDS, which traditionally represented the 48 contiguous states in the United States, despite the interconnections between Canada and the United States.

The purpose of this report is to outline the modifications made to ReEDS in order to fully integrate Canada in its modeling framework. This report discusses the major modeling changes and includes example scenario results. It is not intended to be an analysis of a particular topic or policy but rather a demonstration of new capabilities of ReEDS. It is intended that future

[1] http://energy.gov/pi/office-policy-and-international-affairs/initiatives/us-canada-clean-energy-dialogue-ced.

[2] There are a number of capacity expansion models that represent Canada. Energy2020 from Systematic Solutions Inc. (http://energy2020.com/energy2020.html) is an energy sector system dynamic model of the United States and Canada (SSI and ICF 2012). CIMS from Simon Fraser University (http://www.emrg.sfu.ca/Our-Research/Policy-Modelling) is a computable general equilibrium model of the Canada economy and energy system (MKJA 2009). Integrated Planning Model (IPM) from ICF International (http://www.icfi.com/insights/products-and-tools/ipm) is a linear optimization electric sector model that includes Canadian and U.S. regions (Environment Canada 2005). These models do not include the same detailed representation of renewable technologies as ReEDS; however, we relied on data from these models to inform the ReEDS model development described in this report.

[3] Alaska and Hawaii are not included in the ReEDS model.

analyses with ReEDS will take advantage of these new capabilities. Finally, this report is intended to be a companion report to the full ReEDS documentation (Short et al. 2011).

Section 2 provides a brief description of the ReEDS model framework and modifications made to include Canadian regions. Section 3 describes the input data used. Section 4 provides a sample of model outputs based on a preliminary scenario analysis conducted. We offer conclusions and next steps in Section 5.

2 Modeling Framework

ReEDS is a linear programming model with a sequential optimization structure that steps through time while optimizing each 2-year period from 2010 to 2050. The objective function in each optimization period is used to minimize the 20-year net present value cost to build and operate generation and transmission capacity. For each optimization period, 17 time-slices represent the seasonal and diurnal changes in electricity demand and generation dispatch, including variable output from wind and solar power plants. Statistical calculations estimate capacity value, forecast error reserves, and curtailment for variable generation.

ReEDS has been used to investigate a variety of different energy policies, including carbon cap and trade, renewable portfolio standards (RPS), and clean energy standards (Bird et al. 2011; Logan et al. 2009; Mignone et al. 2012). It has also been exercised as the scenario-development model in a number of technology-specific studies, including 20% Wind Energy by 2030 (U.S. DOE 2008), SunShot Vision Study (U.S. DOE 2012), and the Renewable Electricity Futures Study (RE Futures) (NREL 2012). More information on the model can be found in the ReEDS documentation (Short et al. 2011) and in the previously mentioned reports.

2.1 Model Regions

The original version of ReEDS includes 134 balancing areas (BAs) and 356 wind/concentrating solar power (CSP) regions in the contiguous United States. It models the U.S.-Canada interaction as a boundary condition with five injections points. Canada injects power on a fixed schedule into those points (Short et al. 2011). The primary changes we have made to ReEDS include expanding the number of model regions and incorporating Canadian load, generator, transmission, and renewable resource data. We describe the new Canada-specific data and data processing methods in Section 3.

Integrating Canada into ReEDS includes the addition of 18 new BAs and 45 new wind/CSP resource regions, as shown in Figure 1. The BAs (colored regions) define the boundaries where load is met and generators are dispatched. The model transmission network connects BAs. The new BAs only cover areas where the grid is directly connected and therefore do not include the Yukon Territory, Northwest Territories, Nunavut, and parts of Newfoundland and Labrador.[4] The resource regions (faint lines) define the borders where wind (and CSP)[5] resources are specified. The resource regions allow ReEDS to capture the spatially diverse resources present in Canada in greater spatial resolution than possible with the BAs, including the variability and uncertainty differences of wind and the differences in grid interconnection costs among regions (see Section 3.2.4).

[4] The Labrador region that is adjacent to Quebec is represented in the model, while Newfoundland Island is not represented.
[5] CSP power plants require a threshold of direct normal irradiance. The solar resource in Canada does not meet this threshold, and therefore we do not model CSP in Canada.

As shown in Figure 1, we subdivided the BAs in British Columbia, Alberta, Ontario, and Quebec with many wind regions primarily to better represent the abundant high quality wind resource in these large geographic areas. In particular, we subdivide northern Quebec into 23 wind resource regions to capture the diverse wind resource quality and transmission limits in the area. However, we only consider northern Quebec as a single BA due to its limited population and load.

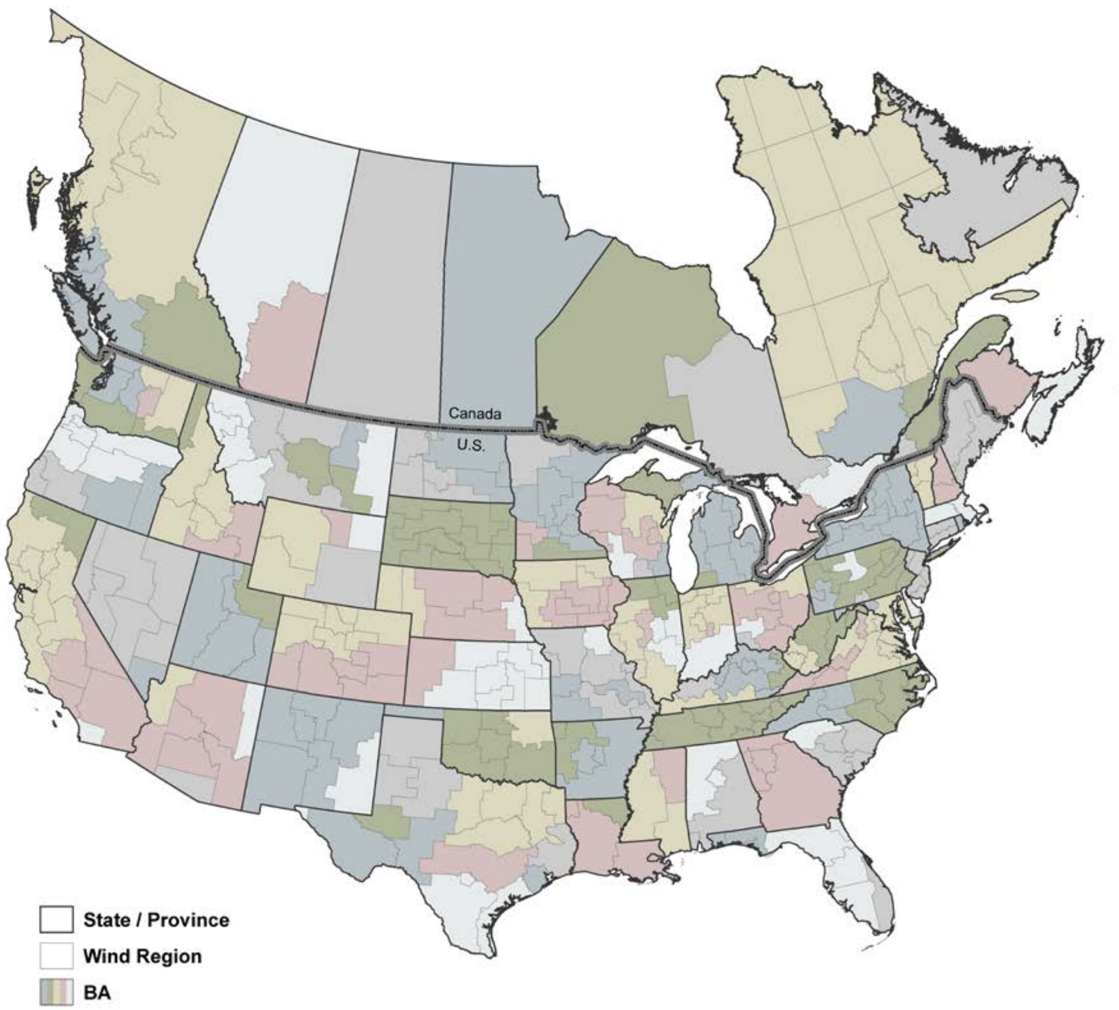


Figure 1. Map of Canadian and U.S. balancing areas with wind region divisions shown

2.2 Model Time-Slices

There are 17 time-slices in ReEDS that represent the seasonal and diurnal variations in electricity demand, wind, solar, and other resources (Table 1). Although these time-slices capture bulk variations in load, wind generation, and solar generation throughout a typical day in each season, they are insufficient to capture short-term hourly and sub-hourly variability in the power system. To accommodate this simplification, statistical calculations are performed in ReEDS. These calculations, including capacity value and curtailments of variable generation resources, rely on the assumption that the demand follows a Gaussian distribution within each of the 17 time-slices. Accordingly, we estimate the variances and means in demand for each time-slice for the new Canada regions (see Section 3.1).

Table 1. Time-Slice Definitions for ReEDS

Time-Slice	Number of Hours Per Year	Season	Time of Day	Time Period
H1	736	Summer	Night	10 p.m. to 6 a.m.
H2	644	Summer	Morning	6 a.m. to 1 p.m.
H3	328	Summer	Afternoon	1 p.m. to 5 p.m.
H4	460	Summer	Evening	5 p.m. to 10 p.m.
H5	488	Fall	Night	10 p.m. to 6 a.m.
H6	427	Fall	Morning	6 a.m. to 1 p.m.
H7	244	Fall	Afternoon	1 p.m. to 5 p.m.
H8	305	Fall	Evening	5 p.m. to 10 p.m.
H9	960	Winter	Night	10 p.m. to 6 a.m.
H10	840	Winter	Morning	6 a.m. to 1 p.m.
H11	480	Winter	Afternoon	1 p.m. to 5 p.m.
H12	600	Winter	Evening	5 p.m. to 10 p.m.
H13	736	Spring	Night	10 p.m. to 6 a.m.
H14	644	Spring	Morning	6 a.m. to 1 p.m.
H15	368	Spring	Afternoon	1 p.m. to 5 p.m.
H16	460	Spring	Evening	5 p.m. to 10 p.m.
H17	40	Summer	Peak	40 highest demand hours of summer 1 p.m.to 5 p.m.

3 Data for Canadian Regions

In this section, we describe the data sources used for the Canadian regions and the steps taken to process the data into a model-compatible format. The data used relate to electricity demand, the existing generation fleet, new conventional generators and storage, renewable resource data, fuel prices, transmission data, and environmental regulations.

3.1 Electricity Demand

The majority of the electricity demand data comes from provincial documents and datasets. The process to convert raw demand data into a usable format for ReEDS generally involves (1) spatially redistributing the raw data to fit BA boundaries, (2) calibrating annual demand to match the 2010 model start year, (3) shaping the raw data to match the ReEDS time-slice definitions, and (4) calculating means and variances in demand for each time-slice to inform the statistical calculations of capacity value and curtailment for variable generation (see Short et al. 2011). The specific methodology and datasets used for each province are summarized in the sections below. For provinces with multiple BAs, we sub-divided the provincial demand data based on population.[6] The majority of the demand datasets were gathered for 2010, the start year of ReEDS. Future demand projections were calibrated to the reference case of NEB's Energy Futures study (NEB 2011). Demand profiles are assumed to remain static over time.

In most regions of the United States, the peak demand hours generally occur during the summer months and are typically driven by demand for air conditioning. As such, the time-slice structure in ReEDS is designed to capture a peak time-slice (H17) during the summer afternoons (see Table 1). As peak demand in most areas of Canada occurs in winter, the ReEDS H17 peak time-slice is usually not the actual peak demand time-slice for Canadian regions. For example, Figure 2 shows the British Columbia (BC) hourly demand (BC Hydro 2012a) aggregated to each of the 16 non-peak time-slices. As shown in Figure 2, BC is a winter-peaking region. The box-and-whisker plots show the maximum and minimum values, upper and lower quartiles, median value, and outliers.[7] The ranges give an indication of intra-time-slice variability used in the statistical calculations in ReEDS. This difference in peak demand prevents ReEDS from having as much dispatch resolution around the peak hours in Canada compared to the United States; however, the planning reserve constraints in ReEDS ensure that sufficient capacity is procured.

[6] We used census data from Statistics Canada (2011) to determine populations.
[7] Outliers indicate data points that are greater (less) than 1.5 times the upper (lower) quarter.

