Seamless Electricity Trade between Canada and US Northeast

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Summary

We analyse how the wholesale electricity market deregulation could modify exchanges between three Canadian regions (Ontario, Quebec and New Brunswick) and two U.S. regions (New York and New England), which were already trading electricity before the regulatory change took place in 1997. We find that the pre-1997 exchanges already made possible fuel cost savings of $397.2 million per year while deregulation adds annual savings of $358.7 million. Canadian regions are the main beneficiaries under the assumption that exports are priced at the marginal costs of the importing regions. Imports from the Canadian regions, although significant, are not large enough to lower the marginal costs of the U.S. regions. Hence electricity deregulation across the border should not significantly decrease prices in the U.S. regions although the latter are becoming more dependant upon imports from Canada. Greenhouse gas emissions increase by 4.3 Mt CO_2 eq. in the wake of the open wholesale electricity market because of the low cost of coal, particularly in Ontario. Environmental concerns and the limited availability of additional hydroelectric power in Canada could change the trade patterns as electricity demand continue to grow.

Key words: Electricity, deregulation, trade

JEL Classification Numbers: JEL L94

Introduction

The U.S. wholesale electricity market is open to competition since January 1997 through FERC Order 888 which allows producers, local distribution utilities or any FERC licensed marketers to exchange electricity at market prices. FERC imposed some reciprocity conditions upon foreign applicants that required the latter to give access to their transmission power grid along the lines adopted for the U.S. wholesale market. Canadian electric utilities, which are mostly owned by the provinces, applied for and received their FERC licences to participate in this new open market. Electricity was already flowing across the border between the two countries before the structural change. In 1996, Canada exported 42.2 TWh (terawatt-hours) i.e. 7.7% of its total production and purchased only 1.1 TWh[1]. The net export in Canada favour follows from the price differentials between the two countries. For instance, the 1996 average prices were 15.2¢/kWh in New York and 14.1¢/kWh in New England, while they were respectively 7.3, 4.9 and 6.3¢/kWh in Ontario, Quebec and New Brunswick, which are the northern contiguous neighbors[2]. The low Canadian prices are due to their reliance on hydro power and to public ownership[3].

In Canada, the deregulation of the U.S. wholesale market of electricity is seen as an opportunity for its electric power industry to increase its profit due to the cost advantage, the flexibility of hydro power production and the seasonal complementarity between the summer peak demand in the United States and the winter peak demand in Canada[4].

The purpose of this paper is to analyse the price and trade effects for the five aforementioned regions, resulting from the seamless border created by deregulation. Because there were already significant exchanges across these five regions, it is of interest to assess the incremental trade coming out of the new context. Particular attention is paid to the direction of the power flows, the identification of transmission bottlenecks between regions, CO_2 emissions, the overall cost savings and their distribution among the five regions. The identification of critical factors such as

[1] There was a combination of firm exchanges (electricity available at all times during the period of agreement) and interruptible exchanges (electricity available under the agreement that the delivery could be interrupted at the option of the supplier).
[2] Values are expressed in Canadian $. The Canadian $ was worth 0.73 U.S.$ in 1996.
[3] For an analysis of the effects of public ownership on the price of electricity in the Canadian context, see Bernard and Thivierge (l988).
[4] See National Energy Board (2003).

the costs of fossil fuels facilities and the limited availability of hydro resources points to some impending problems as the demand for electricity continue to grow.

Our analysis differs and complements the study realized by Hale et al. (2000). The latter probed the effects of electricity market deregulation in PJM, ECAR, New York and New England by considering individual generation plants and the transmission links to the load during the summer peak hour only. Their purpose was to measure the effects on the marginal costs of delivering power to the local load and to identify transmission bottlenecks. The regional emphasis was put on New York and New England and they identified significant transmission bottlenecks in western New York and in northern New England. Exchanges with Canada, which are larger than the exchanges with the U.S. neighbors, are not included. We focus on electricity exchanges between regions across a seamless border. Each region has a given annual load to serve, a set of available generating capacities with their associated fuel costs and interconnections to neighboring power grids. The year is divided into four uneven periods: winter peak (300 hours), spring (3930 hours), summer peak (600 hours) and fall (3930 hours). The stepwise representation of the load curve and the presence of hydro power plants with limited energy allow us to capture the specific role of hydro power. Exchanges with producers located outside the five regions of interest are taken as given and they are set at their pre-97 levels.

The presentation proceeds as follows: in section one, we describe the underlying analytical framework and we underline key features of the data that enter into the cost minimization problem. In section two, we present and discuss the results in order to highlight the potential role that could be played by electricity market deregulation. Toward this end, we build three scenarios: the first scenario assumes that each region has to satisfy its load with its own power plants only, that is, each region operates under autarky. In the second scenario, exchanges with the contiguous neighbors are set at their pre-97 levels. In the third scenario, all the available resources are pooled together to meet the load in each of the five regions subject to constraints imposed by generating capacities, interconnection capacities and hydroelectric resources. It is assumed that deregulation would lead to free trade and to overall cost minimization. In the fourth section, we discuss some impending problems related to growing concerns with respect to environmental protection and the link to average fuels costs and to the limited availability of new indigenous power sources.

