Canadian Electricity Structure and the Impact on Pricing, Trade and the Environment

*by Pierre-Olivier Pineau**

Introduction

A lot has been written on electricity market structure. Much less is discussed on integrating different electricity markets, on the kind of benefits it could bring, and–even more critically–on estimating these benefits. This paper shows that important differences in Canadian electricity markets create distortions that are economically and environmentally harmful. Important indirect subsidies are provided to electricity consumers in many provinces, which leads to inefficient consumption levels–and to missed environmental gains. An estimated total yearly subsidy of $10 billion is indeed offered to consumers in only four provinces (British Columbia, Saskatchewan, Manitoba and Québec), preventing a reduction of up to 57,000 kilotonnes of greenhouse gas (GHG) emissions to happen. Such a reduction represents almost a third of the Kyoto reduction effort required from Canada, based on the 2005 emission level.

The paper first presents the main features of the Canadian electricity sector structure, in terms of ownership, price, capacities and market outcomes. Section 2 provides an estimate of the indirect subsidy that electricity consumers receive in four provinces. This subsidy, if removed, would increase prices and lead to electricity consumption reductions. In hydropower provinces, the electricity made available could be exported and reduce GHG emissions. These steps are covered in Section 3. In Section 4, transmission issues to allow electricity exports are analyzed, and Section 5 identifies the five obstacles preventing a new electricity structure to emerge from the current situation.

The Canadian Electricity Sector Structure

Ownership, Price and Capacities

The Canadian electricity sector structure is characterized by two very strong features: public ownership and decentralization at the provincial level. Decentralization has produced ten different electricity sectors, with independent planning, pricing policies and environmental strategies. Public ownership, dominant in seven out of ten provinces,[1] creates incentives to keep a pricing policy based on costs, especially when costs are low, as is the case in provinces with high hydropower capacity. This is so because governments, although reaping public companies' profits, are under pressure from the electorate and industrial interest groups to sell electricity according to average cost principles, which maintains low and predictable prices. See Pineau (2007) for a detailed overview of the current situation in Canada. For an historical analysis explaining the development of the electricity sector in Canada, see Froschauer (1999).

Low cost electricity from hydropower in British Columbia, Manitoba and Québec results in higher per capita consumption than in other, higher cost, provinces. This can clearly be seen in Figure 1, where per capita consumption (total provincial electricity demand divided by total population) decreases as price increases (residential price is used as a proxy for provincial price level). Of course, many other factors contribute to electricity consumption, such as economic activity (GDP), industrial structure, temporal behaviour patterns and weather (Mazer, 2007). This explains why in Figure 1, despite a clear trend, there are significant variations. Table 1 shows the installed capacity by type of generating units for six of the ten Canadian provinces.[2]