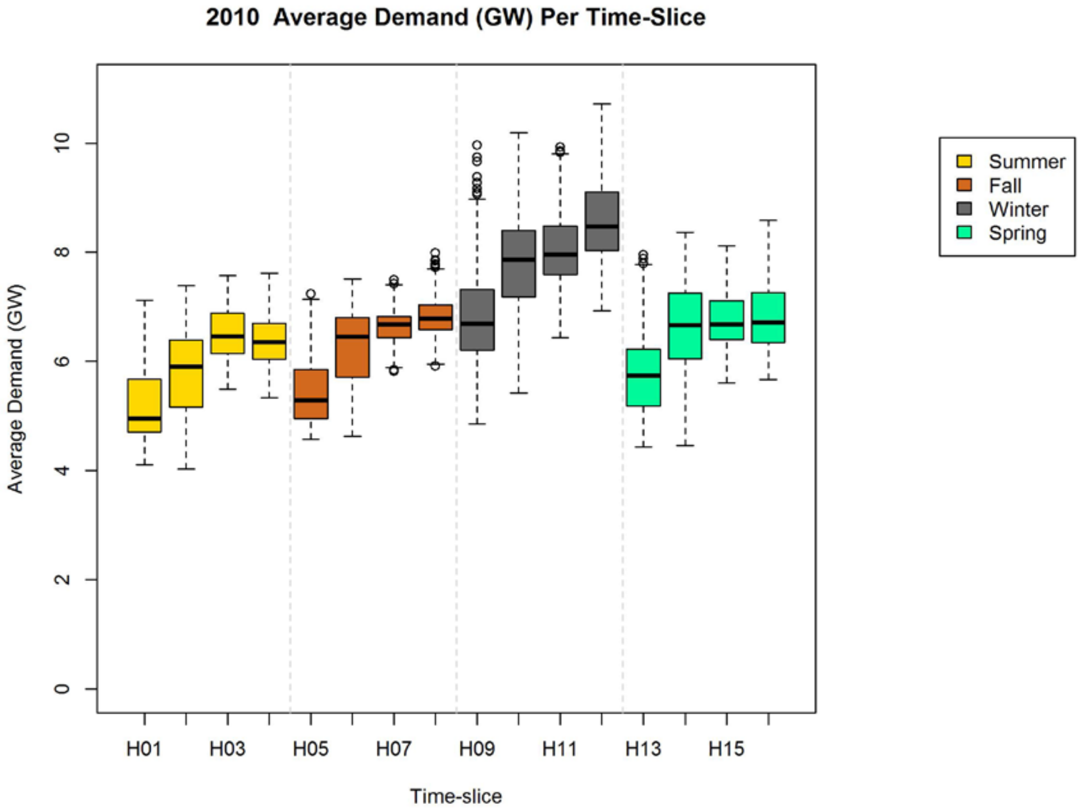


Figure 2. British Columbia 2010 demand by time-slice (BC Hydro 2012a)

We describe data sources for each province:

- British Columbia: Demand is sourced from the BC Hydro Corporation (BC Hydro 2012a), which published hourly demand data for multiple years including 2010.
- Alberta: Demand was calculated from 10-minute time-series data from the Alberta Electric System Operator (AESO) (AESO 2010). Alberta's demand is relatively flat with only minor seasonal differences and is winter-peaking.
- Saskatchewan: Annual demand from SaskPower (SaskPower 2011a) was used for Saskatchewan; however, hourly data was not available. The demand profile and variances for Saskatchewan were assumed to be the same as that for neighboring Alberta.

- Manitoba: Hourly data was not available for Manitoba, but the total annual demand in Manitoba was obtained using a forecasted[8] 2010 annual demand from Manitoba Hydro (Manitoba Hydro 2008). The time-slice demand profile was taken from Ontario's west region and scaled to match Manitoba's total forecasted load in 2010. We scaled the variance from Ontario's west region to represent the variance for Manitoba.
- Ontario: Hourly demand data[9] for Ontario was obtained on a zonal[10] level from Ontario's Independent Electric System Operator (IESO) for multiple years, including 2010. The zonal data was aggregated into the ReEDS BAs.
- Quebec: The demand data for Quebec was developed using the monthly total demand from Hydro-Quebec (Hydro-Quebec 2011a) and the average daily load profile from Richards (2007). We assumed that the diurnal load profile was the same for all seasons and the demand profile was scaled to match the monthly total demand. We assumed the variance to be 15% of the average demand in a time-slice. This assumption is loosely based on variances calculated for all other provinces. The summer peak time-slice (H17) was assumed to be 15% higher than the H3 time-slice.
- New Brunswick: The time-slice demand profile for New Brunswick was calculated from an hourly dataset[11] obtained from the New Brunswick System Operator for 2010.
- Nova Scotia: The monthly demand profiles for Nova Scotia were obtained using forecasted 2010 monthly demand from the Nova Scotia Utility and Review Board (2009). The monthly data from Nova Scotia was used along with the daily demand profiles developed for New Brunswick to develop the time-slice demand profile and the demand variances.
- Newfoundland and Labrador: Newfoundland was not represented in the ReEDS model due to a lack of connectivity between it and the rest of the Canadian system. Labrador is represented in ReEDS as there are existing, and potentially future, generators located on Labrador used to serve load centers in other parts of mainland Canada. However, due to the small load[12] in Labrador relative to the rest of the Canada, we assumed zero electricity demand from Labrador for all years.

[8] After we had completed data collection for this report, Manitoba Hydro published their 2012 Market Forecast report (Manitoba Hydro 2012). The 2010 annual load forecast used for this report (Manitoba Hydro 2008) is slightly higher than the actual 2010 annual demand given in the 2012 Market Forecast report.

[9] Hourly demand data for Ontario was downloaded from the Independent Electric System Operator (IESO) 2010 "Zonal Demands Archives." Accessed December 19, 2012: http://www.theimo.com/imoweb/marketdata/ZonalDemands.asp.

[10] Zones are defined in Ontario's 2008 transmission system report (Independent Electric System Operator 2008).

[11] Hourly load dataset for 2010 downloaded from the New Brunswick System Operator website: http://www.nbso.ca/Public/en/op/market/data/reports/report_List.aspx?path=\historical%20system%20information.

[12] Labrador's electricity demand of nearly 2.5 TWh in 2004 (NLDNR 2005) is small compared with Canada's electricity demand of over 530 TWh in 2004 (Statistics Canada 2012).

3.2 Generation Technologies

The modeling characteristics of generation technologies in ReEDS are described in detail in Short et al. (2011). Generators in ReEDS are grouped by technology and BA and treated as a single unit. Generators in Canada are treated similarly. This section describes the data used for the existing Canadian generation fleet, assumptions underlying new conventional fossil and nuclear generators, assumptions for storage technologies, and the data and data processing for renewable resources.

3.2.1 Existing Capacity

Existing capacity for all technologies comes primarily from the Ventyx Velocity Suite dataset (Ventyx 2010). The values from Ventyx were compared to provincial-level data from the NEB's Energy Futures study (NEB 2011). Where there was a large difference between Ventyx data and NEB data, NEB data was used and placed into the appropriate BA. Where possible, the values were also double-checked with provincial-level documents from the local provincial utilities or system operators. Figure 3 shows the 2010 Canadian generator capacity by technology and region based on the Ventyx Velocity Suite. Heat rates for the existing fleet of plants were calculated by technology and province from energy output and fuel input data from NEB's Canadian Energy Futures study (NEB 2011). Table 2 summarizes the capacity by technology type and province represented in ReEDS for the 2010 Canadian power system.

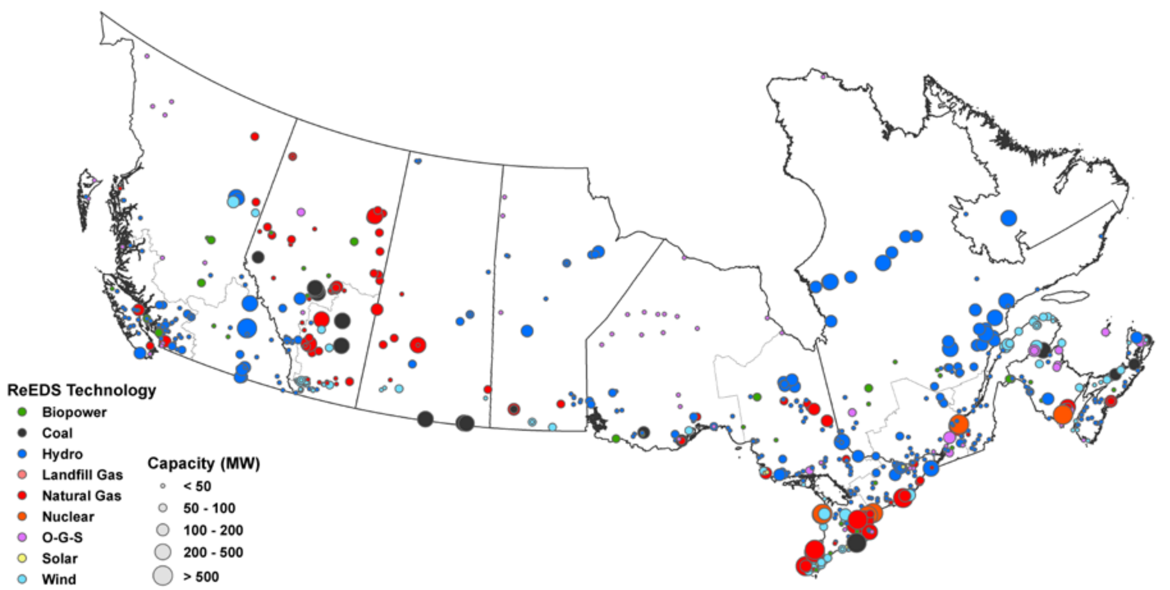


Figure 3. Existing electric-generating capacity (Ventyx 2010)

Table 2. 2010 Capacity of Electric-Generation Units[a] (GW)

Province	Coal	Gas-CC	Gas-CT	Nuclear	Hydro	Biopower	Wind	PV	OGS
British Columbia	-	0.29	0.22	-	12.7	0.57	0.07	-	1.09
Alberta	6.27	1.87	2.40	-	0.89	0.23	0.64	-	0.61
Saskatchewan	1.68	0.69	0.69	-	0.85	-	0.26	-	0.14
Manitoba	0.08	-	0.25	-	5.12	-	0.24	-	0.16
Ontario	3.50	5.30	1.36	11.5	8.07	0.10	1.61	0.11	2.36
Quebec	-	0.53	1.01	0.68	36.3	0.13	0.96	-	0.67
New Brunswick	0.51	0.26	0.63	0.68	1.04	0.03	0.29	-	1.49
Nova Scotia	1.25	0.15	0.22	-	0.38	0.02	0.30	-	0.35
Newfoundland and Labrador[b]	-	-	0.24	-	5.45	-	-	-	0.49
Total (GW)	13.3	9.1	7.0	12.8	70.9	1.1	4.4	0.1	7.4

[a] Gas-CC (natural gas combined cycle), Gas-CT (natural gas combustion turbine), PV (photovoltaic), OGS (oil/gas steam turbine)
[b] Only generators located in Labrador are represented in ReEDS.

3.2.2 Conventional Technologies

We represent all major conventional electricity-generating technologies in ReEDS, including three types of coal technologies, natural gas combined cycle (CC), natural gas combustion turbine (CT), and nuclear power. Conventional technologies are characterized by their nameplate capacity, capital costs, operation and maintenance (O&M) costs, heat rates, outage rates, and emission factors. Other factors, such as minimum generation points and financing and construction assumptions, are also considered.

Retirement schedules are exogenous to the model. Short et al. (2011) lists retirement schedules for all technology types. Retirement dates of most technologies depend on the age of the plant with additional usage-based retirements for coal. Near-term announced retirements are also applied to coal plants in the United States. For Canada, scheduled near-term coal retirements are based on NEB's Energy Futures study (NEB 2011). Retirement schedules for all other plant types in Canada are treated the same as in the United States.

3.2.3 Storage Technologies

Resource and cost estimates for new pumped storage hydropower (PSH) and compressed air energy storage (CAES) were not available for Canadian regions. Therefore, new builds of these technologies were not allowed. Existing PSH was represented with a total of 175 MW[13] in Ontario. Utility-scale battery is another storage option in ReEDS and does not have any location restrictions. Costs for utility-scale batteries in Canada are assumed to be the same as in the United States.

[13] Sir Adam Beck Pump Generating Station. http://www.opg.com/power/hydro/niagara_plant_group/adambeckpgs.asp.

3.2.4 Renewable Technologies

Canada has abundant renewable resources, particularly wind and hydropower. We focus our data collection and model development efforts on these two renewable technologies and make simplifying assumptions for other renewable technologies.

3.2.4.1 Wind

Wind resource data for all modeled Canadian regions is based on Environment Canada's Wind Energy Atlas[14] 5-km dataset. The dataset is representative of the wind power density for turbines with 80-m hub heights (Figure 4). Both onshore and offshore wind resources are considered for this analysis. However, we limit offshore wind resources in ReEDS to less than 30-m depth for both the United States and Canada.

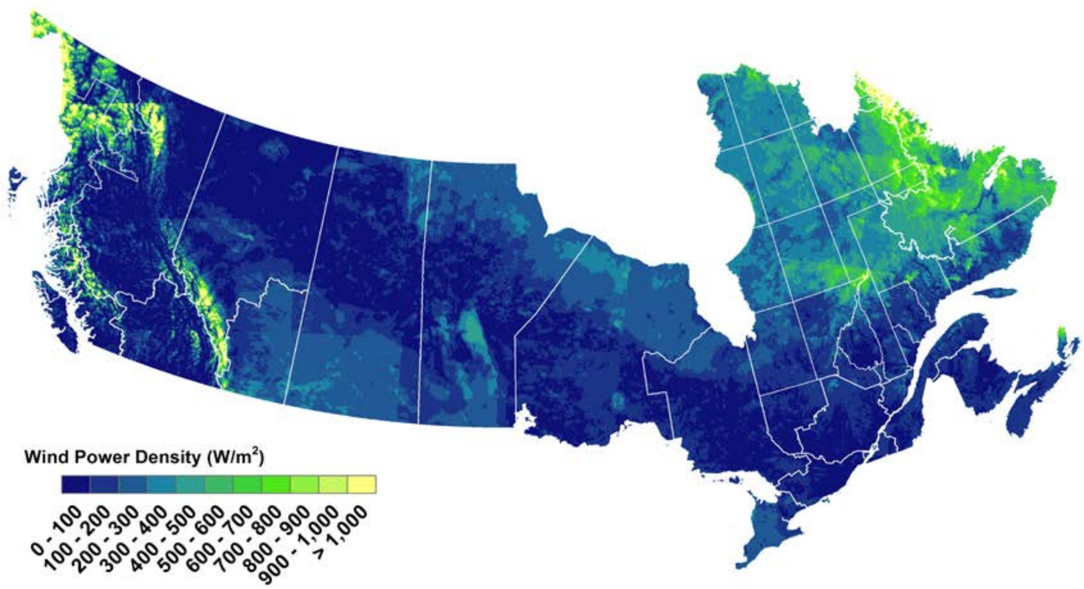


Figure 4. Wind power density from the Canadian Wind Energy Atlas dataset

[14] http://www.windatlas.ca/en/index.php.

