Chapter 13

Fragmented Markets: Canadian Electricity Sectors’ Underperformance

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1 INTRODUCTION

Canada is a very important energy producer: in 2011, it was the sixth largest oil producer, third in natural gas, eighth coal exporter, and third hydropower producer (IEA, 2011), while it was the second world uranium producer (WNA, 2012). Overall, in 2009, Canada ranked fifth in terms of total primary energy production, only behind China, the United States, Russia, and Saudi Arabia (EIA, 2012). Given these statistics, one could expect that the energy sector in Canada is a defining sector, well structured and organized. In reality, the Canadian energy sector is broken into a multitude of uncoordinated subsectors, with a myriad of small players and no common voice, explaining why Canada has an inconsequential influence in world energy affairs. The electricity sector, on which this chapter focuses, is representative of this situation. Worst, it is currently not engaged in significant reforms that could generate additional economic and environmental benefits for all regions of the country.

In the next section, a description of the 10 provincial Canadian electricity markets is provided, with an analysis of their respective evolution over the last 15 years. Although each province has its own characteristics, they can be grouped in three categories:

1. Hydropower-dominated provinces: British Columbia (BC hereafter), Manitoba (MB), Quebec (QC), and Newfoundland and Labrador (NL), characterized by low production costs, a dynamic export orientation and public ownership.

2. Restructured provinces: Alberta (AB), Ontario (ON), and New Brunswick (NB) that moved away from the centrally managed model through the creation of an independent system operator (ISO) and more competitive
wholesale markets. These provinces struggle with investment challenges and high prices. Trebilcock and Hrab (2006), in a predecessor of the current volume, present the restructuring experiences of AB and ON. A more comparative perspective is provided in this chapter, with the extra benefit of additional years of reforms.

3. Traditional provinces: Saskatchewan (SK), Nova Scotia (NS), and Prince Edward Island (PEI) structured along vertically integrated utilities and highly dependent on fossil fuels, leading to high prices as in restructured provinces.

Figure 13.1 shows the geographic distribution of provinces and their installed generating capacity. It illustrates the fragmentation of the sector, with no province of the same group being neighbors, except in the smaller Eastern markets.

In Section 3, an argument is developed to make the case for greater electricity sector integration across provinces and with neighboring US states. Such harmonization would go much beyond the already in place transmission access policies, under which provincial transmission providers file Open Access Transmission Tariffs (OATT) with the US Federal Energy Regulatory Commission (FERC) in response to the 1996 order 888 Promoting Wholesale HydroCoal/oilNatural GasWindNuclearDiesel

FIGURE 13.1 Canadian installed generating capacity, in megawatts, 2006 (NEB, 2008).
Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities. It would involve more coordination in generation and transmission planning, discussions to implement standard market designs and the adoption of common greenhouse gases (GHG) emission targets, and renewable and efficiency goals. Even more critically, provinces would have to allow electricity prices to converge toward a market level better reflecting the value of energy and the state of the system. In short, Section 3 argues that the Canadian electricity sectors should embrace a new collaborative paradigm, in order to successfully meet the challenges of a competitive world under carbon constraints, followed by the chapter’s conclusions in Section 4.

2 ELECTRICITY MARKETS IN CANADA

2.1 A Global View of the Canadian Electricity Sector

With its population of about 35 millions (0.5% of the world), the Canadian electricity production is impressive: 603 TWh in 2009 or 3% of world’s total (IEA, 2011). This amounts to about 18,000 kWh per capita, six times the world average generation per capita. Furthermore, 75% of the Canadian electricity is produced with no direct GHG emission. In fact, 60% of the Canadian power production is coming from hydro (364 TWh in 2009) and 15% from nuclear sources or 90 TWh (IEA, 2011).

Paradoxically, GHG emissions from the electricity sector remain a major concern in Canada, as they represented 14% of the 690 million tons emitted in 2009 (Environment Canada, 2011), second only to the road transportation sector, responsible for 19% of all GHG emissions. This is explained by the important reliance on fossil fuels, especially coal, in many provinces (AB, SK, NB, and NS). Figures 13.1 and 13.2 illustrate the relative importance of the different sources of supply and trade in the 10 Canadian provinces. Table 13.1 presents the amount of generation capacity by type in Canada, with its distribution across classes of producers, government-owned, investor-owned, or industrial producers.

As shown in Table 13.1, provincial (and municipal, in some cases) governments are important owners of power plants in Canada, especially hydro, nuclear, and conventional steam ones (mostly burning coal). The private sector nevertheless owns an important share of the generation capacity, in all provinces—even if in some provinces the share of private ownership is as low as 2% (Manitoba).

This situation mostly results from the Canadian constitution, specifying that (article 92A.1):

\[\text{in each province, the legislature may exclusively make laws in relation to [...] development, conservation and management of sites and facilities in the province for the generation and production of electrical energy.}\]
TABLE 13.1 Generation Capacity in Canada by Type and Class of Producer in 2009 (Statistics Canada, 2012c)

<table>
<thead>
<tr>
<th>Type</th>
<th>Megawatt</th>
<th>Percentage</th>
<th>Government-Owned, %</th>
<th>Investor-Owned, %</th>
<th>Industry, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>74,961</td>
<td>58</td>
<td>87</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>Wind</td>
<td>3,026</td>
<td>2</td>
<td>7</td>
<td>91</td>
<td>2</td>
</tr>
<tr>
<td>Tidal</td>
<td>4</td>
<td>0</td>
<td>0</td>
<td>100</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>13,345</td>
<td>10</td>
<td>62</td>
<td>38</td>
<td>0</td>
</tr>
<tr>
<td>Conventional steam</td>
<td>26,493</td>
<td>21</td>
<td>56</td>
<td>37</td>
<td>7</td>
</tr>
<tr>
<td>Combustion turbine</td>
<td>10,313</td>
<td>8</td>
<td>36</td>
<td>50</td>
<td>14</td>
</tr>
<tr>
<td>Internal combustion</td>
<td>601</td>
<td>0</td>
<td>40</td>
<td>22</td>
<td>38</td>
</tr>
<tr>
<td>Total installed capacity</td>
<td>128,743</td>
<td>72</td>
<td>21</td>
<td>7</td>
<td></td>
</tr>
</tbody>
</table>

