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# Deep decarbonization in Northeastern North America: The value of electricity market integration and hydropower

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**Abstract:** In several countries, electricity systems are under strong decarbonization pressure. In particular, the Canadian provinces of Quebec and Ontario as well as the states of the northeastern United States have committed to cut their greenhouse emissions by more than 70% (with respect to emission levels of 1990). Increased collaboration and integration between jurisdictions could decrease such decarbonization costs, especially when important hydropower resources are available.

Using a capacity expansion and dispatch model of the Northeastern North American electricity sector, we analyze the impact of emission reduction targets, load levels and availability of power technologies in a range of scenarios, in order to assess the benefits of regional cooperation. Our results show that for deep decarbonization, the electricity system costs can be significantly reduced through integration, especially by adding more interconnection capacity. These costs savings and benefits are however not evenly allocated between jurisdictions, creating potentially difficult collaboration incentives.

**Keywords:** Electricity sector integration, decarbonization, hydropower, Northeastern North America

**Résumé :** Dans plusieurs pays, les systèmes électriques sont soumis à une forte pression de décarbonisation. En particulier, les provinces canadiennes du Québec et de l'Ontario ainsi que les États du nord-est des États-Unis se sont engagés à réduire leurs émissions de gaz à effet de serre de plus de 70 % (par rapport aux niveaux d'émission de 1990). Une collaboration et une intégration accrues entre les juridictions pourraient réduire ces coûts de décarbonisation, en particulier lorsque d'importantes ressources hydroélectriques sont disponibles.

En utilisant un modèle d'expansion de la capacité et de répartition du secteur électrique du nord-est de l'Amérique du Nord, nous analysons l'impact des objectifs de réduction des émissions, des niveaux de charge et de la disponibilité des technologies énergétiques dans une série de scénarios, afin d'évaluer les avantages de la coopération régionale. Nos résultats montrent que pour une décarbonisation en profondeur, les coûts du système électrique peuvent être réduits de manière significative par l'intégration, notamment en ajoutant une plus grande capacité d'interconnexion. Toutefois, ces économies de coûts et ces avantages ne sont pas répartis de manière égale entre les juridictions, ce qui crée des incitations à la collaboration potentiellement difficiles à mettre en œuvre.

**Mots clés :** Intégration du secteur de l'électricité, décarbonisation, hydroélectricité

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# 1 Introduction

Emission pathways consistent with 1.5°C (or 2°C) global warming require reaching net zero emissions by 2050 (or 2070), according to Masson-Delmotte et al. (2019). Such level of decarbonization will require profound changes in the energy systems and a greater role for electricity (Williams et al., 2012). Key sub-national governments in Northeastern North America committed to limiting emissions to 80-95% below 1990 levels by 2050 by joining the Under2 Coalition: New York and all New England states (except Maine) in the United States and Ontario and Quebec in Canada (Under2 Coalition, 2019). They all have significant climate policies, including in some cases regional cap-and-trade markets covering the electricity sector: the Regional Greenhouse Gas Initiative for the Northeastern states (RGGI, 2019) and the Western Climate Initiative for two Canadian provinces (Quebec and Nova Scotia), see WCI (2019). However, their cooperation in the electricity sector has been mostly limited to bilateral trade of surplus power (CEA, 2016). While the region includes five areas (New York, New England, Ontario, Quebec and the Atlantic provinces), there are currently more than five very different electricity market designs. They share one reliability coordinating institution, the Northeast Power Coordinating Council (NPCC, 2019), but they otherwise plan their respective power systems in almost complete disregard of integration benefits and regional resources potential.

In this multi-region setting, electricity market integration and cooperation can occur in multiple ways, for example, through coordinated capacity planning, pooled capacity resources or electricity trade. Such cooperative actions can support the transformation of power systems to achieve decarbonization goals, through:

- Economies of scale in large capacity investment projects.
- More efficient power dispatch (Newbery et al., 2016) and access to low-cost renewable energies across regions.
- Load balancing and smoother generation in a wider territory (Bahar and Sauvage, 2013).
- Greater economic value of renewable generation, by reducing electricity curtailment (Newbery et al., 2016).

This paper illustrates the value of electricity market integration in a context of a region strongly committed to deep decarbonization. It also explores the enabling role of hydropower in such decarbonization, as Northeastern North America is characterized by a large hydropower installed capacity: its 64 GW of hydropower represent 5.5% of the world's hydropower, while the region has 0.8% of the world population.

Using a capacity expansion and dispatch model of the Northeastern North American Electricity Sector, this article explores the impact of multi-regional integration on capacity investments, annualized costs, electricity trade and marginal prices of carbon. We present results under scenarios of decarbonization targets, load levels, and availability of nuclear power and carbon-neutral natural gas.

Our contribution is twofold. On the modelling side, our work includes a detailed characterization of hydropower generation in an energy policy study for electricity sector decarbonization, considering investments in generation, transmission and storage capacity. Although previous works have analysed the value of interconnectors between thermal and hydro-dominated systems for energy policy, their modelling approach typically consists either in replicating historical hydropower output (underestimating the energy storage effect of reservoirs) or in aggregating the hydropower resources into a single power plant (see for instance Dolter and Rivers (2018), and Dimanchev et al. (2020)). Whereas aggregation methods reduce the model complexity, they tend to overestimate the operational flexibility of multireservoir systems,[1] which is a critical aspect in deep decarbonization studies (Härtel and Korpås, 2017). Quebec's hydropower complex consists in several interdependent reservoirs, whose actual operation involves multiple operational and environmental constraints (Gauvin et al., 2018). Rather than exactly reproducing all the operational aspects of this system, we explicitly represent its main reservoirs in order to reduce our model complexity while obtaining satisfactory estimates.

[1] Confirming the trade-off between complexity and accuracy in hydropower models, Brandão (2010) and Härtel and Korpås (2017) report approximation errors ranging from 6% to 11% of the objective value, depending on the approximation method and the composition of the hydropower system

**Table 1: Generation and consumption in Northeastern areas, 2017 Energy Information Administration (2019), Statistics Canada (2019b).**

| Area | Aggregate | | Per capita | |
|---|---|---|---|---|
| | Generation [TWh] | Consump. [TWh] | Generation [MWh] | Consump. [MWh] |
| New York | 128.07 | 144.99 | 6.55 | 7.42 |
| New England | 105.23 | 115.46 | 7.08 | 7.77 |
| Quebec | 212.09 | 173.72 | 25.38 | 20.79 |
| Ontario | 150.96 | 133.72 | 10.60 | 9.39 |
| Atlantic | 63.08 | 35.91 | 26.25 | 14.94 |

On the policy side, this work estimates the gains from regional electricity market integration in a context of decarbonization (Newbery et al., 2016, 2019). Specifically, we explore the impact of integration through inter-regional transmission investments and by means of capacity pooling to meet peak load. We find that the gains from market integration increase as the level of decarbonization deepens, making regional electricity market collaboration a necessary condition for a least-cost fight against climate change.

In Section 2 we start by presenting the unique context of the electricity sector in Northeastern North America, then we present our model and data in Section 3. Results and discussion follow in Section 4, and policy implications in Section 5. The model documentation is in Appendix A and the supplementary data in Appendix B.

## 2 Electricity markets in Northeastern North America

Northeastern North America, as shown on Figure 1, covers New York and the six New England states,[2] in the United States, and Ontario, Quebec and four smaller Atlantic provinces[3] in Canada. It has a combined population of about 60 millions (Statistics Canada, 2019c, U.S. Census Bureau, 2018), which would place it between Italy and France as a country. Despite a shared reliability organization, the NPCC, each of the five areas has its own electricity market design. New York has an open competitive electricity market, operated by the New York Independent System Operator (NYISO, 2019). In New England, the Independent System Operator (ISO-NE) operates the power system, administers the wholesale electricity markets and is in charge of planning (ISO-NE, 2019). In addition to the ISO-NE, each New England state has its own public utilities commission, regulating investor-own electricity companies (USLegal, 2019), as well as its own set of environmental and renewable targets, such as renewable portfolio standards (DSIRE, 2019). In Ontario, the Independent Electricity System Operator is responsible for managing and operating the electricity market and the power system of the province (Ontario IESO, 2019). In Quebec and Atlantic provinces, the electricity markets are dominated by vertically integrated electricity companies, without independent system operators (see Pineau (2013) for more details on the Canadian electricity markets). The situation is therefore very different from the European single market in electricity, pushed by the European Commission since 1996 (see Pollitt (2019) for an account and assessment).

In addition to these multiple institutional disparities , each area in Northeastern North America has very distinct supply and demand characteristics. Table 1 shows the large electricity generation and consumption of Quebec, especially as compared to its Southern neighbors, New York and New England. Generation portfolios also show significant differences among Northeast areas: whereas natural gas dominates in New England and New York, hydropower is the main electricity source in Quebec, and nuclear power accounts for nearly one third of the generation capacity in Ontario (see Table 2). Prices are also widely different in each area, indicating some possible gains in economic efficiency and resources allocation.

[2] Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont

[3] New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland and Labrador

**Table 2: Generation and storage capacity in Northeastern areas in 2017. Data for NE and NY correspond to net summer capacity Statistics Canada (2019a), U.S. EIA (2019b): [a]US data by energy source. [b]Canada data by generator type.**

| Type | Capacity [GW] | | | | | |
|---|---|---|---|---|---|---|
| | NE | NY | QC | ON | AT | Total |
| Hydroelectric | 1.96 | 4.56 | 40.44 | 9.12 | 8.10 | 64.18 |
| Nuclear | 4.00 | 5.40 | | 13.33 | 0.70 | 23.43 |
| Other | 0.35 | 0.24 | | | 0.02 | 0.61 |
| Pumped Storage | 1.80 | 1.50 | | | | 3.30 |
| Solar | 0.96 | 0.26 | | 2.30 | 0 | 3.52 |
| Wind | 1.40 | 1.99 | 3.43 | 5.08 | 1.17 | 13.07 |
| Natural Gas [a] | 15.84 | 21.76 | | | | 37.60 |
| Coal/Petro./Biom. [a] | 8.72 | 5.71 | | | | 14.43 |
| Steam turbine [b] | | | 0.48 | 5.27 | 3.84 | 9.59 |
| Combustion turbine [b] | | | 0.82 | 5.15 | 1.07 | 7.05 |
| Total | 35.03 | 41.42 | 45.36 | 40.49 | 14.95 | 177.25 |

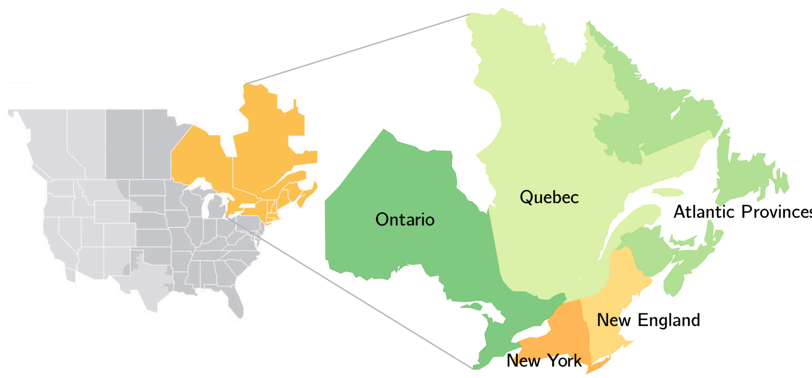



**Figure 1: Northeastern North America areas. Credits: Mapchart.net and ISO-NE.**

# 3 Methodology and data

This work focuses on the following three research questions, in the context of the Northeastern North America electricity sector: What cost-effective investments in generation, energy storage and transmission capacity would be necessary to meet decarbonization targets? What is the value of regional integration (cooperation) to achieve deep decarbonization? What is the contribution of hydropower to the expansion of renewable energies in the region? The following methodology is deployed to answer these questions.