We process the raw power density data to create wind supply curves for use in the ReEDS optimization. Exclusions, similar to those applied to the U.S. resource, account for environmental and land-use restrictions to wind development (Table 3).

Table 3. Wind Resource Exclusions—Criteria for Defining Available Windy Land

Environmental Criteria[a]	**Data/Comments**
2) 100% exclusion of land managed by the National Park Service and Fish and Wildlife Service	Protected Planet and World Heritage sites (IUCN and UNEP 2012)
3) 100% exclusion of federal lands designated as park, wilderness, wilderness study area, national conservation area, wildlife refuge, wildlife area, wild and scenic river, or inventoried road-less area	Protected Planet and World Heritage sites (IUCN and UNEP 2012), Exclusions and Avoidance areas taken from NREL WREZ GIS portal (Western Governor's Association & U.S. Department of Energy 2009)
Land-Use Criteria	**Data/Comments**
4) 100% exclusion of airfields, urban, wetland, and water areas.	USGS North America Land Cover (LULC), version 2.0, 1993 (USGS 1993); Environmental Systems Research Institute airports and airfields (ESRI 2006); Natural Resources Canada, Earth Sciences Sector, and the Centre for Topographic Information (2005)
5) 50% exclusion of non-ridgecrest forest	Ridgecrest areas defined using terrain definition script, overlaid with USGS LULC data screened for the forest categories (USGS 1993)
Other Criteria	**Data/Comments**
1) Exclude areas of slope >20%	Derived 1-km resolution gtopo30 data (USGS 1996)
6) 100% exclusion of 3 km surrounding criteria 2 and 4 (except water)	Merge datasets and buffer 3 km

[a] The criteria are numbered in the order they are applied.

The available wind capacity by region and wind class is shown in Figure 5. The wind classes are defined by wind power density, as listed in Table 4. The remaining wind technical resource modeled, after the GIS exclusion layers are applied, totals 1,943 GW for the regions of Canada modeled. Table 4 provides the wind technical potential by power class for onshore and shallow offshore wind.

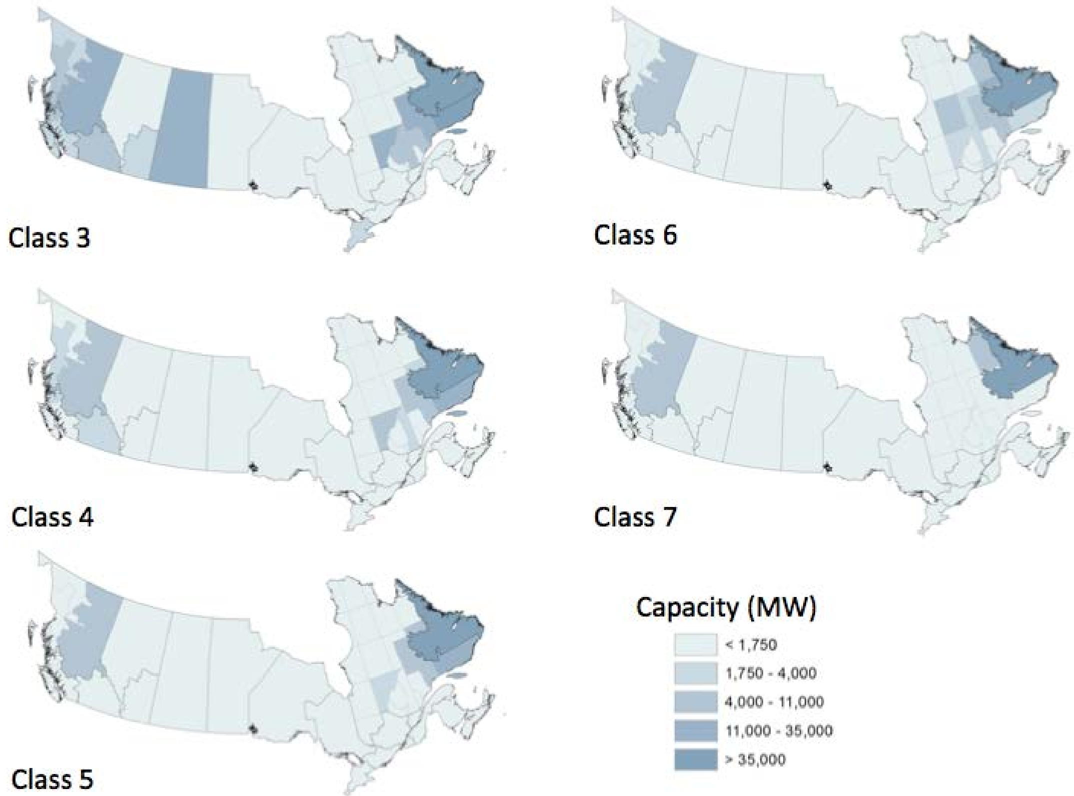


Figure 5. Wind resource by class and region

Table 4. Classes of Wind Power Density

Wind Power Class	Wind Power Density (W/m^2)	Onshore (GW)	Offshore (GW)	Total (GW)
3	300–400	245	159	404
4	400–500	264	314	578
5	500–600	205	250	455
6	600–800	262	105	367
7	>800	74	65	139
	Total (GW)	1,050	893	1,943

Because access to and cost of transmission can vary substantially between undeveloped wind sites, we developed a GIS-based supply curve for each wind resource region and wind resource class. Each step on the supply curve represents the available capacity that can be connected to the existing grid at a particular cost. These supply curve costs are in addition to the capital cost. There are five supply curve bins in each of the five classes of wind for each wind resource region. Examples of supply curves for all power classes in region 365, located in northwest BC, are shown in Figure 6.

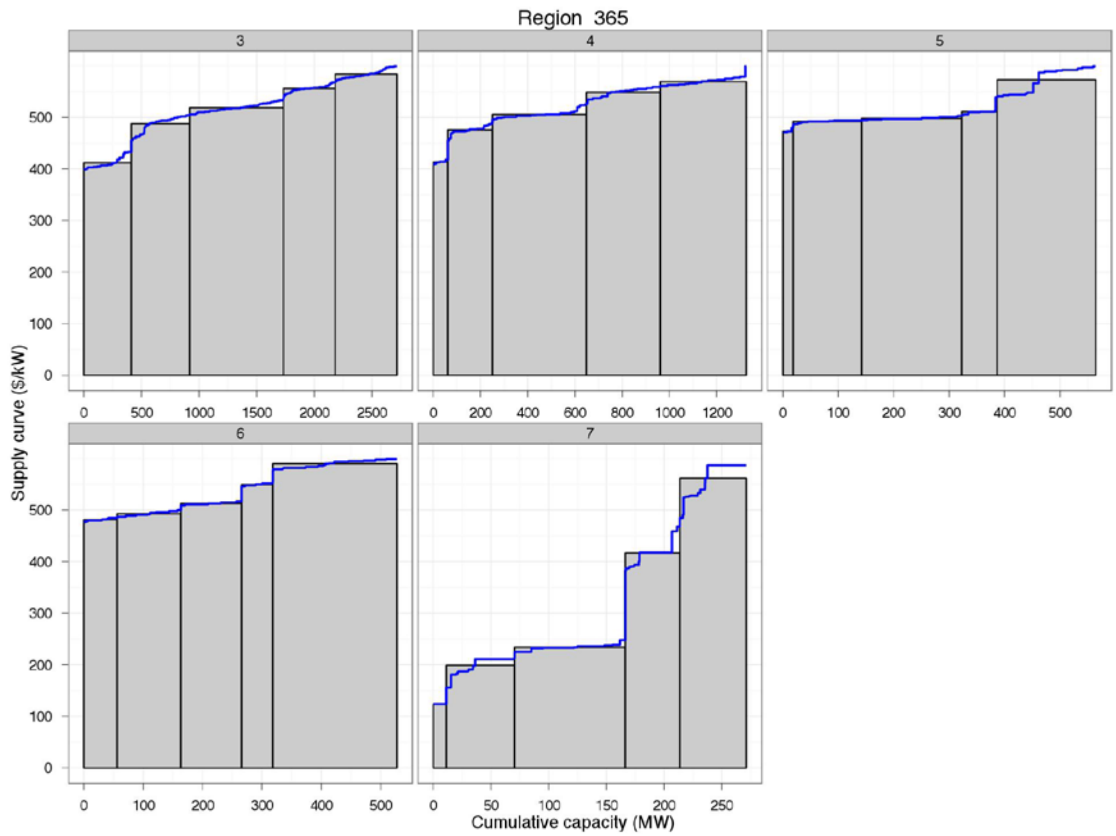


Figure 6. Wind supply curves for five wind power classes in region 365 located in northwest British Columbia

In addition to the resource and annual capacity factors for wind, the temporal resolution in ReEDS requires seasonal and diurnal power output profiles. Due to data limitations, wind profiles in Canadian regions are given the same profile as the contiguous regions in the United States. In addition, the statistical calculations used in ReEDS to capture the intra-time-slice variability rely on correlations of wind output between regions and classes. We assume this spatial correlation of wind output by region is a function of the north-south (Δy) and east-west (Δx) distance (km) as given by the following equation:

$$correl(\Delta x, \Delta y) = e^{-0.0031 \cdot \Delta x} \cdot e^{-0.0017 \cdot \Delta y}$$

This equation assumes an exponential decrease in wind resource correlation between two sites as the distances between the two sites (i.e., Δx and Δy) increase. The exponential coefficients were developed based on a study of wind speed correlations in the midwest United States (Simonsen 2004). In the United States, the profiles and correlations are based on modeled and actual wind speed data for specific points. Although the correlations between wind resource regions in the United States and Canada differ in range, the correlations follow the same general trend (Figure 7).

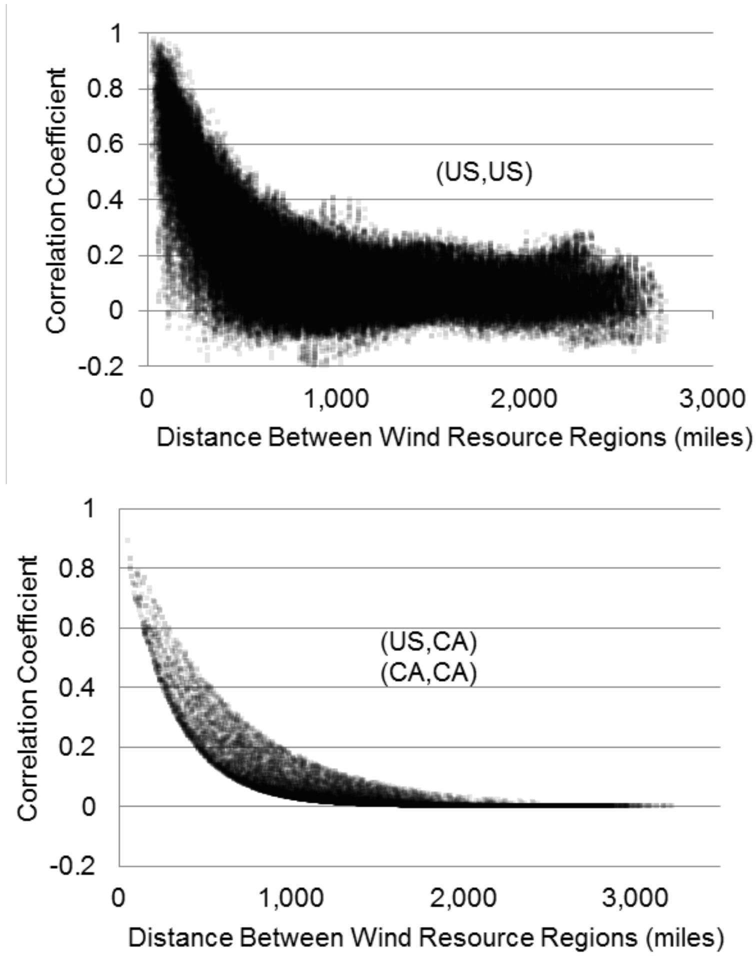


Figure 7. Modeled correlation coefficients between wind resource regions

Note: The top chart represents a correlation between two wind regions in the United States (i.e., US,US), calculated using wind time-series data. The bottom chart represents correlation coefficients between two wind regions in Canada (i.e., CA,CA) or between one in Canada and one in the United States (i.e., CA,US), calculated using the $correl(\Delta x, \Delta y)$ equation.

3.2.4.2 Hydropower

Undeveloped hydropower resource is based on provincial data as well as data from the International Energy Agency (IEA) International Small Hydro Atlas[15] (IEA 2012). Both of these datasets were compiled by ICF International (Environment Canada 2005) for use in their Integrated Planning Model (IPM). The Atlas represents small non-dispatchable hydro and includes location and capital cost of potential new small hydro capacity. New large hydro resources were restricted to planned large hydro facilities in Quebec, Manitoba, and British Columbia.[16] Because cost information was not specified for the large hydro facilities, we assumed the per-megawatt capital cost to be the same as that of the lowest-cost small hydro

[15] Data provided by Natural Resources Canada's CanmetEnergy. http://canmetenergy.nrcan.gc.ca/home.
[16] The large hydro resource is not fully represented in this initial data collection. For example, we did not include the Lower Churchill Falls project in Labrador (3,074 MW). Further work is needed to represent the full large hydro resource potential and costs in ReEDS.

resource in the Atlas. Figure 8 shows the modeled capital cost supply curve for new hydropower in Canada. We consider four cost classes of new hydro resources for each province. Assumptions regarding capacity available at each cost class are presented in Table 5.