Here are the main findings that can be drawn from our three scenarios: the pre-97 exchanges made possible fuel cost savings of $397.2 million per year for the five regions and they reduced CO_2 emissions by 9.8 Mt CO_2 eq. or 6.1% relative to autarky. Free trade brings additional fuel cost savings of $358.6 million per year or 7.5% of total fuel cost, while CO_2 emissions go up by 4.3 Mt CO_2 eq.[5] or 2.9% relative to the pre-97 exchange scenario. If we assume that electricity exports are sold at prices equal to the marginal costs of the importing regions, we find that the bulk of the cost savings translates into higher profits for Quebec, Ontario and New Brunswick while New England and New York receive much smaller gains. As Hale et al. (2000), we also find significant transmission bottlenecks toward New England that has relatively high fuel costs. The direction of power flows depends upon the order of the fuel costs associated with different types of generating equipment. Environmental concerns, particularly related to greenhouse gas emissions, are likely to change these fuel costs and no relief is to be expected from new hydro power due to the mature state of its development.

Section one: The analytical framework and electricity market information

In order to capture the short-term effects associated with the 1997 deregulation of the U.S. wholesale electricity market, we use the 1998 data on load, available generating capacities, average fuel costs, and interconnection capacities. Under the three scenarios which are called respectively autarky, pre-97 exchanges and free trade, we assume that available generating resources are used to minimize the total fuel cost of satisfying the load of each region while taking into account the constraints related to generating capacities, interconnection capacities and available hydroelectricity. The results of the three cost minimization problems[6] yield the optimal use of the generating capacities in each region and the trade flows during the four periods of the year. Some relevant economic information is embodied in the marginal costs of serving the load of each region.

[5] Mt = 10^6 tons and CO_2 eq. = CO_2 equivalent.

[6] Matlab is used to solve the cost minimization problems.

We now present a brief description of the data that enter into these cost minimization problems. This helps to understand the nature of the analysis and also to interpret the results associated with different trade rules.

Table 1 shows our stepwise representation of the load curve in MW(megawatts) within each of the five regions. Canadian regions have winter peak demand due to electrical space heating, while New York and New England have summer peak load due to air conditioning. Altogether the five regions face a winter peak load.

The upper part of Table 2 displays the available generating capacity by region. Hydro generating capacity represents 41.7% of the total; this is due mostly to Quebec where hydro power plants account for 94.1% of its total capacity. Its hydro power stations are backed by large reservoirs which are filled by spring runoff and which store water for the rest of the year until the next cycle starts; the production from such hydro power plants is very flexible. In terms of relative importance, hydro generating capacity is followed by oil (24.0%), nuclear (14.5%), coal (11.1%), natural gas (6.4%) and other (2.2%). We assume other generating capacities[7] to be must-run units and their utilization rates are based on recent experiences. The last line of Table 2 shows the total electricity (TWh) that can be produced by the hydro power stations. In order to remove some of weather randomness, we average hydroelectric output over the three years period, 1994, 1995 and 1996, prior to market deregulation. The 262.3 TWh produced by hydro power plants represent 42.6% of overall electricity demand (616.03TWh) of the five regions in 1998.

Finally, if we compare the peak demand in each region with the local generating capacity, we see that no region is short of capacity. So the immediate benefit of electricity market deregulation is to give access to power stations that have lower generating costs.

Table 3 shows the average fuel costs by generating type in each region and the latter follow more or less this increasing order: hydro, nuclear, coal, oil and natural gas. However, there are some exceptions: natural gas average costs are less than oil average costs in Quebec and Ontario. Furthermore, oil in New Brunswick (1884MW) is cheaper than coal in New England (3311MW).

[7] Geothermal, solar, wind and biomass.

Interconnection capacities between contiguous regions appear in Table 4. Figure 1 shows the geographical layout of the high voltage interconnections that link the power grids of the five regions. Quebec occupies a pivotal position and it has large interconnections with all its neighbors. In general, the north-south interconnections of the three Canadian regions to the U.S. power grids are larger than the east-west interconnections among themselves. This is expected due to the seasonal complementarity of the power grids along the north-south axis. The size of the interconnections that link the five regions can be considered to be large when they are compared to what exists elsewhere in North America. Nonetheless, if we set aside New Brunswick that has much smaller generating capacities than the other four regions, we see that interconnection capacities are small relative to the peak demand in each region. This limits the role that competition from outside sources can play in each region and the extent that marginal costs can be equalized in the new deregulated market.

