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Evaluating an interconnection project: Do strategic interactions matter?

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Abstract: High-Voltage Direct Current (HVDC) merchant transmission lines allows trade across separate power markets and often in different countries. The flows on existing cross-border lines are often assessed as suboptimal, which may be due to the light regulation that often prevails in this case. We study the impact of Physical Transmission Rights (PTRs) allocation on the management of an HVDC interconnection between a thermal and a hydroelectricity market, assuming dynamic water management. We use a two-stage game formulated as an Equilibrium Problem with Equilibrium Constraints (EPEC) to model the strategic trade between the New York (US) and Quebec (Canada) systems. The numerical model is calibrated with public data. We find that although the interconnection can create wealth, a high concentration of PTRs can destroy value because of dumping strategies. The impact of trade on local price levels may be of concern and calls for the functional unbundling of traders and generators.

Keywords: Electricity, interconnection, dumping, HVDC, PTR, EPEC

Acknowledgments: This paper is a part of Sébastien Debia's PhD thesis. Some of his working papers are quoted, being previous chapters of his thesis.

1 Introduction

It is widely recognized that improving integration between jurisdictions is essential in the development of power markets. One of the major rationales for such improvement is a comparative advantage argument: integration makes it possible to take advantage of the complementarity between two systems. For example, thermal-dominated and hydro-dominated markets are recognized as very good complements. On the supply-side, the hydro system provides cheap, clean and fast-to-procure energy to a carbon-intensive thermal system with slower ramp rates. A thermal system is not subject to the hydrological cycle, which is needed to provide a baseload. On the demand-side, a hydro system is typically situated in a low-demand area, so connecting it with a more demand-intensive area increases its profitability. But integration also provides benefits in terms of security of supply, in that it increases the volume of idle capacity in case of unexpected shocks on the supply or the demand side (Stoft (2002)). Finally, improving markets' integration reduces market power (Borenstein et al. (2000)).

An important share of the integration's process is based on large investments in High Voltage Direct Current (HVDC) interconnections.[1] Contrary to its Alternate Current (HVAC) alternative, HVDC is not subject to loop flows, and therefore can be used to directly connect cheap-generation areas to high-demand ones. Furthermore, HVDC flows are controllable, and so can be used as a means to control network externalities. Finally, HVDC transmission has a lower loss rate than does HVAC over long distances. A significant share of these investments ought to be merchant-based.[2] In this model, private investors finance the interconnection and collect revenues based on the price spread between the two connected markets (Brunekreeft (2005)).[3] These market-based revenues are collected through the sell of access rights, which may be either financial or physical (see Joskow and Tirole (2000)). Financial rights associated with implicit auctions are known to provide more competitive trade between markets (Joskow and Tirole (2000); Ehrenmann and Neuhoff (2009)). A holder collects the price differential times his number of rights, while physical management is done by a regulated operator. This type of design however requires a high level of coordination between the two markets (de Hautecloque and Rious (2011)), which is not the case in general for inter-jurisdictional trade.[4] Alternatively, access could be provided through the sale of Physical Transmission Rights (PTRs). This type of right allows its holder to inject/retrieve power directly at one end of the line. As such, each agent takes an active part in the management of the line. More specifically, investors in new merchant interconnectors in the United States can allocate the entire transmission capacity at a negotiated rate through bilateral transactions (FERC (2013)). Such allocation of PTRs can lead to strategic behavior, especially when the interconnectors link two different jurisdictions, with no joint market-power monitoring (Joskow and Tirole (2000)).

This paper investigates the impact of different allocations of transmission rights on the management of a merchant interconnection project. We base our analysis on a representative HVDC project: the CHPE interconnection project. This underground interconnection between Quebec and southern New York state is a merchant investment project with a capacity of 1,000 MW. It is being developed by Transmission Developer Incorporated (TDI) and its cost is estimated at US$2.2 million.[5] This project has the interesting feature of connecting a thermal-dominated system with a hydro-dominated one. Also, the seasonality of demand is not the same in the two markets, which increases the trading potential between the two regions.

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[1] In 2014, the European Union listed 30 HVDC initiatives as projects of common interest for security of supply EC (2014). In 2015, there were officially eight merchant projects between Canada and the US (IEA (2015)).

[2] Historically, investment in transmission infrastructure is regulated as this sector is subject to significant economies of scales. In a regulated model, two jurisdictions must have an agreement to allocate the costs and revenues of an interconnection (Hogan (2011); Joskow and Tirole (2005)). This scheme is considered the first-best, as the resulting investment would maximize the social welfare. However, despite a greater need for interconnection capacity, this regime do not permit sufficient investment (Brunekreeft et al. (2005)).

[3] This price-spread criterion only imperfectly reflects the potential welfare gain of an interconnection and, consequently, leads to a lower level of investment (Joskow and Tirole (2005)). This type of scheme is often considered as a second-best approach (de Hautecloque and Rious (2011); van Koten (2012); Boffa et al. (2015)).

[4] The Nortwestern Europe (NWE) market is a very specific case, and this multinational area could be accounted for a unique jurisdiction. The European Commission enforce a regulatory framework, notably through the Third Energy Package. Consequently, institutions enforcing cooperation between regulators (ACER) and coordination between system operators (ENTSO-E) exists (de Hautecloque and Rious (2011)).

[5] See the website `http://www.chpexpress.com/`. Last visited in 2016-09-30.

We model the interconnection between the power systems of the province of Quebec and the state of New York as a strategic game on a three-node network: New York North (N), South (S) and Quebec (QC).[6] We use an Equilibrium Problem with Equilibrium Constraints (EPEC) approach to model a bilevel trading game. The lower stage corresponds to the maximization of the local welfare under production capacity constraints in each region, given the level of trade, and results in local market-clearing prices.[7] Each region is characterized by its own mix of generation technologies. The strategic game takes place at the upper stage, where traders of each generation company strategically trade on the interconnection. Their access to the interconnection is limited by their initial allocation of PTRs. In other words, each player's trade capacity on the interconnection provides bounds on the strategy space. We consider two possible cases. In the first case, integrated traders, who consider the management of production assets, anticipate the effect of trade on local market-clearing prices and choose their strategies as profit-maximizers. In the second case, traders and producers are functionally unbundled,[8] such that each representative trader affiliated to a region is a local price-taker, while it is nevertheless a price-maker in the other areas.

This study is not properly speaking an assessment of the HVDC project's value. For such an evaluation, the interested reader may look at Frayer and Trinidad (2012) and Pineau et al. (2015). The goal of this study is to assess how strategic trading may impact the price differential between two jurisdictions, in a context where inter-jurisdictional regulation is light (Spees and Pfeifenberger (2012)). The price differential constitutes the core value of such projects, and the extent to which this type of interconnection is subject to imperfect arbitrage has been largely demonstrated empirically (see Bunn and Zachmann (2010); Balaguer (2011); Meeus (2011); Gebhardt and Hffler (2013); Antweiler (2016)). However, not much had been done in the literature to evaluate this impact. The vast majority of numerical evaluations of interconnection benefits assume perfect competition, and thus, perfect arbitrage of price differentials (see Doorman and Froystad (2013); Billette de Villemeur and Pineau (2016); Newberry et al. (2016) for some recent examples). In the following, we review the literature dealing with market power and trade in electricity markets.

A literature about strategic management of interconnections has grown out of Joskow and Tirole (2000) and the idea that use-it-or-loose-it (UIOLI) rules would avoid possible PTR's withholding issues. But releasing rules, such as UIOLI, require a strong inter-jurisdictional regulatory framework to be enforced (de Hautecloque and Rious (2011)), and can be circumvented if their definition lacks. For example, the UIOLI rule is defined on a daily basis whereas the product is delivered on, e.g., a half-hourly basis (Bunn and Zachmann (2010)). The UIOLI rule also makes PTRs a very rigid instrument under uncertainty. An initial holder would run the risk of losing potentially valuable rights under this rule, in a context where uncertainty may cause dumping as an insurance strategy (Antweiler (2016)). Hence, the releasing provision of a PTR may be triggered just before gate closure. For example, US regulator FERC decided to apply the UIOLI rule just before real-time in the case of the Neptune cable between PJM and Long Island (FERC (2003)). Unused rights are available from noon to five p.m. one day before start of service (PJM (2015)). Such a restricted operational window tends to reduce the effectiveness of the UIOLI rule. Finally, a UIOLI rule would be void if not coupled with a must-offer provision for the line investor and initial holder of the rights. But, Brunekreeft and Newberry (2006) show that such provision would largely impede merchant investment under uncertainty. In a context where investment is lacking, such a provision tends to be undesirable.[9] Consequently, the extent to which this type of interconnection is subject to imperfect arbitrage has been largely demonstrated empirically (see Antweiler (2016); Balaguer (2011); Bunn and Zachmann (2010); Gebhardt and Hffler (2013); Meeus (2011); Pineau and Lefebvre (2009)).

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[6] Quebec is currently interconnected to upstate New York only. The transmission bottleneck N and S generates persistent inter-regional price spreads (NYISO (2014b)). This structure encourages both regions to be considered separate but interconnected markets that are operated by a single entity, the New York Independent System Operator (NYISO).

[7] This is equivalent to assuming that players behave competitively on the spot markets, which is consistent with the observations made in the NYISO state of the market report (Patton et al. (2016)). This observation is generally made for Northeastern US power markets. The Quebec power producer—Hydro-Québec Production—supplies the local demand at a regulated tariff, such that it may also be considered as a price-taker on its local market.

[8] Functional unbundling is an incomplete form of unbundling. In addition to separating the bookkeeping between two divisions within a firm (accountancy unbundling), it also consists in separating the operations and management of these two divisions.

[9] Several papers deal with the problem of investment in interconnections, which is not the primary topic of this paper. We refer the interested reader to van Koten (2012) and Boffa et al. (2015).

Whereas a substantial literature exists on market power in a transmission network, the subset devoted to two-stage games is much more sparse. Among this subset, no articles, to the best of our knowledge, use an information structure similar to Joskow and Tirole (2000). In a substantial part of Joskow and Tirole (2000), a monopolist maximizes a two-stage program where trade is decided on before production.[10] Their main result is that an importer with market power has an incentive to withhold its PTRs in order to maintain its mark-up on the local price. Accordingly, any allocation to such a player would create inefficiencies in the absence of UIOLI. However, most of the numerical bilevel models of strategic behavior in an electricity network are developed for alternate current (AC) transmission models. In these models, the information structure is reversed. Players bid their production (or supply function), then the independent system operator (ISO) proceeds to an optimal dispatch, i.e., it selects the best bids in order to maximize social welfare subject to network constraints. Such a game is very difficult to solve, as an equilibrium may not exist due to the non-convexity of the feasible set (Borenstein et al. (2000); Cardell et al. (1997)). In Cardell et al. (1997), a Cournot duopoly over a three-node meshed network may behave contrary to the canonical capacity-withholding pattern. Indeed, each producer may *increase* its generation level (w.r.t. the competitive level) in order to saturate the capacity constraint on one line. Such a strategy limits the feasible set of competitor reactions, raising the price at the consumption node. Ehrenmann and Neuhoff (2009) extend Cardell et al. (1997) to simulate market coupling in CWE, and compare their results with Hobbs et al. (2005), which runs an open-loop (one stage) model with the same data. They find that the integrated market design (where the ISO proceeds to optimal dispatch and producers anticipate it) dominates the separated market design (where transmission rights are explicitly auctioned) from a welfare perspective. Indeed, such anticipation tend to increase competition between nodes. These two models are included in the review Neuhoff et al. (2005). Yao et al. (2008) models an EPEC where, in the upper level, Cournot generators sell forward on a perfectly arbitraged market, anticipating the lower level where the spot market clears. On the spot market, the ISO and the generators act simultaneously. This study generalizes the welfare-enhancing result of Allaz and Vila (1993) to network-constrained Cournot producers. Our paper is similar to this one, except that the HVDC interconnections are part of a illiquid forward market.

Our study is also related to the international trade game in Brander and Krugman (1983), known as the reciprocal dumping model. Two symmetric monopolies with constant marginal cost compete through international trading. Such trading is costly, as it involves a transportation cost. The two local monopolies discriminate in prices between the two markets—equating their marginal revenue in them—such that they are willing to sell in both, which causes the cross-hauling of goods.[11] As by construction the two prices are equal in the two markets, the free-on-board (FOB) foreign price[12] for each player is necessarily lower than the home price, and cross-hauling is thus equivalent to reciprocal dumping. Debia and Zaccour (2016) extended this model to a two-stage game where monopolists must supply local demand at a price equalizing their (increasing) marginal cost. They show in an asymmetric case that dumping occurs as a mean to increase producers' marginal cost, and therefore, the local price. The definition of dumping is reinforced in that the firm in the high-price market is willing to export its product for a price lower than its marginal cost. Debia and Pineau (2016) analyze the case of strategic trading over a finite interconnection where producers and traders are unbundled. They show that, in this case, dumping does not occur anymore.

The contributions of this paper are the following. First, we propose a modeling framework to analyze the impact of PTR allocation on the trading pattern in controllable-flow HVDC interconnections. Second, we show that connecting a hydro-dominated system with a thermal-dominated one—two highly complementary systems—does not create value *per se*. If not monitored correctly, such interconnection may even destroy wealth. This effect is largely due to a dumping strategy, in the sense of Debia and Zaccour (2016). Third, we

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[10] This sequentiality, which is referred to as non-commitment in the industrial organization literature (see e.g. Tirole (1988)) and as a closed-loop information structure in the game theory literature (see e.g. Fudenberg and Tirole (1991)), is a realistic representation of the decision process on interconnections (see e.g. Gebhardt and Hffler (2013)). The contrary situation, where one decision impacts another but the two are taken simultaneously, is referred to as a commitment situation or an open-loop information structure.

[11] Cross-hauling refers to a two-way trade of a homogeneous good. Such situations are relatively common in international trade, and are sometimes referred as intra-industry trade. It may occur in a strategic setting (see e.g. Brander (1981)) as well as in a competitive one (see e.g. Eden (2007)).

[12] The FOB foreign price is defined as the foreign price minus the transport cost, which would then be paid by the exporter.

show the critical influence of the link between traders and producers on market outcomes. To that extent, unbundling operations and trading inside a generator company may be a policy outcome worth considering.

The rest of the paper is organized as follows: In Section 2, we introduce the model. In Section 3, we explain how we build our database. In Section 4, we show the results and discuss them, in the integrated and unbundled cases, with and without CHPE. Section 5 concludes.