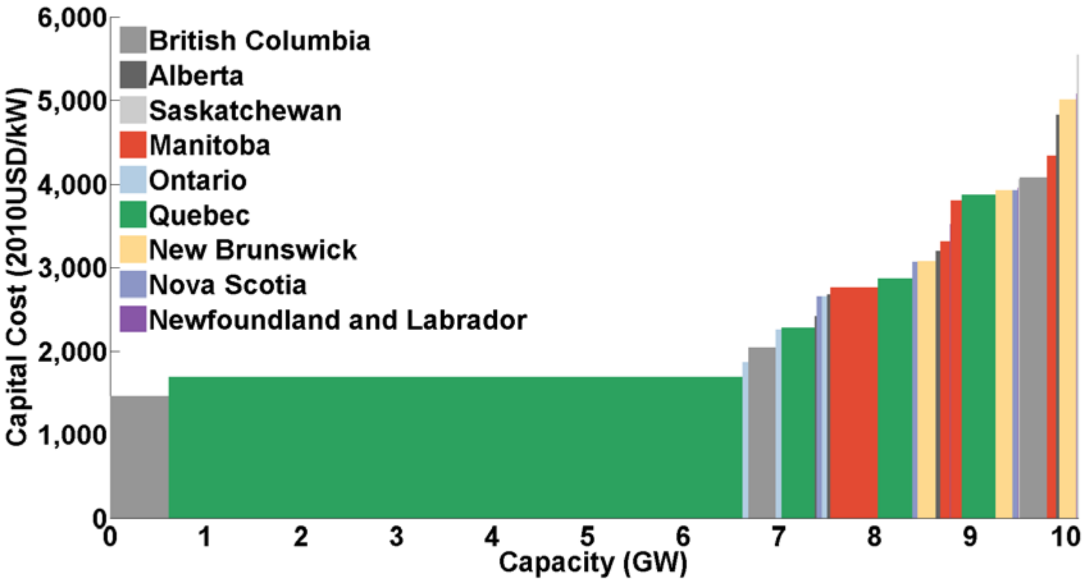


Figure 8. New Canadian hydropower capital cost supply curve

Table 5. Hydro Resource Available (MW) in Each Cost Bin (2010 USD/kW)

	Class 1		Class 2		Class 3		Class 4	
Province	**MW**	**$/kW**	**MW**	**$/kW**	**MW**	**$/kW**	**MW**	**$/kW**
British Columbia[a]	-	-	616	1,461	290	2,048	286	4,079
Alberta	19	2,423	39	2,677	48	3,201	32	4,837
Saskatchewan	12	4,053	13	5,555	-	-	-	-
Manitoba[a]	494	2,765	101	3,318	117	3,806	100	4,345
Ontario	-	-	58	1,864	59	2,259	54	2,656
Quebec[a]	6,000	1,693	347	2,277	363	2,873	353	3,878
New Brunswick	-	2,383	186	3,084	180	3,930	174	5,013
Nova Scotia	1	2,294	54	2,651	55	3,076	54	3,932
Newfoundland and Labrador	-	-	6	3,527	6	3,963	6	5,084

[a] Large hydro resource, as specified in the IPM documentation (Environment Canada 2005), is added to the lowest cost bin for each province.

Output from hydropower facilities is restricted by seasonal capacity factors (see Table 6) based on historical generation data from Environment Canada, compiled by ICF (Environment Canada 2005). The capacity factors are the same for all BAs in a province and apply to both existing and new hydro capacity. We treat all existing (as of 2010) hydropower capacity to be dispatchable and conservatively treat all new hydropower capacity to be non-dispatchable due to a lack of data on reservoir and flow restrictions. For dispatchable hydro, the capacity factor is used to create an energy constraint for generation in a given season. We apply minimum generation levels to all dispatchable capacity.[17] We assume uniform output with each season from all non-dispatchable hydropower capacity.

The flexibility of hydropower can play an important role in managing variability of generators (e.g., wind and solar) and load. This may influence efficient system operation and investment decisions, particularly for new wind capacity in Canada and the northern United States. Future research using ReEDS can explore the degree to which hydropower can help support variable generation and to understand the sensitivities with our assumptions on dispatchability and annual capacity factors.

Table 6. Seasonal Hydro Capacity Factors Used for Both Existing and New Hydro Capacity

Province	Fall/Winter Capacity Factor	Spring/Summer Capacity Factor
British Columbia	0.608	0.524
Alberta	0.215	0.308
Saskatchewan	0.443	0.474
Manitoba	0.719	0.712
Ontario	0.545	0.494
Quebec	0.618	0.498
New Brunswick	0.336	0.317
Nova Scotia	0.303	0.206
Newfoundland and Labrador	0.850	0.560

3.2.4.3 Solar

We represent utility-scale PV in ReEDS with no resource restrictions applied in both Canada and the United States. We assume that Canadian regions have the same solar PV profiles and annual capacity factors as contiguous BAs in the United States. Future work will improve this assumption; however, with the limited deployment of solar technologies in our preliminary scenario analysis (Section 4), this simplifying assumption does not significantly affect model results.

CSP power plants require a threshold of direct normal irradiance. The solar resource in Canada does not meet this threshold, and therefore we do not model CSP in Canada.

3.2.4.4 Biomass

The biomass feedstock supply curve for each Canadian BA is simply assumed to be the same as that of the contiguous BAs in the United States. The biomass feedstock supply curves represent the quantity and associated price for a power plant to buy biomass to produce power. The biomass feedstock can be either used in a dedicated biopower plant or in a converted coal-fired plant that can cofire biomass and coal.

[17] The minimum generation level is a seasonal constraint within ReEDS. The minimum generation fraction for Canada is assumed to be 30% of peak seasonal output.

3.2.4.5 Geothermal

We currently do not represent geothermal resources in Canada. This could be the subject of future work.

3.3 Fuel Prices

Natural gas supply and demand dynamics are represented in ReEDS through annual supply curves. The supply curve for each year is exogenously specified and represents the price of natural gas to power producers as a function of electric-sector consumption. The supply curve for U.S. supply-demand dynamics was developed from Annual Energy Outlook (AEO) 2011 (U.S. EIA 2011) scenarios based on a regression analysis to capture price elasticity and demand from the non-power sector.

A single supply curve is used to represent the combined natural gas consumption of the Canadian and U.S. power sectors. We modified the U.S.-only supply curve based on data from the NEB Energy Futures study (NEB 2011); the natural gas supply curve was shifted to capture the additional supply of and demand for natural gas in Canadian regions while the slope of the supply curve was not modified. A figurative representation of the natural gas supply curve and how it is shifted to include Canada is shown in Figure 9. The green line in Figure 9 is the linear supply curve developed using a multi-variable regression on the AEO 2011 scenarios (Logan et al. 2012) and represents the relationship between electric-sector consumption and prices in the United States. The green curve is then shifted so that the equilibrium price remains the same but the corresponding consumption includes Canada. The Canadian consumption (Q_{CAN}) and its changes through time come from the NEB Energy Futures study (NEB 2011). The new supply curve (red line) changes through time by adjusting the price intercept up or down based on projections from AEO 2011.

The supply curve changes over time to reflect production and demand dynamics of different scenarios of the AEO 2011 and the NEB Energy Futures study. It does not react to changes in other sectors (industrial, commercial, and residential) and does not reflect dynamics between fuel supply and demand beyond the interactions that are embedded in the AEO 2011 and the NEB Energy Futures study.

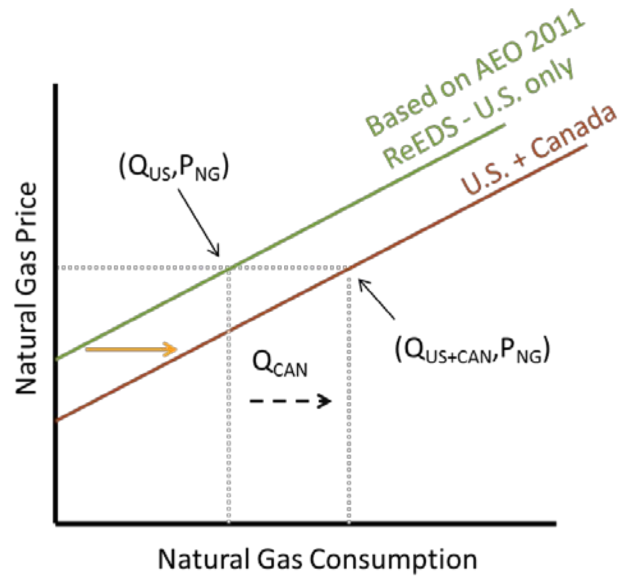


Figure 9. Figurative representation of the natural gas supply curve in a single year

Coal prices are set by province and change over time but are completely inelastic to demand. We assume Canadian coal prices from the reference scenario in the NEB Energy Futures study. Where no coal price was available, the national average coal price was used.

The price of Uranium used for power generation is assumed to be inelastic to demand and is set on an annual basis based on the AEO 2011 reference scenario. Uranium prices are assumed to be the same for Canada and the United States.

3.4 System Operation

Planning reserve margins in Canada are assumed to be in line with the North American Electric Reliability Corporation (NERC) target reserve margins and are shown in Table 7 (NERC 2011). The planning reserve margin constraint is held at the BA level, but BAs are allowed to trade firm capacity, subject to transmission constraints, to meet their individual planning reserve margin constraint.

Table 7. NERC Reference Margin Level for Canadian Regions (NERC 2011)

NERC Region	NERC Reference Margin Level
MRO-Manitoba Hydro	12.0%
MRO-SaskPower	13.0%
NPCC-Maritimes	20.0%
NPCC-Ontario (IESO)	21.3%
NPCC-Quebec	9.7%
WECC-AESO	12.3%
WECC-BC	12.3%

Operating reserves must be provided as a fraction (7.5%) of demand in a time-slice, plus any additional operating reserve requirements induced by the forecast uncertainty of variable resources. Operating reserves are intended to represent contingency reserve requirements (6%) and frequency regulation requirements (1.5%). More detail on the treatment of operating reserves can be found in the ReEDS documentation (Short et al. 2011).

3.5 Transmission

The Canadian power system is part of an integrated transmission grid with the United States and parts of Mexico. However, power markets in Canada largely follow provincial boundaries. ReEDS limits the power transfers between provinces and BAs based on the existing transmission infrastructure but allows for the option to build new transfer capacity between BAs.

For ReEDS, aggregated existing transmission transfer capacity limits between BAs were estimated from a combination of provincial-level data and NEB's Compendium of Electric Reliability (NEB 2004); where more recent provincial-level data was not found, NEB's values were used. Table 8 lists the sources of transmission data for each province. Figure 10 shows the aggregated transfer capacity limits between regions. The transfer limits are bi-directional; the same capacity limit is applied to power flowing in both directions.

Table 8. Source of Transmission Data

Province	Source
British Columbia	BC Hydro 2012b
Alberta	Alberta Electric System Operator 2009 Alberta Electric System Operator 2011
Saskatchewan	SaskPower 2011b
Manitoba	Manitoba Hydro 2011
Ontario	Independent Electric System Operator 2008
Quebec	Hydro-Quebec 2011b
New Brunswick	New Brunswick System Operator 2011 New Brunswick System Operator 2012
Nova Scotia	Nova Scotia Utility and Review Board 2009
Newfoundland and Labrador[a]	Hydro-Quebec 2011b

[a] Only Labrador is represented in ReEDS. Because Labrador is connected only to Quebec, we use the transmission data between Quebec and Labrador based on Hydro-Quebec (2011b).

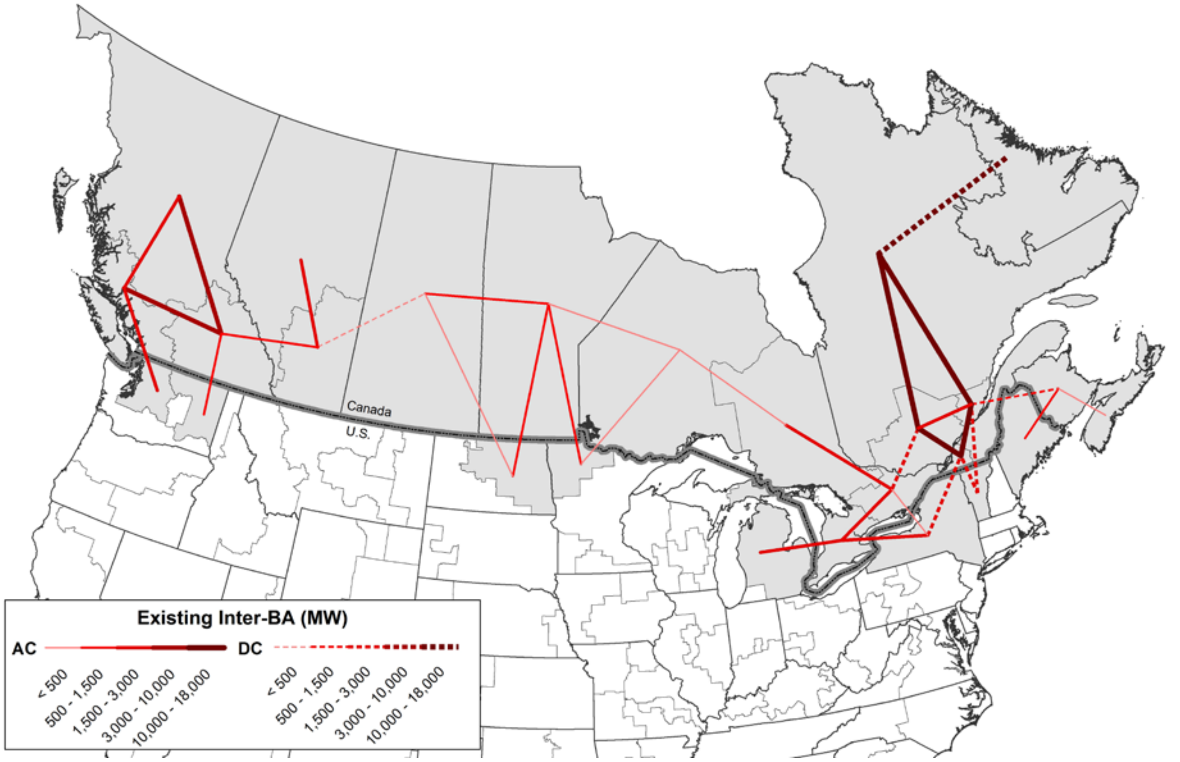


Figure 10. Map of aggregated transmission lines in ReEDS

Note: We model transmission lines using the geographic centers for each BA, as shown in this map.