Table 5 shows our estimates of the net electricity exchanges as they existed before 1997. We can observe that Quebec was a net exporter to all its neighbors, particularly to New England and New York. New England, which is a high cost region, was receiving power from its three neighbors, including New York that was also getting electricity from all its other neighbors. Although Ontario had small electricity imports from Quebec, overall it is a net exporter to New York and to its other neighbors.

It is of interest to analyse how these trade flows could be changed in the wake of the wholesale electricity market deregulation. In order to keep the problem at a manageable scale without limiting unduly the validity of the analysis, we take as given the exchanges with power grids other than the five regions included in the study. This information is shown in the lower part of Table 5.

Section two: Results and analysis

Now we turn to the presentation of the results. For each scenario i.e. autarky, pre-1997 exchanges and free trade, we show the optimal use of the generating capacities, total CO_2 eq. emissions associated with coal, oil and natural gas uses[8], the total fuel cost and the marginal costs of providing one more kWh during the four periods of the year in each region. Furthermore, under the assumption that export prices are equal to marginal costs of the importing regions, we compute the profit changes of each region as we move from autarky to pre-1997 exchanges and then to free trade.

Table 6 displays the production and the CO_2 emission under autarky. We observe that Quebec has more than enough hydro resources available to meet its own demand. Hence it has no CO_2 emission and its marginal cost is nil in each period of the year as it is seen in Table 10. All other regions make full use of their available hydro resources. The fuel cost of nuclear power is very low and as a result, the available nuclear capacity is also fully used in Ontario, New Brunswick, New England and New York. Electricity generated from coal is the marginal source in Ontario (2.07¢/kWh) while oil is the marginal source in New Brunswick (2.37¢/kWh), in New England (3.15¢/kWh) and in New York (3.02¢/kWh). The cost of electricity produced from natural gas is high relative to other sources that are sufficient to satisfy the load in each region. The low marginal costs of the Canadian regions show that the latter had a definite cost advantage over the U.S. regions before any trade is taking place. Total CO_2 emissions are 159.6 Mt CO_2 eq. and they originate from New York (65.9 Mt CO_2 eq.), New England (55.6 Mt CO_2 eq.), Ontario (32.2 Mt CO_2 eq.), and New Brunswick (5.8 Mt CO_2 eq.).

When we move from autarky to the pre-1997 exchanges, it can be seen in Table 7 that production increases in the Canadian regions (+21.6TWh) at the expense of the two U.S. regions (-21.6TWh) Quebec gets the largest production increase, i.e. 18.4TWh, and now it uses not only all its available hydroelectric resources, but also all its nuclear and natural gas generating capacities; even its oil generating capacity, which is its marginal source, is fully utilized in the winter and in the summer peak period. As it can be seen from Table 10, Quebec marginal cost is higher than in any other region and in that sense, its net exports are too high. The marginal costs of the other four regions stay unchanged relative to autarky. This leaves open the possibility of gains from trade as long as the interconnections have no bottlenecks.

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[8] Here are the CO_2 emissions (Mt CO_2 eq. /TWh) by source: coal : 0.975, oil : 0.778 and natural gas : 0.511. See Gagnon (2000).

The pre-1997 exchanges reduce CO_2 emissions from 159.6 Mt CO_2 eq. under autarky to 149.8 Mt CO_2 eq., i.e. 9.8 Mt CO_2 eq. The CO_2 emissions go down in New England (-10.3 Mt CO_2 eq.) and New York (-6.6 Mt CO_2 eq.). However they increase in Quebec (+4.0 Mt CO_2 eq.), Ontario (+2.7 Mt CO_2 eq.), and New Brunswick (+0.3 Mt CO_2 eq.).

As it can be seen in Table 11, the total fuel cost savings made possible by the pre-1997 exchanges are \$397.2 million. Fuel costs decrease in the two U.S. regions while they increase in the three Canadian regions. If we assume that export prices are set equal to the marginal costs of the importing regions, Table 12 reveals that the Canadian regions are the main beneficiaries of the exchanges while Quebec gets \$343.2 million out of the \$397.2 million and that the U.S. regions obtain very little benefits. Here is the reason why the benefit distribution is so lopsided: Quebec has some low cost hydro and nuclear capacities available under autarky while the pre-1997 exchanges reduce production in the two U.S. regions, but not enough to lower their marginal costs which are set equal to import prices.

Table 8 shows that free trade decreases further production in New England (-18.04TWh) and in New York (-12.26TWh) and increases production in Ontario (+21.89TWh) which has some low cost coal generating capacity and in New Brunswick (+13.27TWh) which makes use of low cost oil generating capacity. Due to its high cost, the oil generating capacity in Quebec cannot meet the competition (-4.87TWh). CO_2 emissions move in the same direction as production, however they increase in total from 149.8 Mt CO_2 eq. to 154.1 Mt CO_2 eq. This is particularly the case in Ontario (+21.3 Mt CO_2 eq.) and in New Brunswick (+10.3 Mt CO_2 eq.).