2 The model

We model the interconnection between the Quebec (QC) power system and the New York Independant System Operator (NYISO) power market as a three-node network. NYISO's prices are made at a zonal level. Yet, a transmission bottleneck from north (N) to south (S) permits us to meaningfully simplify the framework (NYISO (2014b)). This point will be further developed in the subsection devoted to the NYISO power market. Seasonality is taken into account by fragmenting the problem into four periods: winter, spring, summer and fall. Each season is subdivided into two representative load segments: peak (P) and off-peak (OP). Each load segment l has a duration dur_l in number of hours. The seasonality impacts many aspects of the model, e.g. cost and demand function, power plant capacity and water inflows. Each load segment has a certain duration in hours.

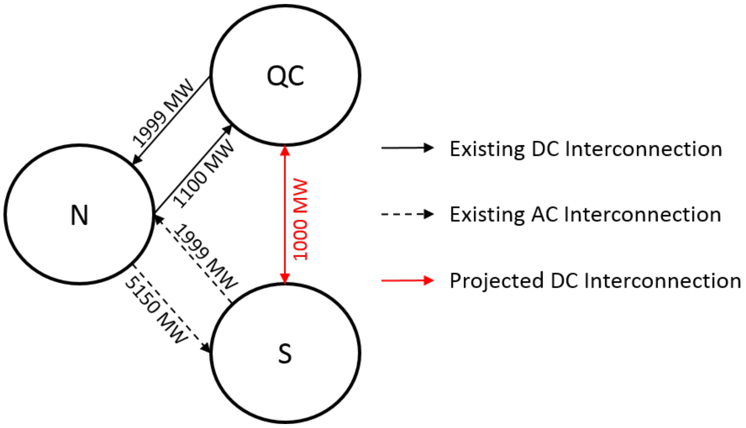

Figure 1: The three-node representation

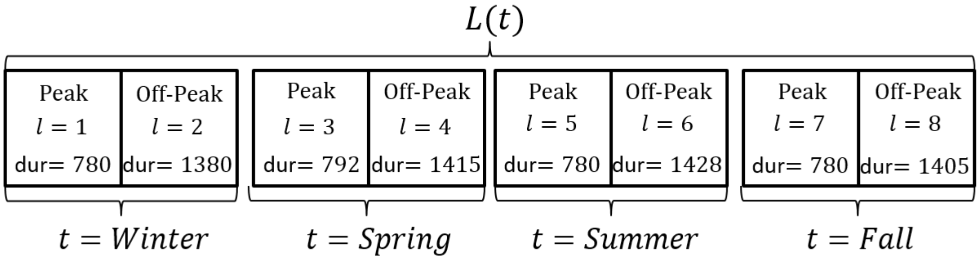

Figure 2: Representation of the seasonality

2.1 Lower stage: Nodal optimization

We assume that an efficient local regulation commits the agents in the market to behave competitively, i.e., to consider the market price as given. According to Patton et al. (2016), "the [New York] Day-Ahead and Real-Time Markets provide competitive incentives for resources to perform efficiently and reliably." For Quebec, the power system is mostly regulated and largely unbundled. Production, distribution and transmission are functionally separated within the public monopoly Hydro-Québec (HQ) (Hydro-Québec (2015b)). Hence, Quebec's power system could also be represented as a "competitive market" between HQ Production and HQ Distribution.[13]

The lower stage is solved by deriving the Lagrangian of a quadratic welfare-maximization program under market clearing constraints. Such an approach gives the same outcome as a decentralized competitive market without externalities or transaction costs. In the following, we present our model using the Karush-Kuhn-Tucker (KKT) equilibrium conditions derived from this Lagrangian, since they are nicely interpretable as individual rationality conditions (Gabriel et al. (2013)). For the notation, we used the following conventions: uppercase letters are the parameters, lowercase ones are the primal variables, and Greek letters are for the dual variables associated to the primal constraints. In our setting, the primal variables are interpretable as quantities, whereas the dual ones are interpretable as prices.

The demand side at each node i is considered a representative consumer maximizing his net welfare at each load segments l by setting its consumption q_{il} for a given price π_{il}. The corresponding inverse demand function is assumed affine, with parameters A_{il} and B_{il} calibrated to reflect a realistic value (cf. Section 3). Since consumption must be at least zero, the price at equilibrium is at least equal to its marginal utility, that is, the corresponding KKT condition for the demand is

$$\pi_{il} \geq A_{il} - B_{il} q_{il} \;\perp\; q_{il} \geq 0 \quad \forall i, l. \tag{1}$$

This condition takes the form of a complementarity slackness condition where the $\perp$ symbol represents the complementarity slackness between the constraint and its associated multiplier, i.e., the multiplier is nonzero only if the constraint is binding (Gabriel et al. (2013)). In the present case, it is interpretable as follows: consumption increases until marginal utility equals price. For a price strictly greater than the marginal utility, consumption should be zero. On the supply side of each node i, a regulated monopolist generator maximizes its profit by setting generation quantities y_{ikl} from each technology k during each load segment l taking the price π_{il} as given:

$$\pi_{il} - \mu_{ikl} \leq C_{ikt} + D_{ikt}\, y_{ikl} \;\perp\; y_{ikl} \geq 0 \quad \forall i, k, l \tag{2a}$$

$$y_{ikl} \leq \overline{Y}_{ikt} \;\perp\; \mu_{ikl} \geq 0 \quad \forall i, k, l \tag{2b}$$

As for the demand, the short-run marginal cost of production is assumed affine, with parameter C_{ikt} and D_{ikt} calibrated to reflect realistic values (see Section 3).[14] The production is subject to capacity constraints. To each constraint is associated a multiplier μ_{ikl}, which is interpretable as the scarcity rent of the marginal MWh produced by the technology k. At equilibrium, the price contains the scarcity rent. The price is set such that it clears the market, that is, it is the multiplier associated to the market-clearing constraint

$$q_{il} - \sum_{k \in K} y_{ikl} + \sum_{f \in F} \sum_{j \neq i} x^f_{ijl} = 0 \;\perp\; \pi_{il} \in \mathbb{R} \quad \forall i, l. \tag{3}$$

The multiplier π_{il} of the equilibrium constraint is the cost for the market to supply one more unit of demand. In that sense, it is a market price. The volume of net exports x^f_{ijl} from node i to j during load segment l is settled by the players f in the upper stage. At the lower stage they are considered given. Because they impact the equilibrium conditions, export variables *parametrize* this stage of the model. Further conditions are tailored to represent the structure of the QC power system and the NYISO power market, as described next.

2.1.1 The NYISO power market

The NYISO market follows nodal pricing for the supply side and zonal pricing for the demand side. There are 11 zones (A to K) as illustrated in Figure 3. The market is characterized by a bottleneck from the

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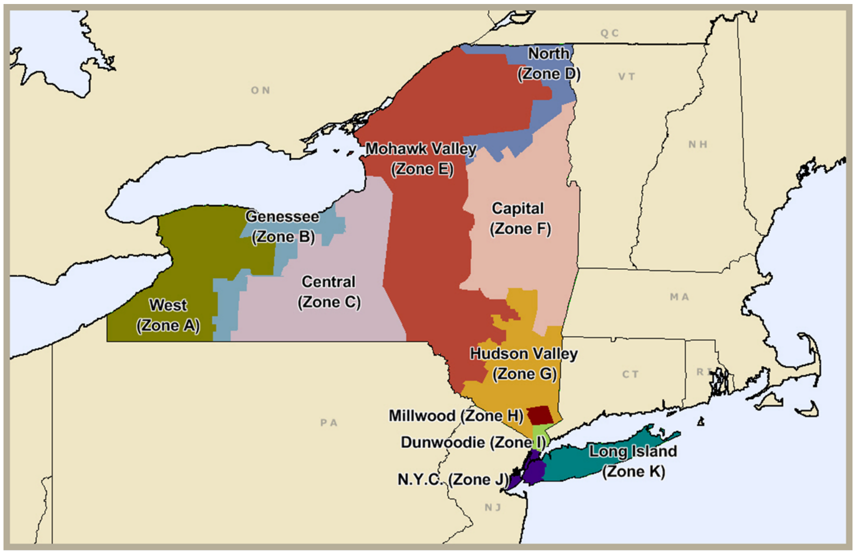
[13] Quebec's regulated price takes the form of a regulated tariff that includes a part for fixed cost. We omit this and assume that the regulation enforces marginal-cost pricing. For Quebec, the marginal cost includes the water availability opportunity cost, as we will see later. Furthermore, the short-run marginal production cost being (quasi-) constant for hydro production, the marginal cost pricing results in a (quasi-) flat rate. To avoid numerical illness, we assume some small-angle slope for the short-run marginal cost.

[14] As we will see in the data section, we aggregate power plants by segment, to which we apply a slope. This reduces the dimension of the problem while implicitly capturing the diversity of technologies.

northern area—which we call *North* (N)—to the New York City area—which we call *South* (S) (NYISO (2014b)). Accordingly, we approximate the zonal market into a two-area market. When the bottleneck is not saturated, the two areas are coupled. Area N bundles zones A (West) to F (Capital), and area S covers zones G (Hudson Valley) to K (Long Island).



Source: FERC - http://www.ferc.gov/market-oversight/mkt-electric/new-york/elec-ny-reg-des.pdf

Figure 3: Demand zones of the NYISO power market

They are connected by a finite transmission capacity, $LS = 5,150$ MW from N to S, and $LN = 1,999$ MW in the opposite direction (NYSRC (2013)). As part of a single jurisdiction (NYISO), and being in alternate current, this line is perfectly arbitraged in the sense that, following optimal dispatch, power $trans_l$ will flow naturally from a high-priced area to a low-priced area until the line is congested (Bohn et al. (1984)). We assume without loss of generality that power $trans_l$ flows from N to S, trans_l being positive for an export from N to S and negative for an import by N from S.

$$\pi_{\{S\}l} - \pi_{\{N\}l} = \theta_l^+ - \theta_l^- \quad \perp \quad \text{trans}_l \qquad \forall l, t \tag{4a}$$

$$-LN \leq \text{trans}_l \leq LS \quad \perp \quad \theta_{lt}^-,\ \theta_{lt}^+ \geq 0 \quad \forall l, t \tag{4b}$$

Region N has several hydropower plants. They are mostly large run-of-river plants located in the northwestern part of the state. They are considered in the model as other generation technologies. N also contains two pumped-storage plants ($k = PS$): Bleinheim-Gilboa (1,160 MW) and Lewiston (240 MW). These pumped-storage plants serve mainly to store water $stor_l$ during off-peak periods and to release power during peak periods. Accordingly, we represent them as an intra-seasonal arbitrage tool, that is, for $i = N$ and $k = PS$, the equilibrium conditions for pumped storage are

$$\pi_{il} \geq \ \text{eff}\ \sigma_t - C_{ikt} \qquad \perp \ \text{stor}_l \geq 0\ \forall l \tag{5a}$$

$$\sum_{l \in L(t)} \text{dur}_l \left(y_{ikl} - \text{eff stor}_l \right) = 0 \qquad \perp \ \sigma_t\ \forall t, \tag{5b}$$

and a term σ_t is added in the RHS of Equation (2a) for the pumped-storage generation technology. Such a pumping-and-releasing operation is relatively inefficient in the sense that more power is consumed than produced. For instance, Bleinheim-Gilboa only releases 73% of the power initially consumed for pumping up water to its reservoir.[15] Accordingly, we assume an efficiency parameter $\text{eff} = 0.73$. Furthermore, we consider that pumping has an unit operational cost of $C_{\{N\}\{PS\}t}$, which is equal to the releasing one.[16] The

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[15] See `http://www.waterpowermagazine.com/features/featurepumped-storage-powers-up-for-new-york-summer/`, last consulted on 2015-02-04

[16] Pumping is already upper-bounded by the releasing production capacity through the intra-seasonal balance Equation (5b).

equilibrium constraint (3) is modified to take these elements into account:trans_l for the transmission between the two areas, and stor_l in N.

$$q_{il} + \sum_{f \in F} \sum_{j \neq i} x^f_{ijl} - \sum_{k \in K} y_{ikl} + \text{trans}_l + \text{stor}_l = 0 \qquad i = N, \tag{6a}$$

$$q_{il} + \sum_{f \in F} \sum_{j \neq i} x^f_{ijl} - \sum_{k \in K} y_{ikl} - \text{trans}_l = 0 \qquad i = S. \tag{6b}$$

More details on the supply structure of the NYISO market appears in the data section 3.1.1

2.1.2 The Quebec power system

For Quebec, the supply side is mainly composed of three technologies: traditional hydro dams ($k = H$), run-of-river plants ($k = RoR$) and a CCGT thermal plant.[17] The hydro-reservoir technology is subject to a water availability constraint. When production takes place, the stock of water w_t decreases. Water in the reservoir is replenished with inflows I_t, mainly rain and snowmelt. Because production and inflows vary at each instant of time, the reservoir management problem is a dynamic one.[18] Hence, the water management constraints are written for $i = QC$ and $k = H$:

$$w_{t+1} = w_t + I_t - \sum_{l \in L(t)} \text{dur}_l \; y_{ikl} \qquad \perp \lambda_{t+1}, \; \forall t \tag{7a}$$

$$w_0 = W_0 \qquad \perp \lambda_0 \tag{7b}$$

$$W_0 \leq w_T \qquad \perp \lambda_T \geq 0 \tag{7c}$$

$$\underline{W} \leq w_t \leq \overline{W} \qquad \perp \omega^-_t, \omega^+_t \geq 0 \; \forall t \tag{7d}$$

The condition (7a) describes the dynamics of the stock of water w_{t+1} in Quebec's reservoirs expressed in TWh. Its evolution depends on the stock of water in the current period w_t plus the inflow of water I_t, minus the power produced from hydro-reservoir plant in Quebec in the previous period over the two segments of load. These two segments are weighted by the duration dur_l of period l in hours. The associated dual variable λ_{t+1} represents the opportunity cost at t to keep water available for the next period $t + 1$. Equations (7b)–(7c) are initial and terminal conditions. Since the problem lasts one representative year, we are requiring the terminal level of water to be greater than or equal to the initial one.[19]

Most of the RoR plants are situated downstream of reservoirs, and their production depends on the rivers' flow, which in turn, depends on the quantity of water processed by upstream reservoirs. In practice, the optimal management of a "valley" formed by a group of hydro-reservoir and run-of-river plants is far too complicated to be modeled here.[20] To simplify the approach, we assume that, for $i = QC$, the ROR generation capacity is a linear by-product of the hydro-reservoir generation.

$$y_{i\{RoR\}l} \leq y_{i\{H\},l} \frac{\overline{Y}_{i\{RoR\}l}}{\overline{Y}_{i\{H\}l}} \;\perp\; \rho_l \geq 0, \; \forall l \; ; \; i = QC \tag{8}$$

This relation between the two types of production might be a rough approximation of the reality, but we think it captures the big picture. In the case of the RoR technology, the optimality condition (2a) is modified to take into account constraint (8), that is, by adding $(-\rho_l)$. In the case of the hydro-reservoir technology, (2a) become, for $i = QC$,

$$\pi_{il} - \mu_{i\{H\}l} - \beta\lambda_{t+1} + \rho_l \frac{\overline{Y}_{i\{RoR\}l}}{\overline{Y}_{i\{H\}l}} \leq C_{i\{H\}l} + D_{i\{H\}l} \; y_{i\{H\}l} \;\perp\; y_{i\{H\}l} \geq 0. \tag{9}$$

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[17] The gas turbine of Bécancourt has a nameplate capacity of 411 MW. As a combined cycle plant, its specification are dealt within Equations (2) and are not concerned with the following developments. On top of this, 24 diesel turbines of an aggregated nameplate capacity of 131 MW are used to supply small autonomous networks in low-population-density areas. As they are not injecting into the main network, they are not accounted for in our model.