FIGURE 13.2 Provincial generation, imports and exports of electricity in 2010 (Statistics Canada, 2012a,b).
A similar article specifies the same for nonrenewable natural resources, which leaves little room for the federal government in the energy sector. As a result, each province has its own electricity policy and regulatory agency, leading to disparate electricity tariffs, generation and transmission plans, and renewable/clean energy goals. This fragmented approach in almost all aspects of the sector is the main cause of its underperformance, as detailed in Section 3.

The federal government, in Ottawa, is still involved in four energy areas (NRCan, 2012):

1. interprovincial and international energy trade and infrastructures, through the National Energy Board (NEB), an independent federal regulatory agency, located in Calgary, Alberta. The NEB is the Canadian equivalent of the FERC, albeit with less visibility, power, and drive to implement reforms;
2. regulation of nuclear power, through the Canadian Nuclear Safety Commission;
3. nuclear science and technology, through Atomic Energy of Canada Limited;
4. energy research and development, through different programs and research laboratories, such as CanmetENERGY, the principal federal performer of energy R&D.

In addition, the federal government supports renewable energy in various ways and has an impact on the energy sector through federal environmental legislation.

In this context, each province developed its electricity sector independently, leading to very different generation portfolios (Figures 13.1 and 13.2). Diverse market outcomes also result from this: Figure 13.3 illustrates the provincial per capita consumption in 2009 as a function of the average revenue per kilowatt-hour, in Can$ cents/kWh (¢/kWh), a proxy for the electricity price. It shows that per capita consumption varied from less than 10,000 kWh per year in some provinces including BC, ON, PEI, to more than 20,000 kWh in QC, while prices ranged from less than 6 ¢/kWh (MB) to almost 14 ¢/kWh (PEI). The per capita QC consumption is significantly higher than in other low-cost provinces (MB and BC) mostly because energy-intensive industries (aluminum, pulp, and paper) were attracted by the larger availability of hydropower. Electric heating, commonly used, also contributes to explain the high electricity consumption.

In the following sections, each province is reviewed and compared to other provinces of the same category (hydro, reformed, and traditional).

1. Reliability standards are however commonly established through the regional entities of the North American Electric Reliability Corporation (NERC).
2.2 Hydropower-Dominated Provinces: British Columbia (BC), Manitoba, Quebec and Newfoundland and Labrador (NL)

2.2.1 Overview

In these four provinces, producing 56% of the Canadian electricity, power is almost exclusively generated by hydropower plants: 89% in BC, 99% in MB, and 97% in QC and NL (Statistics Canada, 2012a). They all have a commercially oriented, provincial government-owned, integrated company dominating the market: BC Hydro, Manitoba Hydro, Hydro-Quebec, and NL Hydro. Given the historical low cost of their generation portfolio and their cost-of-service rate regulation, these provinces have the lowest electricity rates in Canada (Figure 13.3).

In Table 13.2, the main components of the market structure are presented, illustrating the importance of the provincial company in all subsectors of the market. These companies, however, have distinct generation, transmission and distribution business units, and file OATT with the US FERC. This transmission open access allows the dominant company, private producers, and industrial ones to trade beyond their jurisdiction. The

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2. NL does not file OATT because it is not interconnected with the United States (IEA, 2010).
TABLE 13.2 Market Structure and Main Players in Hydro Provinces

<table>
<thead>
<tr>
<th></th>
<th>BC</th>
<th>Manitoba</th>
<th>Quebec</th>
<th>NL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation</td>
<td>BC Hydro, FortisBC, Nelson Hydro, RTA, Teck + IPPs</td>
<td>Manitoba Hydro + small IPPs</td>
<td>Hydro-Québec (HQ) Production, RTA, TransCanada + other IPPs</td>
<td>NL Hydro (Nalcor) and Newfoundland Power (Fortis) + IPPs</td>
</tr>
<tr>
<td>Capacity in megawatts (2009)</td>
<td>15,220</td>
<td>5,640</td>
<td>42,485 (47,913)</td>
<td>7,417 (1,989)</td>
</tr>
<tr>
<td>Transmission</td>
<td>BC Hydro[\textsuperscript{b}]</td>
<td>Manitoba Hydro</td>
<td>HQ TransÉnergie</td>
<td>NL Hydro and Newfoundland Power</td>
</tr>
<tr>
<td>Distribution</td>
<td>BC Hydro, FortisBC, and some municipal utilities</td>
<td>Manitoba Hydro</td>
<td>HQ Distribution + 9 municipal distribution companies</td>
<td>NL Hydro and Newfoundland Power</td>
</tr>
<tr>
<td>Ministry responsible</td>
<td>Energy and Mines</td>
<td>Innovation, Energy and Mines</td>
<td>Natural Resources and Wildlife</td>
<td>Department of Natural Resources</td>
</tr>
<tr>
<td>Regulator</td>
<td>BC Utilities Commission</td>
<td>Public Utilities Board</td>
<td>Régie de l’énergie</td>
<td>Board of Commissioners of Public Utilities</td>
</tr>
<tr>
<td>System operator</td>
<td>BC Hydro</td>
<td>Manitoba Hydro</td>
<td>HQ</td>
<td>NL Hydro and Newfoundland Power</td>
</tr>
<tr>
<td>OATT since</td>
<td>2006</td>
<td>1997</td>
<td>1997</td>
<td>–</td>
</tr>
<tr>
<td>Market design</td>
<td>Centrally managed model with bilateral contracts</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\[\text{a} \text{Hydro-Québec has contractual rights over a 5,428 MW hydropower plant located in NL (Churchill Falls generating station) until 2041 (Hydro-Québec, 2012a). In practice, this increases the QC generating capacity and decreases NL’s one by 5428 MW. It corresponds to about 30 TWh per year transferred from NL to QC (Figure 13.1).}