## 3.1 Modelling approach

We developed a capacity expansion and dispatch model for determining the necessary investments in generation, transmission and energy storage to meet decarbonization targets at minimum operation and investment costs (see Appendix A for the complete linear programming model). Considering the regional projections on capacity retirements of fossil fuel plants (U.S. EIA, 2019a), we exclude oil and coal power from the model.

To compute the operation costs of investment decisions, the model simulates the chronological power system operation during 8760 hourly time-steps in a representative year, considering the variability of renewable energies and the inter-temporal effects of hydropower reservoirs. The operational decisions include power production for each type of generator, power exchanges between jurisdictions, electricity curtailment, energy storage and discharge, demand response and load shedding levels.

To achieve a balance between model accuracy and computational complexity, we model the North America Northeast region as a 5-node network, with each node corresponding to one jurisdiction and the links representing the current and potential inter-regional transmission capacity.

Our formulation includes the following constraints:

- Hourly power balance. In each jurisdiction, total load equals the sum of net domestic generation, net energy storage, net electricity trade, demand response and load shedding.
- Capacity requirements. In each jurisdiction, sufficient domestic capacity must be installed to meet peak load. In cooperation scenarios, neighbouring jurisdictions can contribute to meet capacity requirements.
- Power exchanges. Net electricity trade between interconnected jurisdictions must not exceed the current and expanded transmission capacity.
- Carbon emissions. Aggregate emissions from electricity generation are limited by decarbonization targets.
- Demand response and load shedding limits. In response to high electricity prices or insufficient generation capacity, power consumption can be reduced via demand response or load shedding in specific hours and jurisdictions. We use a block structure for demand response, with increasing cost, as shown in Appendix B, Table 12.

## 3.2 Modelling power technologies

We represent the techno-economic characteristics of power technologies as described next. Data sources are discussed in Section 3.3 and supplementary data is presented in Appendix B.

- Intermittent renewables. Wind and solar power are limited by their installed capacity and their generation profile in each jurisdiction. Given that technical and economic inefficiencies usually reduce renewable energy output (Yang et al., 2012), we apply a 20% derating factor to wind and solar power. Moreover, to represent the marginally increasing costs of widespread wind power, we define capacity expansion blocks with incremental investment costs.
- Nuclear power. To reflect the limited flexibility of nuclear power plants in the region, we define a minimum nuclear generation level equal to 80% of the installed capacity, and we allow nuclear curtailment, at a cost of $20/MWh.
- Natural gas. The model incorporates two types of natural gas generators: Simple Combustion Turbines (CT) and Combined Cycle Gas Turbines (CCGT). CCGT yields higher efficiency and less emissions than CT although the investment cost of CCGT is usually higher. Due to such differences, in general CT can be economically operated only during peak-load hours. Moreover, in some decarbonization scenarios we include an option of carbon-neutral natural gas generation, at a significantly higher operational cost. This option can represent either a carbon-neutral fuel or a carbon capture and storage system incorporated into this type of generators.
- Hydropower. The hydropower systems were modelled as described in Bouffard et al. (2018), considering the interdependences between the main reservoirs in Quebec (see Appendix B, Figure 15 for a schematic representation of Quebec's hydrosystem). The model specifies three types of hydropower facilities:
  - Flow-of-the-river: without water storage capacity.
  - Intra-day reservoirs: with *daily* cyclic storage capacity.
  - Large reservoirs: with *yearly* cyclic storage capacity.

  Whereas in hydropower facilities with intra-day or large reservoirs water can be stored for future time periods when hydroelectricity can yield higher economic value, in flow-of-the-river facilities the hydroelectricity production is coupled in time with river inflows.

  To reduce the model size we aggregate similar power plants in each region, except in Quebec where we explicitly represent the main hydropower plants and their water flow interdependences. For each hydropower plant we define operational variables for hydroturbine discharges, water spill and water storage, as Figure 2 schematically shows. The model computes the hydroelectricity production as a linear function of the turbine discharges.
- Energy storage. The model includes options for electrical storage and pumped water storage. For both types of storage we assume a daily cyclic storage capacity. Due to the geographic requirements and

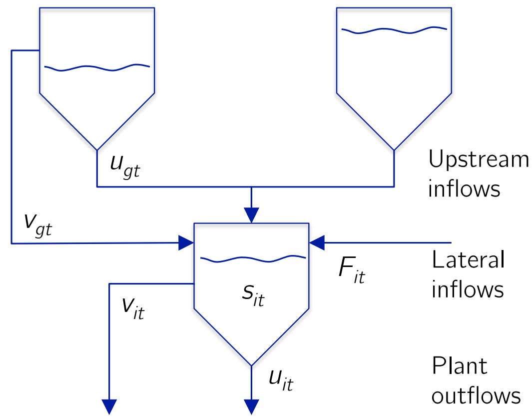



**Figure 2: Schematic representation of a hydropower system. Hydroturbine discharges ($u$) and water spill ($v$) flow to downstream power plants and affect power generation and stored water volumes ($s$). Water flowing into the system ($F$) also impacts power generation and water levels. Adapted from Oliveira et al. (2002).**

investment costs for pumped storage, we assume its capacity fixed and equal to the currently installed capacity.

- Transmission. The model represents the cross-border interconnections with linear energy losses, without considering sub-regional transmission bottlenecks.

## 3.3 Data

Here we describe the data sets used in our model to characterize the North American Northeast electricity sector, while in Appendix B we present some of the actual values used in the model.

- Demand. Hourly load for all jurisdictions come from their system operator (ISO New England, 2018, New York ISO, 2018, Ontario IESO, 2018), except for Quebec (Hydro-Québec Distribution, 2018) and for the Canadian Atlantic Provinces. In this latter case, it was estimated from Statistics Canada (2018) based on the hourly load data of New Brunswick (New Brunswick Power, 2018).
- Initial installed capacity. Transmission capacity data was collected from a variety of sources for Quebec interties (Hydro-Québec, 2018), New York interties with Ontario and New England (NYISO, 2017), and New England interconnections with the Atlantic Provinces (NPCC, 2018). For generation and pumped storage, summer capacity data for US states was collected from U.S. EIA (2019b), whereas for Canadian provinces data capacity was sourced from Statistics Canada (2019a).
- Wind generation profile. Generation profiles for Canadian provinces are estimated from multiple real wind sites, based on GE Energy Consulting (2016). For US jurisdictions, wind profiles were obtained from NREL (2017).
- Solar generation profile. For Canadian jurisdictions, solar profiles are based on actual solar production from Ontario (Ontario IESO, 2017b). For US territories, solar profiles were generated from National Renewable Energy Laboratory (2017b).
- Hydropower system. We use historical data inflows from Environment and Natural Resources Canada (2017), Ministere de l'Environnement et de la Lutte contre les changements climatiques (2017) for modelling 71% of Quebec's hydro system (consisting of 5 large reservoirs, 4 intra-day reservoirs and 8 run-of-the-river hydropower plants). For the remaining hydroelectric capacity of Quebec, as well as for every other jurisdiction, hydro systems were modelled as run-of-the-river power plants, with inflows estimated from historic hydropower production (Ontario IESO, 2017a, Statistics Canada, 2017, U.S. EIA, 2017). See Figure 15 and Tables 13-15 in Appendix B for more details.
- Investment and operation costs. For generation and storage, we use cost estimates from Vimmerstedt et al. (2019). For transmission lines, investment costs are based on the flying distances between the main

**Table 3: Analyzed integration modes.**

| Integration Mode | Cooperative action | | |
|---|---|---|---|
| | Elec. trade | Coord. trans. expansion | Pooled generation capacity |
| No trade | | | |
| Trade only | ✓ | | |
| Expanded transmission | ✓ | ✓ | |
| Pooled capacity | ✓ | | ✓ |
| Deep integration | ✓ | ✓ | ✓ |

cities in each jurisdiction, assuming the unitary costs of a 500kV HVDC 3,000 MW bipole transmission line (National Renewable Energy Laboratory, 2017a). We include a transmission loss (5.8% of power exchanges, based on Hydro-Québec (2017)). We compute the annualized cost of investments based on the social planner's perspective, assuming an annual discount rate of 6%, and a depreciation period equal to the lifespan of the asset.

### 3.4 Integration modes and decarbonization scenarios

We analyze five regional integration modes based on combinations of three cooperative actions: *i*) cross-border electricity trade, *ii*) coordinated transmission capacity expansion, and *iii*) pooled generation capacity for meeting peak load (see Table 3). We define the integration modes as follows:

- No Trade. Electricity systems operate in autarky, and thus integration is nonexistent and interconnection capacity is not used. By contrast with high integration modes, the outcomes from this No Trade mode allow to illustrate the value of existing interconnections and electricity trade.
- Trade Only. Jurisdictions trade electricity to maximize the benefits for the whole region. However, transmission capacity remains fixed at its current level, and generation capacity for peak load requirements is held individually by each jurisdiction.
- Expanded Transmission. In addition to electricity trade, jurisdictions coordinate optimal transmission capacity expansion.
- Pooled Capacity. Neighbouring jurisdictions trade electricity and pool capacity to meet peak load, but transmission capacity remains constant.
- Deep integration. Jurisdictions deploy all the three cooperative actions: electricity trade, expanded transmission capacity and pooled generation capacity.

In Section 4 each of these integration modes is analyzed under different scenarios, illustrating relevant policy contexts and constraints. These scenarios allow us to assess the sensitivity of the results to four key aspects: 1. Decarbonization level, 2. Availability of nuclear power, 3. Availability of carbon-neutral natural gas and 4. Load level.

1. Decarbonization level. Despite the existing decarbonization goals in the region (Under2 Coalition, 2019), the actual decarbonization level achieved by 2050 (or any other year) may vary due to multiple factors. For example, whereas scientific findings point towards stricter decarbonization goals, actual emission reductions will be determined by political will, technological evolution, market dynamics and social acceptability of decarbonization policies. To reflect such a variety of goals and better illustrate the shape of the decarbonization cost curve, we run scenarios with emissions reduction ranging from 50% to 99% with respect to 1990 emission levels.[4]
2. Nuclear power. We consider scenarios with and without nuclear power, as public support for this technology can shift in response its perceived risks and benefits (De Groot et al., 2013, Perlaviciute and Steg, 2014).

[4]Emissions reduction of 50%, 70%, 80%, 90%, 95% and 99%.