As it is expected, free trade make marginal costs more equal across the five regions, however they are not completely equalized due to interconnection bottlenecks. Table 9 points out the congested interconnections. As it can be seen from the lower part of Table 10, the low marginal cost regions are Ontario, which has cheap coal production, and New Brunswick where the cost of electricity production from oil is low. Both regions are attempting to displace the high oil cost of New England facilities either directly or indirectly through Quebec and New York which act as intermediaries. New York and Quebec that are linked by large interconnections, share the same marginal costs while there are still marginal costs differences between New Brunswick and Ontario on one hand and New England on the other hand. It should be remembered that this result depends on the average fuel costs by generating type as presented in Table 3. Different fuel costs could change trade flows.

Table 11 shows that free trade makes possible additional fuel cost savings of $358.7 million per year relative to the pre-1997 exchanges. The last row of Table 12 presents the distribution of these savings under the assumption that export prices are set equal to the marginal costs of the importing regions. Again the Canadian regions are the main beneficiaries. New England receive $35.2 million while New York receives almost no gain because its marginal cost based on oil production stays unchanged.

Section three: Problems on the horizon

The main result of our analysis is that free trade in the wholesale electricity market between the U.S. Northeast and Canada provides significant benefits to Canadian producers that have low cost generating facilities while congested interconnections create barriers to the complete equalization of marginal costs.

The results depend on the average fuel costs as they were presented in Table 3; changes in these costs could redirect trade flows and give rise to congestion at other interconnections. One of the main factors behind the benefits accruing to Canada as a result of electricity market deregulation is the fact that large coal generating facilities in Ontario have a lower average cost than the coal generating plants in New England and New York. In December 2002, Canada ratified the Kyoto Protocol and now it is committed to lower greenhouse gas emissions to minus 6% below their 1990 level over the first test period of the protocol, i.e. 2008 to 2012. Electricity from fossil fuels is singled out as an activity that is expected to make a significant contribution to greenhouse gas emission reduction. The New England states and New York are also planning to decrease greenhouse gas emissions. However, they are not constrained by the fairly short horizon imposed by the Kyoto Protocol. Furthermore, concerns with respect to air quality in large cities in Southern Ontario jeopardize further the use of coal generating plants that are located in this area. As the situation tightens in Ontario, this province may turn to import as it was doing just before the mid-August massive blackout. It must also be recalled that nearly half of Ontario nuclear generating capacity is out of service while it is being retrofitted or waiting for a decision in this respect. Cost overrun is casting a long shadow over this prospect. So Ontario which used to have excess generating capacity, may become a net importer.

We have seen that hydro resources make a significant contribution to the load in the five regions and Quebec occupies the leading position in this regard. Hydro resources provide a mean to perform arbitrage operations between peak and off-peak use and hence contribute directly to electricity price equalization over the course of the year. Thus far, hydro power sites have been developed according to the increasing order of their costs. The stage in Quebec has been reached where the costs of undeveloped hydro resources are about equal to the cost of natural gas power plants. So no major contribution from additional hydro power should be expected. Natural gas is becoming the fuel of choice for new power plants in the five regions and trade will be directed not so much by cost differentials but by seasonal load diversity.

Conclusion

A cost minimization framework of serving the load subject to physical constraints is used in this paper to analyse how the deregulation of the wholesale electricity market could change trade flows between three Canadian regions (Ontario, Quebec and New Brunswick) and two U.S. regions (New York and New England), which were already trading electricity before the regulatory change took place in 1997. We associate wholesale electricity market deregulation with price taking behavior and cost minimization. This is how a well functioning competitive market is supposed to operate. However, experience with electricity market deregulation has shown that there are some reasons why electricity markets may not lead to that kind of behavior. First, transmission pricing may interfere with cost minimization at the production level. Second, when the limits imposed by interconnection capacities are binding, producers may reduce output from low cost production units in favour of high cost units to increase the market clearing prices in the constrained markets. Third, hydro resources, which are quite flexible, could also be shifted around to influence the prices in some constrained markets[9]. This is why our estimate of fuel cost savings under wholesale market deregulation should be considered as an upper bound. However,

[9] See Bushnell (2003).

we think that the analysis is still valid in providing a reasonable estimate of the fuel cost savings and of their distribution across a seamless border. Furthermore, the results point to some upcoming problems as the growing electricity demand puts pressure on available resources that are more and more constrained due to environmental concerns.