ReEDS uses a linearized DC power flow methodology to model transmission constraints for the AC network. The power flow methodology takes into account the capacity limits of the transmission lines and the line impedances—estimated based on the aggregate line capacity and length—which drive distribution factors. Line lengths are assumed to be the distance between centers of transmission-connected BAs. As in real transmission networks, flow control is possible for DC lines.

We model other characteristics of the Canadian transmission system, including line losses and costs, in the same manner as the U.S. system (Short et al. 2011). All regions in Canada are assumed to have the same transmission costs and losses. However, Quebec is modeled as a separate asynchronous interconnect, and therefore the cost for additional capacity across its borders includes the cost to build an AC-DC-AC inter-tie.

3.6 Policies and Incentives

We attempt to capture the major energy policies in Canada, including federal and provincial requirements and incentives.[18] We summarize the representation of these policies in ReEDS in this section. Further work is needed to fully represent these complicated and interacting policies.

[18] CanWEA provides a summary of initiatives on wind energy at http://www.canwea.ca/pdf/Fed%20and%20provincial%20initiatives.pdf.

The Canadian federal government has an accelerated depreciation program for renewable energy, called the Capital Cost Allowance (CCA). This incentive grants geothermal, wind, and small hydropower resources a 50% declining accelerated depreciation benefit. It grants conventional, large hydropower a 30% declining accelerated depreciation benefit. This incentive program has a similar effect to the 5-year U.S. Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. Therefore, we model these incentives in a manner identical to the U.S. MACRS schedule (Pletka and Finn 2009).

Many provinces in Canada have clean energy goals, but only a few have formal mechanism to promote clean energy development.

- BC has a carbon tax of $30/tonne of carbon dioxide (CO_2) that is applied to all carbon sources (British Columbia's Ministry of Finance 2012). BC also has a goal of becoming electrically independent by 2016 (British Columbia's Ministry of Energy, Mines, and Petroleum Resources 2007). Finally, based on the Clean Energy Act,[19] BC requires 93% of its electricity to come from renewable resources by 2020. We implement similar RPS policies in the same manner as state RPS policies in the United States.
- Ontario has a feed-in tariff (FIT) for renewable energy resources (Ontario's Ministry of Energy 2007). However, this FIT is not modeled in ReEDS because it has a strict stipulation that renewable energy developers must use locally manufactured parts and services. This stipulation would affect the technology cost, but it is unknown by how much. Ontario has a goal to reduce carbon emission, and in doing so has instituted a phase-out of coal generation (Province of Ontario 2009). We represent this through retiring all of the existing coal in Ontario by 2020. Finally, Ontario has an RPS that will require 30% of their electricity to come from renewable resources by 2030.
- Nova Scotia has an RPS that will require 25% and 40% of their electricity to come from renewable resources by 2015 and 2020, respectively (Nova Scotia Department of Energy 2010).

Table 9 summarizes the Canadian provincial policies and incentives modeled in ReEDS.

Table 9. Provincial Policies and Incentives Modeled Within ReEDS

Province	Policies Modeled
All	Accelerated Capital Cost Allowance (CCA) program for renewables
British Columbia	Carbon Tax - $30/tonne CO_2 Electrically independent by 2016 93% RPS by 2020
Ontario	Accelerated coal retirements: no coal by 2020 30% RPS by 2030
Nova Scotia	RPS: 25% by 2015 and 40% by 2020

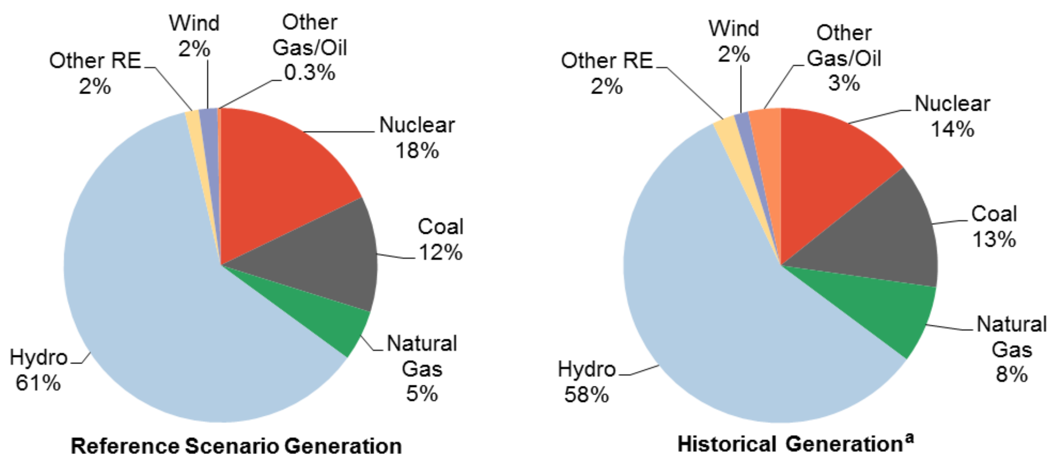
[19] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_10022_01.

4 Sample Model Results

To demonstrate the capabilities of the updated ReEDS model, we explore two capacity expansion scenarios for the combined (Canada and U.S.) system: (1) a reference scenario where only existing policies are modeled, and (2) a clean electricity standard (CES) scenario. Both scenarios use the demand, technology costs, and fuel prices described in Section 3. These scenarios are intended to demonstrate model capabilities and should not be interpreted as projections of future market trends, technology costs, or renewable and conventional market potential. In addition, scenario results presented here should not be interpreted as analysis of any proposed or legislated policies.

4.1 Comparison With Historical Generation

Similar to the U.S. system, we have populated the initial model year (2010) in ReEDS based on the existing *capacity* for generation, transmission, and storage in Canada (see Section 3.2). On the other hand, historical (2010) generation is determined through the ReEDS dispatch algorithm and is not calibrated to the 2010 values. The reason we do not initialize the model through calibration is to ensure that dispatch of all years are treated consistently so that trends can be observed. Nonetheless, we find that the ReEDS dispatch is largely in line with actual generation. Figure 11 shows the actual and modeled generation shares for Canada in 2010. The historical generation mix was from Statistics Canada.[20]



[a] The 2010 historical generation is based on Statistics Canada CANSIM Tables 127-0007 and 128-0014.

Figure 11. Modeled (left) and actual historical (right) Canadian electricity generation mix in 2010

As shown by Figure 11, differences between 2010 modeled and actual generation are less than 5 percentage points (of total generation) for all generation types. Modeled 2010 nuclear generation shows the largest deviation from historical values. On balance, ReEDS uses more nuclear and hydropower—and less gas and oil—than the actual historical value. Other reasons for disparities with historical data include differences in assumed versus actual outage rates and

[20] Data taken from CAMSIM Table 127-0007 (Electric power generation, by class of electricity producer, annual) and CAMSIM Table 128-0014 (Electricity generated from fossil fuels, annual). http://www5.statcan.gc.ca/cansim/a33?RT=TABLE&themeID=4012&spMode=tables&lang=eng.

non-economic dispatch, which would not be seen by the least-cost optimization of ReEDS. Further work is needed to understand all the reasons for these differences. Nonetheless, these differences are relatively small and do not significantly influence trends in power system evolution under future scenarios.

4.2 Scenario Framework

To demonstrate model capabilities, we model two scenarios of future Canadian and U.S. electric system expansion. A reference scenario represents the evolution of the power system under currently existing policies only. The second scenario represents a CES scenario, where 80% and 95% of electricity generation in the combined Canadian and U.S. power systems are from clean technologies by 2035 and 2050, respectively.[21] The clean crediting scheme modeled is loosely based on the carbon emission factors of each technology type relative to that of a pulverized coal plant without carbon capture and sequestration (CCS). In particular, all renewable and nuclear generation is fully credited as clean electricity (100%)—generation from coal with CCS is credited as 90% clean, generation from natural gas CC with CCS is credited as 95% clean, generation from natural gas CC without CCS is credited as 50% clean, and all other generation is not given any clean credits.[22]

Although the modeled CES shares many similarities with proposed legislation in the United States (e.g., The Clean Energy Standard Act of 2012[23]), we did not attempt to model all aspects of the proposed legislation. Therefore, the preliminary scenario analysis presented here should not be interpreted as analysis of this or any other policies. We also did not implement any pending regulations or policies in Canada or the United States in regards to emission controls. In addition, the scenarios explored here are intended to demonstrate model capabilities and should not be interpreted as projections of future market trends, technology costs, or renewable and conventional market potential.

The CES policy driver is the only difference between the two scenarios; all other assumptions are identical. Major model assumptions include demand growth, fuel prices, and technology cost and performance and are largely derived from AEO 2011 for the United States from NEB for Canadian regions (Section 3). Table 10 shows technology capital costs used in this analysis. Other assumptions used for the preliminary scenario analysis are largely the same as those used in the RE Futures study (NREL 2012). As a least-cost optimization model, technology costs, which have a great deal of uncertainty over the 40-year study period, have a large impact on deployment results.

[21] The modeled CES requirement begins with a total clean energy fraction of 45% in 2015, increases 1% per year to 50% in 2020, and then increases 2% per year to 80% by 2035. The requirement increases linearly between 2035 and 2050.
[22] We assume a 90% capture rate for all CCS technologies.
[23] http://www.energy.senate.gov/public/index.cfm/democratic-news?ID=67e21415-e501-42c3-a1fb-c0768242a2aa.

Table 10. Overnight Capital Costs (2010 USD/Watt) for Major Generation Types, AEO 2011 (Extrapolated to 2050)

Technology[a]	2010	2020	2030	2040	2050
Gas-CC	1.00	0.97	0.81	0.72	0.72
Gas-CT	0.68	0.64	0.52	0.46	0.46
Coal	2.28	2.79	2.38	2.15	2.15
Nuclear	3.91	4.92	3.92	3.48	3.48
Gas-CC-CCS	1.98	1.83	1.45	1.26	1.26
Coal-CCS	3.68	4.84	3.87	3.40	3.40
Onshore Wind	2.01	2.44	2.14	1.96	1.96
Offshore Wind	3.99	5.52	4.49	3.97	3.97
Utility-Scale PV	6.19	5.72	4.07	3.39	3.39

[a] Gas-CC (natural gas combined cycle), Gas-CT (natural gas combustion turbine), Gas-CC-CCS (natural gas combined cycle with carbon capture and sequestration), Coal-CCS (coal-fired with carbon capture and sequestration), PV (photovoltaic)

4.3 Future Capacity Deployment

One of the primary outputs of the ReEDS model is the amount and location of capacity deployed. We present the capacity expansion results for the reference and CES scenarios in this section. We separate capacity in the United States and Canada to compare trends. However, it should be noted that ReEDS decision making is based on an overall system (integrated Canada and U.S.) least-cost optimization.

Table 11 and Figure 12 show capacity expansion from 2010 to 2050 in the United States and Canada for the reference scenario. Capacity expansion trends in both the United States and Canada are dominated by natural gas. In the United States, natural gas capacity is two times greater in 2050 than in 2010, with much of that capacity from new natural gas CC plants, while Canadian natural gas capacity is about three times greater in 2050 than in 2010. All other technologies experience little or no growth in the reference scenario. Lifetime-based retirements result in nuclear, oil/gas steam, and coal capacity attrition. However, new pulverized coal capacity additions return the cumulative coal capacity[24] to approximately 2010 levels.[25] Among renewable technologies, wind shows greatest capacity deployment in both the United States and Canada; however, the rate of growth in wind over the next 40 years was found to be much smaller than what has been seen in the last decade.

[24] At least 85% of the generation from cofire capacity (coal and biomass) can be derived from coal fuel in ReEDS. Therefore, we include cofire with dedicated coal for the purpose of estimating retirements of existing coal capacity.
[25] The reference scenario does not consider a large-scale policy push for carbon emission reductions in the United States or Canada. However, there exists proposed measures that would prevent new coal (without CCS) additions in both countries. For the United States, the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards (U.S. EPA 2012).

Table 11. Total Installed Capacity (GW) for the United States and Canada for the Reference Scenario

	2010		2020		2030		2040		2050	
Technology[a]	**US**	**CA**	**US**	**CA**	**US**	**CA**	**US**	**CA**	**US**	**CA**
Nuclear	102	13	102	13	99	13	58	11	58	11
Coal	305	13	233	9.0	202	7.1	189	7.9	237	14
Cofire[b]	4.7	-	34	0.1	43	0.1	54	0.1	69	0.1
Gas-CC	207	9.2	241	11	382	15	522	19	544	20
Gas-CT	140	7.5	167	14	169	19	165	23	161	25
Hydro	76	71	76	77	77	79	77	79	77	79
Other RE[c]	13	1.2	23	1.2	33	1.9	38	6.0	43	6.0
Wind	39	4.1	64	4.8	69	6.9	77	16	84	22
Other Gas/Oil	99	7.5	71	6.8	25	5.8	5.3	1.9	4.6	1.3
Storage	20	0.2	31	0.2	35	0.2	36	0.2	36	0.2

[a] Gas-CC (natural gas combined cycle), Gas-CT (natural gas combustion turbine), Other RE (other renewable electricity)
[b] Up to 15% of the generation from cofire capacity can be derived from biomass fuel in ReEDS.
[c] Other RE includes solar, dedicated biomass, and geothermal.