3. Carbon-neutral natural gas ($CO_2$-free NG). To represent the possible availability of carbon-neutral natural gas power plants (using for instance renewable natural gas or carbon capture and storage), we include scenarios with access to a more expensive carbon-neutral natural gas option.[5]
4. Load level. Electricity sector decarbonization along with energy efficiency and electrification of energy-intensive activities, such as transportation and residential heating, are generally accepted strategies for achieving a low-carbon economy. However, the future load level resulting from such strategies is still hard to predict as their implementation effectiveness is uncertain, and also because of the opposing effect of widespread electrification and energy efficiency with respect to net electricity load. Therefore, to analyze different future electricity demands, we look at three load levels: 100%, 125% and 150% with respect to the 2018 load in the region.

# 4 Results and discussion

Unless otherwise stated, results are presented for our "baseline scenario", which is a 90% decarbonization level with nuclear power limited to its existing installed capacity, no access to carbon-neutral natural gas and no load growth.

## 4.1 Costs under decarbonization targets

Our main result is that higher levels of integration lower decarbonization costs. This effect is amplified with deeper decarbonization levels. Not allowing trade, the least integrated mode, results in exponentially larger costs as the emissions limit gets tighter, see Figure 3. The value of trade becomes increasingly visible, as the emissions limit tightens, through the difference between the No Trade and the Trade Only modes. However, at high decarbonization levels (beyond 90%), expanding interconnection capacity is also necessary to achieve the largest cost savings: 99% decarbonization would only cost slightly more than $10 billion per year (in additional costs) for the whole region under Expanded Transmission or Deep Integration, as Figure 3 shows. Without the ability to add transmission lines, the cost would jump to more than $20 billion. Not allowing trade (reverting to autonomous sub-regions) would lead to a total yearly regional cost beyond $35 billion (No Trade mode in Figure 3).

Pooling capacity does not lead to important cost savings, only marginal ones. This is why the Pooled Capacity and Deep Integration modes are closely following the Trade Only and Expanded Transmission modes in Figure 3.

## 4.2 Cost effect of load level, nuclear power and carbon-neutral natural gas

Detailed cost results for all cases considered in our study are presented in Table 4 and Figure 4. They display the incremental annualized regional investment and operation costs for a 90% decarbonization level. In addition to the value of integration, Table 4 and Figure 4 reveal the significant impact of a nuclear ban, of the availability of carbon-neutral natural gas ($CO_2$-free NG) and of load increases.

Excluding the existing 24,000 MW of nuclear capacity leads to major increases in decarbonization costs. A large share of this cost is the direct replacement value of the installed capacity, but the system value of nuclear also appears in these cost increases. In a No Trade mode (with 100% load and no $CO_2$-free NG), nuclear power has a yearly value of $27.6 billion, which progressively decreases to $15.43 billion under Deep Integration. The system value of nuclear power is effectively replaced by higher levels of coordination in transmission and generation capacity.

Carbon-neutral natural gas ($CO_2$-free NG) is only valuable in high load growth scenarios and low integration modes. It has no value, for instance, in the 100% load and limited nuclear scenarios, except in the No Trade mode. Again, this shows the value of integration: $CO_2$-free NG is less needed if regional integration is more advanced. Interestingly, the availability of $CO_2$-free NG can, in some higher load growth cases, make the Pooled Capacity mode slightly more valuable than the Expanded Transmission mode. In the 125% and

[5]The cost of this option is simply assumed to be five times greater than natural gas.

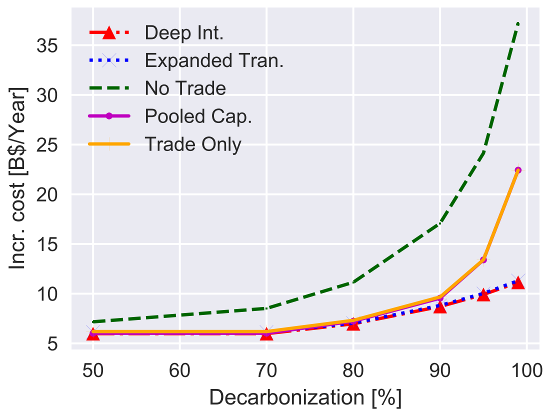



**Figure 3: Annualized cost of operation and incremental investments.**

**Table 4: Results for all integration modes in the baseline scenario (90% decarbonization w.r.t. 1990 emission levels).**

| | | | Incremental cost of strategies [US$ Billions] | | | | |
|---|---|---|---|---|---|---|---|
| Load | Nuclear | $CO_2$-free NG | No Trade | Trade Only | Pool. Cap. | Exp. Trans. | Deep Int. |
| 100% | Lim. | No | 17.1 | 9.7 | 9.5 | 8.8 | 8.71 |
| | | Yes | 15.1 | 9.7 | 9.5 | 8.8 | 8.7 |
| | No | No | 44.7 | 30.7 | 30.4 | 24.7 | 24.1 |
| | | Yes | 31.4 | 26.3 | 26.0 | 24.6 | 24.1 |
| 125% | Lim. | No | 33.9 | 24.5 | 24.2 | 21.90 | 21.54 |
| | | Yes | 26.0 | 23.1 | 22.8 | 21.9 | 21.5 |
| | No | No | 68.7 | 53.2 | 52.8 | 44.1 | 42.6 |
| | | Yes | 45.4 | 42.7 | 41.9 | 42.0 | 40.7 |
| 150% | Lim. | No | 58.1 | 46.3 | 45.9 | 40.93 | 39.61 |
| | | Yes | 41.6 | 39.7 | 38.9 | 39.1 | 38.0 |
| | No | No | 98.7 | 80.4 | 79.9 | 65.4 | 63.2 |
| | | Yes | 62.2 | 60.8 | 59.8 | 60.2 | 59.0 |

150% load scenarios, with CO2-free NG and no nuclear, Pooled Capacity (with costs at \$41.9 and \$59.8 billion, respectively) is slightly less expensive than Expanded Transmission (\$42.0 and \$60.2 billion). This is explained by the possibility to use available natural gas power plants from other jurisdictions, without emissions, instead of investing in new, local, generation capacity and/or transmission.

Load increase is often considered unavoidable in decarbonization scenarios of the entire society (e.g. Williams et al. (2015), with a 50% electricity load increase). In this paper we focus on the decarbonization of the power system rather than the whole ecomony, and we use the 2018 hourly load level as our baseline case. We nevertheless include load growth scenarios corresponding to 125% and 150% of the 2018 level. In such circumstances, total cost would increase more under low integration levels. This shows that integration not only lowers the cost of power system decarbonization, but it also reduces the cost of electrification. For instance, a 25% load increase would add \$16.9 billion per year in the case of No Trade, limited nuclear and no carbon-neutral natural gas (and 90% decarbonization), but only \$12.8 billion under Deep Integration. One should also note that while load is only increasing by 25%, total incremental cost doubles. This comes from the fact that all new load is supplied and balanced with new investments, whereas in the no load-increase scenarios, existing capacity plays an important role. This finding on the greater cost impact of increasing load under low integration modes is always true, except in some specific cases. When carbon-neutral natural gas is available, the No Trade mode is the one with the lowest additional costs when load increases (only \$10.9 billion in No Trade compared to \$12.8 in Deep Integration, with 25% load growth and limited nuclear). This is explained by the required overbuilt of capacity in the No Trade mode, which lowers the pressure for new investments when load grows. Despite these lower additional costs when load increases, the No Trade mode remains much more costly than other integration modes (see Table 4 and Figure 4).

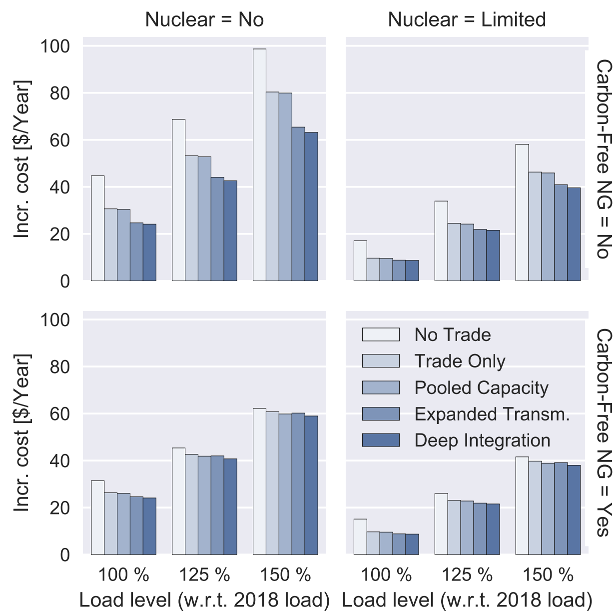



**Figure 4: Annualized operational costs and incremental investment cost under 90% emission reduction w.r.t. 1990.**

## 4.3 Generation capacity and interconnection investments

The lower costs presented in the previous subsection are largely explained by the reduced investment needs in generation capacity. Figure 6.a clearly illustrates the reduced new capacity required under higher integration modes: from more than 80 GW of incremental generating capacity in the No Trade mode, it is halved to about 40 GW if trade is allowed, and further reduced to less than 30 GW if additional transmission can be built between regions. In this latter integration mode, transmission avoids the need to install significant solar capacity, which otherwise represents close to 50% of the new capacity.

Total installed capacity is shown in Figure 6.b, illustrating the importance of the existing hydro, nuclear and natural gas capacity.

Increased integration reduces total cost by avoiding investment in new generation capacity, even if it requires additional transmission capacity. Figure 5 illustrates the growing need for interconnections between jurisdictions: from an additional 2.5 GW in low decarbonization scenarios (50 to 70%), up to about 23 GW of new transmission lines would be required if optimal transmission investments were possible. Interconnections with Quebec grow by very large amounts in the 99% decarbonization scenario: more than 10 GW of additional transmission lines to New York, New England and Ontario would be needed, mostly to allow balancing the large quantities of intermittent renewables (mostly wind in these cases). The left and right panels of Figure 5 illustrate the changing pattern of investments caused by pooling capacity. If some interconnections appear useful in all cases (2 GW between New York and Ontario), Deep Integration justifies more interconnection between Quebec and Ontario and less between New York and New England than in the Expanded Transmission mode.