[18] The objective function of the producer is modified in consequence. It consists in summing discounted periodic profits, where each subperiod is weighted by its duration in hours. The discount rate is seasonal, and thus should be a fourth-root of an annual discount rate, thus negligible along a year.

[19] This represents the idea of long-term reservoir management, and is in line with HQ's projection (Hydro-Québec (2015a)).

[20] An example of river basin optimization can be found in Apparigliato (2008), Chapter 4 for example.

The Quebec's price π_{il} not only contains the usual short-run marginal cost and the scarcity rent $\mu_{i\{H\}l}$, but also the opportunity cost of water $\beta\lambda_{t+1}$, where β is the discount rate. This aspect tends to reduce the production of hydropower. But producing more traditional hydropower also increases available power in the RoR plants. This effect, captured by ρ_l, tends to increase hydro-reservoir generation. Finally, one needs to derive the Euler's equation, that is, in this case, the optimality condition for the inter-temporal management of the stock of water:

$$\beta\lambda_{t+1} = \lambda_t + \omega_t^+ - \omega_t^- \quad \perp \quad w_t \ \forall t. \tag{10}$$

This equation states that the shadow value of water today, adjusted for potentially binding constraints, must be equal to its discounted shadow value for the next season. If water becomes scarce, increasing its opportunity cost, it will affect all periods equivalently, modulo the discount factor β and the reservoir capacity constraints ω_t^+ and ω_t^-.

The equilibrium conditions enumerated up to this point describe the lower stage of the model. They are a rough approximation of the reality, but they result in a system of linear complementarity equations. This system has the nice property of offering a unique equilibrium (Gabriel et al. (2013)), which is a global optimum in terms of welfare. This is crucial when one wants to insert this equilibrium as a lower stage of an EPEC (Hu and Ralph (2007)).

2.2 Upper stage: The interconnection game

Trade between New York and Quebec is made through HVDC interconnectors. In the competitive benchmark, a fringe of traders maximizes its profits over a given price differential. The details of their modeling are in Appendix A.1. In the strategic cases, the players are considered to be representative generation companies that strategically trade energy on foreign markets. Their access is limited to the physical transmission rights (PTRs) they hold, in MW. There are three players, one per node. A player represents all the producers at a node. The player HQ is affiliated to the node QC, the player UNY is affiliated to the node N, and the player $SENY$ is affiliated to the node S. Such affiliation is given by a dummy parameter $bin_i^f = \{0, 1\}$, 1 being affiliated, and 0 not. Each player is a leader w.r.t. the market clearing, but plays simultaneously with other players (including the fringe). In other words, each firm plays Cournot against the others and Stackelberg with respect to the ISOs. This corresponds to a bi-level program for each player. We transform each bilevel model into a single-level optimization problem using the KKT conditions, a mathematical program with equilibrium constraints (MPEC). The collection of these MPEC is an EPEC.

We look at two cases, which correspond to different assumptions about the strength of local regulation. The first case corresponds to a situation where traders and producers are integrated, i.e., a trader maximizes both trading and production profits when setting its strategy. This case corresponds to a rational expectation behavior. In the second case, we assume that the local regulation is strict enough to mitigate the ability of each node-affiliated trader to anticipate its local market clearing. We refer to this case as an “unbundling” situation, e.g. where the communication between the trading and operation departments of a same firm is constrained.

In the first case, each player anticipates the market clearing process at every node, in accordance with the traditional assumption of rational expectation. Consequently each player's profit function consists in a trade-off between local and trading profits, given by the following program:

$$\max_{x_f \cup \mathbf{Y} \cup \mathbf{\Gamma}} \sum_{t=0}^{T-1} \beta^t \sum_{l \in L(t)} \mathrm{dur}_l \sum_{i \in I} \mathrm{bin}_i^f \left[\sum_k y_{ikl} \left(\pi_{il} - C_{ikt} - D_{ikt} \frac{y_{ikl}}{2} \right) + \sum_{j \neq i} x_{ijl}^f \left(\pi_{jl} - \pi_{il} \right) \right] \tag{11a}$$

subject to

$$x_{ijl}^f = -x_{jil}^f \qquad \perp \zeta_{ijl}^f \ \forall i, j \neq i, l, t \tag{11b}$$

$$-PTR_{ijl}^f \leq x_{ijl}^f \leq PTR_{ijl}^f \qquad \perp \psi_{ijl}^f, \phi_{ijl}^f \geq 0 \ \forall i, j \neq i, l \tag{11c}$$

$$\text{equilibrium conditions } (1) - (10) \tag{11d}$$

where $x_f = \{x_{ijl}^f\}$ $\forall i, j, l$ is the vector of strategies of firm f, $\mathbf{Y} = \{y_{ikl}, q_{il}, w_t, \mathrm{trans}_l, \mathrm{stor}_l\}$ $\forall i, k, l, t$ is the lower-stage vector of primal variables, and $\mathbf{\Gamma} = \{\pi_{il}, \mu_{ikl}, \rho_l, \lambda_t, \omega_t^-, \omega_t^+, \sigma_t, \theta_l^-, \theta_l^+, \}$ $\forall i, k, l, t$ is the lower-level vector of dual variables. A positive x_{ijl}^f expresses an export from i to j. Equation (11b) is to account for the fact that an export from node i to j corresponds to an import in the opposite direction. The volume in MW of power traded is bounded above and below by the amount of PTRs each player owns, as stated by the constraint (11c).

In the second case, regulation takes the form of enforcing local price-taking behavior at the upper stage. Each player considers a local price parameter P_{il} instead of the variable π_{il}, and thus cannot see how exports raise the profitability of their local production. This could be interpreted as the operations department only being able to communicate a threshold price to the trading department, below which trade is not profitable, as opposed to the first case where the firm's supply function is communicated. in other words, the trading department maximizes

$$\max_{x_f \cup \mathbf{Y} \cup \mathbf{\Gamma}} \sum_{t=0}^{T-1} \beta^t \sum_{l \in L(t)} \mathrm{dur}_l \sum_{i \in I} \mathrm{bin}_i^f \left[\sum_k y_{ikl} \left(P_{il} - C_{ikt} - D_{ikt} \frac{y_{ikl}}{2} \right) + \sum_{j \neq i} x_{ijl}^f \left(\pi_{jl} - P_{il} \right) \right], \qquad (12)$$

subject to the constraints(11b)–(11d). This price-taking assumption is extensively discussed in the companion paper, Debia and Pineau (2016). In short, local regulation is designed to mitigate the ability of a trader, who is also a stakeholder in the corresponding system, to game the local price settlement by strategically setting trading quantities. For example, it may over-export or under-import in order to raise its local market price. Since the production y_{ikl} is set such that the price equates the marginal cost in the lower level, the first part of the traders' objective function—the local production component—is in fact parametrized. Therefore, its problem becomes equivalent to a one-sided price-making trader. This setting is used in Smeers and Wei (1997), where marketers buy power at an injection node for a constant price, and sell it at the withdrawal node, maximizing their profits against the inverse demand function at that node.

Given the many complementarity conditions present in the lower stage, this problem is non-convex, and finding a global optimum for each player is particularly hard (Scheel and Scholtes (2000)). Using the structure of the game, we obtained Local Nash Equilibria as defined in Hu and Ralph (2007). As we explain in Appendix A.2, we were able to find an approximate of the global equilibrium in most cases. In the other cases, we searched for multiple equilibria, see Appendix C.2.

3 Data

3.1 Supply-side

The supply-side construction is based on plant-level data. Abbreviations for the thermal generators type and prime mover are based on Energy Information Association (EIA) initials, defined in Table 1. A very detailed dataset is too heavy to be handled in the game-theoretic model developed. Consequently, we adapt the available raw dataset into a simplified database fitting the assumptions of our model.

Table 1: EIA initials

Type		Prime mover	
Acronym	Name	Acronym	Name
ST	Steam Turbine	UR	Uranium
CC	Combined Cycle	BIT	Bituminous Coal
IC	Internal Combustion	NG	Natural Gas
GT	Gas Turbine	FO6	Residual Fuel Oil
		FO2	Distillated Fuel Oil
		KER	Kerosene

3.1.1 New York

Table 2 presents the capacity data for New York. Based on the type of generators and on their “fuel type 1,” as reported in the NYISO “Gold Book” NYISO (2014a), we associated each plant to a category. For thermal plants, we extrapolated a heat rate, using EIA statistics for 2013 (EIA (2015)), which are averaged over the US. We ended up with ten categories of traditional thermal plants, plus nuclear.[21] Upstate New York also has run-of-river (RoR) hydropower plants, and there are very small thermal plants with renewable fuel (wood, wastes, etc.) in both parts of the state. From this database, we also retrieved the variable operation and maintenance costs (V. O&M) for thermal plants. For RoR and other renewable plants, we used data from NREL (2012). As we are at a short-term-operation level, we only consider short run-marginal costs, and accordingly, we didn’t take into account the fixed O&M or capital costs.[22]

Table 2: Variable O&M, heat rate and capacity by area and technology

Generator Type	Fuel Type 1	V. O&M ($/MWh)	Heat Rate (BTU/kWh)	Capability (MW)			
				Winter		Summer	
				N	S	N	S
Others	Renew.	0	—	593	218	595	212
RoR	Water	6	—	4,185	78	4,193	79
ST	UR	2.14	10,449	3,372	2,076	3,357	2,061
ST	BIT	4.47	10,089	1,485	0	1,495	0
CC	NG	3.6	7,667	5,967	4,290	5,094	3,898
IC	NG	10.37	9,573	104	0	104	0
ST	NG	15.45	10,354	0	3,585	0	3,570
GT	NG	15.45	11,371	53	2,108	48	1,923
ST	FO6	15.45	10,334	1,668	4,409	1,584	4,389
IC	FO2	10.37	10,401	0	0	56	55
GT	FO2	15.45	13,555	0	2,322	0	1,902
GT	KER	15.45	13,555	0	1,183	0	959

We bundle plants along the two areas (N and S) defined in the previous section and calculate the capability of each category of plant in each area. This capability is expressed as a *dependable maximum net capability*, that is, the gross electrical output of each generator under the most restrictive seasonal conditions, less the station service load. This capability is measured in winter and summer in NYISO (2014a). For thermal plants, the primary factor inducing a difference between winter and summer capacities is the water and air cooling temperatures. Consequently, capability in winter is higher than in summer. We approximate the spring and fall capability as an average between winter and summer capabilities. The renewable-fuel plants are composed of wind turbines as well as thermal plants with non-intermittent renewable fuel sources, like wood and solid waste.[23]

To compute the fuel cost for each type of plant, we calculate the fuel price for each season in $/MMBTU, then we use the heat rate to determine the fuel cost for each technology in $/MWh. This approach permits us to take into account price seasonality, especially for natural gas and oil products. Using the heat rate, we calculate the fuel cost for each type of plants. Similarly, using carbon content of each fuel and the heat rate, we calculate a carbon cost for each type of plant. The detail of these operations is explained in Appendix B.1. Adding variable O&M, fuel and carbon costs, we obtain the short-run marginal cost (SRMC) for each type of power plant. Since our model is complex by construction, we reduce the dimensionality of the technologies into five segments k: Base, Mid, Shoulder, Peak and Super-Peak. We defined each segments on the basis of apparent discontinuities in the cost structure. These results are displayed in Table 3.

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[21] We considered that methane fuel is a natural gas.

[22] To be estimated on a $/MWh basis, an assumption on the charge rate of each plant would have to be made, which is not desirable here, as such a rate is an outcome of the model.

[23] All wind farms are located in N. To take into account their intermittency, we compared the nameplate capacity to their total output in 2013, as reported in NYISO (2014a). We derived from this a weighted-average capacity factor of $\approx$ 23.37%. We then obtained an available capacity of $\approx$ 404.2 MW. In terms of solar photovoltaic plants, only one farm is reported in the south, with a capacity 31 MW, which we considered negligible. Other plants in the “Others-Renew” category are small thermal plants to have renewable fuels, which are considered to have zero cost and be non intermittent. Batteries are considered to have zero capability in the Gold Book, and zero production was reported.

Table 3: Marginal cost of generation by segment

Generation Segment k	Plant Type	SRMC ($/MWh)				Capability (MW)			
		Winter	Spring	Summer	Fall	Winter		Summer	
						N	S	N	S
Base	Renew	0	0	0	0	8,151	2,372	8,145	2,353
	RoR	6	6	6	6				
	ST-UR	5.16	5.16	5.16	5.16				
Mid	ST-BIT	38.15	38.27	38.01	40.07	7,452	4,290	6,589	3,899
	CC-NG	53.54	43.22	38.76	43.05				
Shoulder	IC-GT	72.73	59.84	54.27	59.63	158	5,694	148	5,494
	ST-NG	82.89	68.96	62.94	68.73				
	GT-NG	89.52	74.21	67.60	73.96				
Peak	ST-FO6	181.96	172.72	174.10	171.81	1,668	4,465	1,584	4,443
	IC-FO2	243.31	219.42	233.21	234.74				
Super-Peak	GT-FO2	319.03	287.89	305.87	307.86	0	3,504	0	2,860
	GT-KER	351.66	303.30	323.32	326.53				

Table 4 shows the final cost-function parameters C_{ikt} and D_{ikt} used in Equation (2a). For each segment k we first calculate the average marginal cost weighted by the capacity of each plant type, this weighted average cost corresponding to the gravity center of each segment.[24] We define the ordinate C_{ikt} of each segment as being 0.8 times the weighted average cost of this segment.[25] In the case of the Base segment, we just assume the ordinate to be null. To define the slope D_{ikt} of each segment, we need to define a second point. This second point is given by assuming that the weighted average cost corresponds to the segment's median level of production. Note that C_{ikt} are in $ per MWh, whereas D_{ikt} are in $ per GWh. Also, the Shoulder segment in area N is excessively high because there is very little capacity available in this area.