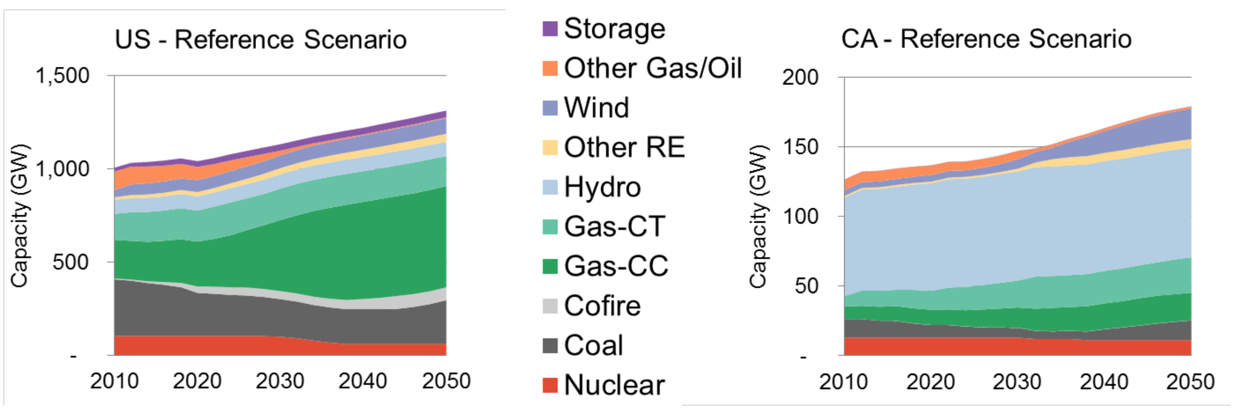


Figure 12. Capacity expansion for the United States (left) and Canada (right) in the reference scenario

Figure 13 shows the installed capacity in 2050 for onshore wind, natural gas CC, coal, and hydropower in the reference scenario. Onshore wind installed capacity is concentrated in the Midwest, Texas, and California for the United States and in BC and Quebec for Canada. Natural gas and coal are highly concentrated in the East near the large load centers. Hydropower is concentrated on the west coast, in Manitoba, and in the Northeast (Quebec, Ontario, and New York).

The reference scenario shows a future with relatively modest increases for renewable installations in the United States and Canada. It indicates that with no new energy policies, the U.S. system will remain dominated by fossil capacity, particularly natural gas. Hydropower capacity remains dominant in Canada, and growth in natural gas and wind is noticeable, particularly during the last half of the study period.

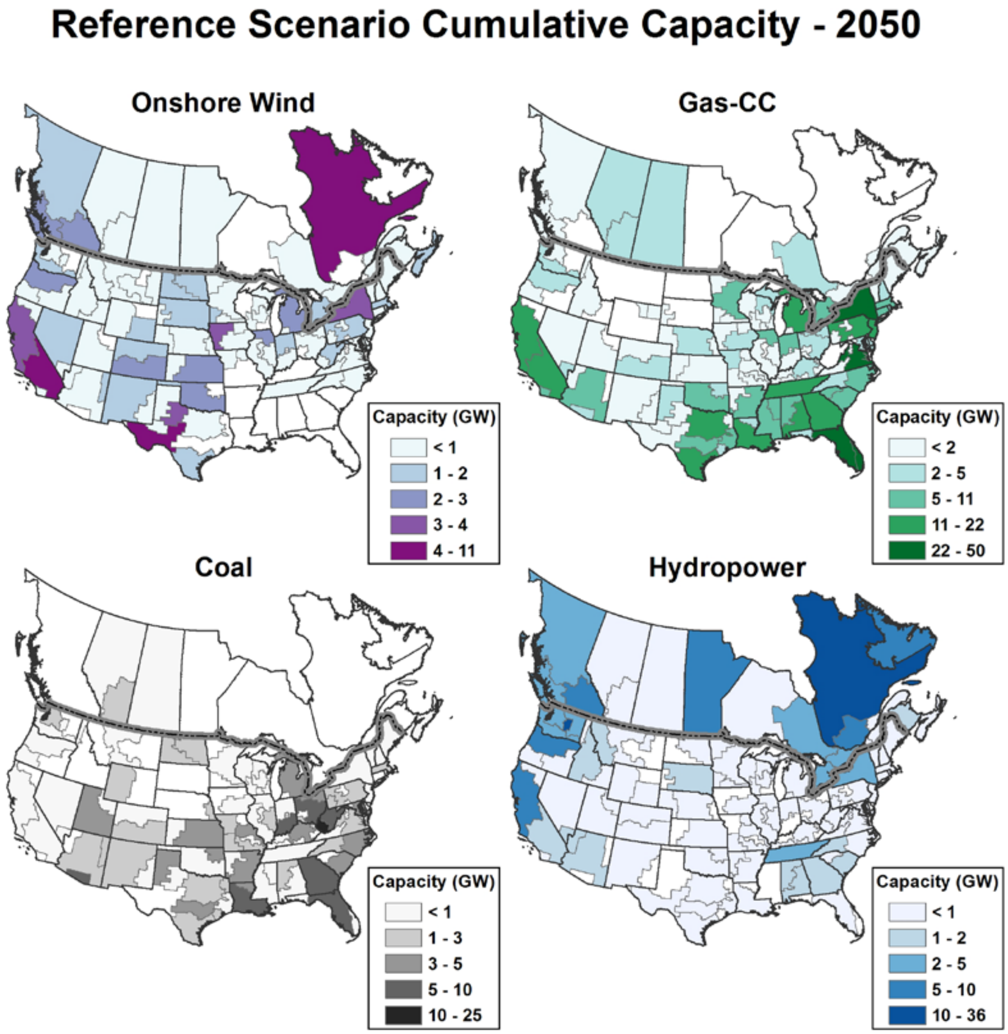


Figure 13. 2050 installed capacity for wind, hydro, coal, and natural gas-CC technologies in the reference scenario

Table 12 and Figure 14 show capacity expansion from 2010 to 2050 in the United States and Canada for the CES scenario. Because existing coal generation receives zero credit toward the CES requirement, the model retires one-third of the existing coal capacity[26] by 2030 and approximately 75% by 2050 in the combined system. This reduction in coal capacity is replaced by a mix of clean technologies. Because ReEDS assumes that biomass-coal cofire capacity can generate up to 15% of its energy from biomass, some of the dedicated coal capacity is converted to be cofire-ready.[27] With a nearly full clean energy credit, coal-CCS and gas-CC-CCS deployment grows significantly after 2030. Natural gas capacity without CCS grows rapidly, especially in the United States, during the first half of the study period but remains largely flat after 2030 as the CES becomes increasingly stringent. Overall, natural gas capacity remains a

[26] We include cofire with dedicated coal for the purpose of estimating retirements of existing coal capacity.
[27] For this scenario, biomass receives a full clean energy credit toward the CES. As such, cofire generation can receive up to a 0.15 clean energy credit.

large player due to the relative low prices of natural gas and the half (gas-CC) and nearly full (gas-CC-CCS) clean crediting for these technologies. Growth in nuclear and wind is much larger than in the reference scenario. In particular, wind grows at an average of 4.3 GW per year from 2010 to 2050. For comparison, recent historical annual wind installation rates in the United States have been roughly 5–10 GW per year.[28] Other renewables show modest growth as well, under the technology cost assumptions used for this analysis. CES scenarios using other technology projections lead to dramatically greater renewable deployment levels (e.g., Logan et al. 2012).

Table 12. Total Installed Capacity (GW) for the United States and Canada for the CES Scenario

	2010		2020		2030		2040		2050	
Technology[a]	**US**	**CA**	**US**	**CA**	**US**	**CA**	**US**	**CA**	**US**	**CA**
Nuclear	102	13	102	13	106	13	110	12	154	13
Coal	305	13	232	9.0	79	4.6	2.3	1.7	0.1	0.5
Cofire[b]	4.7	-	34	0.1	129	2.8	115	2.9	80	3.0
Coal-CCS	-	-	-	-	4.6	-	21	4.9	61	15
Gas-CC	207	9.2	241	11	398	12	441	13	417	12
Gas-CC-CCS	-	-	-	-	6.0	-	150	0.4	191	1.5
Gas-CT	140	7.5	167	14	152	16	145	17	128	19
Hydro	76	71	76	77	83	79	87	79	88	79
Other RE[c]	13	1.2	23	1.2	40	5.6	62	6.0	70	6.1
Wind	39	4.1	64	4.8	90	20	136	40	160	46
Other Gas/Oil	99	7.5	71	6.8	25	5.8	5.3	1.9	4.6	1.3
Storage	20	0.2	31	0.2	36	0.2	48	0.5	53	0.8

[a] Coal-CCS (coal-fired with carbon capture and sequestration), Gas-CC (natural gas combined cycle), Gas-CC-CCS (natural gas combined cycle with carbon capture and sequestration), Gas-CT (natural gas combustion turbine), Other RE (other renewable electricity)
[b] Up to 15% of the generation from cofire capacity can be derived from biomass fuel in ReEDS.
[c] Other RE includes solar, dedicated biomass, and geothermal.

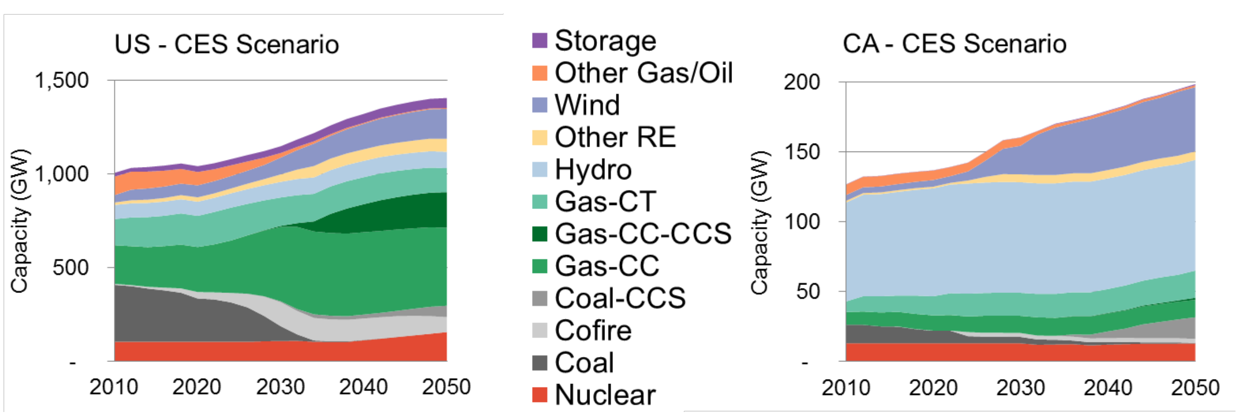


Figure 14. Capacity expansion for the United States (left) and Canada (right) in the CES scenario

[28] Historical annual growth rates are based on Lawrence Berkeley National Laboratory's 2011 Wind Technology Market Report. http://eetd.lbl.gov/ea/ems/reports/lbnl-5559e.pdf.

Figure 15 shows the installed capacity in 2050 for onshore wind, natural gas CC with CCS, coal with CCS, and nuclear. Geographic deployment trends of onshore wind for the CES scenario are similar to the reference scenario but with additional wind in Alberta, Saskatchewan, Labrador, and in the northeast and midwest United States. Natural gas with CCS capacity is located in the eastern United States and California, whereas coal with CCS is located mainly in the southwest United States and Alberta.[29] Nuclear deployment is concentrated on the eastern United States.

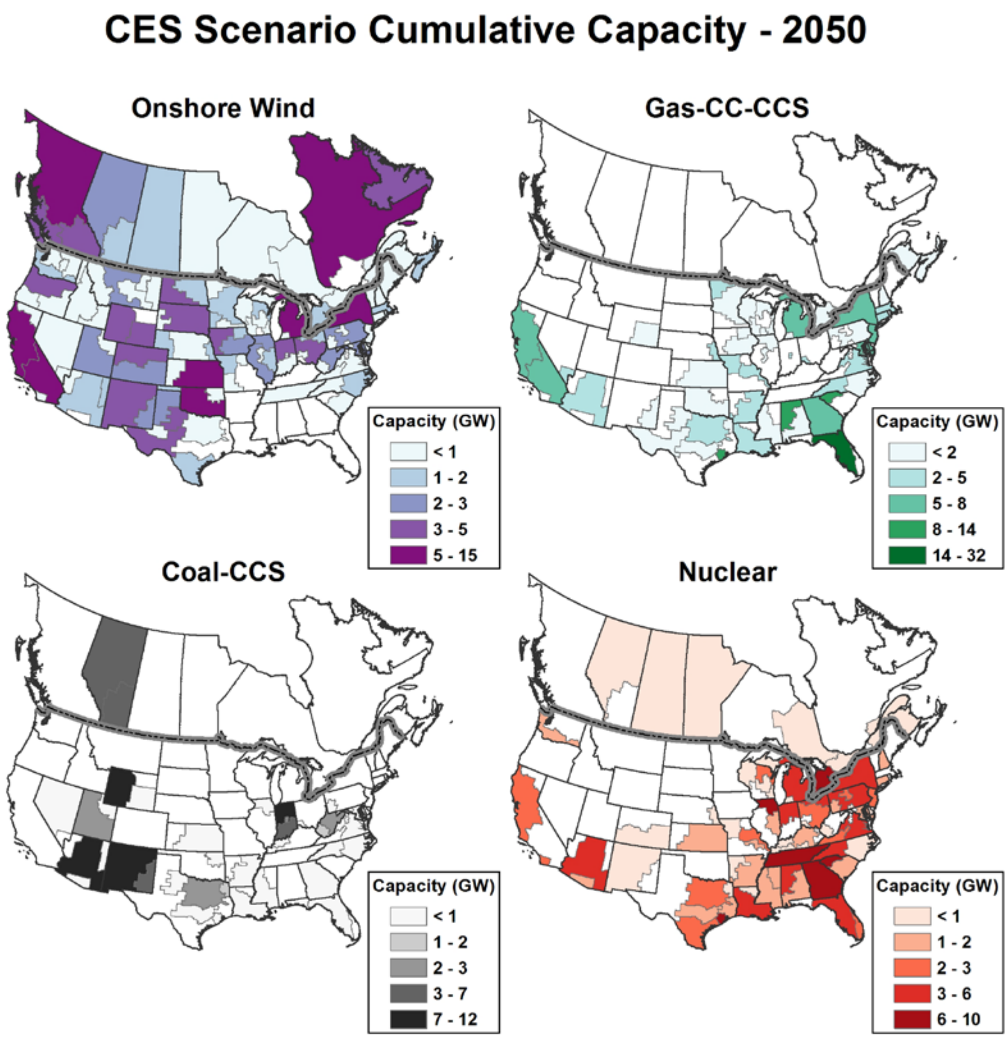


Figure 15. 2050 installed capacity for wind, nuclear, coal-CCS, and natural gas-CCS technologies in the CES scenario

[29] We do not model locational suitability or other carbon sequestration restrictions for CCS technologies.