\[\text{b} \text{Between 2003 and 2010, the independent, government-owned BC Transmission Corporation was in charge of transmission in BC (BC Hydro, 2012b).}\]

wholesale market is also open. Independent power producers (IPPs) can therefore sign purchase power agreements (PPAs) with distribution companies or sell to large electricity consumers. The latter never happens,
However, as the distribution company offers low industrial rates, making it difficult for IPPs to compete.

The low cost of hydropower generation, leading to low electricity rates, never created an impetus for reform, at least from a consumer’s perspective. From a shareholder’s (government’s) perspective, the incentives for reforms are divergent: on the one hand, maintaining low rates helps obtaining political support, but on the other hand, government’s revenues could benefit more from the economic dividend resulting from the low-cost electricity production sold at higher prices (in export markets). These dual incentives led to a development strategy focusing on low provincial regulated rates, while at the time being active in export markets. BC Hydro indeed created as early as 1988 its trading subsidiary, Powerex, now active all across North America (Powerex, 2012). Figure 13.4 illustrates the BC system with its interties with...
the United States (about 2,500 MW) and with Alberta (about 1,200 MW; Pineau, 2009).

HQ Energy Services (United States), a wholly owned subsidiary of Hydro-Quebec, obtained a license as a power marketer in the US wholesale market in 1997 (Hydro-Quebec, 2012b). This allows Hydro-Quebec to trade with all its neighbors, and beyond, through its multiple interties (Figure 13.5).

Manitoba Hydro became a full member of the Mid-Continent Area Power Pool (MAPP) in 1996, entering into power exchange agreements with US power marketers (Manitoba Hydro, 2012a). In 2005, Manitoba Hydro also became a full member of the Midwest Independent Transmission System Operator (MISO). The MB retail market remains nevertheless regulated and disconnected from wholesale price signals.

BC Hydro and Hydro-Quebec pay important yearly dividends to their provincial government: Can$230 million in 2012 for BC Hydro (BC Hydro, 2012a) and Can$1,958 million in 2011 for Hydro-Quebec (Hydro-Quebec, 2012a). They could generate these profits given the allowed rate of return on distribution and transmission activities and profits in the generation sector.
(partly relying on exports and energy marketing activities).\(^3\) In MB, regulation does not allow Manitoba Hydro to include a rate of return on its cost of service.\(^4\) Furthermore, it seldom pays a dividend to its shareholder, using net revenues to maintain low rates\(^5\) and invest in new projects.

In NL, because of its remote location and sparse population, the context is slightly different. A provincial energy company, Nalcor Energy, was created in 2007 by the provincial government as a tool to implement its energy plan (NL, 2007). This plan aims at a better control over the development of the province’s energy resources. Nalcor Energy is the parent company of NL Hydro and of other companies involved in hydropower and oil and gas development. Since 2009, Nalcor also has an energy marketing subsidiary to sell its increasing hydropower production in the Northeastern US electricity markets. As it is still in its development stage, Nalcor never paid a dividend to its shareholder (Nalcor, 2012).

\[2.2.2 \text{ Hydro Provinces Reform Assessment}\]

Following the opening of the wholesale market in the US (FERC order 888 in 1996), hydro provinces have been very active to adjust their regulatory structure to optimize their external commercial activities. If some discussions to further reform these markets were occasionally held (see for instance Clark and Leach, 2007, for the case of QC), no major restructuring happened. Business units have been separated and OATT filed, to comply with US regulation, but competition remains marginal in the wholesale market: it is limited to a few PPAs with the main distribution company and absent in the retail market.

\[2.3 \text{ Restructured Provinces: Alberta, Ontario, and New Brunswick}\]

The lack of hydropower potential limited the expansion of the generation segment in these provinces and made them rely much more on thermal generation (fossil fuel and nuclear), leading to higher production costs. Resulting high prices, together with a stronger appetite for competition in the organization of markets, opened the way to reforms in these provinces.

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3. BC Hydro and Hydro-Quebec, in their generation activities, have to supply a “heritage” amount of electricity at historical low cost to their consumers: about 50 TWh in BC (BC, 2003) and 165 TWh in QC (Hydro-Quebec Act, article 22). Beyond these quantities, the cost of generation is not regulated in these two provinces, and distribution units have to sign competitive contracts with their generation sister unit or IPPs.

4. Only operating and capital costs can be charged to consumers (article 39.1 of The Manitoba Hydro Act, “Price of power sold by corporation”).

5. Not only are electricity rates low in MB, but for commercial consumers (General Service Small and Medium), a decreasing-block tariff structure is adopted (Manitoba Hydro, 2012b), leading to little or no consumption efficiency incentives.
Indeed, impetus for reform came in these provinces from a desire to have less regulation and government’s involvement (Daniel et al., 2007) and, at least in ON, to control cost (Trebilcock and Hrab, 2006). Table 13.3 provides an overview of these three restructured markets.