Table 4: New York cost function parameters

Segment k	Area	C_{ikt} ($/MWh)				D_{ikt} ($/GWh)			
		Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Base	N	0	0	0	0	1.28	1.28	1.28	1.28
	S	0	0	0	0	3.97	3.99	4.01	3.99
Mid	N	40.28	33.74	30.87	33.93	2.71	2.40	2.34	2.42
	S	42.83	34.58	31.01	34.44	4.99	4.22	3.98	4.21
Shoulder	N	62.73	51.52	46.55	51.34	199.03	168.51	157.70	168.21
	S	68.28	56.68	51.65	56.49	6.00	5.07	4.70	5.05
Peak	N	145.59	138.21	139.31	137.46	43.65	42.51	43.98	42.28
	S	146.20	138.67	139.89	138.08	16.37	15.57	15.74	15.50
Super-Peak	N	—	—	—	—	—	—	—	—
	S	264.04	234.49	249.39	241.35	37.67	36.84	43.60	39.49

Pumped-storage is a special technology as it is present on the supply-side and the demand side. We set the cost parameters $C_{\{N\}\{PS\}t}$ at $6/MWh, i.e. the Var. O&M cost of traditional hydro and a very low $D_{\{N\}\{PS\}t}$ at $0.11/GWh, similarly to hydro-reservoirs plants in QC (see Table 5 below).

3.1.2 Quebec

Generation capacity in Quebec is divided into two segments: "Heritage" ("Patrimonial") and not. Heritage generation corresponds to traditional hydro-reservoirs and run-of-river plants owned by HQ. Non-heritage plants include owned by private third parties who may wish to sell their production to HQ, intermittent renewable energy and import contracts (e.g. the Churchill Falls contract) (Hydro-Québec (2015b)). In our calibration, we consider such capacity as exogenous injection parameters, as we are lacking descriptive

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[24] Consequently, the same segment in the two areas have different average marginal costs.

[25] This scalar is *ad hoc*. It is set in order to avoid overlapping between the segments in the same node, while allowing a sufficient slope in order to reflect technology diversity within a segment. The calibration results are in Appendix C.1.

statistics. For the Heritage part, HQ owns and operates 36,643 MW of installed capacity. Of this, traditional hydro represents 22,583 MW, run-of river plants 13,517 MW, and one CC-NG 411 MW. We use data from NREL (2012) for variable O&M costs, and the same interpolation method as previously used for hydro. For the CC-NG, we apply the same method as for the supply side in New York.

Table 5: Quebec cost function parameters

Segment k	C_{ikt} (\$/MWh)				D_{ikt} (\$/GWh)			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
H	4.80	4.80	4.80	4.80	0.11	0.11	0.11	0.11
RoR	4.80	4.80	4.80	4.80	0.18	0.18	0.18	0.18
CC-NG	42.83	34.58	31.01	34.44	52.11	42.06	37.72	41.90

A critical set of parameters to calibrate is the water inflows for the reservoirs. In Denault et al. (2009), the authors find a yearly average inflows of 188.9 TWh over the period 1958-2003. This average contains inflows for the whole heritage capacity, i.e. hydro-reservoir and run-of-river plants. But our parameter for inflows covers only hydro-reservoir, and no public data on this is available. Therefore, we extrapolate the level of water at the beginning of each season based on available data for production and reservoirs for years 2012–2013 (Hydro-Québec (2014, 2015a)), as explained in Appendix B.2. Taking the average over these two years, we obtained the inflow data given in Table 6.

Table 6: Inflows in Quebec reservoirs (TWh)

Winter	Spring	Summer	Fall
-6.660	59.807	31.894	21.053

Negative inflows in winter may be explained by the water freezing and by the fact that it is not raining but snowing, which is not usable as energy. We use Hydro-Québec (2015a) to define the terminal condition of the water level.

3.2 Import parameters and transmission capacity

3.2.1 Import parameters

In this partial equilibrium context, we consider the net imports from neighboring areas as fixed. The calibrated import parameters are displayed in Table 7.

Table 7: Import parameters

Area	Import Parameters (MW)							
	Winter		Spring		Summer		Fall	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QC	2,867.19	2,889.04	1,929.89	2,078.64	827.79	1,082.08	1,856.85	2,062.17
N	563.215	759.12	722.33	883.78	737.49	1,130.01	716.26	806.21
S	1,080.83	896.10	823.775	599.485	989.13	1,195.31	813.46	537.88

For NYISO, data on interface volumes are available directly from the NYISO website. We average hourly data by load segment over the period 2012–2013. Imports and exports are separated between upstate and downstate New York using the system representation in NYSRC (2013). Presently, upstate New York is interconnected to New England, Ontario, PJM and Quebec, whereas downstate New York is interconnected to New England and PJM only. Detailed information on these interfaces can be found in Table 22 (Appendix B.3). Obviously, the trade parameters in Table 7 does not include exchanges with Quebec. Seasonal values are reported in Table 23 for both years.

No accurate and publicly available data on cross-border power exchanges exists for Quebec. We deduce the 2012–2013 trade volumes from HQ Production data on production, consumption, purchases and sales (Hydro-Québec (2014)). Power accounted as reception at interconnections and at injection nodes for non-heritage plants, which includes intermittent renewable production, is considered as gross imports. HQ Production's commitments to third parties consist of all its out-of-market trades. These volumes are considered gross exports. We finally calculate Quebec imports net of exports and exchanges with New York, as reported in Table 7.

3.2.2 Intra-NYISO transmission capacity

To summarize all the lines linking the NYISO areas N and S, we use data from the zonal representation of the network in NYSRC (2013), p.37. In this report, a total transmission capability from UPNY to SENY (which correspond to our areas N and S, respectively) of 5,150 MW is calculated. No transmission capability in the other direction is reported. In practice, and as we see in our model, flows on this line only go toward S, such that the size of the transmission capability in the other direction has little influence on our results. Since this report includes a transmission capability going from East (our area S plus zone F) to West (our area N minus zone F) of 1,999 MW, and since there is a loop between zones E, F and G, we report this latter value as the transmission capability from S to N.

3.3 Demand side

Numerical models of electricity markets generally require that price-elastic demand functions be specified across a variety of scenarios. A common practice is to presume a given elasticity for some price-quantity pair and to calibrate the corresponding affine demand function around this point. The elasticities used for calibration typically range from -0.1 to -0.4 (Andersson and Bergman (1995); Borenstein et al. (1999); Wolfram (1999); Neuhoff et al. (2005); Lijesen (2007); Billette de Villemeur and Pineau (2012, 2016)). There is significant contention in the literature on estimates of electricity-demand elasticities (Borenstein (2005)), which motivated our avoidance of calibration based on a literature survey. Instead, we use estimates tailored to our setting obtained by Benatia (2016) in a companion paper.[26]

We construct the regional demand functions for electricity as affine functions based on econometric estimates of own-price demand elasticities in upstate New York. The estimation strategy consists in using the effects of wind power production as a supply shifter to identify the demand slope parameter in a linear specification. Absent wind power data, the price variable is instrumented by wind speed, and the model is estimated using the instrumental variables and generalized method of moments. Further details can be found in Benatia (2016). This approach delivers statistically significant price elasticities around -.065 for 2012–2013. We calibrate the demand functions for the three regions based on this point estimate.

The data used to calibrate the demand functions are publicly available on NYISO's and HQ's websites. The exercise is conducted for each of the four seasons, in both peak and off-peak periods, resulting in eight demand functions per region (see Appendix B.3). The point elasticity is assumed to hold at each respective mean price and demand level, for each load segment and region, from which we derive the slope and intercept parameters of the corresponding affine demand functions. Since there is no wholesale electricity price in Quebec's regulated system, we assume a constant energy price of 38.6 CAD/MWh following the discussion in Pineau (2014).[27] Average price and demand levels are reported in Table 8, while Table 9 displays the estimated demand slope and intercept for each load segment and region. The parameters of the inverse demand Equation (1) are easily derived, since the estimated slope corresponds to $-\frac{1}{B_{il}}$ and the estimated intercept corresponds to $A_{il}B_{il}$. Seasonal average values and estimates for 2012 and 2013 are displayed in Table 24 and Table 25.

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[26] The literature on demand elasticities in electricity markets is broad and the interested reader is referred to the surveys in Taylor (1975); Patrick and Wolak (1997); Lijesen (2007), and most recently, Heshmati (2014).

[27] This is equivalent to 37.5 USD/MWh using the yearly average exchange rate for 2013 from the Bank of Canada. For more details on the value of electricity in Quebec, see Pineau (2014) p.14–16 (in French).

Table 8: Hourly average loads (MWh) and prices (USD)

Area	ID	Hourly Average Loads (MWh) and Prices (USD)							
		Winter		Spring		Summer		Fall	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QC	Price	37.50	37.50	37.50	37.50	37.50	37.50	37.50	37.50
	Load	27,636	24,939	20,881	18,307	18,084	14,897	20,036	16,940
N	Price	42.78	33.96	34.42	24.69	41.61	24.52	38.28	27.07
	Load	8,668	7,117	7,776	6,315	8,861	6,720	7,902	6,320
S	Price	63.56	45.33	45.26	29.43	60.47	28.80	45.62	31.20
	Load	11,058	8,429	10,511	7,836	14,193	10,392	10,871	8,052

Table 9: Estimated demand parameters

Area	ID	Estimated Demand Parameters							
		Winter		Spring		Summer		Fall	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QC	Slope	-47.87	-43.20	-36.17	-31.71	-31.32	-25.80	-34.70	-29.34
	Inter.	29,431	26,559	22,237	19,496	19,259	15,864	21,337	18,040
N	Slope	-13.16	-13.61	-14.67	-16.61	-13.83	-17.80	-13.41	-15.16
	Inter.	9,231	7,579	8,281	6,725	9,436	7,157	8,415	6,730
S	Slope	-11.30	-12.08	-15.08	-17.29	-15.24	-23.43	-15.48	-16.76
	Inter.	11,777	8,976	11,193	8,345	15,114	11,067	11,577	8,575

4 Results

Our model produces some expected general results in the competitive benchmark case (referred as "Comp" in the subsequent tables and figures). First, adding the CHPE line leads to an increase in welfare of approximatively \$45M. Second, this increase is accompanied by a redistribution of wealth, and inevitably, winners and losers: overall, producers win whereas consumers and traders lose. See Table 10. In the net importing region (S), it is the reverse: consumers benefit from lower prices. Nevertheless, from a local welfare perspective, all areas win in the process. Third, prices converge in the competitive case (see Table 11), the weighted average price differential being reduced by 40%, from \$5.74/MWh to \$3.42/MWh.[28] Intuitively, the competitive traders on the internal line between N and S are losing a lot with CHPE. Their profits are based on the congestion rent between N and S, i.e., the price differential between those two nodes times the volume they trade. Since, in the competitive case, the resource allocation is more efficient with CHPE, the congestion rent is reduced.

However, PTR allocation has a great impact on welfare. Figure 4 below shows the evolution of total welfare by case (CHPE and No CHPE, integrated and unbundled) and by scenario (100,90,...,0), and the evolution of the price spread, centered to 0 for the competitive case. Scenario 100 corresponds to the case where HQ owns all the rights. Conversely, scenario 0 to the case where UNY and $SENY$ own 100% of the rights on their associated line, QC-N and QC-S, respectively. Every scenario uses the same logic, with HQ having access to the two lines, and the NY players only having access to their associated line.

In the integrated case, adding CHPE could even destroy wealth when HQ owns most of the rights. Our unbundled case, where traders are local price-takers, efficiently mitigates the impact of PTR distribution on

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[28] This index consists in a nested weighted average price (WAP). We first calculated the weighted average price in each region. Then, we took the absolute value of the three price spreads between each region. For each area, we calculated the average price spread with its neighbors, weighting each neighbor by its respective total consumption. We finally calculated the average price spread among the three regions weighted by each region's consumption. In mathematical terms, if Q^i is the total consumption in area i and P^i its weighted average price, then

$$WAP\text{-Spread} = \sum_i \left[Q^i \times \frac{\sum_{j\neq i} \frac{Q^j \times |P^i - P^j|}{\sum_{l\neq i} Q^l}}{\sum_k Q^k} \right].$$

Table 10: Welfare distribution in the competitive case

	No CHPE (B$)			CHPE (B$)		
Local Welfare	Cons	Prod	Tot	Cons	Prod	Tot
QC	40.831	5.129	45.960	40.586	5.394	45.980
N	12.260	2.435	14.700	12.245	2.469	14.714
S	23.121	0.902	24.023	23.258	0.838	24.096
Total	76.212	8.467	84.679	76.089	8.701	84.790
Line	QC-N	QC-S	N-S	QC-N	QC-S	N-S
Cong. Rent	0.053	—	0.173	0.032	0.034	0.093
Total		0.225			0.159	
Welfare		84.904			84.949	

welfare, compared to the integrated case: wealth transfer between agents is much closer to the competitive case and produces higher welfare in every case. But, when most of the PTRs are owned by the NY players, it still has non-negligible distributive effects. In our case, price convergence is not synonymous with improved competition. Indeed, as can be seen in scenarios 100 and 90 with integrated traders without CHPE, prices converge more, on average, than in the competitive case, but the welfare results are, of course, lower. One could note that, within each case, the closer to zero is the price-convergence index, the higher is the welfare. Finally, adding CHPE may aggravate the situation on the price-spread but it improves it in most cases. We explain these results case by case, in the following subsections.

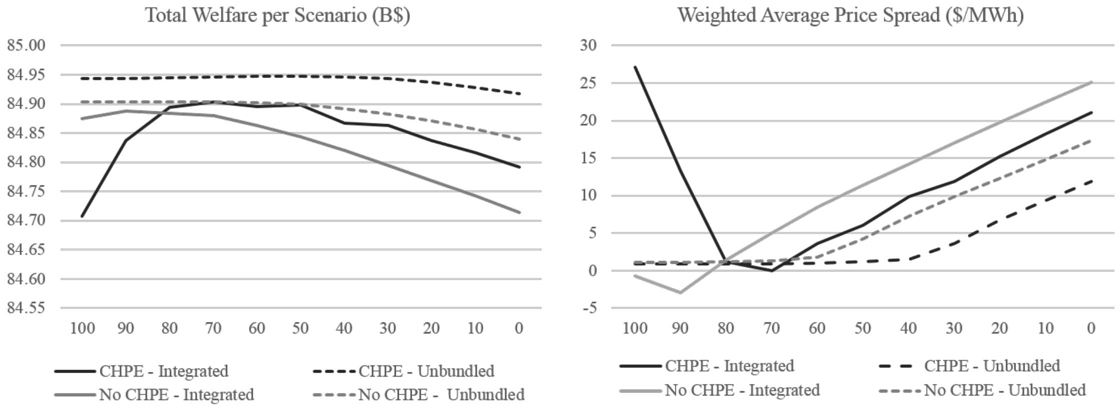

Figure 4: Total welfare and price spread measure

4.1 Case 1: Integrated trading and production

In this case, players maximize the objective function (11a). Players' strategy consists in a trade-off between exporting in order to raise their respective local price and potential trading profits on the interconnector. The trading pattern, depicted in Figure 5, varies significantly with the allocation of PTRs. Whereas HQ over-exports to the point where it always fully uses its PTRs, the best strategy for the NY players could be likened to *anti-arbitrage*. That is, the NY players have a tendency to direct their trading volume against the price differential.