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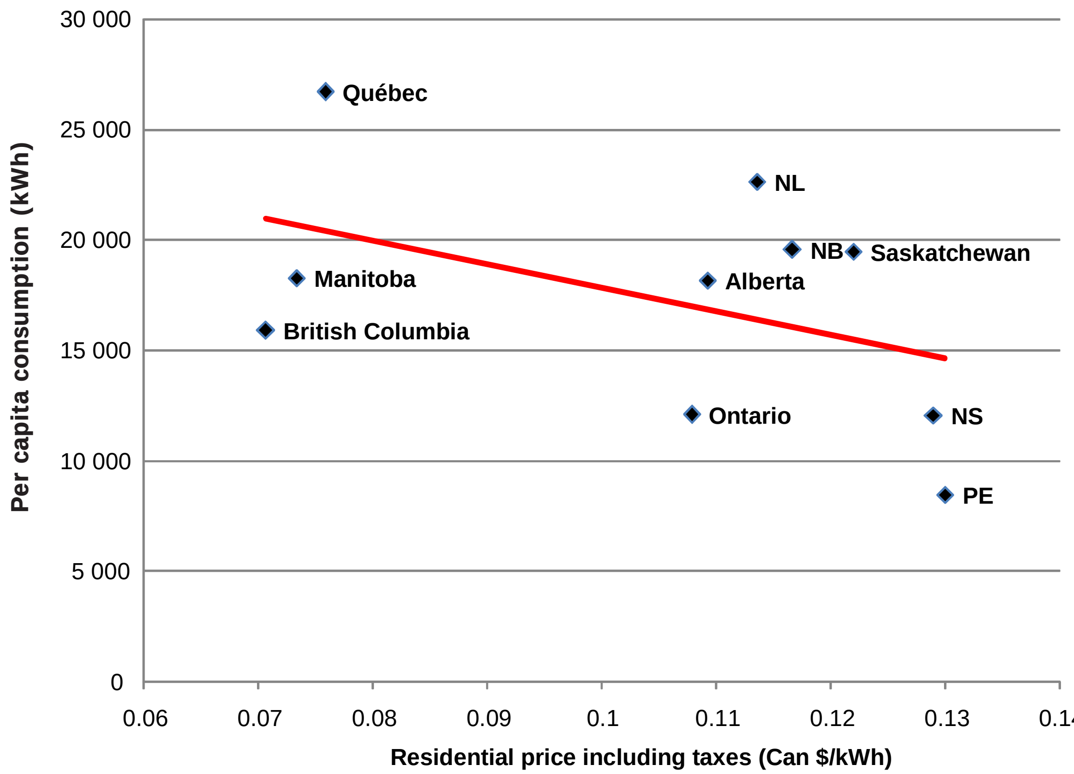
But strong public ownership does not necessarily entail price regulation, as Ontario and, to a lesser extent Alberta, prove. Both provinces have important provincial or municipal government owning electricity companies and an hourly spot market, fixing the electricity market price. All other provinces use a pricing policy based on average cost, including a return on investment, with very little concern for marginal costs (and consequently, for economic efficiency).[3]

Figure 1: Per Capita Electricity Consumption and Price, 2006



SOURCES: Statistics Canada, 2007, and Hydro Québec, 2006.

Table 1: Nameplate Capacity of Existing and Planned Electric Generating Units in Six Provinces, 2005
(MW)

Type of Electric Generating Unit (EGU)	AB	BC	MB	ON	QC	SK	Total
Hydro	815	12,369	5,427	7,627	37,238	849	64,324
Nuclear				12,278	680		12,958
Unscrubbed Coal-Subbituminous	5,225		100				5,325
Oil/Gas Steam	1,048	1,017	132	2,146	600	217	5,160
Unscrubbed Coal-Bituminous	145			5,013			5,158
Cogeneration - Combined Cycle	1,799	240		1,585	550	475	4,649
Combustion Turbine	421	205	269	286	1,004	162	2,348
Unscrubbed Coal-Lignite				525		1,716	2,241
Biomass - Wood and Wood Waste	278	568	23	271	261	63	1,464
Cogeneration - Combustion Turbine	911	110		308			1,329
Combined Cycle	460			580		150	1,190
Unscrubbed Coal (selective catalytic reduction bituminous)				980			980
Coal (selective catalytic reduction and SO2 scrubber)				980			980
Cogeneration - Oil/Gas	155	63		224		21	463
Wind	302			17	102	33	454
Scrubbed Coal	450						450
Combined Cycle	4	29		168			201
Pumped Storage				174			174
Other	27			104	29		160
Total	**12,040**	**14,601**	**5,951**	**33,265**	**40,464**	**3,687**	**110,008**