4.4 Future Generation

Future generation trends largely follow the capacity trends described above. Figure 16 shows annual generation by technology in the United States and Canada in the reference scenario. For the U.S. system, natural gas shows the largest growth, reaching 35% of total generation by 2050, which approaches the 41% share of coal.[30] Changes in the Canadian generation mix over time are not as significant as in the United States, with hydropower remaining dominant (54% of total generation in 2050). However, wind and biopower[31] become significant contributors to Canadian generation during the last two decades, reaching 11% and 5% of total 2050 generation, respectively.

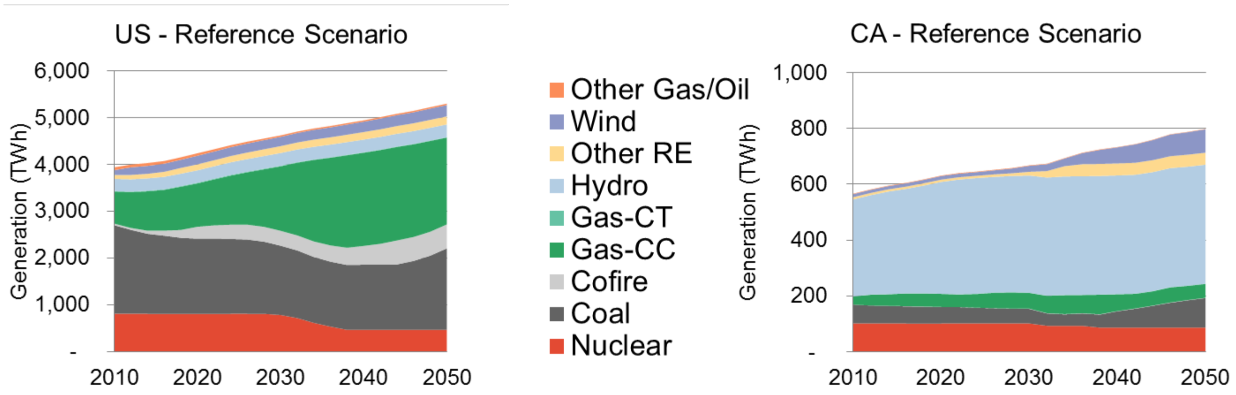


Figure 16. Generation expansion for the United States (left) and Canada (right) in the reference scenario

Under the CES scenario, the United States continues to rely on fossil fuel but with a dominant share from CCS technologies. In particular, gas-CC-CCS generation reaches 29% of total U.S. generation by 2050 and total natural gas generation reaches 40% by 2050. Pulverized coal generation without CCS is largely phased out, while generation from coal-CCS reaches 8% of total generation in 2050. Growth in nuclear generation shows moderate increases (from 20% of total generation in 2010 to 23% in 2050). Generation from U.S. renewable resources increases somewhat, most notably from wind generation (from 3% of total generation in 2010 to 9% in 2050); however, under the technology and fuel cost assumptions used, the transformation to a clean electricity future relies more strongly on non-renewable technologies. In contrast, the CES drives the Canadian generation mix toward renewable generation. In particular, wind generation grows significantly, reaching 20% of total Canadian generation in 2050, while CCS (predominantly coal) generation is about 14%. Although absolute generation from hydropower grows slightly over time, fractional generation decreases to 48% in 2050 (compared with 61% in 2010). This is a direct result of Canadian domestic load growth and an increase in electricity exports out of Canada (see Section 4.6). Figure 17 shows these generation trends over time for the United States and Canada in the CES scenario.

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[30] Here, coal generation includes both dedicated coal and the coal fraction of cofire.
[31] Here, biopower generation includes both dedicated biopower and the biomass fraction of cofire.

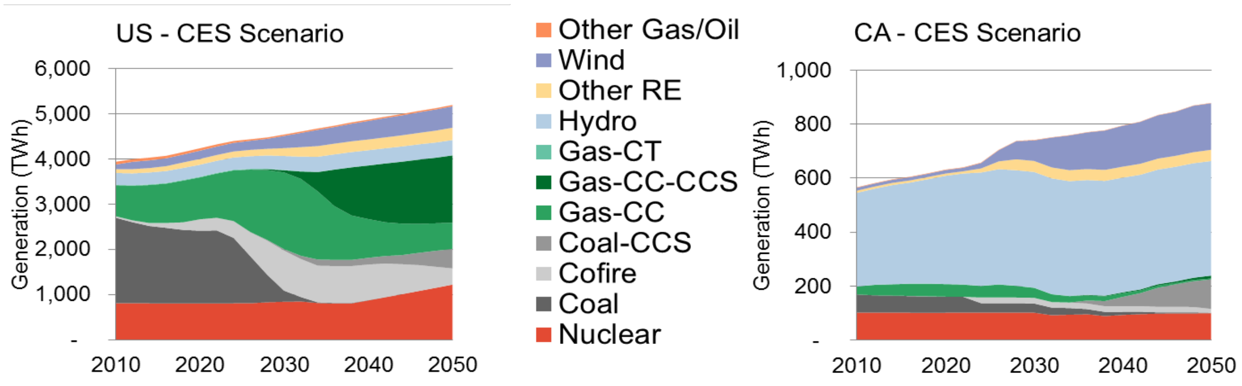

Figure 17. Generation expansion for the United States (left) and Canada (right) in the CES scenario

4.5 Transmission Expansion

There is limited growth in transmission infrastructure under the reference scenario. Between 2010 and 2050, 19 million MW-miles of new transmission lines were built in the United States and Canada (Figure 18) in comparison with 150–200 million MW-miles existing in the U.S. system in 2010 (NREL 2012). These transmission values represent inter-BA transmission only and do not account for intra-regional transmission capacity needed. Total transmission expansion in the CES scenario (18 million MW-miles) is similar to the reference scenario due to heavy reliance on CCS technologies and relatively limited reliance on more-remote renewable resources. Figure 19 shows that new transmission lines in the reference scenario are somewhat concentrated in the midwest and southern United States. New transfer capacity between the United States and Canada are primarily located in the Northwest (between BC and Washington) and the central region (between Saskatchewan, Manitoba, North Dakota, and Minnesota). Very little new inter-provincial transmission lines were built in the reference scenario; however, large new transmission capacity was deployed between northern Quebec and southern Quebec largely to deliver wind and hydropower from the North to the load centers in the South.

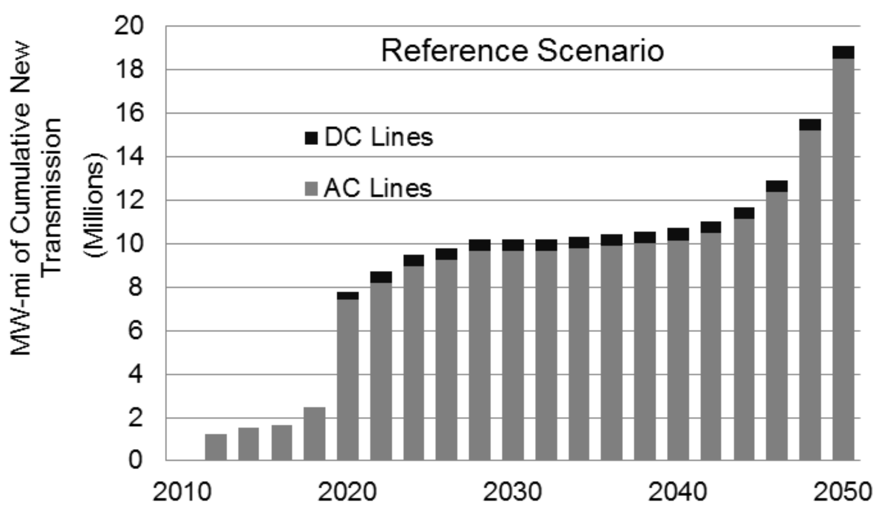

Figure 18. Transmission expansion in the reference scenario

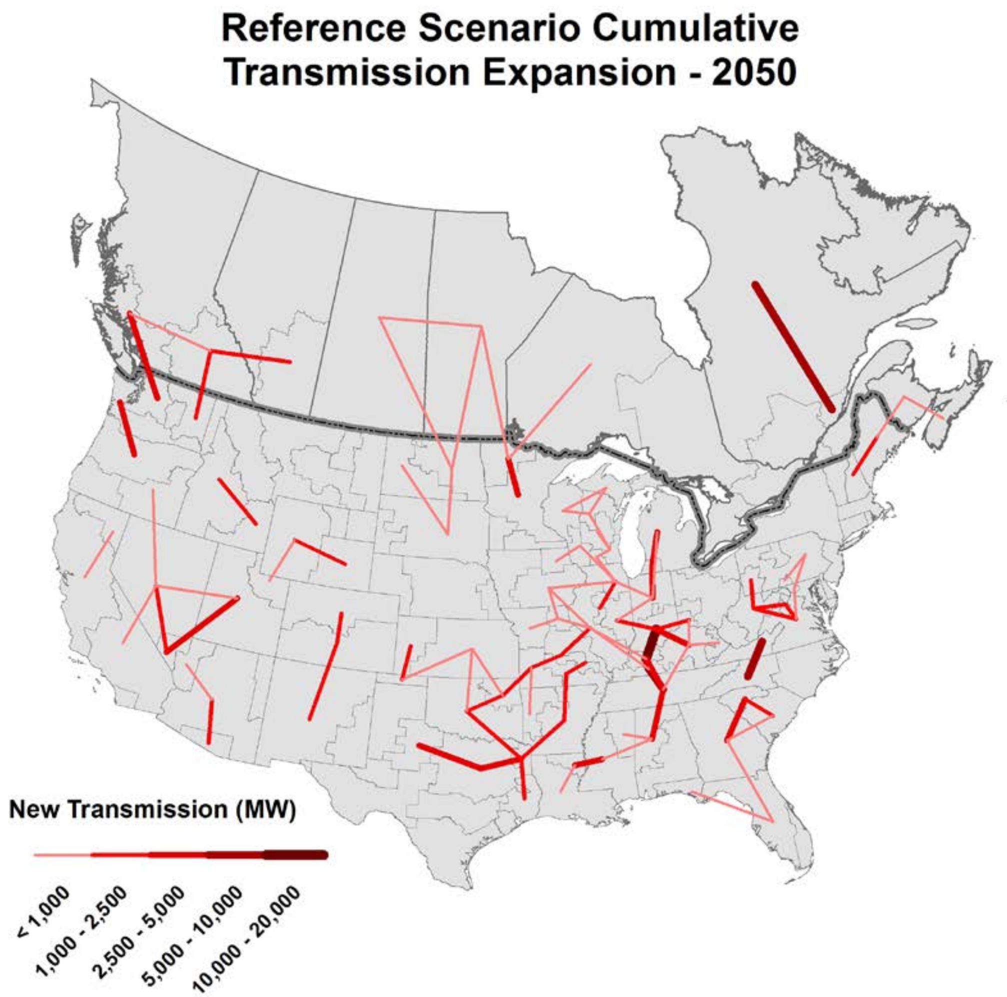

Figure 19. Inter-BA transmission lines deployed between 2010 and 2050 in the reference scenario

4.6 Electricity Transfers Across the Canada-U.S. Border

The primary value of having an integrated Canada-U.S. modeling framework is the ability to analyze dynamics of electricity transfers between the two countries. Although further work is needed to fully understand the drivers for electricity imports and exports, the preliminary scenario analysis demonstrates changing behavior along the Canada-U.S. interface under a modeled policy option. The newly developed integrated Canada-U.S. ReEDS model allows us to analyze these requirements under different future scenarios.

Figure 20 shows net electricity transfers over time across the Canada-U.S. border in the reference scenario, CES scenario, and projections from the NEB.[32] All projections indicate a positive net transfer from Canada to the United States; however, the magnitude of transfers varies across scenarios. Annual energy transfers in the reference scenario remain largely constant over time and are small compared to total generation (<1% of U.S. generation, 5%–8% of Canadian generation). However, instantaneous power transfers can be larger. The annual net energy transfers projected in the ReEDS reference scenario are less than, but similar to, the projections from the NEB; both NEB and the ReEDS reference scenario project a similar (small) amount relative to total generation.

A combined Canada-U.S. CES as modeled in the CES scenario can have significant implications for electricity transfers between Canada and the United States. An average of 50 TWh per year additional net exports from Canada are observed in the CES scenario in the later years. These additional exports correspond with an increase in wind generation in Canada under the CES scenario as described in Section 4.4. We expect that scenarios with greater wind or hydropower deployment, such as through lower technology costs or further incentives for clean generation, will result in even greater cross-border transfers of electricity. In addition, scenarios with different policies between the two countries could lead to interesting import/export dynamics. The integrated modeling framework developed here can be used to evaluate such policy scenarios.