<table>
<thead>
<tr>
<th>TABLE 13.3 Market Structure and Main Players in Reformed Provinces</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Alberta</strong></td>
</tr>
<tr>
<td><strong>Generation</strong></td>
</tr>
<tr>
<td><strong>Capacity in megawatts (2009)</strong></td>
</tr>
<tr>
<td><strong>Transmission</strong></td>
</tr>
<tr>
<td><strong>Distribution</strong></td>
</tr>
<tr>
<td><strong>Ministry responsible</strong></td>
</tr>
<tr>
<td><strong>Regulator</strong></td>
</tr>
<tr>
<td><strong>System operator</strong></td>
</tr>
<tr>
<td><strong>OATT since</strong></td>
</tr>
<tr>
<td><strong>Start of the market</strong></td>
</tr>
<tr>
<td><strong>Market design</strong></td>
</tr>
<tr>
<td><strong>Public reference price</strong></td>
</tr>
</tbody>
</table>
The key distinctive feature is the presence of an ISO setting a publicly available hourly reference price. Such ISO and reference price are absent in all other Canadian provinces. As shown in Table 13.3, AB was the first to open its market in 1996, followed by ON in 2002 and NB in 2004. NB, however, does not have a competitive power pool: its wholesale market is structured around physical bilateral contracts with a redispatch market, in which a “Final Hourly Marginal Cost” is defined.

NB implemented an OATT in 2004, when it restructured its sector, while AB and ON have put in place transmission service provisions and tariffs which are compatible with the OATT reciprocity and nondiscrimination, allowing them to not file OATT with the FERC (IEA, 2010).

In the next three sections, the restructuring process of each of these three provinces is reviewed. These sections do not enter into the details of the restructuring efforts. The goal is rather to provide an overview and to offer a global understanding of the Canadian electricity sectors. Daniel et al. (2007) and AESO (2006) offer a full focus on the AB experience, and Trebilcock and Hrab (2006) provides a complete ON review and analysis of the early reform experience in both AB and ON. Blakes (2008) and IEA (2010) also provide some additional details on the market structure of these two provinces. EDA (2006) presents the current ON electricity market in detail.

2.3.1 Alberta: Competition with Limited Interconnections

With the absence of provincial government-owned electricity company and already disintegrated electricity market structure (a combination of municipally owned and investor-owned utilities), AB had a natural predisposition for electricity market reform. The main driver for reform was a large support for less government involvement in the power sector. If it introduced a competitive power pool as soon as 1996 (Table 13.4), the regulation of wholesale electricity prices only stopped in 2001. Retail consumers have also been allowed to switch retailer from 2001 but could also remain with their distributor-retailer under the Regulated Rate Option (RRO). The RRO was regulated until 2006 and, from 2006 to 2010, it progressively evolved toward a monthly rate entirely based on projected market prices (month-ahead prices). As of May 2012, 35% of residential consumers had switched to a contract with a different electricity retailer (Alberta, 2012b).

The Alberta restructuring experience, while deployed in steps, still required adjustments: 2003 merger of the market and transmission operators into the AESO and addition, in 2008, of some long-term supply adequacy indicators, out of concerns that investment in generation would not be sufficient. Investment in transmission is also recognized to be an issue, not only within the province, but also with neighbors, as Alberta is “one of the least interconnected jurisdictions in Canada with only two transmission interties.
providing limited export and import capacity” (AESO, 2009; Alberta, 2008). Indeed, interties with BC and SK (Figure 13.6) can only import a maximum of 1200 and 150 MW, respectively, with the BC intertie not being able to reach that maximum because of internal network constraints in AB (AESO, 2009). This affects the ability to import cheaper electricity, mostly from BC, and to smooth out some price volatility.

The AB restructuring experience has been mostly an inward process, with the development of new Albertan institutions—AESO and the Market Surveillance Administrator (MSA)—which has not reduced electricity prices compared to jurisdictions with similar fossil fuel system (such as SK; Figure 13.2). It neither introduced greater confidence in the long-term adequacy of generation and transmission infrastructures.

### 2.3.2 Ontario: An 8-Month Experience

The ON electricity sector restructuring was also carefully prepared with a 4-year adjustment period (1998–2002). The main driver, in the ON case, was to try to infuse more rigor in power sector investment and expenditures, through competition and private ownership. If competition was indeed implemented, no privatization materialized in ON. The main reform mistake, however, was to let the retail price be entirely connected to the wholesale market price. This exposed unprepared and unhedged retail and commercial consumers, after May 1, 2002, to the exceptionally high price volatility of Summer 2002. It produced a political backlash that was fatal to the competitive system put in place. A rate freeze followed in December 2002, ending an 8-month full deregulation experience. Centralized planning and long-term supply contracts were reintroduced in 2004, with the creation of the Ontario Power Authority (OPA). See Table 13.5 for the timeline of

| 1996 | Creation of the power pool and of the independent transmission administrator. |
| 2001 | Beginning of the current market structure and opening of retail competition (MSA, 2010). |
| 2003 | The Power Pool and the independent transmission administrator are merged into the Alberta Electricity System Operator (AESO). |
| 2006 | Regulated Rate Option—monthly price based on a mix of electricity purchased through long-term contracts and the following month’s projected market price. |
| 2010 | Regulated Rate Option—100% based on the following month’s projected market price. |
the Ontario restructuring experience. Since 2005, with the introduction of the regulated price plan (ending the rate freeze) and of the smart meter initiative, the Ontario market remained mostly unchanged. Generators bid daily in a competitive markets, while being hedged against any risks with contracts for difference signed with the OPA.