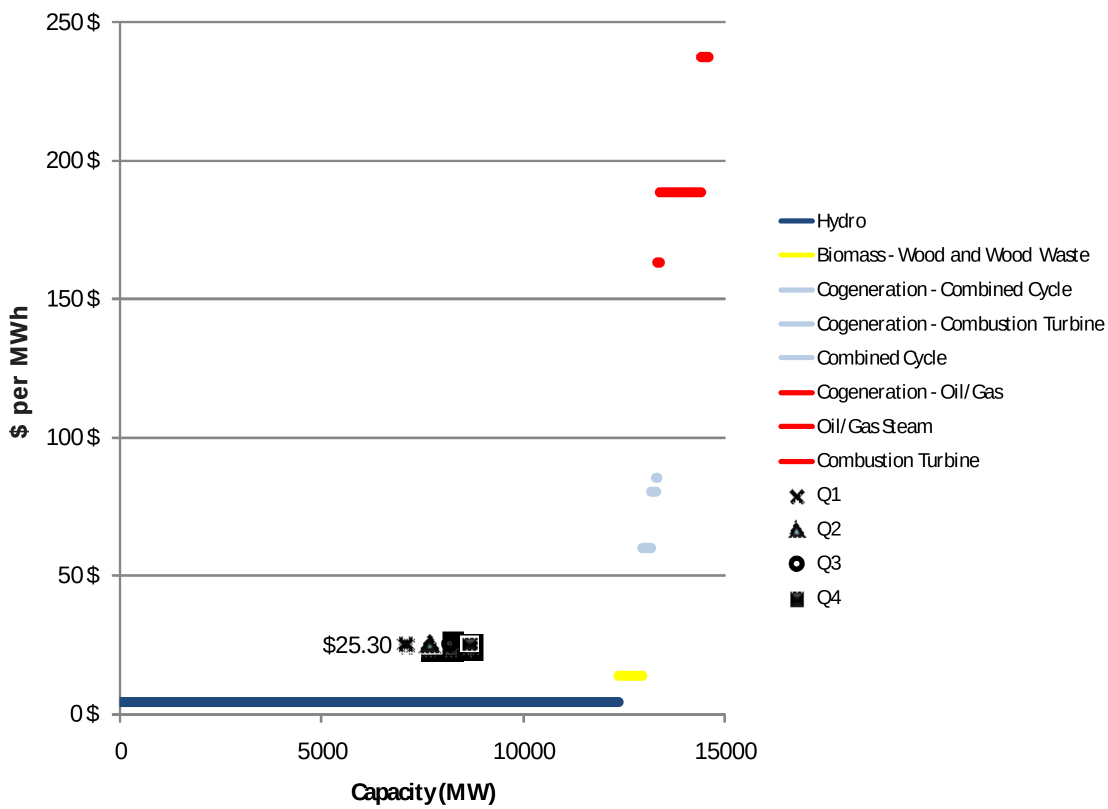
SOURCE: EC, 2005.

Market Outcomes

The different provincial electricity market structures allow very different market outcomes to be observed across Canada, as already seen in Figure 1. This is a unique situation in the energy sector, where, despite some regional differences, gasoline and natural gas prices follow similar trends. In electricity, electric generating units (EGUs) are specific to the province and are mostly dedicated to satisfy provincial electricity demands, because of regulation or lack of trading possibilities.

These very different market outcomes are illustrated in more detail in Figures 2 and 3, displaying the EGUs ordered by increasing marginal production cost in BC and Alberta. The actual market outcomes are displayed for the four "load quartiles". These load quartiles are four demand periods of equal length (one fourth of the year or 2,190 hours) with increasing demand. For each of these quartiles, the average load and average energy price can be obtained (more details on this in Section 2). In BC, the energy price is regulated and is $25.30/MWh.[4] It stays constant for consumers in all quartiles. That is, as the average load quartile increases from 7,073 MW (Q1), to 7,661 (Q2), to 8,159 (Q3) and finally to 8,645 MW (Q4), the energy price remains the same for consumers (see also Table 2 for these average load quartiles). Hydro EGUs can by used to meet demand most of the time, avoiding the use of more expensive EGUs.[5]