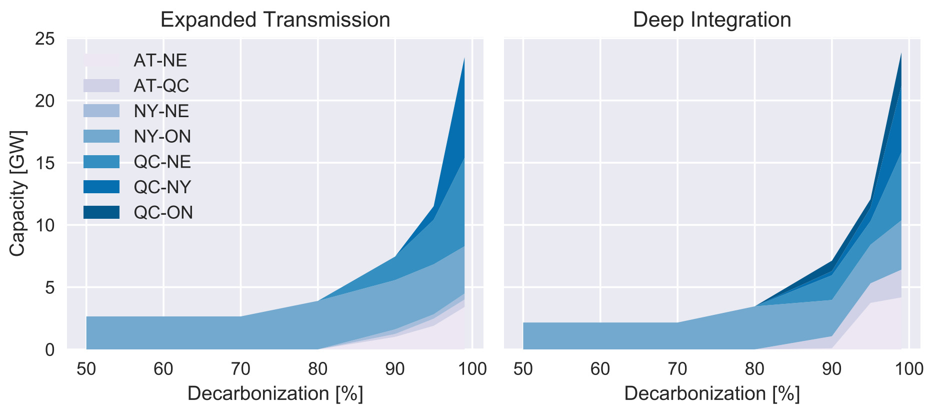
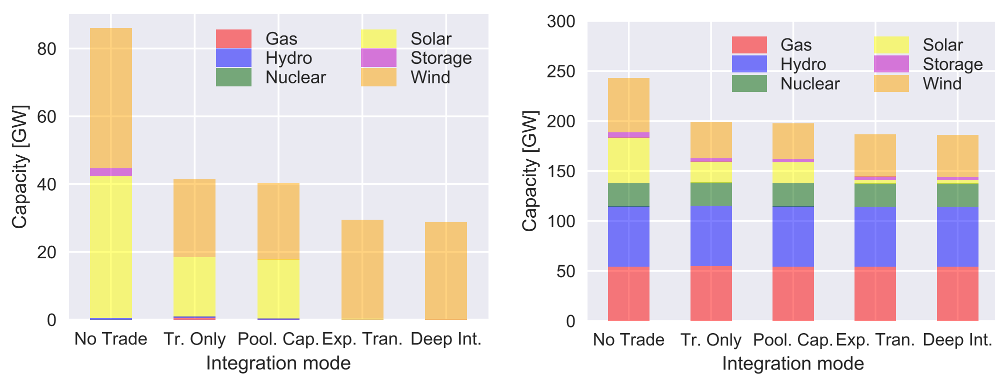



**Figure 5: Transmission expansion under different integration modes and decarbonization levels.**




(a) Incremental capacity (b) Total capacity

**Figure 6: Generation and storage capacity under 90% decarbonization.**

## 4.4 Regional impacts of integration

Although integration could yield savings for the whole region, the costs and benefits of such cooperation could be asymmetric among jurisdictions due to the differentiated sub-regional generation capacity. To analyze such effect, we look at the wholesale price and total cost impact of the five strategies on each jurisdiction.

In the absence of redistribution mechanisms such as subsidies, the impact on wholesale prices is probably the most visible one for consumers, when regional integration progresses. Negative reactions to price increases can be devastating in policy changes, even if such policy increases the global welfare. Figure 7 illustrates the steady convergence of wholesale prices under high integration modes. High price regions (New York, New England, Atlantic) would get lower prices with more integration (and conversely would experience much higher prices under a No Trade mode). Quebec and Ontario, with their low production cost generation mix (based respectively on hydropower and nuclear, see Table 2) would, on the contrary, face much higher prices with regional integration. Table 5 provides more details on regional wholesale price impacts in our five integration modes, for the baseline scenario. Two key points come out of this Table. First, mean wholesale prices converge with increasing levels of integration, as already noted in Figure 7. Under Deep Integration the difference between the highest mean wholesale price jurisdiction (New England) and the lowest (Quebec) is only \$8.6/MWh, while this difference is \$57.9/MWh in the Trade Only mode and \$140.9/MWh in the No Trade mode. The second key point is the reduction in price variations within each jurisdiction: higher integration levels result in more stable hourly wholesale prices for each region. Looking at the range of prices


**Figure 7: Mean marginal (wholesale) electricity price under 90 % decarbonization.**

**Table 5: Marginal (wholesale) electricity prices under integration modes in each jurisdiction for the baseline scenario (90% decarbonization)**

| Mode | Statistic | Marginal price [$/MWh] | | | | |
|---|---|---|---|---|---|---|
| | | AT | NE | NY | ON | QC |
| | Max. | 700.0 | 380.3 | 339.8 | 243.8 | 2.5 |
| No Trade | Mean | 119.9 | 134.5 | 143.4 | 27.2 | 2.5 |
| | Min. | 4.8 | 0.0 | 0.0 | -11.0 | 2.5 |
| | Max. | 115.4 | 115.4 | 115.4 | 108.7 | 102.4 |
| Trade Only | Mean | 78.9 | 93.5 | 90.5 | 35.6 | 46.6 |
| | Min. | 5.9 | 5.9 | 5.9 | 2.5 | 2.6 |
| | Max. | 162.9 | 110.4 | 110.4 | 104.0 | 98.0 |
| Pooled Cap. | Mean | 78.6 | 91.4 | 88.8 | 36.2 | 56.0 |
| | Min. | 5.9 | 6.3 | 5.9 | 2.5 | 41.4 |
| | Max. | 75.3 | 75.3 | 79.9 | 75.3 | 70.9 |
| Expanded Transm. | Mean | 67.1 | 71.0 | 67.7 | 61.1 | 59.6 |
| | Min. | 5.9 | 5.9 | 5.9 | 5.6 | 5.9 |
| | Max. | 79.2 | 74.6 | 79.2 | 74.6 | 70.3 |
| Deep Integr. | Mean | 67.4 | 72.1 | 70.3 | 63.5 | 65.7 |
| | Min. | 5.9 | 5.9 | 5.9 | 5.6 | 6.3 |

under each integration mode (difference between the maximum and minimum prices), we can observe that it falls from \$334.0/MWh in the No Trade mode to \$106.9/MWh in Trade Only and to only \$69.6/MWh in Deep Integration. If price stability (i.e. lower volatility) is valued by consumers, then further regional integration should also be valued.

While wholesale price levels are highly visible, minimizing the overall cost should be the guiding economic principle for decarbonization. However, it matters for regional coordination to understand how costs are allocated. Figure 8 shows the regionally disaggregated cost from Figure 3 for three modes (No Trade, Trade Only and Expanded Transmission). While the decarbonization cost reduction is clearly visible as the integration level progresses, especially for deep decarbonization, the cost burden is not evenly shared between regions. For instance, when transmission investments are allowed (under Expanded Transmission or Deep Integration), Quebec experiences higher costs on its territory than in other scenarios beyond 90% decarbonization. New England and New York, conversely, experience much lower costs in these cases. Indeed, Ontario and, to a much greater extent, Quebec would benefit more under the Trade Only mode (Figure 9) than in Expanded Transmission, because in the latter case they significantly invest to lower the regional decarbonization cost, but export price goes down, their profitability decreases and they are not remunerated for the system value (i.e. balancing of intermittent generation) of their investment. Jurisdictions with higher decarbonization costs (New York and New England) will need to recognize their significant cost reduction under Expanded Transmission (in comparison to Trade Only) to incentivize Quebec to move towards greater integration. If proper cost and revenue allocation mechanisms are not well established, individual jurisdictions may not have the adequate incentives to cooperate.

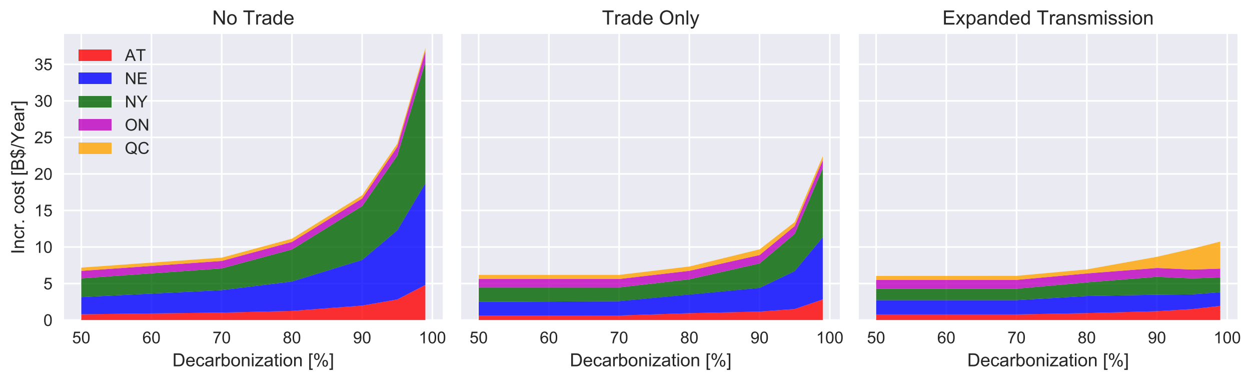



**Figure 8: Annualized cost of operation and incremental investments by jurisdiction and decarbonization level.**

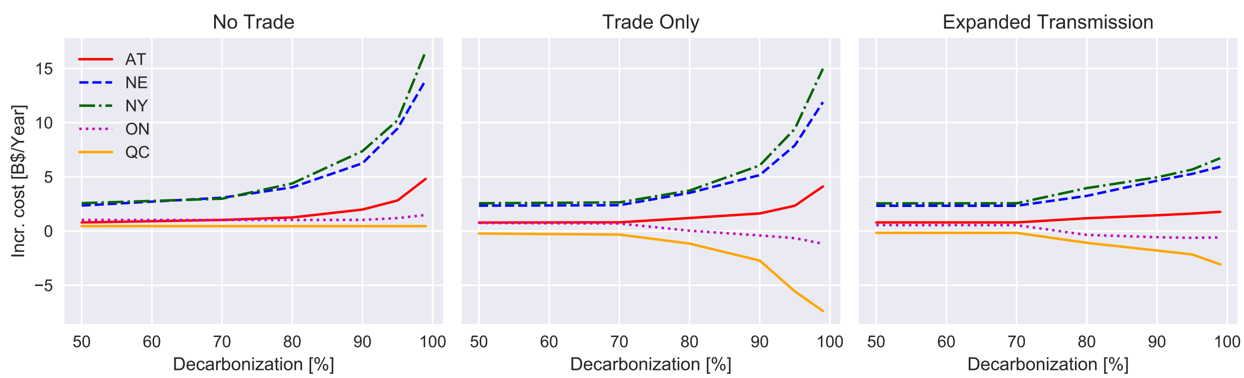



**Figure 9: Net annualized cost of operation and incremental investments - considering electricity trade balance.**

While trade patterns are do not differ radically under our different scenarios (as the fundamental competitive advantages do not change), some interesting results can be discussed. Figure 10 shows the trade volumes and directions under Trade Only, Expanded Transmission and Deep Integration. More energy can be imported in New England and New York, from Ontario and Quebec, when transmission investments can be made (Expanded Transmission and Deep Integration). Under Deep Integration, Quebec imports more from Ontario and exports more to the Atlantic than in Expanded Transmission, thus playing a more significant balancing role in the region. These trade patterns reflect the transmission capacity expansions shown in Figure 5.

## 4.5 Marginal price of carbon

Another visible indicator of concern for policy makers and consumers is the marginal carbon cost. High marginal carbon costs can discourage climate action, by giving the impression that such action is too costly. Figure 11 illustrates how the marginal carbon price can be drastically reduced in the power sector with a high integration level. At deep decarbonization levels (95% and beyond), not allowing transmission investment makes the marginal carbon price jump to $1,000 and more, while such cost falls well below $500 per ton in the Expanded Transmission and Deep Integration modes.

## 4.6 Annual energy profile

Figures 12 and 13 show the annual energy generation, imports and exports by jurisdiction, and the aggregated regional daily generation by source. It clearly indicates the wider penetration of wind generation in Ontario and Quebec in the Trade Only and Expanded Transmission modes, compared to the No Trade mode. Solar power is also made less useful under higher integration levels, as the various wind profiles better complement each other than solar generation, and as transmission capacity allows this complementarity to be effective.