The Ontario restructuring experience, while introducing more transparency in the Ontario electricity market, mostly through the IESO, has led to a hybrid system where competitive prices coexist with regulated ones, for both generators and consumers. With its smart metering initiative and time-of-use pricing, Ontario is the only jurisdiction in Canada that provides all consumers with more elaborated price information, beyond the monthly flat (or two tier) rate. This initiative is a success in terms of deployment, with 99% of residential and commercial consumers equipped with smart meters as of June 2012 (OEB, 2012c). Out of them, 89% are on the time-of-use regulated price plan.

More competition in the Ontario electricity system, however, is unlikely to develop under the current conditions, despite its various interties
(Figure 13.7), offering many short-term trading opportunities. Indeed, the Integrated Power System Plan currently being prepared (OPA, 2011) requires the refurbishment of 10,000 MW of nuclear power, and the addition of 2000 MW of nuclear power by 2030, while shutting down all coal power plants by 2014. Such plans, because of the required financial guarantees, will heavily rely on government’s involvement and will not be deployed through a competitive market.

### TABLE 13.5 Timeline of Electricity Restructuring Events in ON (Canada Energy, 2012).

<table>
<thead>
<tr>
<th>Year</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>Energy Competition Act, unbundling the integrated (generation and transmission) government-owned Ontario Hydro into different entities: (1) Ontario Power Generation (OPG) focused on generation, (2) Hydro One focused on transmission and distribution, and (3) the Independent Electricity System Operator (IESO) focused on electricity system dispatch (until 2004, the IESO was known as the Independent Market Operator). No privatization occurred.</td>
</tr>
<tr>
<td>2001</td>
<td>Bruce Power, a private company, assumes operational control of eight nuclear generating stations, a total of 6200 MW (Bruce Power, 2012). These units are leased from OPG.</td>
</tr>
<tr>
<td>May 1st, 2002</td>
<td>Opening of the wholesale market, with retail price based on wholesale market, without real-time metering and price information. Electricity bills double or triple during the summer due to exceptionally hot weather.</td>
</tr>
<tr>
<td>December 2002</td>
<td>The Electricity Pricing, Conservation and Supply Act, lowering and freezing the retail electricity price at 4.3¢/kWh (commodity charge, excluding all other charges such as network and other charges). This disconnected retail and wholesale markets.</td>
</tr>
<tr>
<td>2004</td>
<td>Electricity Restructuring Act, creating the Ontario Power Authority, to ensure an adequate, long-term supply of electricity (planning and long-term contracts with generators).</td>
</tr>
</tbody>
</table>
| 2005 | Two major initiatives:  
  
  *Regulated Price Plan* for residential and commercial consumers, “that provides stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators” (OEB, 2012a). Consumers without smart meters have an increasing block tariff, while consumers with smart meters have time-of-use tariffs. Both tariffs are adjusted every 6 months.  
  
  *Smart Metering Initiative*, aiming at having all electricity consumers equipped with smart meters by 2010 (OEB, 2012b). |
2.3.3 New Brunswick: Back to Vertical Integration

Restructuring in NB, implemented in 2004, was designed to avoid the price volatility experienced in AB and ON but also to foster competition. The creation of the New Brunswick System Operator (NBSO) guaranteed the independence and transparency in the market, allowing long-term bilateral contracts to be signed between generators and both distributors and large consumers. The integrated New Brunswick Power Corporation (NB Power) became the New Brunswick Power Holding Corporation (NB Power Group) with subsidiary companies: Generation, Nuclear, Transmission, and Distribution.

In 2011, however, the government of NB announced the “Reintegration of NB Power” as a vertically integrated publicly owned utility (following the BC and QC model) and the dissolution of NBSO, with the system operation functions back to NB Power. These were actions 1 and 2 of the 2011 Energy Action Plan (New Brunswick, 2011). This move, back to a traditional structure, comes after a series of energy events that have created high tensions in the NB electricity market:

- High cost of fossil fuels: With its high reliance on coal, oil, and natural gas power plants (more than 50% of its capacity), electricity production...
costs in NB have been hit by the price increase of these three commodities during the 2000–2008 period, especially since all of the coal, oil, and natural gas are imported.

- Problems with the nuclear refurbishment: The refurbishment work of the 680 MW Candu-6 nuclear power plant, commissioned in 1982, started in March 2008, and was scheduled to last 18 months and to cost Can$1.4 billion. Multiple delays have occurred, with overruns of Can$1 billion (CBC News, 2010) and return to service only planned for Fall 2012 (NB Power, 2011).

- Failed takeover of NB Power by Hydro-Quebec: In October 2009, the QC and NB governments unexpectedly announced the acquisition of most of NB Power assets by Hydro-Quebec. This would have been the first takeover of a provincially owned utility by another one. This plan would have provided price and supply security for NB, and a lucrative access to the NB and US market for Hydro-Quebec. However, NB and the transaction had to be canceled in March 2010 (Quebec, 2010).

These events led the province of NB to rethink its energy strategy and to focus on five key objectives (New Brunswick, 2011): low and stable energy prices, energy security, reliability of the electrical system, environmental responsibility, and effective regulation. In addition to a return to a vertically integrated electricity company, more emphasis will be put on regional electricity partnerships, such as the Atlantic Energy Gateway, an initiative “to promote and facilitate the development of clean and renewable energy sources in Atlantic Canada.” (Canada, 2009).

2.3.4 Restructured Provinces Reform Assessment

None of the three reforms in AB, ON and NB can claim to be a success, at least using the six objectives of electric restructuring defined in AB (AESO, 2006):

1. A competitive, efficient, and innovative electricity marketplace.
2. New generators and many new service providers.
3. Informed consumers choosing from competitive, attractive options.
4. Continued downward pressure on rates.
5. Incentives for conservation and the wise use of energy.
6. Smart technologies and green power options that contribute to environmental goals.