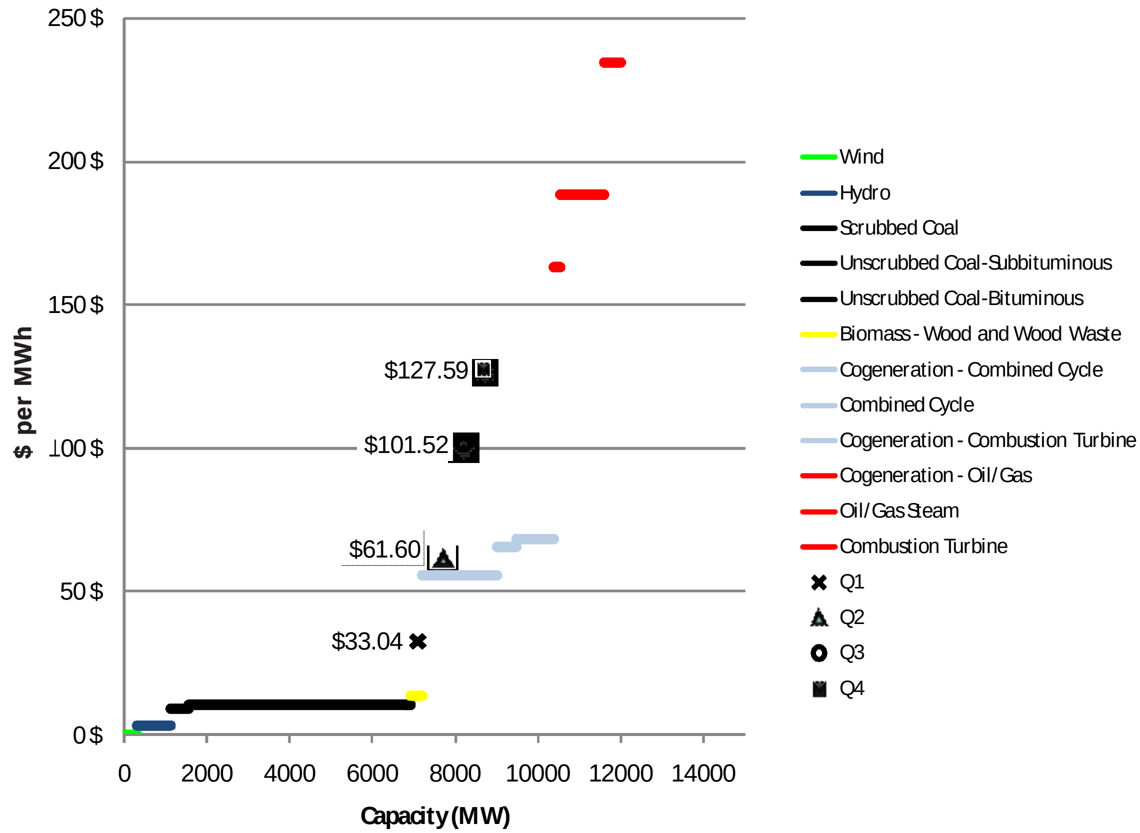
Figure 2: BC Electric Generating Units by Marginal Generation Cost and Demand Data, 2006



SOURCE: EC, 2005.

In Alberta, the market price for energy increases with demand levels: when demand is low (Q1: 7,104 MW on average), the average market price for this quartile is $33.04/MWh (2006 market price, see also Table 2). As demand rises to higher levels, price increases to reflect the higher marginal value of the product. In Q2 (average load of 7,695 MW), the average market price is $61.60/MWh. In Q3 (8,195 MW), the market price is $101.52/MWh, and during the peak quartile (Q4), an average load of 8,683 MW is sold at $127.59 per MW, on average, at each hour.

Figure 3: Alberta Electric Generating Units by Marginal Generation Cost and Demand Data, 2006



SOURCE: EC, 2005.

This situation perfectly illustrates the following economic paradox: while some consumers value a single megawatt-hour at $127, on average, during 2,190 hours in Alberta, BC Hydro is selling energy to its consumers at $25. Of course, at $127/MWh, some expensive EGUs are economic to operate in Alberta, such as natural gas power plants (cogeneration-combined cycle, combined cycle, cogeneration-combustion turbine) and therefore, they produce. Meanwhile, in BC, consumers facing the relatively low energy price of $25/MWh use the plentiful hydropower resources they have, indirectly ignoring the $102 they could make by selling in Alberta instead of using the electricity in BC. This is a very high opportunity cost.

This captures the core of the argument made in this paper:

1. Electricity prices do not reflect the value of the resource across Canada.
2. This situation accounts to a subsidy indirectly given to some consumers (those in low-cost, regulated-price provinces).

3. These low prices result in inefficient consumption levels, preventing “clean” hydropower to be exported to market-based provinces, becoming a substitute to diesel, natural gas and/or coal-fuelled EGUs.
4. With such exports (and adequate transmission capacity), important reductions of GHG could be obtained.