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<u>Figure 1</u>

High voltage interconnections

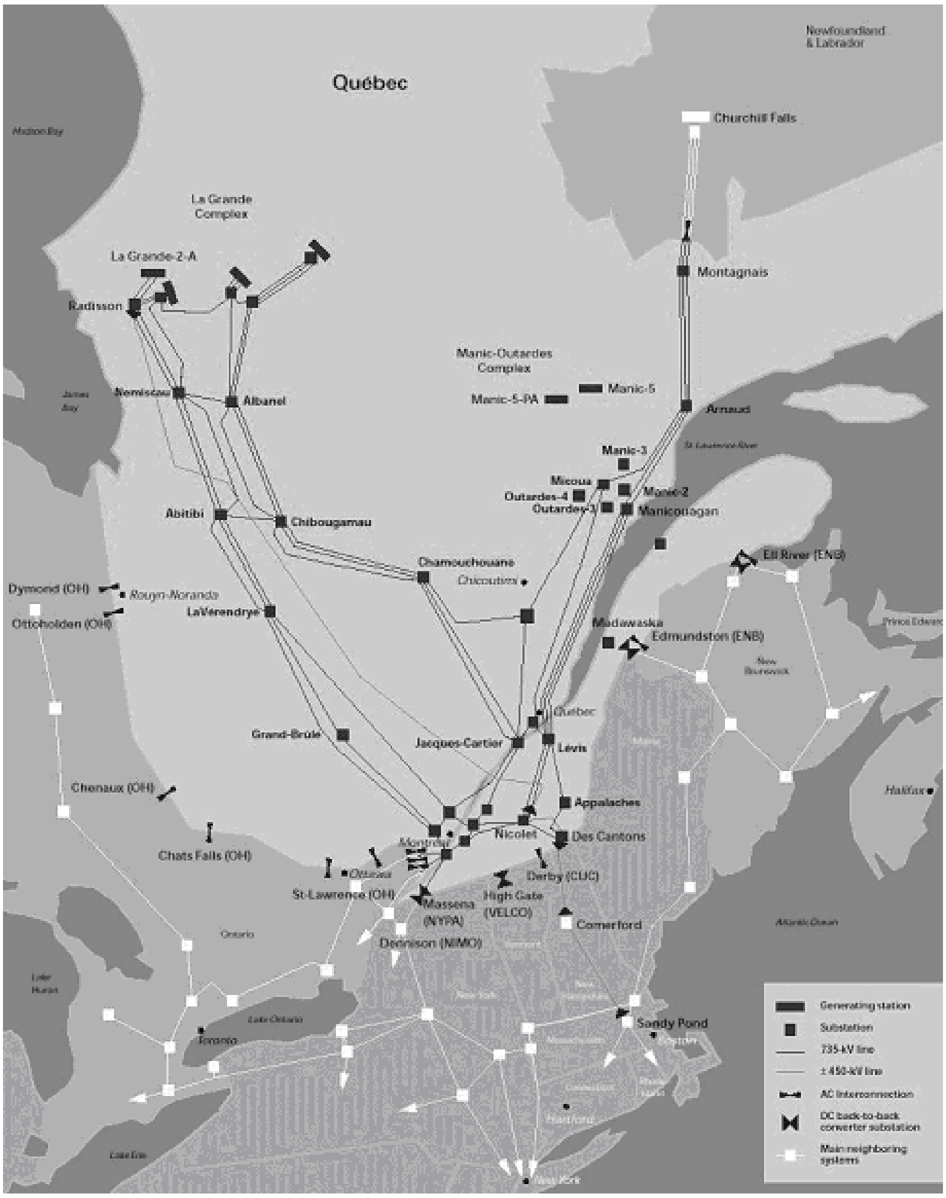

Table 1
1998 Demand (MW)

Period	Quebec[1]	Ontario	New Brunswick	New England	New York	Total
Winter (300 h)	34 295	22 330	3 333	19 800	24 150	103 908
Spring (3930 h)	20 461	16 087	1 668	12 428	16 132	66 776
Summer (600 h)	20 461	21 387	1 668	22 100	28 960	94 576
Fall (3930 h)	20 461	16 087	1 668	12 428	16 132	66 776

Estimated by the authors from North American Reliability Council (1998, 1999).
1 For Quebec, we use the 1999 data due to the 1998 ice storm. 2300 MW of generation for own use by private companies are added to arrive at Quebec total demand.

Table 2
1998 Available generating capacity (MW) and hydroelectricity (TWh)

Type	Quebec	Ontario	New Brunswick	New England	New York	Total
Hydro	37 996[1]	8 034	919	3 599	5 470	56 018
Nuclear	675	8 728[2]	680	4 365	4 981	19 429
Coal	--	7 797	570	3 311	3 262	14 940
Oil	1 596	2 302[3]	1 884	11 930	14 600	32 312
Natural Gas	37	1 803	--	1 858	4 959	8 657
Other[4]	90	334	511	1 599	469	3 003
Total	40 394	28 998	4 564	26 662	33 741	134 359
Hydroelectricity[5]	190.140[6]	39.818	3.000	4.380	24.930	262.268