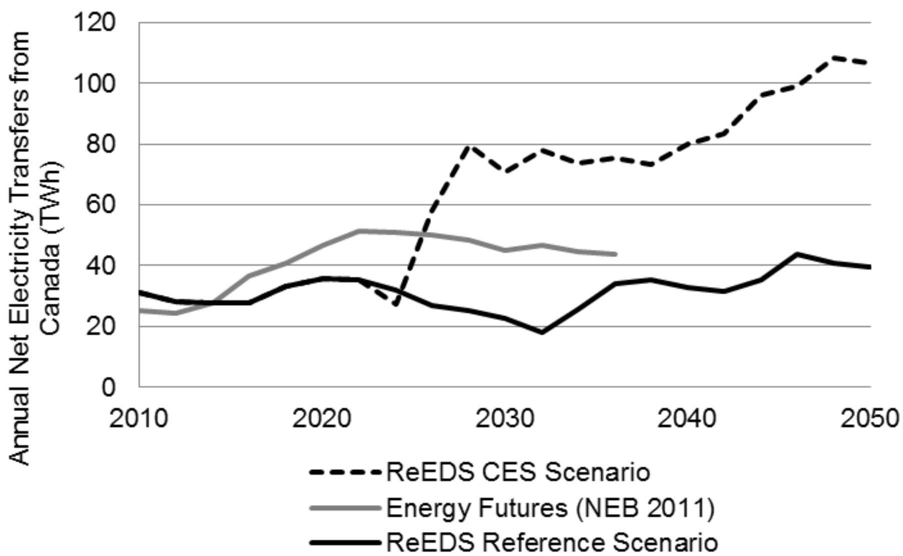

Figure 20. Net electricity transfers between Canada and the United States

Note: The CES requirement is first binding after 2022. Therefore, the net electricity transfers are unaffected between the CES and the reference scenario up to this point.

[32] The reference scenario from the NEB Energy Futures 2011 work was used as a comparison in Figure 20 and this section.

In addition to *energy* transfers, other aspects of power system operation can be evaluated with the integrated model. For example, Figure 21 shows contracted firm capacity between the United States and Canada in the reference scenario during the peak time-slices in each season. In aggregate, the United States obtains firm capacity from Canada during the summer when the majority of the continental U.S. electricity demand is peaking. Conversely, in aggregate, Canada obtains firm capacity from the United States in the winter when the majority of Canada electricity demand is peaking. The different peaking periods in Canada and the United States allow sharing of reserve services across the border and therefore reduce the need for new capacity in both countries. This, and other synergies, can be the subject of future analysis.

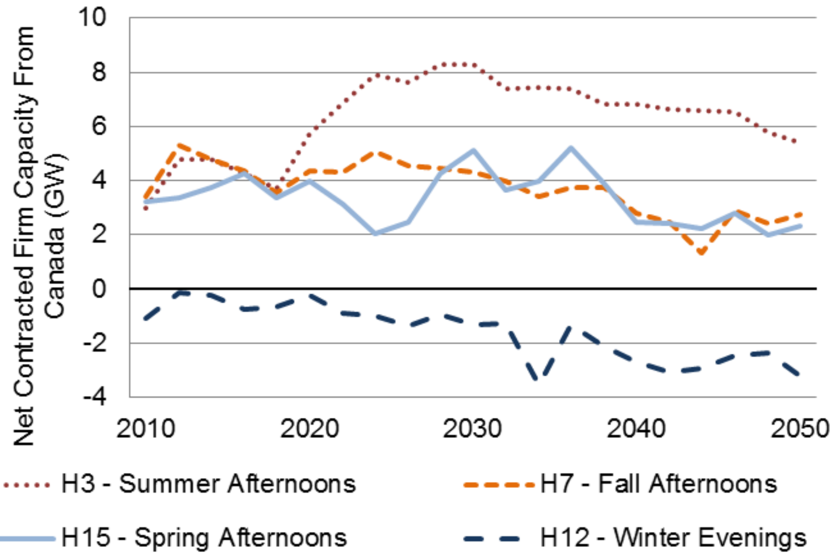

Figure 21. Net exported contracted firm capacity from Canada for the reference scenario

4.7 Electricity and Natural Gas Prices

ReEDS provides estimates of electricity prices and fossil fuel prices for each scenario. Figure 22 shows national average retail electricity prices in the United States and Canada for the reference and CES scenarios. In the reference scenario, electricity prices increase in both countries, growing by 16% in the United States and 13% in Canada over the 40-year study period (in real dollar terms). Greater increases are observed in the CES scenario. By 2050, electricity prices are 8% and 2% higher[33] in the CES scenario than the reference scenario in the United States and Canada, respectively. The lower incremental price to meet the CES in Canada reflects the fact that Canada's generation mix originated with greater shares of clean generation, based on the clean crediting assumed here, compared to the United States. Therefore, reaching the clean energy targets in Canada required fewer investments in the power sector compared to the United States.

[33] The Canadian electricity prices were found to be lower under the CES scenario in the 2030s. Nonetheless, deviations in Canadian electricity prices were small between both scenarios.

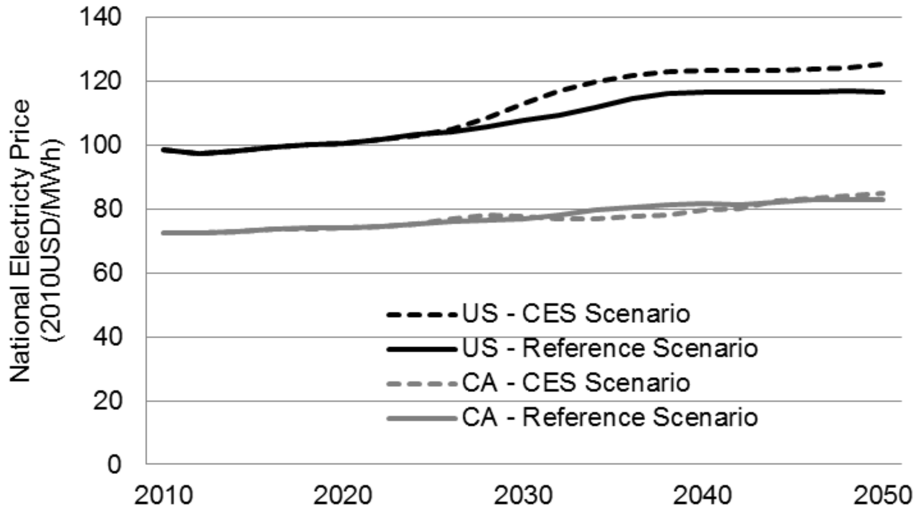

Figure 22. Average retail electricity prices

Figure 23 shows natural gas prices and power sector natural gas consumption for the reference and CES scenarios. We assume a single natural gas market between Canada and the United States and therefore do not have separate prices in the two countries. In both scenarios, natural gas prices remain below $6/MMBTU until 2024 and increase to about $9/MMBTU by 2040. Despite these natural gas price increases, power sector natural gas consumption grows significantly and peaks at 14 quads per year in the reference scenario. Natural gas consumption and prices are slightly higher in the CES scenario as generation from gas-CC-CCS and gas-CC technologies are significant.

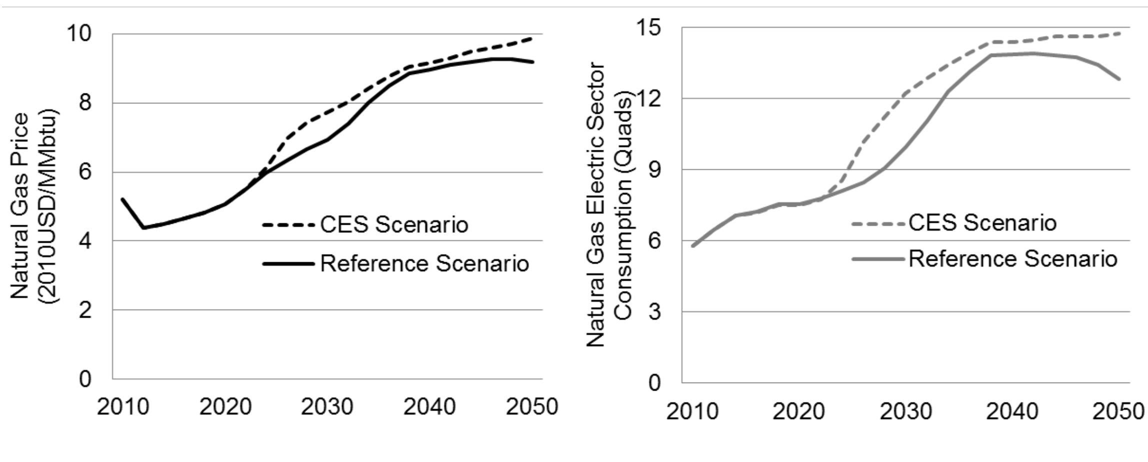

Figure 23. Power sector natural gas price (left) and consumption (right)

4.8 Carbon Dioxide Emissions

In the reference scenario, annual CO_2 emissions[34] from the United States and Canada together reach 2.7 Gtonnes by 2050 (up from 2.2 Gtonnes in 2010). As shown in Figure 24, a vast majority of these power sector emissions are from the United States, which also has a much higher carbon intensity in 2050 (0.49 tonnes/MWh in the United States versus 0.13 tonnes/MWh in Canada). This is a direct result of the continued reliance on fossil fuel for power generation in the United States compared with the large reliance on hydropower in Canada. Not surprisingly, in the CES scenario, we see a significant reduction (about 70%) in CO_2 emissions from 2010 levels by 2050 in both the United States and Canada (see Figure 24).

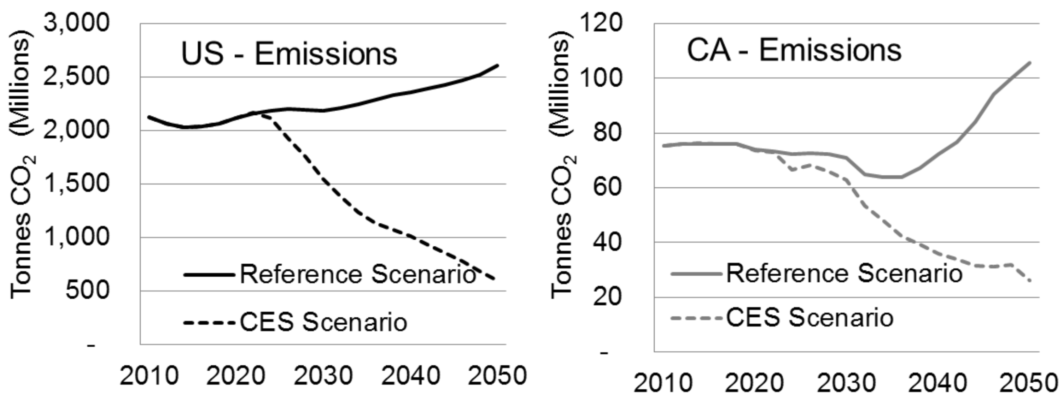

Figure 24. Annual power sector CO_2 emissions for the United States (left) and Canada (right)

[34] Note that the CO_2 emission numbers reported in this section do not include the CO_2 equivalent for other greenhouse gases nor do they include emissions from dedicated heating or combined heat and power.

5 Summary and Future Work

In this report, we present developments to the ReEDS model to fully integrate the Canadian power system. The model development efforts include adding multiple BAs and regions for Canada and collecting and processing data on Canadian renewable resources and power system infrastructure. The fully integrated model retains ReEDS's unique attributes, such as its high geographic resolution and statistical treatment of variable resources. By integrating a representation of the Canadian power system into the ReEDS capacity expansion model, we can evaluate the dynamics of cross-border interactions under a wide range of future electricity scenarios.

We present preliminary scenario analysis results using this integrated Canada-U.S. version of ReEDS. These preliminary results indicate that, under a reference scenario with no new energy policies and assuming technology and fuel costs consistent with AEO 2011, growth in natural gas generation will be significant over the next 40 years in both Canada and the United States while growth in non-fossil technologies will be more limited. As a result, CO_2 emissions from the combined Canadian and U.S. system rise to 2.7 Gtonnes/year by 2050 in the reference scenario. We also evaluate a CES scenario, which results in greater deployment of primarily CCS and nuclear technologies in the United States and wind technologies in Canada. Under the CES scenario, installed wind capacity reaches 46 GW by 2050 in Canada, a significant increase from the 4 GW of installed wind capacity in 2010. We found that the incremental increase in the 2050 national average retail electricity price of the CES scenario compared to the reference scenario is higher by 8% in the United States and 2% in Canada. CO_2 emissions for 2050 in the CES scenario are found to be about 70% lower than that in the reference scenario.

The preliminary scenario analysis also demonstrates interesting interactions between the Canadian and U.S. power systems. Net electricity transfers between Canada and the United States are found to remain limited in the reference scenario during the study period. However, under a CES, we found a significant jump in net electricity exports from Canada to the United States that corresponds with increased wind deployment in Canada. In addition, even under the reference scenario, where net energy transfers are small relative to total generation, we observe seasonally varying firm capacity contracts between the two countries that help to limit the need for new capacity additions. Future work will focus on understanding the drivers of these interactions, including synergies between the two systems and impacts of energy policies.

Other future work could include an updated data collection effort. In particular, we plan to refine the resource and technology data, including wind and solar time-series data; solar, biomass, and geothermal resource data; a better representation of hydropower and pumped-hydropower resource; nuclear availability and dispatch; and CCS resource limitations. The initial work presented in this report provides the groundwork for these improvements and for future analyses of the Canadian and U.S. electricity sectors.

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