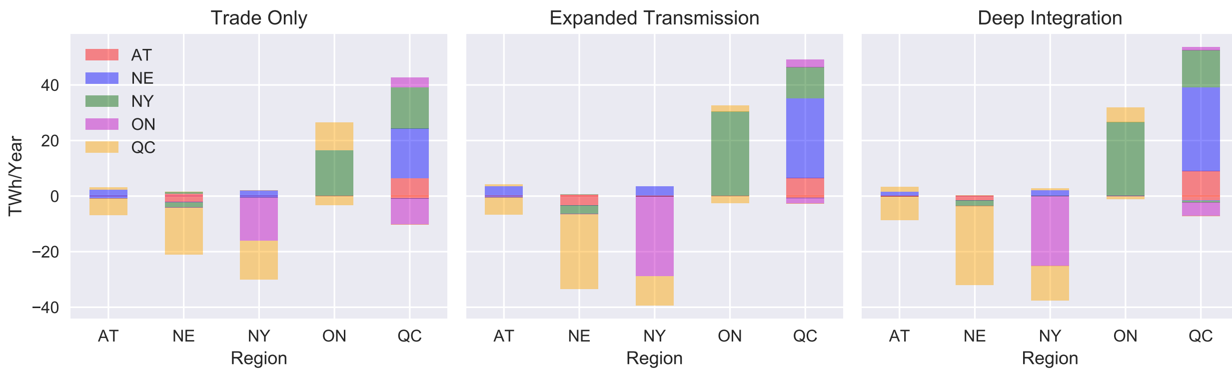



**Figure 10: Annual electricity trade under deep integration with 90% decarbonization.**

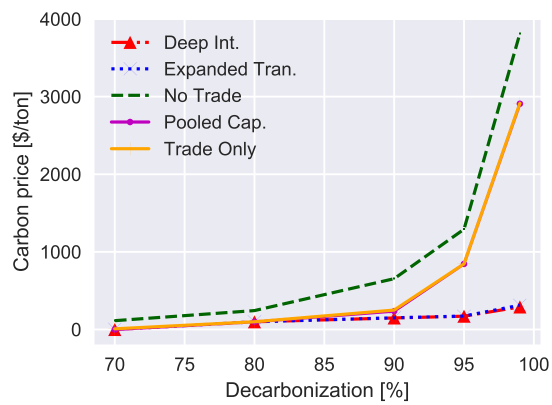



**Figure 11: Marginal carbon price under different decarbonization levels.**

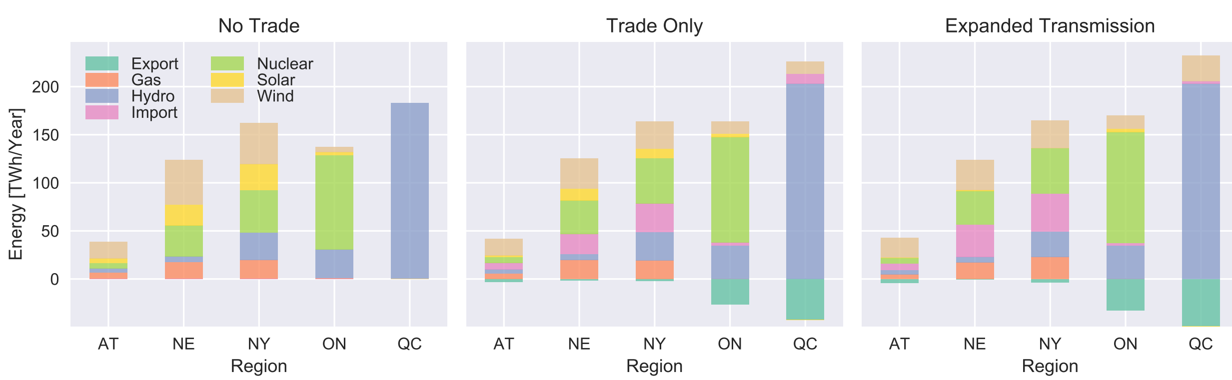



**Figure 12: Annual energy balance trade under deep integration with a 90% decarbonization.**

## 4.7 Hydropower and electricity trade for load balancing

As shown in the previous results, regional integration allows for significant gains. Some of these gains are directly related to the large hydropower and water storage capacity in Quebec. Various statistics illustrate the enhanced role of hydropower as regional integration strengthens.

- Energy storage. Hydropower provides generation flexibility and load following capacity, thus avoiding the need for dedicated energy storage. The correlation of hydro generation with global load and with wind generation shows that such flexibility is better used in more integrated scenarios. Table 6 illustrates the reduced correlation (from 0.8 to 0.75) of hydropower generation with regional load when there is no

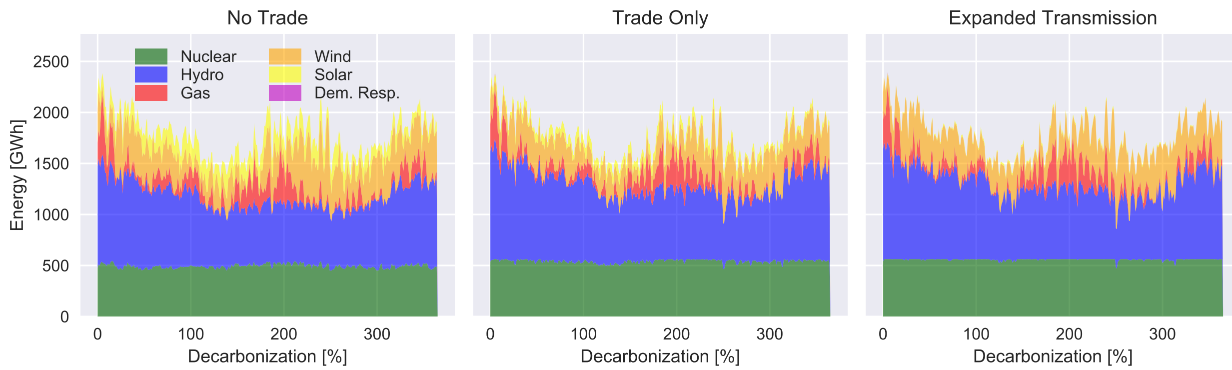



**Figure 13: Sources of daily generation under No Trade, Trade Only and Expanded Transmission modes (in baseline scenario).**

**Table 6: Hydropower impacts on wind production and curtailment.**

| Mode | Correlation | | Wind Power | |
|---|---|---|---|---|
| | Total Load-Hydro | Wind-Hydro | Generation (TWh) | Curtailment (%) |
| No trade | 0.75 | 0.16 | 112.1 | 29.8% |
| Trade Only | 0.80 | -0.06 | 102.7 | 1.8% |
| Expanded Trans. | 0.79 | -0.27 | 120.8 | 0.2% |
| Pooled Capacity | 0.80 | -0.09 | 102.1 | 1.5% |
| Deep integration | 0.80 | -0.28 | 120.1 | 0.1% |

trade and the increasingly negative correlation of hydro and wind, as integration increases (from 0.16 to -0.28), illustrating the growing complementarity of the two and the balancing role of hydropower.

- Wind energy optimization. By being able to ramp up and down, hydro production allows more wind generation to be used, and reduces the proportion of curtailment of wind power. While more wind generation is cost effective when investment in transmission is allowed (Table 6), the percentage of curtailed wind steadily declines with increased integration: from close to 30% in the No Trade mode, trade drastically reduces it to 1.8% (in Trade Only). Then, additional layers of integration bring it down to 0.1% in Deep Integration, when capacity is regionally optimized and therefore every unit of available energy is used.
- While hydropower is called upon more frequently, its ramp up and down capacity is more solicited under increased integration. Table 7 provides the lower and upper bounds of the hourly ramp values generated in our model. We observe that although integration leads to a wider ramp interval, minimum and maximum hourly ramps are realistic and remain below 14% of Quebec's hydro capacity, a cited limit for hydro ramps (see Dimanchev et al. (2020)).

Integration levels result in a different use of hydropower, which affects the stored water level in reservoirs. Figure 14 shows how the water level rapidly decreases during cold months (approximately first 110 days, and last 50 days of the year) as a consequence of high demand for electrical heating in Quebec. During spring, reservoirs quickly refill due to snow-melt, and then they continue refilling more slowly until late autumn. However, under high integration, additional hydropower is used during the air conditioning season (June to October, about day 200 to 300), so reservoirs are more empty.

## 4.8 Discussion

Our analysis illustrates the important economic gains brought by regional integration in a deep decarbonization context. It underscores the exponentially higher costs of decarbonization without additional transmission lines and pooled capacity, especially if no nuclear capacity is allowed and if load grows significantly.

Sharing the cost and benefits of regional integration remains a challenge that we clearly illustrate, but do not resolve. As investment and operational decisions have asymmetric consequences in different jurisdictions

**Table 7: Hydropower ramp in Quebec, corresponding to the 1 and 99 percentile of the hourly ramp distribution.**

| Mode | Hourly ramp [GW] | |
|---|---|---|
| | Max. (1st percentile) | Min. (99th percentile) |
| No trade | -1.47 | 2.15 |
| Trade Only | -3.11 | 3.61 |
| Pooled Capacity | -3.15 | 3.70 |
| Expanded Transmission | -4.51 | 4.73 |
| Deep integration | -4.13 | 4.93 |

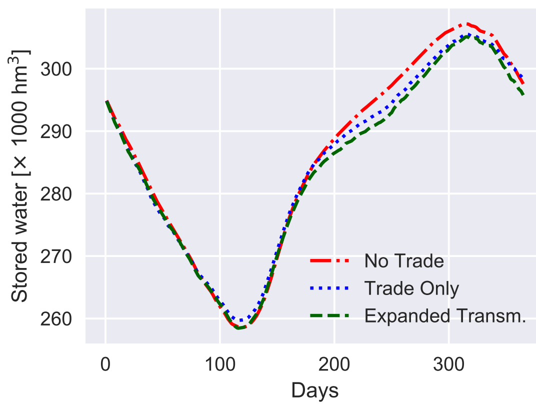



**Figure 14: Stored water volume under different integration modes.**

(in terms of price change, investment burden and net cost), consumers and generators will be better or worse off in ways that will trigger them to oppose integration, despite the clear collective gains. Agreeing on ways to allocate costs and benefits will be key if regional integration is successful. Further research in this area is certainly needed.

Our results also show that hydropower is a clear enabler of decarbonization in the Northeastern context. However, further research would be necessary to estimate the system value of hydropower for supporting the expansion of renewable energies in the region.

Certainly, our model of the North American Northeast electricity sector relies on several simplifying assumptions which must be considered when interpreting all the previous results:

- Perfect competition/perfect coordination. These assumptions are implied by the optimal solution to the capacity expansion and dispatch model, which yields the lowest cost for the whole region. Therefore, our results constitute a upper bound on the actual benefits under market imperfection and suboptimal decisions.
- Perfect foresight. Our model is deterministic, and thus our results are based on the assumption of perfect foresight. This assumption, although not achievable in reality, is still useful to estimate an upper bound on the actual benefits of cooperation under uncertainty.
- Approximate power system operation. Considering that this work is policy-oriented, our model excludes operational details such as ramping constraints, unit commitment, maintenance of generators, and nonlinear interdependences. Regarding power flow, the model represents only electricity trade between the jurisdictions of the North American Northeast. We do not model sub-regional transmission systems and possible congestion at that level. Therefore, our results are optimistic with respect to electricity trade and dispatch efficiency in each jurisdiction.
- Approximate capacity expansion decisions. To reduce the model complexity we represent aggregate system components instead of detailed elements, such as site-specific data, scheduled capacity retirements and multi-year decisions. Thus, our solutions should be interpreted as approximate rather than exact.