Electricity Subsidies in Canada

A subsidy in the energy sector is defined as “any government action that lowers the cost of energy production, raises the price received by energy producers or lowers the price paid by energy consumers” (UNEP, 2002). Similar definitions can be found in documents of various international institutions, such as the OECD’s International Energy Agency (IEA, 2000) or the US Energy Information Administration (EIA, 2000). In many Canadian provinces, price regulation of electricity “lowers the price paid by energy consumers” because the price is based on the average cost rather than on the marginal value of the product. As Figures 2 and 3 show, not only the marginal production cost of electricity rises with quantity, but consumer’s value electricity at higher levels during peak periods–they are ready to pay a higher price for it. Consequently, consumers in BC, Saskatchewan, Manitoba and Québec benefit from an indirect subsidy given by their provincial government through regulated, cost-based electricity prices.

Methodological Discussion

To estimate this subsidy, a reference price has to be found. This reference price can be a forecasted market price (with a market model), the price under an alternative technology, the export price or the long-run marginal cost (Banfi et al., 2005). The subsidy is estimated by the difference between the market price and the regulated price paid by consumers. This approach to estimate energy subsidies is also known as the “price-gap approach”, used for instance in IEA (2000), EIA (2000), Koplow (2004) and OECD (2005).

Here, the reference prices chosen are the average quartile market prices in Alberta, for BC and Saskatchewan, and the average quartile market prices in Ontario, for Manitoba and Québec. These reference prices are not perfect, but no reference price can be ideal. In particular, these reference prices can over or under-estimate the actual market price that would be observed in the different provinces if market prices were introduced. But as introducing market prices comes with high uncertainty on price levels, there is an inherent uncertainty in the market price level that cannot be avoided. The choice of the Alberta and Ontario market prices is a compromise between using real market prices, alternative technologies and export prices.

In order to find the reference market price for each quartile of the year, the following procedure is followed. The year 2006 is divided in four “load quartiles”. The lower quartile groups the 25% lowest loads of the 8,760 hours of the year (these loads are the smallest required capacities to meet demand). The second quartile groups hours that have a load above the 25% lowest but below the median. The third quartile groups those above the median but below the 25% highest. Finally, the fourth quartile groups hours with the top 25% loads. Each quartile contains 2,190 hours (one fourth of the 8,760 hours).

Hourly load and price data are only publicly available for Alberta and Ontario (AESO, 2007 and IESO, 2007). From these data, it is easy to compute the average load and price for each quartile. Table 2 provides this information for Alberta and Table 3 for Ontario. Based on the proportion of the peak load each of these “average quartile loads” represents, average quartile loads are estimated for BC and Saskatchewan (based on the Alberta values) and for Manitoba and Québec (based on Ontario values). The real 2006 peak load data are used when available for each province (when not available, 2004 peak load is used).

Table 2: Peak Demand, Average Quartile Demand and Energy Prices in BC, Alberta and Saskatchewan, 2006

	BC		Alberta		Saskatchewan	
Peak Demand 2004, MW	9,619		8,967		2,800	
Peak Demand 2006, MW	n.a.		9,661		n.a.	
	Average (MW)	Energy Price ($/MWh)	Average (MW)	Energy Price ($/MWh)	Average (MW)	Energy Price ($.MWh)
Q1	7,073.86	25.30	7,104.75	33.04	2,059.14	25.12
Q2	7,661.96	25.30	7,695.41	61.60	2,230.32	25.12
Q3	8,159.76	25.30	8,195.39	101.52	2,375.23	25.12
Q4	8,645.34	25.30	8,683.09	127.59	2,516.58	25.12
Average Energy Cost		25.30		80.90		25.12

SOURCES: NEB, 2004; BCUC, 2003; AESO, 2007; SaskPower, 2007.

The BC price is the “Forecast Heritage Reference Price” (BCUC, 2003). The Alberta price is the average hourly pool price (average System Marginal Price) for the four quartiles (AESO, 2007). The Saskatchewan energy “price” is the average fuel and purchased power costs for 2006 (SaskPower, 2007).