The evolution of the players' strategy w.r.t. the allocation of rights experiences two main phases. First, when most of the rights are allocated to HQ, it owns a dominant position and its strategy consists in constantly exporting, across seasons and time periods, up to scenario 80. There is an absence of arbitrage. After this point, the NY players own a sufficient amount of PTRs to implement their strategy. The anticipation of the opportunity cost of water is critical in this pattern. Accordingly, the PTRs' allocation has a strong influence on a player's strategy and, given the local incentives of each player, it radically changes the trading pattern.

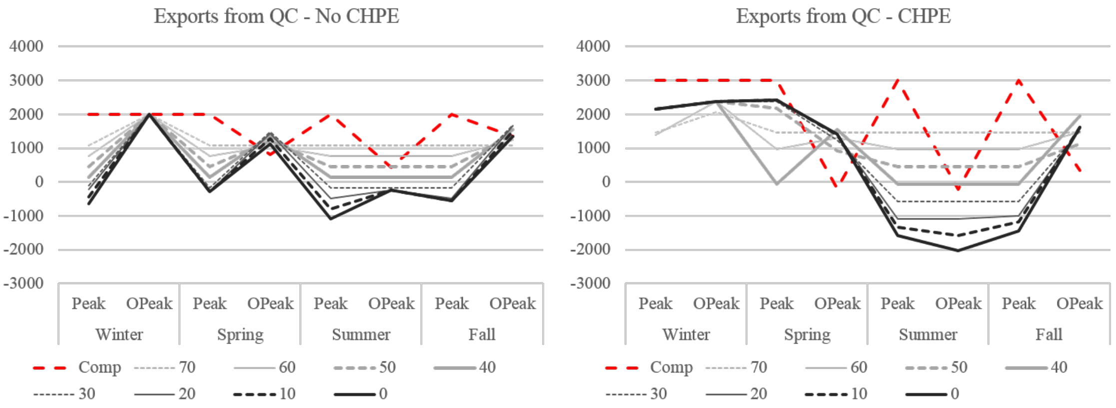

Figure 5: Strategic integrated trading pattern

HQ, the structural exporter in our model, is the one that is over-exporting the most. Such a strategy exercises a lot of tension on the terminal condition of the water stock. The shadow value of water, which is equally reflected in the price throughout the periods (modulo the discount rate), is thus very large, especially as the demand is inelastic. With high exports, the price in QC increase for every period, which boosts the value of HQ's local production. To the extent that its exports are negligible compared to its local supply, it can dump its exports. Consequently it always proceeds with a full-export corner solution. For this player, adding CHPE is just an additional way to increase its exports even more, so as to increase the local price.

For the NY players, the pattern is a bit different. As local producers, they first wish to import as little as possible. There is less need for QC hydropower, and, the final value constraint for water is not as forcefully binding as in the case where HQ owns all the PTRs. The shadow value of water decreases as the NY players own an increasing number of PTRs. On the other hand, a reduction in the water's opportunity cost increases the value of trading by increasing the price spread with QC. This incentive provokes an arbitrage between local profit and trading profit.

Without CHPE, UNY tends to reduce its imports from QC during peak periods, even exporting in summer to raise their local price during these periods of tight supply. During off-peak periods, when an exporting strategy would not cause much increase in price, they import from QC in order to take advantage of the price differential. This result is consistent with Bushnell (2003). In this paper, a Cournot producer that owns hydro and thermal power plants would prefer to schedule its hydro-production during off-peak periods in order to raise the price during peak periods, while hydro does not have much impact on the price during off-peak periods. In our paper, players' access to the interconnection is implicitly equivalent to access to QC hydropower.[29] The trading pattern constantly converges to the 0/100 allocation, like a lake contracting as the dry season progresses.

With CHPE, the pattern is different. Because the internal line linking their respective area is perfectly arbitraged, the two NY players have highly correlated strategies. For example, if UNY sticks to its previous strategy, the price differential between N and QC becomes very large. Because power is more expensive in N, less power flows through the internal line toward S, thereby increasing the price in this area. This increases the imports' profitability for $SENY$. In turn price decreases in S, which decreases the flow even more on the internal line, and therefore also, the price in N. Consequently the two players' strategies converge to a solution which preserves the price differential between N and S.[30]

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[29] This pattern is also consistent with Debia and Zaccour (2016), where dumping is more likely to occur when the local elasticity of supply is relatively low, i.e., in our case, during peak periods. Transmission-related strategic conduct can also be viewed as residual demand manipulations in an auction context, as discussed in Benatia et al. (2016).

[30] From scenario 50 to 100, we have multiple equilibria, so we selected the one maximizing the two players' joint payoff (see Section A.2). As can be seen in Figure 5, the strategies in scenarios 50, 30-0 have the same pattern, more favorable to the player UNY. On the other hand, scenario 40 has a different pattern, similar to scenario 60, which is more favorable to $SENY$. The difference in joint payoff between the different strategy types in these scenarios was in the order of \$1M per year. See Appendix C.2 for all the equilibria found.

Figure 6 shows the weighted average prices in the two NY areas during peak and off-peak periods. Peak WAPs are on the right scale, and off-peak WAPs on the left scale. The effect depicted is clearly depicted: in the case without CHPE, peak WAP in N increases as UNY obtains more rights, such that we see a price convergence between the two areas of NY. In the case with CHPE, there is no such convergence, the price spread decreases very slightly for any allocation of PTRs. In off-peak periods, HQ's over-exporting strategy dramatically decreases the price in NY by canceling the need for the Mid production segments in the state during the spring and fall off-peak periods.

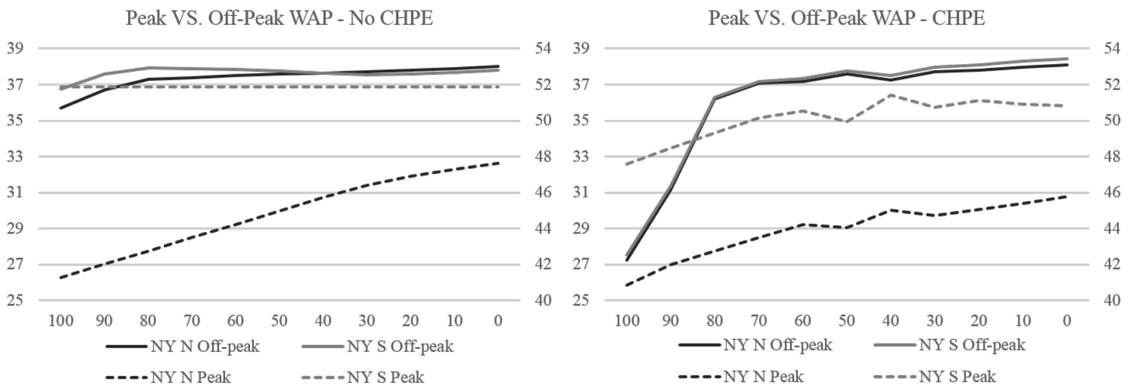

Figure 6: New York weighted average price, peak (right scale) and off-peak(left scale)

Table 11 presents the weighted average prices (WAPs) for the competitive case and for the different PTR allocations. As expected, prices vary whether or not the rights are allocated to a particular player. The magnitude of this variation among the scenarios is relatively large, especially in QC, which can be explained by the opportunity-cost-of-water component of the price, as mentioned previously. When HQ owns most of the rights, the price dramatically increases in QC. NY areas' WAPs increase in the allocation to the NY players to a lesser extent, though an approximately 5% increase in the average price is by no means insignificant. Adding CHPE, the three areas' prices converge more, except when HQ owns 100% and 90% of the PTRs. In the latter scenarios, the average price spread rose almost 500%.

Table 11: Weighted average prices in the integrated case

			Weighted Average Price ($/MWh)										
PTRs to HQ (%)		Comp.	100	90	80	70	60	50	40	30	20	10	0
	QC	35.8	45.9	40.3	34.4	30.3	26.4	23.2	19.9	16.7	13.7	10.8	7.9
No	N	39.3	38.1	39.0	39.6	40.0	40.4	40.8	41.1	41.4	41.7	41.9	42.1
CHPE	S	44.0	43.3	43.8	44.0	44.0	43.9	43.9	43.8	43.8	43.8	43.8	43.9
	QC	37.4	70.2	56.4	45.5	38.0	34.0	31.3	27.2	25	21.3	18.0	14.8
CHPE	N	39.5	33.0	35.8	39.0	39.8	40.2	40.4	40.6	40.7	40.9	41.2	41.4
	S	42.2	36.2	38.7	41.9	42.8	43.1	43.1	43.5	43.5	43.8	43.8	43.8

The distribution of wealth is depicted in Tables 12 and 13 for the case without and with CHPE, respectively. The results are presented as variations from the corresponding competitive case. To keep the comparison consistent with respect to trading profits, we compare each scenario to the competitive case, assuming that in the latter case, each player owns the same percentage of PTRs, which it manages competitively. Producers manage to raise their profit substantially when they own a relatively important share of PTRs. However the extent to which HQ is able to raise its profit is limited to scenarios 100 and 90, after which it has to put up with UNY's strategy. The very large reduction in its profits follows directly from the significant decline in QC prices. The relatively slight variation in consumers' welfare, especially in NY, is due to the fact that we have a very low demand elasticity accompanied with marginal cost pricing. Consequently, the loss of surplus due to a large increase in price does not greatly affect the total area below the inverse

Table 12: Welfare variation in the integrated case without CHPE

		Welfare variation w.r.t. the competitive benchmark (%)										
		100	90	80	70	60	50	40	30	20	10	0
QC	Cons	-3.8	-1.7	0.6	2.1	3.7	4.9	6.2	7.5	8.7	9.8	11.0
	Prod	29.0	13.1	-4.4	-16.7	-28.9	-39.2	-49.8	-60.6	-71.0	-81.4	-91.9
	Tot	-0.1	$-\epsilon$	ϵ	ϵ	ϵ	$-\epsilon$	-0.1	-0.2	-0.3	-0.4	-0.5
N	Cons	0.5	0.1	-0.2	-0.3	-0.5	-0.7	-0.8	-1.0	-1.1	-1.2	-1.3
	Prod	-4.3	-1.3	0.2	1.3	2.4	3.6	5.1	6.7	8.4	10.3	12.3
	Tot	-0.3	-0.1	-0.1	-0.1	$-\epsilon$	0.1	0.2	0.3	0.5	0.7	1.0
S	Cons	0.2	0.1	$-\epsilon$	ϵ	ϵ	ϵ	0.1	0.1	0.1	ϵ	ϵ
	Prod	-1.8	-0.5	0.1	ϵ	-0.1	-0.3	-0.4	-0.6	-0.5	-0.4	-0.2
	Tot	0.1	ϵ	$-\epsilon$	ϵ	ϵ	ϵ	ϵ	ϵ	ϵ	ϵ	ϵ
Cong. Rent		14.9	5.1	-4.8	-14.7	-24.6	-34.5	-44.3	-53.8	-59.2	-62.5	-65.5
Total NY		-0.1	-0.1	-0.2	-0.2	-0.3	-0.3	-0.3	-0.2	-0.2	-0.1	$-\epsilon$
Total		-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.3

ϵ corresponds to a variation lower than 0.05%

demand curve.[31] The impact of strategies on the total welfare is mainly driven by the effect on consumption. Even if it seems unimportant, it is worth noting that 0.1% of \$85B is \$85M. Furthermore, focusing on the sign of the values in Table 12, it can be seen that, from the viewpoint of QC (line "Tot QC") and NY regulators (line "Total NY"), most of these situations (scenarios 100, 90, 50–0) are dominated by the competitive case. The three non-dominated scenarios after this criterion represent only a marginal positive variation in QC wealth w.r.t to the competitive case. The two regulators have thus a strong incentive to cooperate in order to implement rules that would foster more competitive situations.

In the case with CHPE, HQ has more latitude to increase its profit, whereas UNY has to deal with $SENY$ on the management of interconnections. Contrary to the previous case, the worst scenario for welfare is when HQ owns 100% of the PTRs. In this scenario, adding CHPE is even more detrimental to NY producers and QC consumers, compared to the competitive case. Fortunately, HQ's strategy is very sensitive to the amount of rights it owns, and such imbalance in the distribution of wealth is resolved from scenario 80. Nonetheless, these over-exporting scenarios (100–90) create the most wealth for the whole NY area, especially for S. From the point of view of each jurisdiction's regulator, the local welfare in QC and NY (that is, the sum of N, S and the congestion rent for the internal line) is higher in the competitive case in most scenarios (80, 40–0). Such dominated scenarios correspond to the situation where regulators have incentives to cooperate in order to implement a trans-jurisdictional regulatory framework enforcing competitive behavior.

Table 13: Welfare variation in the integrated case with CHPE

		Welfare variation w.r.t. Competitive (%)										
		100	90	80	70	60	50	40	30	20	10	0
QC	Cons	-12.2	-7.2	-3.1	-0.2	1.3	2.4	4.0	4.8	6.3	7.6	8.9
	Prod	83.8	49.4	21.9	1.6	-9.5	-17.4	-29.7	-36.9	-48.5	-59.6	-70.8
	Tot	-0.8	-0.5	-0.1	ϵ	ϵ	ϵ	$-\epsilon$	-0.1	-0.2	-0.3	-0.5
N	Cons	2.9	1.7	0.2	-0.1	-0.3	-0.4	-0.5	-0.5	-0.6	-0.7	-0.8
	Prod	-22.1	-12.4	-2.2	-0.2	0.6	1.3	1.8	2.7	3.9	5.5	7.3
	Tot	-1.3	-0.7	-0.2	-0.2	-0.2	-0.1	-0.1	ϵ	0.1	0.3	0.5
S	Cons	2.0	1.1	0.1	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.5	-0.5
	Prod	-18.1	-8.6	-0.3	0.9	1.1	1.9	3.2	5.1	7.3	10.0	13.3
	Tot	1.3	0.8	0.1	-0.2	-0.2	-0.2	-0.3	-0.2	-0.2	-0.2	$-\epsilon$
Cong. Rent		19.1	13.6	15.4	17.6	11.2	1.9	11.1	4.5	4.4	-4.8	-14.7
Total NY		0.2	0.1	-0.2	-0.3	-0.3	-0.3	-0.4	-0.3	-0.3	-0.2	$-\epsilon$
Total		-0.3	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2

ϵ corresponds to a variation lower than 0.05%

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[31] If the lower level was a Cournot game, this result would not hold, as the prices would increase much more to take advantage of a very low demand elasticity.