Source (Quebec, Ontario and New Brunswick) : Statistics Canada (1998a) and Statistics Canada (1994, 1995, 1996).
(New England and New York) : U.S. Energy Information Administration (1994, 1995, 1996, 1998).
1 Due to a long term contract, 5 428 MW from Churchill Falls in Labrador are included in Quebec capacity.
2 Total nuclear generating capacity is 13 864 MW. Bruce A (2 060 MW) and Pickering A (3 076 MW) nuclear power plants have been take out of service. See Ontario Power Generation (2002)
3 Oil or natural gas can be used as fuel.
4 Geothermal, solar, wind and biomass
5 Average hydroelectricity production (TWh) in 1994, 1995 and 1996.
6 26.649 TWh from Churchill Falls in Labrador are included.

Table 3

1998 Average fuel costs (¢/kWh)

Type	Quebec	Ontario	New Brunswick	New England	New York
Hydro	0.00	0.00	0.00	0.00	0.00
Nuclear	0.18	0.23	0.18	0.18[1]	0.18[1]
Coal	--	2.07	2.35	2.68	2.20
Oil	3.86	3.22	2.37	3.15	3.02
Natural Gas	1.86	3.09	--	4.23	3.93

Source (Quebec, Ontario and New Brunswick) : Statistics Canada (1998b).
(New England and New York) : U.S. Energy Information Administration (1998).
1. No data are available. We use the Canadian information.

Table 4

2000 Interconnection capacity (MW)

From / To	Quebec	Ontario	New Brunswick	New England	New York	Total
Quebec	--	1 195	1 200	2 303	2 695	7 393
Ontario	550	--	--	--	2 325	2 875
New Brunswick	785	--	--	815	--	1 600
New England	1 670	--	815	--	1 600	4 085
New York	1 000	1 300	--	1 425	--	3 725
Total	4 005	2 495	2 015	4 543	6 620	19 678

Source (Quebec, Ontario and New Brunswick) : Canadian electricity association and natural resources Canada (1999).
(New England and New York) : New York Independent System Operator (2000).

Table 5
Net electricity exchanges before 1997 (MW)

From / to		Winter	Spring	Summer	Fall
Within the five regions					
Quebec	Ontario	75	54	72	54
	New Brunswick	505	253	253	253
	New England	1 116	1 073	1 073	1 073
	New York	858	701	701	701
Ontario	Quebec	--	--	--	--
	New Brunswick	--	--	--	--
	New England	--	--	--	--
	New York	450	370	415	370
New Brunswick	Quebec	--	--	--	--
	Ontario	--	--	--	--
	New England	217	315	315	315
	New York	--	--	--	--
New England	Quebec	--	--	--	--
	Ontario	--	--	--	--
	New Brunswick	--	--	--	--
	New York	--	--	--	--
New York	Quebec	--	--	--	--
	Ontario	--	--	--	--
	New Brunswick	--	--	--	--
	New England	130	119	107	119
Outside the five regions					
Ontario	Michigan	242	535	933	535
	Minnesota	20	7	17	19
	Others[1]	2	19	17	19
New Brunswick	Nova Scotia and Prince Edward Island	233	117	117	117
Others[2]	New York	400	251	447	251

Estimated by the authors from Electric Power in Canada (1997), Statistics Canada (1998c), New York Power Pool (2000), National Energy Board (2002)

1 Mostly to Pennsylvania

2 Other than Quebec, Ontario, New Brunswick and New England

Table 6
Production and CO_2 emission: autarky

		(MW)					
Region	Type	Winter	Spring	Summer	Fall	(TWh)	(Mt CO_2 eq)
Quebec	Hydro	34 235	20 401	20 401	20 401	182.86	0
	Nuclear	0	0	0	0	0.00	0
	Coal	--	--	--	--	--	--
	Oil	0	0	0	0	0.00	0
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	60	60	60	60	0.53	--
	Total	34 295	20 461	20 461	20 461	183.39	0
Ontario	Hydro	6 899	4 273	6 942	4 273	39.82	0
	Nuclear	8 728[1]	8 728[1]	8 728[1]	8 728[1]	76.46	0
	Coal	6 757	3 459	6 474	3 459	33.10	32.2
	Oil	0	0	0	0	0.00	0
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	131	131	131	131	1.15	--
	Total	22 515	16 591	22 275	16 591	150.52	32.2
New Brunswick	Hydro	674	341	202	341	3.00	0
	Nuclear	680[1]	680[1]	680[1]	680[1]	5.96	0
	Coal	570[1]	570[1]	570[1]	570[1]	4.99	4.9
	Oil	1 538	90	229	90	1.31	1.0
	Natural Gas	--	--	--	--	--	--
	Other[2]	104	104	104	104	0.91	--
	Total	3 566	1 785	1 785	1 785	15.26	5.9
New England	Hydro	1 862	325	2 108	325	4.38	0
	Nuclear	4 365[1]	4 365[1]	4 365[1]	4 365[1]	38.24	0
	Coal	3 311[1]	3 311[1]	3 311[1]	3 311[1]	29.00	28.3
	Oil	9 107	3 272	11 161	3 272	35.14	27.3
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	1 155	1 155	1 155	1 155	10.12	--
	Total	19 800	12 428	22 100	12 428	106.77	55.6
New York	Hydro	3 467	2 630	5 367	2 630	24.93	0
	Nuclear	4 981[1]	4 981[1]	4 981[1]	4 981[1]	43.63	0
	Coal	3 262[1]	3 262[1]	3 262[1]	3 262[1]	28.58	27.8
	Oil	11 697	4 665	14 560	4 665	48.91	38.1
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	343	343	343	343	3.00	--
	Total	23 750	15 881	28 513	15 881	146.05	65.9
Total		103 926	67 146	95 134	67 146	616.03	159.6