- Availability of existing capacity. Our model identifies necessary capacity investments beyond current capacity (as presented in Table 2), excluding fossil fuel power plants. Because of the fixed initial capacity, potential gains from retiring inefficient power plants are not considered.
- Reserve capacity is not considered, because it would not change the nature of our findings. By not adding requirements for reserve capacity (usually about 15% above peak load), we underestimate total costs and gains from integration.

# 5 Conclusions and policy implications

Many jurisdictions in the world gave themselves ambitious decarbonization targets. Their electricity sector is bound to play a major role, first by being decarbonized itself, and then by allowing electrification of many energy consumption sectors. Collaboration between jurisdictions has the potential to reduce significantly the cost of decarbonization. This paper is the first one to explore in detail the gains from regional electricity sector integration in Northeastern North America, under various levels of integration. We propose a capacity expansion model with hourly operations for the region, and we solve it under various levels of integration and carbon constraints (50% to 99% emissions reduction). We pay a particular attention to hydropower, where large reservoirs in Quebec allow significant energy storage and load-following flexibility. We consider three dimensions of integration: cross-border electricity trade, optimal transmission capacity expansion and pooled capacity for peak load requirements. We are able to document the key benefits provided by the large quantity of hydropower available in the region.

We find that higher integration levels reduce decarbonization costs and that these gains are exponentially higher under deep decabonization targets (above 90%). Additional transmission lines, interconnecting jurisdictions, can save billion of dollars, by allowing more wind to be installed and optimally used. These gains are even more significant if no nuclear capacity is allowed and if load grows significantly - as expected in many deep decarbonization studies. We show how hydropower is instrumental in realizing these gains, by following load and balancing wind power variability.

Our findings also show that price level changes and investment cost sharing are non-trivial issues. Initially low-cost jurisdictions see their whole price go up with integration, which in the absence of subsidies could generate opposition from consumers despite collective gains. In addition, the higher capacity investments and price convergence observed with integration lead to some economic disincentives for some regions despite, again, collective gains. For instance, while New York and New England experience much lower net costs under deep decarbonization, with more transmission lines with Quebec and Ontario, these two Canadian provinces have lower benefits in this integration mode, compared to a status quo in transmission capacity. Unless some allocation mechanisms are deployed to properly incentivize regional collaboration, strong local interests may simply block cheaper integration modes and decarbonization initiatives.

This paper contributes to the understanding of the key benefits of regional electricity sector integration, which are particularly strong when deep decarbonziation is considered. Our focus on Northeastern North America illustrates the key enabling role that hydropower can play in easing a large wind penetration. More research is however needed to understand and price adequately the system value of hydropower.

# 6 Acknowledgements

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# Appendix A Linear programming model for electricity sector decarbonization in the North American Northeast

## Notation

| **Indices and sets** | |
|---|---|
| $t \in \mathcal{T}$ | Planning time periods |
| $r \in \mathcal{R}$ | Regions |
| $(r, \bar{r}) \in \mathcal{L}$ | Existing or new transmission lines between regions $r$ and $\bar{r}$ |
| $s \in \mathcal{S}(r)$ | Electrical energy storage systems in region $r$ |
| $g \in \mathcal{G}(r)$ | Power plants in region $r$ |
| $d \in \mathcal{D}(r)$ | Demand response levels in region $r$ |
| **Subsets of $\mathcal{G}(r)$** | |
| $g \in \mathcal{G}^P(r)$ | Natural gas power plants in region $r$ |
| $g \in \mathcal{G}^H(r)$ | Hydropower plants in region $r$ |
| $g \in \mathcal{G}^N(r)$ | Nuclear plants in region $r$ |
| $g \in \mathcal{G}^R(r)$ | Renewable (wind and solar) power plants in region $r$ |
| $\mathcal{K}(r, g)$ | Power plants of technology $g$ in region $r$ |
| $\mathcal{J}(r, k)$ | Hydropower plant upstream of power plant $k$ in region $r$ |

| **Parameters** | |
|---|---|
| $C$ | Carbon emissions limit [Tons/year] |
| $CE_{rk}$ | Unitary carbon emissions of gas power plant $k$ in region $r$ [Ton/MWh] |
| $\overline{CAP}^G_{rgk}$ | Maximum capacity expansion of power plant $k$ of technology $g$ in region $r$ [MW] |
| $\overline{CAP}^T_{r\bar{r}}$ | Maximum capacity expansion of transmission line $(r, \bar{r}) \in \mathcal{L}$ [MW] |
| $CAP^G_{rgk}$ | Initial generation capacity of power plant $k$ of technology $g$ in region $r$ [MW] |
| $CAP^T_{r\bar{r}}$ | Initial capacity of transmission line $(r, \bar{r})$ [MW] |
| $CAP^S_{rs}$ | Initial capacity of energy storage $s$ in region in region $r$ [MW] |
| $CF$ | Conversion factor for stored water, from $m^3$/s to $hm^3$/day [$\cdot$s$\cdot$hm$^3$ $\cdot$/(day$\cdot$m$^3$)] |
| $DR_{rd}$ | Demand response limit in block $d$ of region $r$ [MWh] |
| $DUR$ | Duration of cyclic energy storage (24 hours by default) |
| $EF_{rs}$ | Efficiency of energy storage in region $r$ during a charge cycle |
| $FC^G_{rgk}$ | Annualized fixed and investment cost of incremental capacity of power plant $k$ of technology $g$ and region $r$ [\$/(year$\cdot$MW)] |
| $FC^S_{rs}$ | Annualized fixed and investment cost of incremental capacity in energy storage $s$ in region $r$ [\$/(year$\cdot$MW)] |
| $FC^T_{r\bar{r}}$ | Annualized fixed and invest cost of incremental capacity in transmission line $(r, \bar{r})$ [\$/(year$\cdot$MW)] |
| $GR_{rgk}$ | Generation profile factor of renewable power plant $k$ of technology $g$ in region $r$ [%] |
| $INF_{rkt}$ | Lateral inflows to hydropower plant $k$ of region $r$ at period $t$ [m$^3$/s] |
| $LOAD_{rt}$ | Electricity load in region $r$ at time $t$ [MW] |
| $LOSS_{r\bar{r}}$ | Fraction of power loss in transmission line $(r, \bar{r})$ [MW/MW] |
| $GN_{rgk}$ | Minimum generation factor of nuclear power plant $k$ in region $r$ [MW/MW] |
| $LS_r$ | Maximum load shedding in region $r$ |
| $PF_{rk}$ | Average productivity factor of hydropower plant $k$ in region $r$ [MW/(m$^3$/s)] |
| $VC^D_{rd}$ | Unitary cost of demand response in segment $d$ and region $r$ [\$/MW] |
| $VC^G_{rgk}$ | Unitary cost of power plant $k$ of technology $g$ in region $r$ [\$/MWh] |
| $VC^{GC}_{rk}$ | Incremental cost of carbon-neutral generation in natural gas plant $k$ in region $r$ [\$/MWh] |
| $VC^L_r$ | Variable cost of load shedding in region $r$ [\$/MWh] |
| $VC^S_{rs}$ | Variable cost of energy storage $s$ in region $r$ [\$/MW] |
| $\underline{WS}_{rk}, \overline{WS}_{rk}$ | Bounds on stored water in reservoir of power plant $k$ [hm$^3$] |
| $WS_{rk0}, WS_{rT}$ | Initial and final stored water in reservoir of power plant $k$ in region $r$ [hm$^3$] |

| **Decision variables** | |
|---|---|
| $cap^G_{rgk}$ | Capacity expansion of generation technology $g$ in region $r$ at site/level $k$ [MW] |
| $cap^T_{r\bar{r}}$ | Capacity expansion of transmission line $(r, \bar{r})$ [MW] |
| $cap^S_{rs}$ | Capacity expansion of energy storage $s$ in region $r$ [MW] |
| $chr_{rst}$ | Charging rate of energy storage $s$ in region $r$ at period $t$ [MW] |
| $dis_{rst}$ | Discharging rate of energy storage $s$ in region $r$ at period $t$ [MW] |
| $dr_{rdt}$ | Demand response in segment $d$, at period $t$ in region $r$ [MW] |
| $gen_{rgkt}$ | Generation of power plant $k$ of technology $g$ during time period $t$ in region $r$ [MWh/hour] |
| $gen^c_{rkt}$ | Carbon-neutral generation in natural gas plant $k$ during time period $t$ in region $r$ [MWh/hour] |
| $gen^p_{rkt}$ | Regular generation in natural gas plant $k$ during time period $t$ in region $r$ [MWh/hour] |
| $ls_{rt}$ | Load shedding in region $r$ at period $t$ [MWh] |
| $nc_{rkt}$ | Nuclear power curtailment in region $r$ at period $t$ and site $k$ [MWh] |
| $ptr_{r\bar{r}t}$ | Power transmission from region $r$ to region $\bar{r}$ at period $t$ [MW] |
| $wd_{rkt}$ | Water discharge in hydropower plant $k$ at time period $t$ in region $r$ [m$^3$/s] |
| $wo_{rkt}$ | Out-of-the-system water spill in hydropower plant $k$ at time period $t$ in region $r$ [m$^3$/s]. This variable represents the amount of spilled water that will not be used in downstream power plants |
| $ws_{rkt}$ | Stored water in reservoir of hydropower plant $k$ at the end of period $t$ in region $r$ [hm$^3$] |
| $ww_{rkt}$ | Water spill in hydropower plant $k$ at time period $t$ in region $r$ [m$^3$/s] |

## Objective function

We minimize the total annualized cost of investment and operation $TC$, including the costs of demand response, load shedding and nuclear curtailment:

$$
\begin{aligned}
TC = & \sum_{\substack{r \in \mathcal{R},\, g \in \mathcal{G}(r), \\ k \in \mathcal{K}(r,g)}} FC^G_{rgk} \cdot cap^G_{rgk} && \text{(fixed cost of generation)} \\
& + \sum_{\substack{r \in \mathcal{R}, \\ s \in \mathcal{S}(r)}} FC^S_{rs} \cdot cap^S_{rs} && \text{(fixed cost of energy storage)} \\
& + \sum_{(r,\bar{r}) \in \mathcal{L}} FC^T_{r\bar{r}} \cdot cap^T_{r\bar{r}} && \text{(fixed cost of transmission)} \\
& + \sum_{\substack{r \in \mathcal{R},\, g \in \mathcal{G}(r), \\ k \in \mathcal{K}(r,g),\, t \in \mathcal{T}}} VC^G_{rgk} \cdot gen_{rgkt} && \text{(unitary costs of power generation)} \\
& + \sum_{\substack{r \in \mathcal{R},\, t \in \mathcal{T}, \\ k \in \{\mathcal{K}(r,g) | g \in \mathcal{G}^P(r)\}}} VC^{GC}_{rk} \cdot gen^c_{rkt} && \text{(carbon-neutral gas incremental cost)} \\
& + \sum_{\substack{r \in \mathcal{R},\, s \in \mathcal{S}(r), \\ t \in \mathcal{T}}} VC^S_{rs} \cdot chr_{rst} && \text{(unitary costs of energy storage)} \\
& + \sum_{\substack{r \in \mathcal{R},\, d \in \mathcal{D}(r), \\ t \in \mathcal{T}}} VC^D_{rd} \cdot dr_{rdt} && \text{(demand response cost)} \\
& + \sum_{r \in \mathcal{R},\, t \in \mathcal{T}} VC^L_r \cdot ls_{rt} && \text{(load shedding cost)} \\
& + \sum_{\substack{r \in \mathcal{R},\, k \in \{\mathcal{K}(r,g) \,|\, g \in \mathcal{G}^N(r)\}, \\ t \in \mathcal{T}}} NC_{rk} \cdot nc_{rkt} && \text{(nuclear curtailment cost)}
\end{aligned}
$$