Table 3: Peak Demand, Average Quartile Demand and Energy Prices in Manitoba, Ontario and Quebec, 2006

	Manitoba		Ontario		Quebec	
Peak Demand 2004, MW	3,916		25,000		36,279	
Peak Demand 2006, MW	4,173		27,375		n.a.	
	Average (MW)	Energy Price ($/MWh)	Average (MW)	Energy Price ($/MWh)	Average (MW)	Energy Price ($.MWh)
Q1	2,206.26	16.44	15,422.99	27.89	20,439.48	27.90
Q2	2,534.05	16.44	17,714.40	40.52	23,476.19	27.90
Q3	2,772.49	16.44	19,381.21	50.92	25,685.15	27.90
Q4	3,097.90	16.44	21,656.05	66.21	28,699.90	27.90
Average Energy Cost		16.44		46.38		27.90

SOURCES: NEB, 2004; Manitoba Hydro, 2007; IESO, 2007; Hydro Quebec, 2007.

The Manitoba “price” is the average cost for water rentals and fuel and power purchases (Manitoba Hydro, 2007). The Ontario price is the average Hourly Ontario Energy Price (HOEP) for each quartile (IESO, 2007). The Québec price is the “Heritage Pool” price (Hydro Québec, 2007).

As Tables 2 and 3 show, energy prices are much higher in market-based provinces than in average cost provinces. The Alberta price is also much higher than the Ontario price. A few explanations can be given to explain the Alberta-Ontario differences. First, Ontario has access to more low cost EGUs than Alberta. As shown in Table 1, Ontario has important hydro and nuclear capacities, which allow the province to avoid using expensive EGUs as often as in Alberta (most of these EGUs are fuelled by natural gas). Second, Ontario is currently more interconnected with its neighbours than Alberta (see Pineau, 2007, for more on this). This allows imports to limit the market price increase when demand is high, compared to a situation where there would be little or no import opportunities, as in Alberta. Finally, Ontario consumers may be more price responsive than Alberta consumers–although no specific empirical justification for such an hypothesis is known to the author.

Results

Using the real average quartile prices of Alberta and Ontario, the difference between these prices and the actual price paid in the four other provinces can be found (BC, Saskatchewan, Manitoba and Québec). Multiplying the consumption in these provinces, for each quartile, by the corresponding price difference, an estimation of the subsidy can be provided for each province. Table 4 shows these estimates.

The subsidy estimates shown in Table 4 simply reflect the amount "saved" by consumers, had they purchased the same amount of electricity at the market price of Alberta or Ontario. The total amount, about 10 billion dollars, indicates that this indirect subsidy (for 2006 only) is large. Two comparison points can be provided: the income of BC Hydro for 2006-07 was almost $4.2 billion (BC Hydro, 2007), and the income of Hydro Québec a little more than $11 billion (Hydro Québec, 2007). These companies would increase their income by 100% and almost 50% under this scenario, with a very large share of the additional revenue simply being profit. In economic terms, these companies would keep the rent that is now distributed to their consumers; see Rothman (2000) for more on rent apportioning.

Table 4: Estimated Subsidy in the Four Regulated Provinces

	Province used for the market reference price (average quartile price)	Approximate number of TWh sold during the four quartiles	Estimated subsidy (millions of dollars)
British Columbia	Alberta	69.07	4,027.49
Saskatchewan	Alberta	20.11	1,175.98
Manitoba	Ontario	23.24	735.83
Quebec	Ontario	215.28	4,350.68
Total		**327.70**	**10,289.99**

If these estimated subsidies are high, they simply reflect the high gap between the marginal value of electricity, as valued in markets, and the production costs on which the price is based in these provinces. To reach economic efficiency, however, there should be no such gap. In a world where consumers in regulated price provinces would face market prices, they would however not buy the same amount of electricity: they would reduce their consumption. The next section explores these consumption reductions.

Impact of Market Price: Power Saving and GHG Reductions

If electric energy in regulated provinces was sold at market price, the final price of electricity for consumers would increase by a significant amount, as illustrated in Table 5. This increase would in turn lead to a consumption decrease, depending on the *price elasticity* of consumers. Espey and Espey (2004) have surveyed a large number of studies estimating the price elasticity of residential electricity consumers, and have found that the average price elasticity is -0.35 in the short-run and -0.85 in the long-run.