If Alberta has a competitive marketplace (objective 1), no new generators made a difference (objective 2) and there is no significant innovation from service providers (objectives 1 and 2). In the only province with Smart
technologies (ON), this development was a result of a government’s decision—not of restructuring (objective 6). Only 35% of all consumers have changed provider in Alberta, illustrating that new options were not attractive or that consumers remain uninformed (objective 3). No price or consumption levels indication show progress on objectives 4 and 5, at least compared to other provinces (for instance, AB versus SK; Figure 13.3).

In all cases, significant market design changes have been implemented, adding to the cost of operating the market. Only in AB was the reform consistently implemented, with no return to regulation (as in ON) or to a traditional market structure (as planned in NB). However, even if AB consumers now face fully competitive electricity prices, they have no opportunity to react to short-term price signals, as residential and commercial consumers are still billed at an average forward price.

Investment issues remain salient in all three provinces. The situation is well summarized by this observation, made by government of NB (New Brunswick, 2011):

New generation assets have not been built by private sector market participants to the extent predicted upon adopting a competitive electricity market model. Developers have found it very difficult to secure financing for new projects because financial institutions and other investors will not finance an independent power project without a long-term utility power purchase agreement in place as a secure source of future revenues.

2.4 Traditional Provinces: Saskatchewan, Nova Scotia and Prince Edward Island

In the three remaining Canadian provinces, no important change was brought to the electricity sector between 1995 and 2013. This is mostly due to the small size of their system (Table 13.6: generation capacity of 4,042 MW in Saskatchewan, and much less in the two other provinces) and to the lack of incentives to try to join a larger, more integrated, electricity system.

Table 13.6 summarizes the main features of the SK electricity sector and of the two other Atlantic provinces, NS and PEI. In all cases, an integrated utility is in charge of the sector, with some IPPs also generating power. Only in SK is the utility publicly owned.

In order to facilitate trade, these provinces have also started to file OATT, but relatively late compared to other provinces: 2001 in SK, 2005 in NS (Blakes, 2008), and in 2008 for PEI (IRAC, 2008).

6. In NB, part of the reasons for returning to a vertically integrated structure was the additional cost burden of the unbundled structure. This was explicitly recognized by the government in its Energy Action Plan (New Brunswick, 2011).
SK benefits from local coal supply, which partly explains the lower electricity price in this province, compared to NS and PEI (Figure 13.3). GHG emissions nevertheless remain a concern, which explains why SaskPower owns wind facilities and has signed PPAs with wind producers (SaskPower, 2012). Its limited interconnections with AB, MB and North Dakota, its US southern neighbor, allow for some trade, but market structures in these four jurisdictions remain designed independently.

In NS and PEI, the situation is slightly different. These provinces rely even more than SK on GHG-emitting thermal power plants, using increasingly expensive imported fossil fuels. Plans are therefore more actively made to increase the electricity supply from alternative sources. NS has indeed two tidal power plants and PEI elaborated a wind energy plan in 2008, aiming at 500 MW of wind capacity by 2013, up from only 111 MW of wind in 2009 (PEI, 2008). However, high cost and the absence of marketable carbon credits from wind-generated electricity have postponed the plan (Blackwell, 2012).
Hydropower supply from the Lower Churchill Project in NL is also seriously considered. Such hydropower supply would however require significant transmission investments, as illustrated by Figure 13.8.

Given the scope of such transmission lines and the limited size of the electricity market in Atlantic provinces, a joint ISO would make sense, as recommended to the NS government in a study it commissioned in 2009 (SNC-Lavalin, 2009). However, despite discussion around an Atlantic Energy Gateway (Canada, 2009), the Atlantic provinces have not taken steps to integrate their electricity market, in one way or another.

2.5 Insights from the Canadian Reform Experiences

Canadian electricity reforms have been only actively implemented in two provinces: AB and ON, even if NB did restructure more than any other provinces beyond these two. The paradox of these restructuring efforts is that while more competition was sought within provincial borders, no effort was made to increase competition from outside, including from the US. Such competition, in particular from hydropower provinces, BC in the case of AB, and MB and QC in the case of ON, would have raised the likeliness of decreasing prices, as cheaper sources of electricity would have entered the market.

In hydropower provinces, while minimal internal reforms were implemented to comply with US requirements, a very competitive and market-oriented behavior was adopted in export markets by provincially owned utilities. These provinces, and especially QC with huge energy storage
capacity behind its dams, also benefit from cheap imports during off-peak hours, allowing them to do some intertemporal arbitrage.

Because of the lack of federal leadership in the electricity sector, and because provincial governments cherish their autonomy in managing their own electricity sector, no common Canadian reform ever attempted to create a common framework, such as in the European Union (EU, 2009) or as in the US, with the failed standard market design initiative led by the FERC (FERC, 2005). The next section presents the reasons for more integration among Canadian provinces and with US states, along with the main obstacles to such harmonization, and some possible paths that could be followed.

### 3 ELECTRICITY MARKET INTEGRATION FORCES AND OBSTACLES\(^7\)

#### 3.1 Electricity Market Integration\(^8\)

Despite the fact that there are “few academic studies which have real theoretical depth (on regional power sector integration)” (ECA, 2010), there is an important consensus on the benefits of such electricity market integration. The United Nations has published many reports on the subject (see in particular UNECA, 2004 and UN, 2006) and so have the World Bank (ESMAP, 2010), the World Energy Council (WEC, 2010), the Organization of American States (OAS, 2007), and even the Commission for Environmental Cooperation (CEC, 2002). This latter organization is a North American organization established in 1994 along with the North American Free Trade Agreement (NAFTA). This literature identifies a series of potential technical benefits achievable through such initiative. Basically, benefits derived from efficiency gains are achievable through trade and increased productive efficiency. These benefits, in the context of electricity markets, are summarized in Table 13.7.