4.2 Case 2: Unbundled trading and production

In this case, players maximize the objective function (12). Consequently, they only maximize their trading profit at the expense of their global one. As seen previously, the total welfare is much higher in this case. Since the traders act as local price takers, the prices when HQ owns most of the rights are the closest to the competitive situation. This is because, in this scenario, HQ trades without seeing the dynamics of water management in the QC price. Hence, it just arbitrages over the price differential on the NYISO thermal system, and thus under-exports, as is expected from a Cournot player with a "constant" marginal cost of trading. In contrast, NY players anticipate QC price dynamics. They are still willing to under-export, in order to increase the price differential as much as possible. Figure 7 shows the overall export pattern from QC to New York along the representative year for all scenarios.

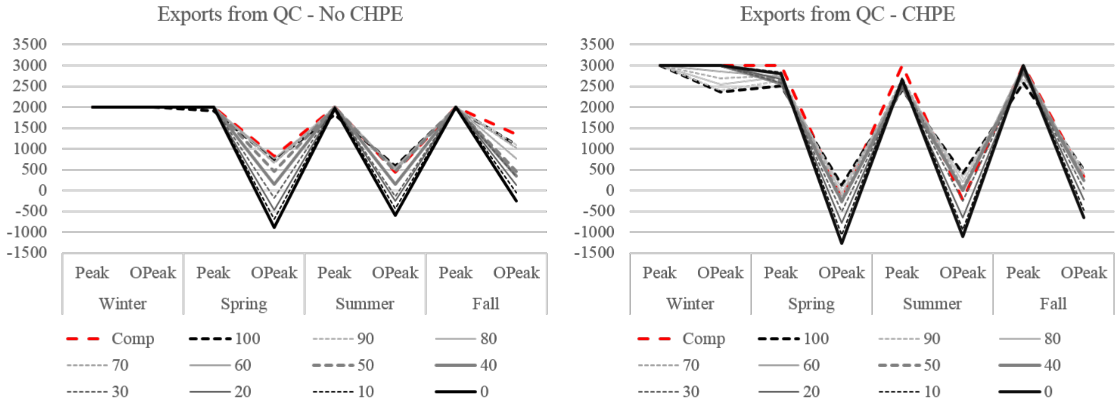

Figure 7: Strategic unbundled trading pattern

The strategic trading pattern is consistent with the perfect arbitrage one. The strategy here only consists in under-exporting, but given the extent of the price differential between QC and the two NY areas during peak periods, the QC export constraint is almost always binding in this case. As the NY players increasingly get more rights, they tend to export to QC during off-peak periods against the price differential. In doing so, they greatly decrease the price in QC, according to the same dynamic principle explained previously. This permits them to realize important trading profits during peak periods. According to our results, this strategy enables them to double their trading gain when they have full access, compared to the case where HQ has full access. The consequence of such a strategy is that NY's off-peak prices increase a lot as NY players obtain rights (see Figure 8).

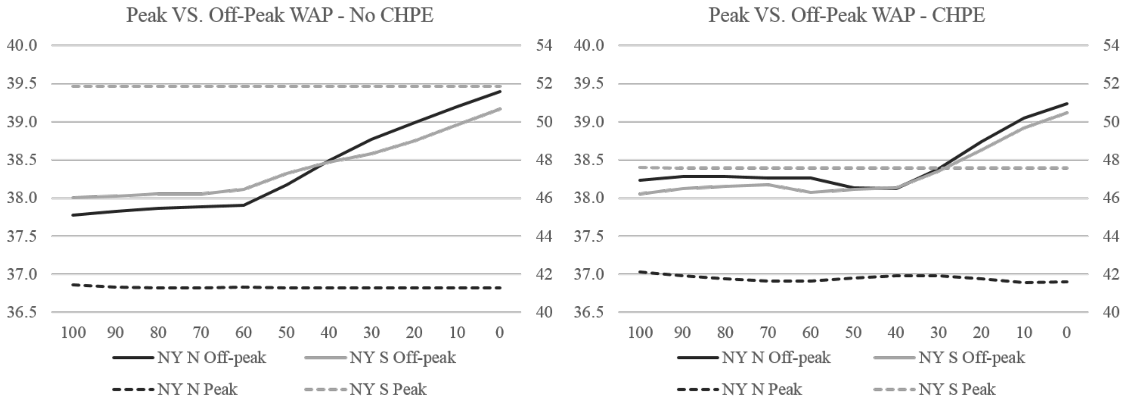

Figure 8: New York weighted average price, peak (right scale) and off-peak (left scale)

Overall, the three regions' prices converge with the construction of CHPE. Table 14 shows the prices obtained in the unbundled cases. The prices vary less throughout the scenarios, compared to the integrated

Table 14: Weighted average prices in the unbundled case

PTRs to HQ (%)		Weighted Average Price (\$/MWh)											
		Comp.	100	90	80	70	60	50	40	30	20	10	0
	QC	36	34.7	34.7	34.6	34.4	33.9	31.2	27.8	24.9	22.2	19.4	16.7
no	N	39.3	39.4	39.3	39.3	39.3	39.4	39.5	39.7	39.9	40.0	40.1	40.2
CHPE	S	44.0	44.0	44.0	44.1	44.1	44.1	44.2	44.3	44.4	44.5	44.6	44.7
	QC	37.4	36.5	36.5	36.5	36.5	36.4	36.2	35.8	33.4	30.0	27.1	24.4
with	N	39.5	39.9	39.9	39.8	39.7	39.7	39.7	39.8	39.9	40.1	40.1	40.3
CHPE	S	42.2	42.2	42.3	42.3	42.3	42.2	42.2	42.3	42.4	42.5	42.7	42.8

case, especially when HQ owns most of the rights. Accordingly, the allocation of wealth, depicted in Tables 15 and 16 for the cases without and with CHPE, respectively, varies much less than in the integrated case. Nevertheless, the case of unbundled NY traders implies large transfers of wealth from QC producers to NY producers. Adding CHPE in this case has the benefit of always improving the situation, as compared to the case without it, irrespective of the allocation of PTRs (see Figure 4). It also produces an aggregated welfare equivalent to the competitive one, which consists mainly in a transfer from QC to N. These transfers are reduced with unbundling. It is worth noting that, contrary to the integrated case, the presence of CHPE never increases the wealth of S consumers compared to the competitive case.

Table 15: Welfare variation in the unbundled case without CHPE

		Welfare variation w.r.t. Competitive (%)										
		100	90	80	70	60	50	40	30	20	10	0
	Cons	0.4	0.4	0.5	0.5	0.8	1.8	3.1	4.2	5.3	6.4	7.5
QC	Prod	-3.5	-3.4	-3.9	-4.3	-6.0	-14.3	-25.1	-34.6	-43.9	-53.4	-63.1
	Tot	ϵ	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.1	-0.2	-0.3	-0.4
	Cons	-0.1	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.1	-0.2	-0.3	-0.3	-0.4	-0.4
N	Prod	0.32	0.3	0.3	0.4	0.5	1.3	2.5	3.8	5.3	6.8	8.6
	Tot	ϵ	ϵ	ϵ	ϵ	ϵ	0.1	0.3	0.4	0.6	0.8	1.1
	Cons	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2
S	Prod	0.2	0.2	0.3	0.3	0.4	0.8	1.1	1.3	1.6	2.1	2.5
	Tot	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Cong. Rent		-0.2	0.3	0.6	0.4	0.6	0.1	-2.9	-5.6	-6.5	-6.5	-6.7
Total NY		-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	ϵ	0.1	0.2
Total		-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1

ϵ corresponds to a variation lower than 0.05%

Table 16: Welfare variation in the unbundled case with CHPE

		Welfare variation w.r.t. Competitive (%)										
		100	90	80	70	60	50	40	30	20	10	0
	Cons	0.4	0.4	0.4	0.4	0.4	0.5	0.6	1.5	2.9	4.0	5.1
QC	Prod	-2.6	-2.7	-2.7	-2.7	-3.0	-3.6	-4.8	-11.9	-22.3	-31.6	-40.9
	Tot	ϵ	ϵ	ϵ	ϵ	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.2	-0.3
	Cons	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.3	-0.3
N	Prod	0.9	0.9	0.7	0.6	0.6	0.6	0.8	1.6	2.7	3.6	5.0
	Tot	ϵ	ϵ	ϵ	ϵ	ϵ	ϵ	0.1	0.1	0.3	0.4	0.6
	Cons	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.1	-0.2	-0.2
S	Prod	-0.2	ϵ	0.2	0.3	0.1	0.2	0.3	1.3	3.2	5.9	8.9
	Tot	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	ϵ	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	-0.1	-0.1
Cong. Rent		-12.2	-9.0	-5.6	-3.0	-6.2	-4.6	-5.8	-7.2	-8.1	-4.6	-5.4
Total NY		-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1	-0.1	ϵ	0.1
Total		$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$	$-\epsilon$

ϵ corresponds to a variation lower than 0.05%

As in the integrated case, some scenarios are dominated by the competitive situation from the local regulators' point of view. Whereas, previously, those dominated scenarios previously corresponded to relatively extreme distributions of PTRs, the dominated scenarios here correspond to more competitive cases where the PTRs are allocated relatively uniformly among the players. This situation is in line with the results in Debia and Pineau (2016). This type of allocation corresponds to a configuration where every players potentially has an interior solution at equilibrium. As such, the market externalities[32] are the most important in this case. Because unbundling is enforced, each player is missing a piece of information about the impact of the others' strategy on their profit through the local price setting. The extent to which they are able to internalize the others' strategy, already imperfect in usual game, is thus even more limited. This limitation allows for a closer-to-competitive result but also causes residual deadweight losses to be more equally distributed among the areas.

4.3 Discussion

These results have to be put in perspective, as our model is deterministic and uses average values by time-period for prices, demand and generation (see calibration results in Appendix C.1). To that extent, the value created by the interconnection, albeit relatively modest, would increase with the existence of more extreme situations. Further, assuming that more variations imply more opportunities to game the market, the distributional effect, already significant here, may be even greater than estimated. Furthermore, water management in QC is subject to many environmental and supply security constraints that are not modeled here. Finally, the price of carbon and natural gas may vary in the future. Greater interests in interconnection can be expected as the prices of these commodities increase.

In interconnected markets with marginal cost pricing, the results of these models suggest a significant dumping issue. In this context, adding a new line does not necessarily imply creating wealth: it depends on how the line is managed. In our worst case, the destruction of wealth amounts to \$165M, compared to \$45M in additional wealth from the interconnection in the competitive case. If an integrated producer-trader owning a large amount of hydro capacity has a dominant access to the interconnector, it could destroy wealth and be remunerated for it. To unbundle this type of agent seems a good approach to mitigate their market power. In the context of a realistic situation where a hydro producer would, as a privileged exporter, own most of the rights, it seems important to restrict communication between their production and trading activities. However, if dominant access is granted to importers in a thermal system coupled to a hydro-dominated system, unbundling may not be sufficient. To a certain extent, their trading strategy is consistent with their production strategy. While an integrated player wishes to raise its local price during all periods, an unbundled players only wishes to raise the price during off-peak periods to profit of a higher price differential during peak period. This type of strategy might bypass current market rules, as most regulatory actions in the electricity markets are designed for peak periods.

When a line is added, we witness an important change in the pattern of strategies in the integrated case, and the emergence of multiple equilibria. It is difficult in this context to predict any typical strategy pattern. Nevertheless, while the trading strategies are different among the equilibria in the CHPE–integrated case, the difference in their impact on the price differential between N and S is rather limited. It has a greater impact on the distribution of wealth than on its creation. Providing all rights to HQ might give it a dramatically dominant position with CHPE, but if each NY player has a monopolistic access to its line, this results in a more competitive situation.

Finally, the equilibrium is dominated by the competitive situation from each regulator's point of view for several scenarios in each case. In these scenarios, regulators would be better off cooperating to implement international jurisdiction which effectively ensures greater competition. It appears that adding CHPE reduces this tendency in both the integrated and the unbundled cases. This can be explained by the fact that adding the new line brings a new player into the game, which splits the market power. But the dominated situation in the integrated and the unbundled cases happens for different types of allocation. This is because they

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[32] By market externalities we mean that each player action has an impact on the others' action, but that they do not anticipate it. They do not "internalize" the others' action in their profit function by considering them as given. Further explanation of this effect is provided in Davis and Whinston (1962).

are different in nature. In the integrated case, a situation is dominated for extreme distributions because it allows each player to fully capture the market power rents, which in turn fundamentally distorts the market signals.[33] In the unbundled case, the dominated situations happen for relatively even distributions, which are consequently the most competitive. These cases correspond to sub-perfect-competition situations where the deadweight losses are relatively uniformly distributed among the areas.

5 Conclusion

This paper highlights some challenges in regional power market integration. Such integration, especially with a hydro-dominated system, is appealing as intermittent sources of renewable energy increasingly come into play. While such integration may be beneficial from a welfare perspective, a deeper understating of its complexities is required. Our analysis of PTR allocation, which is relevant in a context where the FERC allows 100% of PTRs to be assigned to a single entity, shows that promoting merchant transmission lines between markets can be detrimental to welfare under some conditions. If there is no supranational regulatory body monitoring and enforcing competition, then such lines can increase trade for the purposes of manipulating local prices. this increased volume of trade mainly consists in dumping by the dominant player. To the extent that implementing inter-jurisdictional regulations may be a costly process, unbundling the trading and generating activities within firms seems an efficient local alternative.

Currently, most hydro-dominated systems are in strongly regulated jurisdictions. Their tariff for local demand has been fixed by law and is indexed to the inflation rate. This type of regulation decouples the local price from the opportunity cost of exports (and thus water). Consequently, over-exporting is not profitable for a hydro producer, as it cannot raise its local price. But integration between markets is usually promoted through a tariff reflecting the opportunity cost of exports. Our model shows that, given our set of modeling assumptions, such a modification in the legislation might not be desirable if the trading structure of producers *in all the concerned regions* is not taken care of.