## Constraints

*Carbon emissions.* Aggregated emissions of natural gas plants $\mathcal{G}^P(r)$ should not exceed the emission target $C$ for the whole region:

$$
\sum_{\substack{r \in \mathcal{R},\, t, \in \mathcal{T}, \\ k \in \{\mathcal{K}(r,g) \,|\, g \in \mathcal{G}^P(r)\}}} CE_{rk} \cdot gen^p_{rkt} \leq C. \tag{1}
$$

*Power balance.* In each region and time period the total load is equal to the sum of power generation, net energy storage discharge, net electricity trade, load shedding and demand response:

$$\begin{aligned} &\sum_{\substack{g\in\mathcal{G}(r),\\ k\in\mathcal{K}(r,g)}} gen_{rgkt} + \sum_{s\in\mathcal{S}(r)} \big(dis_{rst} - chr_{rst}\big) \\ &+ \sum_{\bar r\in\{\mathcal{R}\,|\,(\bar r,r)\in\mathcal{L}\}} ptr_{\bar r rt}(1-LOSS_{\bar r r}) - \sum_{\bar r\in\{\mathcal{R}\,|\,(r,\bar r)\in\mathcal{L}\}} ptr_{r\bar r t} \\ &+ \; ls_{rt} \; + \sum_{d\in\mathcal{D}(r)} dr_{rdt} = LOAD_{rt}, \quad \forall\,(r,t)\in\mathcal{R}\times\mathcal{T}. \end{aligned} \tag{2}$$

*Transmission capacity.* Power transmission between neighbouring regions should not exceed the interconnection capacity, which is equal to the initial transmission capacity $CAP^T_{r\bar r}$ plus the expanded transmission capacity $cap^T_{r\bar r}$:

$$0 \le ptr_{r\bar r t} \le CAP^T_{r\bar r} + cap^T_{r\bar r}\,, \quad \forall\,(r,\bar r)\in\mathcal{L},\; t\,\in\,\mathcal{T}. \tag{3}$$

*Load shedding.* At each time period and jurisdiction, load shedding is bounded by the shedding limit $LS_r$:

$$0 \le ls_{rt} \le LS_r, \quad \forall\,(r,t)\,\in\mathcal{R}\times\mathcal{T}. \tag{4}$$

*Demand response.* This variable represents the amount of electricity load reduced in response to high electricity prices. For each time period and region, we define demand response blocks $\mathcal{D}(r)$, with demand response limits $DR_{rd}$:

$$0 \le dr_{rdt} \le DR_{rd}, \quad \forall\,(r,d,t)\,\in\mathcal{R}\times\mathcal{D}(r)\times\mathcal{T}. \tag{5}$$

*Power generation.* For each region, power technology, site and time period, power generation should not exceed the generation capacity, equals to the initial generation capacity $CAP^G_{rgk}$ plus the expanded capacity $cap^G_{rgk}$:

$$\begin{gathered} 0 \le gen_{rgkt} \le CAP^G_{rgk} + cap^G_{rgk}, \\ \forall\;(r,g,k,t)\in\mathcal{R}\times\mathcal{G}(r)\times\mathcal{K}(r,g)\times\mathcal{T}. \end{gathered} \tag{6}$$

*Natural gas power.* Power generation from natural gas plants equals regular power production $gen^p_{rkt}$ plus carbon-neutral power production $gen^c_{rkt}$:

$$gen_{rgkt} = gen^p_{rkt} + gen^c_{rkt}, \quad \forall\;(r,g,k,t)\in\mathcal{R}\times\mathcal{G}^P(r)\times\mathcal{K}(r,g)\times\mathcal{T}. \tag{7}$$

*Limits on wind and solar power.* For intermittent renewables, power production is limited by the generation profile factor $GR_{rgk}$ and the installed capacity:

$$\begin{gathered} 0 \le gen_{rgkt} \le GR_{rgk}\big(CAP^G_{rgk0} + cap^G_{rgk}\big), \\ \forall\;(r,g,k,t)\in\mathcal{R}\times\mathcal{G}^R(r)\times\mathcal{K}(r,g)\times\mathcal{T}. \end{gathered} \tag{8}$$

*Minimum generation in nuclear power plants.* Due to the limited flexibility of nuclear power plants, we assume that at every time period a fraction $GN_{rgk}$ of the installed capacity must be in operation, and that nuclear generation is consumed $gen_{rgkt}$ for load fulfilment or curtailed $nc_{rkt}$ (when generation exceeds the load and trade requirements):

$$\begin{gathered} GN_{rgk}(CAP^G_{rgk} + cap^G_{rgk}) \le gen_{rgkt} + nc_{rkt}, \\ \forall\;(r,g,k,t)\in\mathcal{R}\times\mathcal{G}^N(r)\times\mathcal{K}(r,g)\times\mathcal{T}. \end{gathered} \tag{9}$$

*Non-negativity constraints.* Nuclear curtailment $nc_{rkt}$, as well as regular natural gas power $gen^p_{rkt}$ and carbon-neutral natural gas power $gen^c_{rkt}$ must be non-negative:

$$0 \le nc_{rkt}, \quad \forall\;(r,k,t)\in\{\mathcal{R}\times\mathcal{K}(r,g)\times\mathcal{T}\mid g\in\mathcal{G}^N(r)\}, \tag{10}$$

$$0 \le gen^c_{rkt}, \quad \forall\;(r,k,t)\in\mathcal{R}\times\{\mathcal{K}(r,g)\mid g\in\mathcal{G}^P(r)\}\times\mathcal{T}, \tag{11}$$

$$0 \le gen^p_{rkt}, \quad \forall\;(r,k,t)\in\mathcal{R}\times\{\mathcal{K}(r,g)\mid g\in\mathcal{G}^P(r)\}\times\mathcal{T}. \tag{12}$$

*Generation expansion limits.* Generation capacity additions $cap^G_{rgk}$ plus initial capacity $CAP^T_{r\bar r}$, must not exceed the capacity limit: $\overline{CAP}^G_{rgk}$:

$$0 \le cap^G_{rgk} + CAP^T_{r\bar r} \le \overline{CAP}^G_{rgk}, \quad \forall\;(r,g,k)\in\mathcal{R}\times\mathcal{G}(r)\times\mathcal{K}(r,g). \tag{13}$$

*Peak load capacity requirement.* We define capacity requirements according to the integration mode.

- In No Trade, Trade Only and Expanded Transmission modes, we define capacity requirements as the sufficient firm domestic capacity (nuclear or natural gas) to meet net peak load in each jurisdiction, i.e., load plus electricity exports minus the sum of wind and solar power generation, net energy storage discharges and demand response:

$$\begin{aligned}&\sum_{\substack{g\in\{\mathcal{G}^P(r)\,\cup\,\mathcal{G}^N(r)\},\\ k\in\mathcal{K}(r,g)}} \left(CAP^G_{rgk}+cap^G_{rgk}\right)\\ &+\sum_{\substack{g\in\{\mathcal{G}^R(r)\,\cup\,\mathcal{G}^H(r)\},\\ k\in\mathcal{K}(r,g)}} gen_{rgkt}\\ &+\sum_{s\in\mathcal{S}}(dis_{rst}-chr_{rst})+\sum_{d\in\mathcal{D}(r)} dr_{rdt}\\ &-\sum_{r\in\{\mathcal{R}\,|\,(r,\bar r)\,\in\,\mathcal{L}\}} ptr_{r\bar r t}\ \geq LOAD_{rt},\quad \forall\ (r,t)\in\mathcal{R}\times\mathcal{T}.\end{aligned}\tag{14}$$

- Under Pooled Capacity and Deep Integration modes we also compute electricity imports $ptr_{\bar r rt}$ as contributions to meet capacity requirements, i.e.

$$\begin{aligned}&\sum_{\substack{g\in\{\mathcal{G}^P(r)\,\cup\,\mathcal{G}^N(r)\},\\ k\in\mathcal{K}(r,g)}} \left(CAP^G_{rgk}+cap^G_{rgk}\right)\\ &+\sum_{\substack{g\in\{\mathcal{G}^R(r)\,\cup\,\mathcal{G}^H(r)\},\\ k\in\mathcal{K}(r,g)}} gen_{rgkt}\\ &+\sum_{s\in\mathcal{S}(r)}(dis_{rst}-chr_{rst})+\sum_{d\in\mathcal{D}(r)} dr_{rdt}\\ &-\sum_{r\in\{\mathcal{R}\,|\,(r,\bar r)\,\in\,\mathcal{L}\}} ptr_{r\bar r t}\\ &+\sum_{\bar r\in\{\mathcal{R}\,|\,(\bar r,r)\,\in\,\mathcal{L}\}} ptr_{\bar r rt}(1-LOSS_{\bar r r})\ \geq LOAD_{rt},\quad \forall\ (r,t)\in\mathcal{R}\times\mathcal{T}.\end{aligned}\tag{15}$$

*Energy storage capacity.* At each time period and region, charge and discharge rates of energy storage must be less than the storage capacity, i.e., the initial capacity $CAP^S_{rs}$ plus the expanded storage capacity $cap^S_{rs}$:

$$0\leq chr_{rst}\leq CAP^S_{rs}+cap^S_{rs},\quad \forall\ (r,s,t)\in\mathcal{R}\times\mathcal{S}(r)\times\mathcal{T},\tag{16}$$

$$0\leq dis_{rst}\leq CAP^S_{rs}+cap^S_{rs},\quad \forall\ (r,s,t)\in\mathcal{R}\times\mathcal{S}(r)\times\mathcal{T}.\tag{17}$$

*Energy balance in energy storage systems.* To reduce the number of energy storage variables, we assume a cyclic operation of energy storage, using an energy balance constraint for each cycle of duration $DUR$. Thus, the stored energy during each cycle, discounted by the energy efficiency factor $EF_{rs}$, must be equal to the total energy withdraws:

$$\begin{aligned}&\sum_{t'\in[t-DUR,\,t]}\left(chr_{rat'}EF_{rs}-dis_{rst'}\right)=0,\\ &(r,s,t)\in\mathcal{R}\times\mathcal{S}(r)\times\{\mathcal{T}\,|\,t \bmod DUR=0\}.\end{aligned}\tag{18}$$

Notice that in this formulation we deliberately avoid using state variables for energy storage, in order to reduce the model size.