1 Maximum generating capacity
2 Geothermal, solar, wind and biomass

Table 7

Production and CO_2 emission: pre-1997 exchanges

		(MW)					
Region	Type	Winter	Spring	Summer	Fall	(TWh)	(Mt CO_2 eq)
Quebec	Hydro	34 481	21 333	20 192	21 333	190.14	0
	Nuclear	675[1]	675[1]	675[1]	675[1]	5.91	0
	Coal	--	--	--	--	--	--
	Oil	1 596[1]	437	1 596[1]	437	4.87	3.8
	Natural Gas	37[1]	37[1]	37[1]	37[1]	0.32	0.2
	Other[2]	60	60	60	60	0.53	--
	Total	36 849	22 542	22 560	22 542	201.77	4.0
Ontario	Hydro	7 134	4 258	7 013	4 258	39.82	0
	Nuclear	8 728[1]	8 728[1]	8 728[1]	8 728[1]	76.46	0
	Coal	6 897	3 790	6 746	3 790	35.90	35.0
	Oil	0	0	0	0	0.00	0
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	131	131	131	131	1.15	--
	Total	22 890	16 907	22 618	16 907	153.33	35.0
New Brunswick	Hydro	633	339	248	339	3.00	0
	Nuclear	680[1]	680[1]	680[1]	680[1]	5.96	0
	Coal	570[1]	570[1]	570[1]	570[1]	4.99	4.9
	Oil	1 291	154	245	154	1.75	1.4
	Natural Gas	--	--	--	--	--	--
	Other[2]	104	104	104	104	0.91	--
	Total	3 278	1 847	1 847	1 847	15.70	6.2
New England	Hydro	0	557	0	557	4.38	0
	Nuclear	4 365[1]	4 365[1]	4 365[1]	4 365[1]	38.24	0
	Coal	3 311[1]	3 311[1]	3 311[1]	3 311[1]	29.00	28.3
	Oil	9 506	1 533	11 774	1 533	21.96	17.1
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	1 155	1 155	1 155	1 155	10.12	--
	Total	18 337	10 921	20 605	10 921	93.59	45.3
New York	Hydro	0	2 842	4 318	2 842	24.93	0
	Nuclear	4 981[1]	4 981[1]	4 981[1]	4 981[1]	43.63	0
	Coal	3 262[1]	3 262[1]	3 262[1]	3 262[1]	28.58	27.8
	Oil	13 986	3 501	14 600[1]	3 501	40.47	31.5
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	343	343	343	343	3.00	--
	Total	22 572	14 929	27 504	14 929	137.61	59.3
Total		103 926	67 146	95 134	67 146	616.03	149.8