By increasing the regional scope of an electricity market, more of these benefits are achievable. In the Canadian context described previously, where there is a wide diversity of generation technologies and price levels, clearly pooling resources and harmonizing price levels could yield significant gains. There are four areas, in particular, from which efficiency gains would come in the Canadian case.

1. *Removing consumption subsidies in hydro provinces:* Through the low rates in hydropower-dominated provinces, a consumption subsidy is provided to electricity consumers, leading to poor incentives to implement

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7. This section draws from Pineau (2009) and (2012).
8. See also Chapter 14, on the integration of Latin American energy markets, for more on integration issues.
energy efficiency. Opening provincial electricity markets and harmonizing them with their neighbors would raise prices in hydro provinces and lead to energy consumption reduction, which will be free for exports to “thermal” provinces or states—reducing price in these markets. See Pineau (2008) for more on such consumption subsidies and Billette de

### TABLE 13.7 Potential Technical Benefits from Power Sector Integration

<table>
<thead>
<tr>
<th>Benefit</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>Improving reliability and pooling reserves</td>
<td>With access to the production facilities of its neighbors, each region gains access to much greater resources to meet the demand in the case of incident. This increases reliability and reduces the need for local reserves of production capacity.</td>
</tr>
<tr>
<td>Reduced investment in generating capacity</td>
<td>Thanks to pooling, each region can avoid costs of adding further capacity on its own.</td>
</tr>
<tr>
<td>Improving load factors and increasing demand diversity</td>
<td>Greater geographic reach often provides a more diverse demand, where peak periods do not coincide. This helps to avoid operating generating plants only for peak periods, and it uses the generator fleet in a more constant and efficient manner.</td>
</tr>
<tr>
<td>Economies of scale in new construction</td>
<td>With guaranteed access to a much larger market, larger generating stations can be installed, making some economies of scale accessible.</td>
</tr>
<tr>
<td>Diversity of generation mix and supply security</td>
<td>With more types of generation producing electricity, over a larger territory, the system is less exposed to events that affect a particular source of energy (low rainfall, lack of fuel, etc.). This increases the overall security of the integrated system.</td>
</tr>
<tr>
<td>Economic exchange</td>
<td>With a more diversified generating fleet and production costs, it is possible to use less costly technologies, situated in other regions, to meet various energy needs. It becomes possible to use lower cost, but distant, energy resources if equivalent local resources are not available. This reduces the overall operating costs of the system.</td>
</tr>
<tr>
<td>Environmental dispatch and new plant sitting</td>
<td>With a larger territory in which to choose the location of generation facilities, the best sites can be chosen (e.g., areas with less fragile ecosystems or zones with the most favorable winds for wind power).</td>
</tr>
<tr>
<td>Better coordination of maintenance schedules</td>
<td>Greater flexibility and reduced impact can be obtained with a more extensive production fleet.</td>
</tr>
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</table>
Villemeur and Pineau (2012) for the conditions leading to gains from integration.

2. **Gains from less electrical heating**: In QC and some other provinces, space and water electrical heating is common due to the low price of (hydro)electricity. This is inefficient when, simultaneously, more provinces and states build natural gas-fired power plants. Indeed, the heating efficiency of natural gas (more than 85%) compared to producing electricity with natural gas (about 55% efficiency) justifies substituting natural gas to hydroelectricity for heating applications. Such substitution could only happen in a more integrated market, where incentives are aligned to make individual consumers make the correct choice.

3. **Optimize renewable energy location and production**: Rather than having every single province and state develop their own renewable incentive programs within their jurisdiction (where politically convenient), the best renewable opportunities should be developed through a regional process. With a “national electricity grid,” as proposed by the province of NL (NL, 2007) and evoked in AB (AESO, 2009), more markets would have access to undeveloped hydropower. Such development could be cheaper and without intermittency issues, compared to local wind projects. Wind projects are often developed given the lack of local renewable energy alternatives.

4. **Maximizing hydro balancing for wind power**: While provinces with little hydro storage capacity develop significant wind capacity in Canada (AB and ON), real-time balancing opportunities with hydropower storage, available in BC, MB and QC, are impossible due to hour-ahead restrictions in interprovincial electricity trading, as opposed to 5-min dispatch schedules within provinces (IESO, 2012). This seriously limits the use of out-of-province hydro resources in balancing markets and leads to the use of more expensive in-province resources. Under a harmonized electricity market, resources would be used more optimally.

Although no estimate of gains resulting from integration has been computed in a Canadian context, the importance of hydropower in Canada is such that significant efficiency benefits would be obtained. Such belief is at least behind the main recommendation of the IEA concerning electricity markets in Canada (IEA, 2010):

*The government of Canada should facilitate market opening and integration between provincial markets and with neighboring US markets to increase the transparency of generation investment signals, potential for competition in electricity wholesale and retail markets, and to simplify governance and oversight of reliability planning and system operation.*

Within Canada, some voices also underscore, to various extent, benefits of integration: the Canadian Electricity Association (CEA, 2007), the
Canadian Academy of Engineering (CAE, 2009), and think tanks like the C.D. Howe Institute (Pierce et al., 2006) or the Canadian Center for Policy alternatives (Bigland-Pritchard, 2010).