*Water balance in reservoirs.* As in (18), we assume a cyclic operation of reservoirs, except for run-of-the-river power plants, which have no storage capacity. For large and intra-day reservoirs, state variables $ws_{krt}$ are defined *daily* (instead of *hourly*), in order to reduce the model size. Therefore, we define water balance constraints, depending on the type of reservoir feeding each power plant: large reservoir (Eq. 19), intra-day reservoir (Eq. 20) or run-of-the-river (21):

$$\begin{aligned}&ws_{krt}-ws_{kr(t-B)}=\\ &\sum_{t'\in[t-B,t]}\Bigg(INF_{krt'}+\sum_{j\in\mathcal{J}(k)}[wd_{jrt'}+ww_{jrt'}]\end{aligned}\tag{19}$$

$$- wd_{krt'} - wo_{krt'} - ww_{krt'}\Big),$$

$$\forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T}\ \mid\ t \geq B;\, t \bmod B = 0\,; g \in \mathcal{G}^H(r)\};$$

$$\begin{aligned} 0 = \sum_{t' \in [t-B,t]} \Big( & INF_{krt'} + \sum_{j \in \mathcal{J}(k)} [wd_{jrt'} + ww_{jrt'}] \\ & -wd_{krt'} - wo_{krt'} - ww_{krt'} \Big), \\ & \forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T}\ \mid\ t \bmod B = 0\,; g \in \mathcal{G}^H(r)\}; \end{aligned} \tag{20}$$

$$\begin{aligned} 0 = INF_{krt} + \sum_{j \in \mathcal{J}(k)} [wd_{jrt} + ww_{jrt}] - wd_{krt} - wo_{krt} - ww_{krt}, \\ \forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T} \mid g \in \mathcal{G}^H(r)\}. \end{aligned} \tag{21}$$

*Hydropower operation variables.* We also define upper and lower bounds for each of the variables related to the hydropower operation: water spill (Eq. 22), turbine discharges (Eq. 23), hydropower generation (Eq. 24), assuming an average productivity factor $PF_{kr}$ for turbine discharges), and stored water volume (Eq. 25), considering also the initial water volume (Eq. 26) and the target aggregated water volume at the last period $T$ (Eq. 27):

$$0 \leq ww_{rkt} \leq \overline{WW}_{rk}, \quad \forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T} \mid g \in \mathcal{G}^H(r)\}, \tag{22}$$

$$0 \leq wd_{rkt}, \quad \forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T} \mid g \in \mathcal{G}^H(r)\} \tag{23}$$

$$0 \leq gen_{rgkt} \leq PF_{kr} wd_{krt}, \quad \forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T} \mid g \in \mathcal{G}^H(r)\}. \tag{24}$$

$$\underline{WS}_{rk} \leq ws_{rkt} \leq \overline{WS}_{rk}, \quad \forall\ (r,k,t) \in \{\mathcal{R} \times \mathcal{K}(r,g) \times \mathcal{T} \mid g \in \mathcal{G}^H(r)\} \tag{25}$$

$$ws_{rk0} = WS_{rk0}, \forall\ (r,k) \in \{\mathcal{R} \times \mathcal{K}(r,g) \mid g \in \mathcal{G}^H(r)\}. \tag{26}$$

$$\sum_{k \in \mathcal{K}} ws_{rkT} \geq WS_{rT}, \forall\, r \in \mathcal{R}. \tag{27}$$

# Appendix B Supplementary data

Transmission costs are based on the NREL transmission line model National Renewable Energy Laboratory (2017a), considering the unitary standard cost in the US of a HVDC 3-GW 100-Mile transmission line at the year 2014: 298.5 \$/(MW-Km) as the Unitary Line Cost $ULC$ and 244,800 \$/MW as the Unitary Station Cost $USC$. To project these costs to the year 2018, we apply the estimated inflation rate for producers (computed as 3.02% over years 2014 to 2018, based on U.S. Department of the Treasury (2018)). After adding a 0.5% cost of operation and maintenance, the Total Unitary cost $TU$ between jurisdictions is computed as the unitary station costs plus the product between the flying distance times the unitary line cost, that is $TU = (USC + ULC \cdot FD) \cdot (1 + 0.005)$. For computing the annualized cost we consider a lifespan of 80 years.

**Table 8: Initial Transmission Capacities [MW].**

| | QC | ON | AT | NY | NE |
|---|---|---|---|---|---|
| QC | - | 2,705 | 1,029 | 1,999 | 2,275 |
| ON | 1,970 | - | - | 2,000 | 0 |
| AT | 785 | - | - | - | 700 |
| NY | 1,100 | 1,600 | - | - | 1,600 |
| NE | 2,170 | - | 700 | 1,400 | - |

**Table 9: Costs and distances of interconnection lines.**

| Interconnection | Distance [Km]* | Total Unitary annualized cost [\$/MW/year] |
|---|---|---|
| QC-ON | 505 | 409,530.6 |
| QC-AT | 791 | 497,922.5 |
| QC-NY | 534 | 418,493.4 |
| QC-NE | 403 | 378,006.2 |
| ON-NY | 551 | 423,747.4 |
| AT-NE | 655 | 455,889.9 |
| NY-NE | 306 | 348,027.1 |

* Flying Distances ($FD$) between main cities

**Table 10: Investment and operation costs of generation and storage technologies.**

| | Type | Lifespan | Costs | | | |
|---|---|---|---|---|---|---|
| | | | Invest. [K\$/MW] | Fixed O&M [K\$/(MW-Year)] | Variable [\$/MWh] | Fuel [\$/MWh] |
| Gas | CT | 25 | 919 | 19.37 | 7.00 | 33.00 |
| Gas | CCGT | 25 | 926 | 13.33 | 3.00 | 22.00 |
| Nuclear | | 40 | 6,742 | 101.00 | 2.00 | 7.00 |
| EES* | | 10 | 1’384 | 37.11 | - | - |
| Wind | W1 | 25 | 1,200 | 44.00 | 5.90 | - |
| Wind | W2 | 25 | 1,620 | 44.00 | 5.90 | - |
| Wind | W3 | 25 | 3,000 | 44.00 | 5.90 | - |
| Solar | | 25 | 1,111 | 20.00 | - | - |
| Hydro | | 75 | 8,000 | 14.85 | 2.46 | - |

* For Electrical Energy Storage (EES) we assume a round trip efficiency of 81%.

**Table 11: Capacity expansion blocks of wind power.**

| Jurisdictions | Blocks [GW] | | |
|---|---|---|---|
| | W1 | W2 | W3 |
| QC | 10 | 10 | 50 |
| ON | 5 | 5 | 50 |
| AT | 5 | 10 | 50 |
| NY | 5 | 5 | 10 |
| NE | 5 | 5 | 10 |

**Table 12: Demand response block structure used in each jurisdiction.**

| Demand response level | Unit cost [($/MW]) | Capacity (% of load) |
|---|---|---|
| A | 700 | 5% |
| B | 1000 | 5% |
| C | 1300 | 5% |

**Table 13: Storage capacity of large reservoirs in Quebec.**

| Number | Name | Capacity [Billion m$^3$] | |
|---|---|---|---|
| | | Min. | Max. |
| 1 | Caniapiscau | 39.0 | 52.6 |
| 4 | La Grande 3 | 25.2 | 60.0 |
| 5 | Robert Bourassa | 19.4 | 61.7 |
| 7 | Manicougan | 35.2 | 137.9 |
| 9 | Aux Outardes | 10.9 | 24.5 |

**Table 14: Discharge and generation capacity of represented hydropower plants.**

| Code | Name | Capacity | | |
|---|---|---|---|---|
| | | Discharge [m$^3$/s] | | Generation [MW] |
| P1 | Brisay | 1130 | | 469 |
| P2 | Laforge 2 | 784 | * | 319 |
| P3 | Laforge 1 | 1693 | * | 878 |
| P4 | La Grande 4 | 2783 | * | 2779 |
| P5 | La Grande 3 | 3439 | * | 2417 |
| P6 | Eastmain 1 | 840 | | 480 |
| P7 | Eastmain 1-A | 1344 | | 768 |
| P8 | Sarcelle | 1290 | | 150 |
| P9 | La Grande 2-A | 1620 | | 2106 |
| P10 | La Grande 2 | 4300 | | 5616 |
| P11 | La Grande 1 | 5950 | | 1436 |
| P12 | Manic 5 | 717 | * | 1596 |
| P13 | Manic 5-PA | 671 | * | 1064 |
| P14 | Manic 3 | 1590 | * | 1326 |
| P15 | Manic 2 | 2016 | * | 1229 |
| P16 | Manic 1 | 708 | * | 184 |
| P17 | Toulnoustouc | 330 | | 526 |
| P18 | Outardes 4 | 605 | * | 785 |
| P19 | Outardes 3 | 633 | * | 1026 |
| P20 | Outardes 2 | 724 | * | 523 |

* Plants with estimated values.

**Table 15: Rivers represented in the model.**

| Code | Name |
|---|---|
| R1 | Caniapiscau |
| R2 | Laforge |
| R3 | La Grande |
| R4 | De Pontois |
| R5 | Sakami |
| R6 | Giard-Opinaca-Gipoulux |
| R7 | Eastmain |
| R8 | Rupert |
| R9 | Manicouagan |
| R10 | Toulnustouc |
| R11 | Aux Outardes |

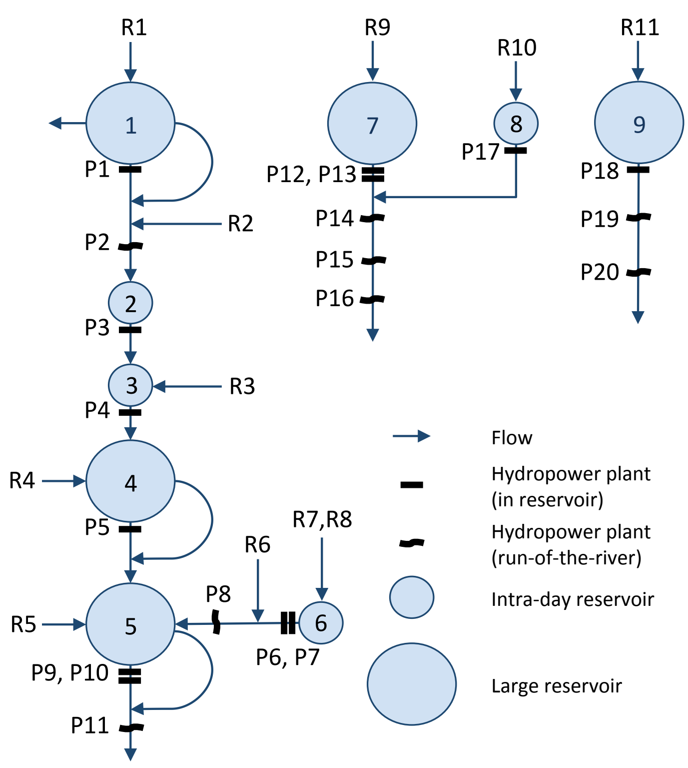


**Figure 15: Representation of Quebec's hydropower system in the model.**