Additional research on the construction of supranational power-market integration and regulation is needed. The current trend of investing in intermittent energy sources increases the desirability of integration between complementary systems, as these more volatile assets need to be hedged, physically as well as financially. Furthermore, there is a debate currently about whether interconnections should be accounted for in capacity mechanisms, which are usually accompanied by supply-commitment measures during critical periods for the beneficiaries. It would be interesting to see what kinds of incentives these measures would bring. Finally, it would be beneficial to integrate this game into a decision analysis model to evaluate a particular investment. This would require an increase in the granularity of our model's specifications, and the development of scenarios, especially on carbon and fuel costs. Our current computing time for each scenario is relatively fast, such that it would not be too costly to increase the number of technologies, demand segments and/or time periods. Since our model is technology-based, it makes it possible to assess gains in terms of carbon emissions due to trade. A more challenging extension would be to incorporate an AC meshed network into the lower stage. This could provide a (more competitive) alternative to market power in th electrical network model using EPEC, e.g. Ehrenmann and Neuhoff (2009), but focusing on critical nodes such as HVDC interconnection ones.

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[33] This claim is however not true in the case "Integrated–CHPE", scenarios 100-90, where the dumping strategy of HQ benefits consumers in NY.

A Model: Supplementary Material

A.1 The fringe of competitive traders

Since the fringe is price-taker, we treat its problem as a part of the lower-level stage. This allows us to solve this particular problem using a much simpler Mixed Complementarity Problem (MCP) formulation. We add the following conditions to the lower-level stage:

$$\pi_{jl} - \pi_{il} = \psi_{ijl} - \psi_{jil} + \delta^+_{ijl} - \delta^-_{ijl} \qquad \perp x^C_{ijl}, \qquad \forall i, j \neq i, l, \tag{13a}$$

$$x^C_{ijl} = -x^C_{jil} \qquad \perp \psi_{ijl} \qquad \forall i, j \neq i, l, \tag{13b}$$

$$-PTR^C_{ij} \leq x^C_{ijl} \leq PTR^C_{ij} \qquad \perp \delta^-_{ijl}, \delta^+_{ijl} \geq 0 \qquad \forall i, j \neq i, l. \tag{13c}$$

An interior solution for the fringe implies that the right-hand side of Equation (13a) is zero, and hence that the price differential should be zero.

A.2 Solution method

Because of the complementarity constraints included in the lower stage's equilibrium conditions, the EPEC formulation $\{(11)\}_{f=HQ,UNY,SENY}$ is non-convex. Consequently, each MPEC (11) is numerically difficult to solve and may not result in a stationary global optimum (Luo et al. (1996)). Nonetheless, our problem has the following properties:

(a) the lower stage is a quadratic program with affine constraints,
(b) the upper stage's constraints are affine, and
(c) the upper stage's objective function is once derivable in x^f.

Conditions (a)-(c) imply that each MPEC (11) has a stationary local optimum (Hu and Ralph (2007); Yao et al. (2008)). Henceforth, the equilibrium $(\mathbf{x}^*, \mathbf{Y}^*, \mathbf{\Gamma}^*)$ of the EPEC $\{(11)\}_{f=HQ,UNY,SENY}$ is a Local Nash Equilibrium as defined in Hu and Ralph (2007).[34] The lower stage being common to every player, an EPEC equilibrium belongs to the class of Generalized Nash Equilibrium (Pang and Fukushima (2005); Pang (2010)). Because of this, there may be an infinite number of equilibria or there may be none.

We solve the EPEC by alternately solving each MPEC using the diagonalization algorithm (Hu and Ralph (2007); Gabriel et al. (2013)). This algorithm consists in building a sequence of solutions that will converge to a fixed point. We use the NLPEC solver in GAMS. At each iteration, the solution was reported as a local optima. To deal with multiple local optima, we operate runs with different starting points. In a first version, we set the initial point of each player's actions at its minimum feasible value for odd iterations. For even ones, the player's action is initialized at its maximum feasible value. Such oscillations give a flavor of global optimality. Indeed, if the algorithm converges to the same point from two opposite corners of the feasible set, then the solution is likely a global one. If this first version does not converge, we try a second version where each starting point is the previous iteration's solution, perturbed by a value ϵ. Similarly to the previous algorithm, the value of epsilon is negative for odd iterations and positive for even iterations. We solve the EPEC with different values of $|\epsilon|$ to find different equilibria. We eliminate strictly dominated equilibria from our selection (if they existed), and then select an equilibrium based on an *ad hoc* criterion: maximization of the joint profit of the unconstrained players. Only the integrated case with CHPE fails to converge in every case for the first algorithm. For those, we thus apply the second algorithm, and three to four types of equilibria, differing in their trading pattern, were found.

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[34] Theoretically, a global optimum could be approximated by transforming complementarity constraint into equivalent "big-M" disjunctive constraints (Fortuny-Amat and McCarl (1981)). However, this method is numerically very costly, as explained in Siddiqui and Gabriel (2012) among others.

B Supplementary Data

B.1 Supply-side: New York

Table 17 describes the prices of fuel inputs per season in 2013. For bituminous coal and natural gas in New York State, data is directly available in \$/MMBTU for electric utilities. For uranium and oil products (FO6, FO2, KER), data is not available and has to be built. For oil products, we take from the EIA database the monthly wholesale/resale price by refiner for each product in \$/gallons, and the retail volume sold by refiner in gallons. From this, we calculate a weighted average price for each season. Then we convert gallons in MMBTU for each fuel type using any web converter, which allow us to calculate the price in \$/MMBTU. For uranium, we use the yearly weighted average price calculated by EIA of \$51.99/lb.

Table 17: Fuel prices by season

Fuel Type	Price (\$/gal) Winter	Spring	Summer	Fall	Energy Content (BTU/gal)	Prices (\$/MMBTU) Winter	Spring	Summer	Fall
UR*	51.99	51.99	51.99	51.99	180,000,000	0.29	0.29	0.29	0.29
BIT						3.05	3.02	3.05	3.22
NG						6.35	4.98	4.43	4.97
FO6	2.40	2.24	2.27	2.23	149,893	15.87	14.94	15.12	14.87
FO2	3.08	2.76	2.95	2.96	138,874	22.17	19.84	21.21	21.33
KER	3.31	2.83	3.04	3.06	134,870	24.58	20.98	22.50	22.71

*The unit for uranium is pound (lb) rather than gallon (gal)

We obtain the fuel cost of each power plant type using the following steps. First we express the heat rate in MMBTU/MWh as

$$\frac{\text{BTU}}{\text{kWh}} = \frac{10^6 \times \text{BTU}}{10^6 \times \text{kWh}} = \frac{\text{MMBTU}}{10^3 \times \text{MWh}}.$$

Then we insert this expression in the fuel cost computation (units are between brackets), that is,

$$\text{Fuel Cost}\left(\frac{\$}{\text{MWh}}\right) = \text{Heat Rate}\left(\frac{\text{MMBTU}}{10^3 \times \text{MWh}}\right) \times \text{Fuel Price}\left(\frac{\$}{\text{MMBTU}}\right).$$

Results are displayed in Table 18.

Table 18: Fuel cost per technology and season

Generator Type 1	Fuel Mover	Fuel Cost (\$/MWh) Winter	Spring	Summer	Fall
ST	UR	3.02	3.02	3.02	3.02
ST	BIT	30.77	30.47	30.77	32.49
CC	NG	48.69	38.18	33.96	38.10
IC	NG	60.79	47.67	42.41	47.58
ST	NG	65.75	51.56	45.87	51.46
GT	NG	72.21	56.63	50.37	56.51
ST	FO6	164.02	154.43	156.29	153.68
IC	FO2	230.59	206.40	220.61	221.90
GT	FO2	300.52	268.99	287.50	289.19
GT	KER	333.21	284.38	305.04	307.83

Also, the New York state is a member of the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade carbon market. Therefore, each power plant must buy carbon emission allowance. Using 2013 seasonal auction prices for 2013 (Potomac (2014)) and the carbon content of each fuel type, we calculate the carbon cost per MMBTU by fuel type in Table 19. Using heat rates and carbon costs as per MMBTU, we are able to calculate the carbon cost in \$/MWh, displayed in Table 20.

B.2 Supply-Side: Quebec

Using Equation (7a), the level of water in one season is equal to the level of water in the previous season minus hydro-reservoir production plus water inflows. On the one hand, HQ Distribution publishes a yearly

Table 19: Carbon price per fuel and season

Fuel Type	Carbon Content (Pounds CO2/MMBTU)	Carbon Price ($/MMBTU) Winter	Spring	Summer	Fall
UR	0	0	0	0	0
BIT	205.6	0.29	0.33	0.27	0.31
NG	117	0.16	0.19	0.16	0.18
FO6	173.6	0.24	0.28	0.23	0.26
FO2	161.3	0.23	0.26	0.22	0.24
KER	159.4	0.22	0.26	0.21	0.24
CO2 ($/Short tons)		2.8	3.21	2.67	3

Table 20: Carbon cost per technology and season

Generator Type 1	Fuel Mover	Carbon Cost ($/MWh) Winter	Spring	Summer	Fall
ST	UR	0	0	0	0
ST	BIT	2.90	3.33	2.77	3.11
CC	NG	1.26	1.44	1.20	1.35
IC	NG	1.57	1.80	1.50	1.60
ST	NG	1.70	1.94	1.62	1.82
GT	NG	1.86	2.14	1.78	2.00
ST	FO6	2.51	2.88	2.40	2.69
IC	FO2	2.35	2.69	2.24	2.52
GT	FO2	3.06	3.51	2.92	3.28
GT	KER	3.02	3.47	2.88	3.24

report with hourly data on heritage and non-heritage production and on sales from HQ Production to HQ Distribution (Hydro-Québec (2014)). Assuming that hydro-reservoir production is equal to the total heritage production times the share of hydro-reservoir capacity in the total heritage capacity, we extrapolate seasonal production for hydro-reservoirs ("H prod" in Table 21).

On the other hand, HQ Production publishes in June and September of each year a report on their security of supply forecast (e.g. Hydro-Québec (2015a)). In each of the June reports, the real water level in TWh on January 1st is stated, and a graph reports the forecast for the two next years. By taking the June 2012, 2013 and 2014 reports, we have the real water levels in TWh on January 1st. Comparing the difference two-by-two along with the total yearly hydro reservoir production, as estimated in the previous paragraph, we obtain the total water inflow in the reservoir during the year. Then, using the graphs, we estimate a proxy of the expected water level at the beginning of each season (1st of April, July, October). Our results are displayed in Table 21.

Table 21: Quebec water inflow

Year	in TWH	Tot Prod A_t	H Prod $B_t = 0.626 \times A_t$	Water Stock W_t	Water Inflow $I_t = W_{t+1} + B_t - W_t$
2012	Winter	50.084*	31.331	102.8*	-4.469
	Spring	38.092*	23.829	67	53.829
	Summer	38.067*	23.813	97	38.813
	Fall	45.504*	28.466	112	27.166
	Total	171.747*	107.440		115.340
2013	Winter	52.510*	32.849	110.7*	-8.851
	Spring	39.620*	24.785	69	65.785
	Summer	38.325*	23.975	110	24.975
	Fall	47.701*	29.840	111	15.840
	Total	178.157*	111.449		97.749
2014	1st Jan			96.1*	

* data measured by HQ

B.3 Demand-side

Table 22: NYISO interfaces

Area	ID	Interface	NYISO Name	Import Weight	Export Weight
	NE1	NEW ENGLAND	SCH - NE - NY	800/1400	800/1600
	ON	ONTARIO	SCH - OH - NY	2000/2000	1600/1600
N	PJ1	PJM	SCH - PJ - NY	1550/4050	1050/2950
	QC1	QUEBEC	SCH - HQ - NY	1500/1500	1000/1000
	QC2	QUEBEC	SCH - HQ_CEDARS	190/190	1/1
	NE1	NEW ENGLAND	SCH - NE - NY	600/1400	800/1600
	NE2	NEW ENGLAND	SCH - NPX_1385	428/428	388/388
S	NE3	NEW ENGLAND	SCH - NPX_CSC	330/330	330/330
	PJ1	PJM	SCH - PJ - NY	2500/4050	1900/2950
	PJ2	PJM	SCH - PJM_NEPTUNE	660/660	660/660
	PJ3	PJM	SCH - PJM_VFT	315/315	315/315
	PJ4	PJM	SCH - PJM_HTP	660/660	660/660

Notes: Import and export weights for *N* and *S* are defined using the Transmission System Representation 2014 IRM Study (NYSRC, 2013). They correspond to the relative Summer Emergency Ratings (MW) between each interface. [New York State Reliability Council (NYSRC), 2013, New York Control Area Install Capacity Requirement. Appendices. December 6, 2013.]

Table 23: Hourly average net imports (MWh)

		Hourly Average Net Imports (MWh)							
Area	ID	Winter		Spring		Summer		Fall	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
	NE1	-208.03	-232.35	49.65	-31.50	-73.60	-4.65	-79.19	-64.12
	ON	484.81	579.18	696.03	816.23	555.78	797.03	526.36	697.29
N	PJ1	288.69	290.73	101.90	69.18	168.67	353.82	203.16	159.76
2012	QC1	1120.34	691.82	1139.95	935.85	1292.22	1010.21	1064.95	887.59
	QC2	47.93	21.24	133.25	66.60	121.10	64.74	118.84	73.79
	TOTAL	1733.75	1350.61	2120.78	1856.36	2064.17	2221.15	1834.12	1754.31
	NE1	-232.04	-245.97	-2.08	-56.01	-119.37	-32.72	-128.06	-93.90
	NE2	121.60	45.46	114.22	77.54	148.63	101.05	77.32	35.19
	NE3	254.19	115.54	289.92	226.69	312.34	264.58	230.48	186.29
S	PJ1	455.96	463.91	150.43	99.18	247.51	565.21	300.93	226.71
2012	PJ2	475.61	416.94	295.26	158.71	125.87	124.60	196.11	169.03
	PJ3	108.59	79.88	72.96	-33.94	66.29	201.39	41.13	40.06
	PJ4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL	1183.91	875.75	920.70	472.17	781.27	1224.12	717.91	563.37
	NE1	-423.23	-365.02	-199.23	-145.91	-29.05	-81.61	-76.11	-128.16
	ON	708.58	968.71	665.56	900.38	702.74	1010.71	719.36	883.94
N	PJ1	275.61	276.99	130.75	159.18	150.44	184.71	138.94	63.71
2013	QC1	733.65	623.58	1076.35	797.98	1333.37	1180.38	1097.22	1046.37
	QC2	93.13	74.11	142.84	89.76	164.58	86.06	145.57	124.81
	TOTAL	1387.74	1578.37	1816.27	1801.39	2322.08	2380.24	2024.98	1990.67
	NE1	-446.88	-396.54	-226.85	-175.91	-67.63	-103.42	-121.38	-150.97
	NE2	22.16	2.90	111.96	77.87	153.55	80.04	46.70	35.54
	NE3	125.01	54.93	261.82	216.66	327.99	316.60	293.08	271.55
S	PJ1	435.94	430.58	179.62	234.33	228.44	285.56	208.76	79.55
2013	PJ2	418.71	411.19	271.05	256.45	471.11	396.77	371.47	219.48
	PJ3	244.77	244.17	95.32	101.84	46.84	164.97	77.08	42.12
	PJ4	178.04	169.21	33.92	15.56	36.68	25.99	33.29	15.11
	TOTAL	977.76	916.43	726.85	726.81	1196.99	1166.51	909.01	512.38