3.2 Obstacles to Better Integration

There are three major obstacles hindering an integration process (Pineau, 2012):

1. the structure of political and electoral incentives at the provincial and federal levels;
2. the redistribution of the gains from a partial or complete integration; and
3. the lack of recognition of environmental benefits resulting from integration.

Because of the provincial nature of electricity systems and their historical role in bringing modern energy amenities to citizens, many consumers see their provincial utility as part of their culture and even, in some cases, of their identity (Froschauer, 1999). They resent seeing out-of-province interference in the electricity sector and consider, to some extent, local electricity production as being a “heritage” (such as in BC and QC—see footnote 5) that should be consumed locally. Given this, and the political convenience of announcing local “green energy projects and jobs,” provincial political parties have little incentives to embark on a reform path that could result in a political backlash, such as experienced by the NB Premier after announcing the Hydro-Quebec takeover of NB Power (Section 2.3.3).

Beyond the provincial political sensitivities over electricity (and energy) issues, electricity integration would have some economic impact on wealth distribution. Consumers having access to low-rate electricity would face higher prices, and producers in higher-rate jurisdictions would lose market share when additional imports would flow into their markets. This contributes to explain why consumers in BC, MB and QC resist change, and why AB remains relatively isolated from its neighbors.

Finally, as hydropower exports do not get any recognition for GHG reductions induced in the market where they are sold, an important benefit remains unaccounted in such trade. This reduces the incentives to develop trade, as some gains are ignored. See Ben Amor et al. (2011) for an estimate of the GHG impacts of hydropower exports from the QC market.

3.3 Possible Approaches to Foster an Integration Agenda in Canada

There are many options to foster an integration agenda in Canada, and with the US, which are not mutually exclusive. They involve information, compensation, and regulatory/legal reforms.
First, not enough information is available on the gains resulting from integration. With more data on economic and environmental benefits of electricity market integration, the case could be better made that such reforms are worth it.

With such data at hand, some compensation schemes could be designed to overcome the resistance of consumers—voters in jurisdictions where price would increase. Because such trade reforms are welfare enhancing, such compensation could be made while leaving no player worse off after the change.

Finally, regulatory and legal changes could be made at different levels: trade agreements, system operations, energy regulatory boards, and possibly at other levels. Within Canada, free trade is not yet fully implemented—especially in energy. The Agreement on Internal Trade (AIT) is indeed being negotiated since 1995 with no agreement at all on energy, despite a common desire “to establish an open, efficient, and stable domestic [energy] market” (AIT, 2007). Through the AIT, and through similar free-trade agreement with the United States (such as the defunct Free Trade Area of the Americas; Pineau, 2004), some electricity market integration could happen. Regional transmission organization could be set up, as proposed for Atlantic Canada (SNC-Lavalin, 2009), with more compatible market designs than now. Provincial energy boards, regulating provincial energy sectors (Tables 13.2, 13.3 and 13.6) could also organize themselves as a unique organization with provincial branches—allowing for more coherence in regulatory decisions. The federal energy regulator (NEB) could play a coordination role in this harmonization of regulatory bodies across Canada.

All the approaches are of course difficult to initiate. However, there is an increasing political recognition in Canada and in the US that more cooperation among provinces and states is required in the energy sector. In July 2012, all provinces except BC agreed to work on a plan that would “ensure that the country has a strategic, forward thinking approach for sustainable energy development […] [and] a more integrated approach to climate change, reducing greenhouse gas emissions and managing the transition to a lower carbon economy” (COF, 2012). This is often labeled as a Canadian National Energy Strategy. Furthermore, New England Governors and Eastern Canadian Premiers have also agreed in July 2012 to “begin work on creating a new regional process to identify longer-term opportunities in electricity markets, increase the flow of clean energy and associated infrastructure development to facilitate achievement of environmental objectives and ensure long-term security of supply through diversification and regional participation” ACNEG-ECP (2012). Although nothing more than working groups will result from these two political initiatives, they are signs that the integration issue is on the political agenda.

4 CONCLUSION

This chapter presented the fragmented Canadian electricity markets and the case for more integration. The 10 Canadian provinces can be grouped in
three categories. First, the “hydropower-dominated provinces” (BC, MB, QC and NL), where a government-owned hydropower company is pervasive. Second, the “restructured provinces,” where the electricity sector is designed around an ISO (AB, ON and NB). Finally, the “traditional provinces” (SK, NS, and PEI), which have relatively small, vertically integrated electricity sectors, dominated by thermal generation. If almost all provinces have implemented OATT and can therefore claim to have an open wholesale sector, only AB has a fully competitive electricity sector. ON has reintroduced regulation in 2002, 8 months only after its market liberalization, and NB now plans to revert to a fully integrated structure after 7 years of experience with its ISO.

The main paradox of electricity reforms in Canada is that the government-owned provincial hydropower companies are the most aggressive in competitive export markets, while by nature (and to follow their main mission) they should concentrate on their domestic market. This is due to the economic value their relatively cheap hydropower has in higher-cost neighboring markets. But despite this, no reform is implemented in these hydro provinces to build on their competitive advantage, such as Norway did with its electricity reforms and integration with other Nordic countries.

Gains from further integration, among Canadian provinces and with US states, would be coming from various sources. Of course, further trade benefits would contribute to these gains but also optimized investments and improved system operations. Political obstacles are however important and hinder the development of a more unified Canadian electricity market. But increasing political recognition that a national energy strategy is important, along with more data on economic and environmental benefits of regional power integration, may lead to positive developments. From the Canadian fragments, a harmonized electricity sector could deliver more than energy—increased wealth and lower environmental impacts. These are outcomes that can hardly be overlooked in our financially and environmentally constrained world.

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