1 Maximum generating capacity
2 Geothermal, solar, wind and biomass

Table 8

Production and CO_2 emission: free trade

		(MW)				(TWh)	(Mt CO_2 eq)
Region	Type	Winter	Spring	Summer	Fall		
Quebec	Hydro	35 327	21 177	21 814	21 177	190.14	0
	Nuclear	675[1]	675[1]	675[1]	675[1]	5.91	0
	Coal	--	--	--	--	--	--
	Oil	0	0	0	0	0.00	0
	Natural Gas	37[1]	37[1]	37[1]	37[1]	0.32	0.2
	Other[2]	60	60	60	60	0.53	--
	Total	36 099	21 949	22 586	21 949	196.90	0.2
Ontario	Hydro	8 034[1]	4 146	8 034[1]	4 146	39.82	0
	Nuclear	8 728[1]	8 728[1]	8 728[1]	8 728[1]	76.46	0
	Coal	7 797[1]	6 461	7 797[1]	6 461	57.80	56.3
	Oil	0	0	0	0	0.00	0
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	131	131	131	131	1.15	--
	Total	24 690	19 466	24 690	19 466	175.22	56.3
New Brunswick	Hydro	919[1]	302	583	302	3.00	0
	Nuclear	680[1]	680[1]	680[1]	680[1]	5.96	0
	Coal	570[1]	570[1]	570[1]	570[1]	4.99	4.9
	Oil	1 884[1]	1 729	1 448	1 729	15.02	11.7
	Natural Gas	--	--	--	--	--	--
	Other[2]	104	104	104	104	0.91	--
	Total	4 157	3 385	3 385	3 385	28.97	16.6
New England	Hydro	3 599[1]	145	3 599[1]	145	4.38	0
	Nuclear	4 365[1]	4 365[1]	4 365[1]	4 365[1]	38.24	0
	Coal	3 311[1]	3 311[1]	3 311[1]	3 311[1]	29.00	28.3
	Oil	2 827	0	5 127	0	3.92	3.1
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	1 155	1 155	1 155	1 155	10.12	--
	Total	15 257	8 976	17 557	8 976	75.55	31.3
New York	Hydro	537	2 867	3 730	2 867	24.93	0
	Nuclear	4 981[1]	4 981[1]	4 981[1]	4 981[1]	43.63	0
	Coal	3 262[1]	3 262[1]	3 262[1]	3 262[1]	28.58	27.8
	Oil	14 600[1]	1 917	14 600[1]	1 917	28.21	21.9
	Natural Gas	0	0	0	0	0.00	0
	Other[2]	343	343	343	343	3.00	--
	Total	23 723	13 370	26 916	13 370	125.35	49.8
Total		103 926	67 146	95 134	67 146	616.03	154.1

1 Maximum generating capacity

2 Geothermal, solar, wind and biomass

Table 9
Origin and destination of electricity under free trade

		(MW)				(TWh)
From / To		Winter	Spring	Summer	Fall	
Quebec	Quebec	33 572	19 126	19 298	19 126	171.98
Ontario		378	550[1]	378	550[1]	4.66
New Brunswick		0	785[1]	785[1]	785[1]	6.64
New England		0	0	0	0	0.00
New-York		344	0	0	0	0.10
Total		34 295	20 461	20 461	20 461	183.39
Quebec	Ontario	0	0	0	0	0.00
Ontario		22 515	16 591	22 275	16 591	150.52
New-York		0	0	0	0	0.00
Total		22 515	16 591	22 275	16 591	150.52
Quebec	New Brunswick	224	0	0	0	0.07
New Brunswick		3 342	1 785	1 785	1 785	16.10
New England		0	0	0	0	0.00
Total		3 566	1 785	1 785	1 785	16.17
Quebec	New England	2 303[1]	1 755	2 303[1]	1 755	15.86
New Brunswick		815[1]	815[1]	815[1]	815[1]	7.14
New England		15 257	8 976	17 557	8 976	85.66
New-York		1 425[1]	882	1 425[1]	882	8.22
Total		19 800	12 428	22 100	12 428	116.88
Quebec	New-York	0	1 069	984	1 069	8.99
Ontario		1 797	2 325[1]	2 037	2 325[1]	20.04
New England		0	0	0	0	0.00
New-York		21 953	12 487	25 491	12 487	120.03
Total		23 750	15 881	28 513	15 881	149.06
Total		103 926	67 146	95 134	67 146	616.03

1: Maximum interconnection capacity

Table 10
Marginal cost (¢ / kWh)

Scenario / Region		Winter	Spring	Summer	Fall
Autarky	Quebec	0.00	0.00	0.00	0.00
	Ontario	2.07	2.07	2.07	2.07
	New Brunswick	2.37	2.37	2.37	2.37
	New England	3.15	3.15	3.15	3.15
	New York	3.02	3.02	3.02	3.02
Pre-1997	Quebec	3.86	3.86	3.86	3.86
	Ontario	2.07	2.07	2.07	2.07
	New Brunswick	2.37	2.37	2.37	2.37
	New England	3.15	3.15	3.15	3.15
	New York	3.02	3.02	3.02	3.02
Free trade	Quebec	3.02	3.02	3.02	3.02
	Ontario	3.02	2.07	3.02	2.07
	New Brunswick	3.02	2.37	2.37	2.37
	New England	3.15	3.02	3.15	3.02
	New York	3.02	3.02	3.02	3.02

Table 11
Fuel cost of electricity production ($ million)

Scenario	Quebec	Ontario	New Brunswick	New England	New York	Total
Autarky	0.0	861.1	159.1	1 953.2	2 184.4	5 157.8
Pre-1997	204.6	919.1	169.5	1 538.0	1 929.5	4 760.6
Free trade	16.7	1 372.3	484.1	969.8	1 559.1	4 401.9

Table 12
Profit changes ($ million)

From / to	Quebec	Ontario	New Brunswick	New England	New York	Total
Autarky / Pre-1997	343.2	31.3	21.3	~ 0	1.4	397.2
Pre-1997 / Free trade	51.1	203.4	68.8	35.2	0.2	358.7