Table 24: Hourly average loads (MWh) and prices (USD) by year

		Hourly Average Loads (MWh) and Prices (USD)							
Area	ID	Winter		Spring		Summer		Fall	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QC	Price	37.50	37.50	37.50	37.50	37.50	37.50	37.50	37.50
2012	Load	27098	24233	20409	17729	18163	14898	20100	17001
N	Price	33.67	26.90	29.96	19.21	39.47	23.75	38.07	29.95
2012	Load	8482	6918	7671	6202	8983	6756	7868	6265
S	Price	42.56	30.49	37.08	21.59	55.06	27.00	46.64	33.68
2012	Load	10922	8283	10558	7823	14353	10483	10820	8009
QC	Price	37.50	37.50	37.50	37.50	37.50	37.50	37.50	37.50
2013	Load	28174	25646	21353	18885	18006	14895	19971	16879
N	Price	51.89	41.03	38.87	30.17	43.76	25.28	38.50	24.20
2013	Load	8855	7315	7880	6428	8739	6684	7936	6375
S	Price	84.55	60.18	53.45	37.27	65.89	30.61	44.60	28.72
2013	Load	11195	8575	10464	7848	14032	10300	10922	8095

Table 25: Estimated demand parameters by year

		Estimated Demand Parameters							
Area	ID	Winter		Spring		Summer		Fall	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
QC	Slope	-59.91	-54.07	-45.27	-39.69	-39.21	-32.30	-43.44	-36.73
2012	Intercept	29882	26967	22578	19796	19555	16108	21665	18317
N	Slope	-16.47	-17.04	-18.37	-20.79	-17.31	-22.29	-16.78	-18.98
2012	Intercept	9373	7696	8408	6828	9581	7267	8544	6834
S	Slope	-14.15	-15.12	-18.88	-21.65	-19.08	-29.33	-19.37	-20.98
2012	Intercept	11957	9114	11365	8473	15346	11236	11755	8707
QC	Slope	-35.82	-32.32	-27.06	-23.73	-23.44	-19.31	-25.97	-21.95
2013	Intercept	28979	26152	21895	19197	18963	15620	21009	17763
N	Slope	-9.85	-10.18	-10.98	-12.43	-10.35	-13.32	-10.03	-11.35
2013	Intercept	9090	7463	8154	6621	9291	7047	8286	6627
S	Slope	-8.46	-9.04	-11.29	-12.94	-11.41	-17.53	-11.58	-12.54
2013	Intercept	11596	8839	11022	8217	14882	10897	11399	8443

C Supplementary results

C.1 Calibrated results with estimated data

Figure 9 shows the model's result in terms of price and load in UNY and $SENY$ where the exports From QC to UNY are fixed at the estimated data (see Table 22). Black lines show the results computed with our model, and gray lines are for the estimated data (see Table 8). For the load, the results are good replicates, which is not surprising given the low elasticity of demand. Computed prices in UNY are on average greater than observed ones, and much flatter. For $SENY$, the computed prices seem correct for the approximated data we used and for all the elements that did not appear in our model, e.g. periodical plant availability.

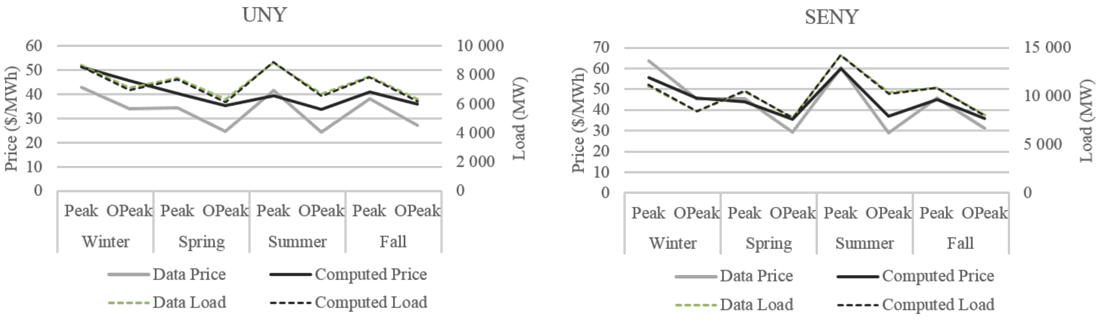


Figure 9: Load and price with data exports: Data Vs. results

C.2 Multiple equilibria in the case "CHPE–integrated"

Here are all the equilibria *found*; however, other may exist.

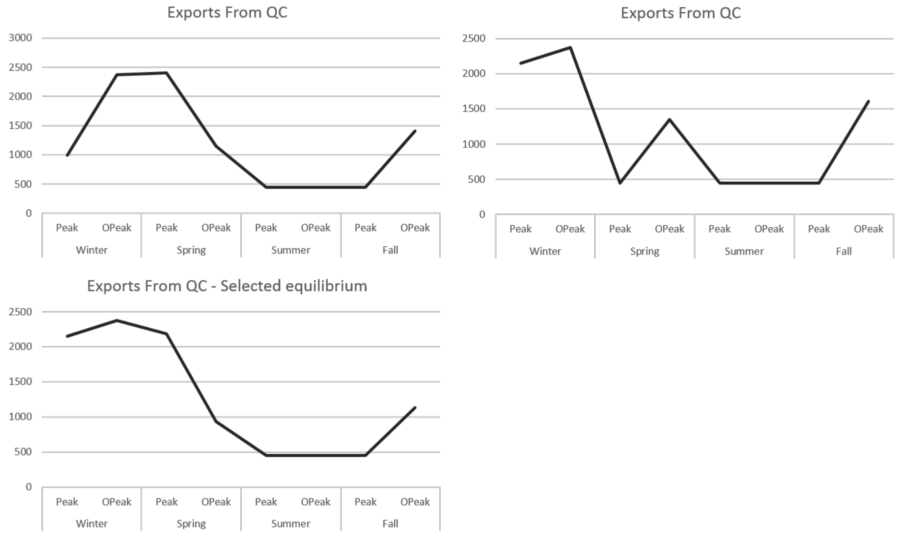


Figure 10: Multiple equilibria in scenario 50

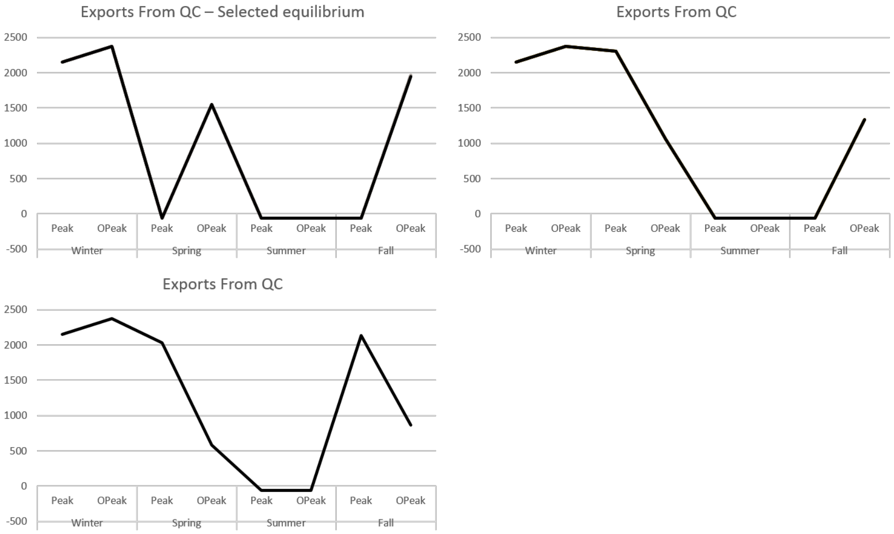


Figure 11: Multiple equilibria in scenario 40

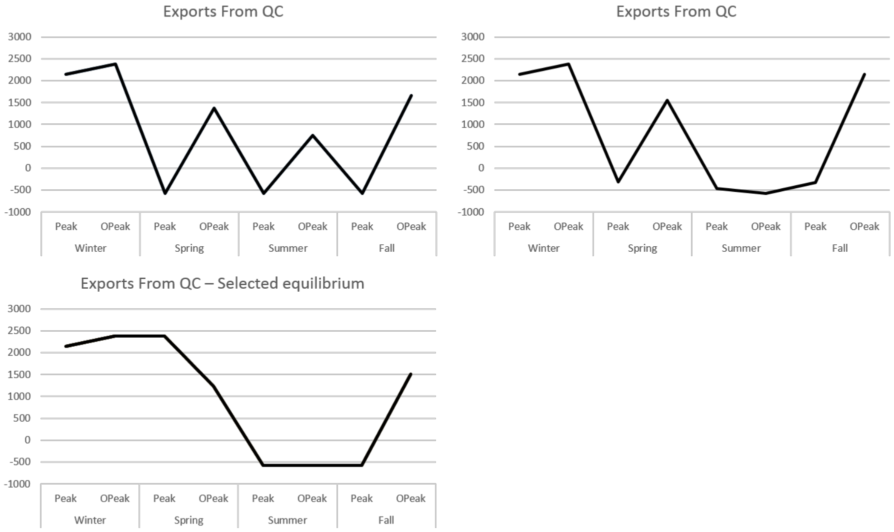
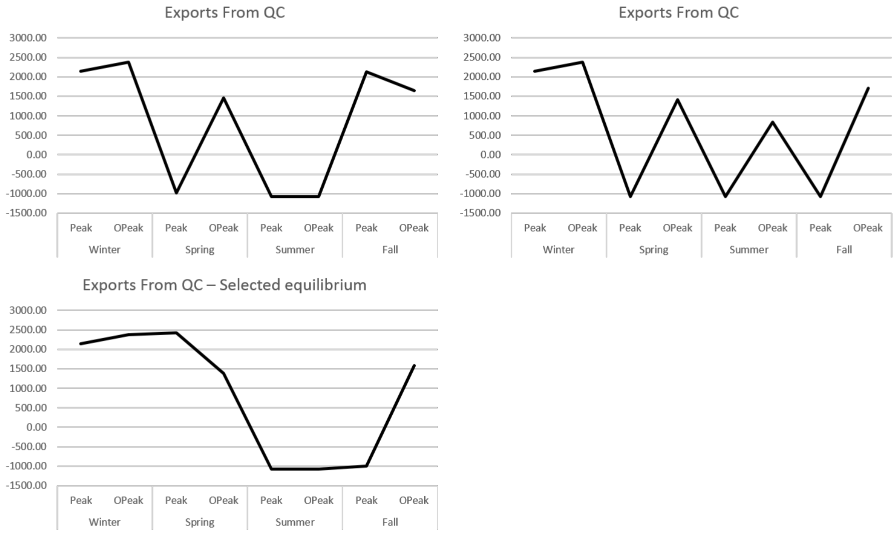


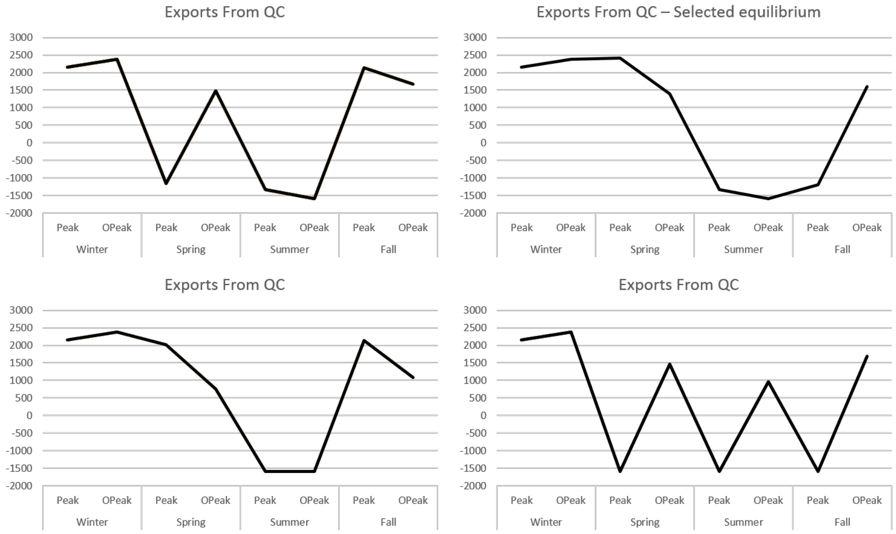
Figure 12: Multiple equilibria in scenario 30


Exports From QC

Exports From QC

Exports From QC – Selected equilibrium

Figure 13: Multiple equilibria in scenario 20

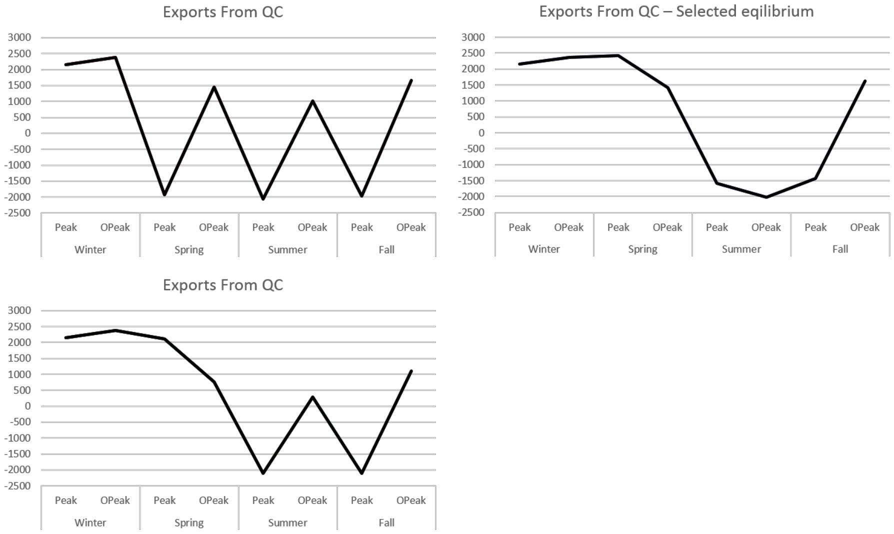

Exports From QC

Exports From QC – Selected equilibrium

Exports From QC

Exports From QC

Figure 14: Multiple equilibria in scenario 10



Exports From QC

Exports From QC – Selected eqilibrium

Exports From QC

Figure 15: Multiple equilibria in scenario 0

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