Table 5 presents the residential price faced by consumers in 2006 (shown in Figure 1) and the average additional energy cost that would be added to these prices if energy was sold at the reference market prices (Alberta and Ontario). From these two price items, the price increase can be computed, and given some price elasticity levels, consumption decreases can be estimated.

Table 5: Price Increase and Consumption Decrease, According to Possible Elasticity Values

	Residential Price (including transmission, distribution and other costs and taxes) 2006, $/kWh (Hydro Quebec, 2006)	Additional Energy Cost ($/kWh)	Price Increase (%)	Consumption decrease *According to elasticity* (%)	
				Short Run -0.35	Long Run -0.85
BC	0.0707	0.0556	79	-27	-67
AB	0.1093				
SK	0.1220	0.0558	46	-16	-39
MB	0.0734	0.0299	41	-14	-35
ON	0.1079				
QC	0.0759	0.0185	24	-8.5	-21

As we can observe in Table 5, the price increase could be very high in percentage points, or could be relatively small: 24% in the case of Québec. Consumption reductions for electricity, a relatively inelastic product, would be of a much smaller scope, in percentage points. If market prices in Alberta were lower, then the price increase in BC and Saskatchewan would not be as important. One can also notice that the price increase in Manitoba and Québec would not even bring the residential electricity price to the Ontario level ... which is higher due to the different additional charges electricity consumers in Ontario have to pay (i.e. regulatory and debt retirement charges, among other).

Price increases, in percentage points, would of course be smaller for higher voltage consumers (mostly industrial consumers), because they face lower distribution costs. Their consumption reduction would therefore be more modest than the ones listed in Table 5. This is why more limited consumption reduction scenarios are explored from here: one with a 10% consumption reduction, and one with 20%. Table 6 shows these results.

Table 6: Estimated Power Consumption Reduction in Regulated Provinces
(TWh)

Consumption Reduction	British Columbia	Saskatchewan	Manitoba	Quebec
10%	6.91	2.01	2.32	21.52
20%	13.81	4.02	4.65	43.50

These electricity consumption reductions would be available in the export markets. By adding energy to the available supply in export markets, they would "push to the right" more expensive EGUs in supply curves such as the ones displayed in Figures 2 and 3. This means that these more expensive EGUs would be used less often. As these units use diesel, natural gas and coal as fuel, the associated CO_2-equivalent emissions would be avoided. Table 7 estimates how much of these emissions would be avoided if electricity consumption reductions were entirely exported. Only BC, Manitoba and Québec electricity is included here, as they produce almost only hydropower. Saskatchewan does not produce hydropower, so it could not export "clean" energy.[6] Table 7 also presents two possibilities: hydropower replacing natural gas-fuelled EGUs or coal-fuelled EGUs (diesel units have been ignored because they are only exceptionally used in Canada).

Table 7: Kilotonnes of CO_2-Equivalent Reduction from BC, Manitoba and Quebec Exports

	kt of CO_2-Equivalent Emissions per TWh (Hydro Quebec, 2003)	Electricity Consumption Reduction Scenario 10%	20%
If Hydro Replaces Natural Gas	422	12,980	25,960
If Hydro Replaces Coal	941	28,944	57,888

SOURCES: Statistics Canada, 2007; and EC, 2005.

Considering that 747,000 kt of GHG were emitted in 2005 (the latest year for which an inventory has been made, see EC, 2007), with 129,000 from electricity and heat generation, CO_2-equivalent reductions presented in Table 7 are non-negligible. Indeed, from 10% to almost 50% of electricity-related GHG could be avoided by simply introducing market based prices in four regulated provinces, and exporting the "saved" electricity to Alberta and Ontario.

With a Kyoto target of 563,000 kt, these GHG reductions represent between 7.05% and 31.46% of the reduction effort to achieve Kyoto. Indeed, a reduction of 184,000 kt is needed to reach the Kyoto target from the 2005 level, and a very conservative 12,980 (7.05% of the reduction) could be achieved simply by *increasing economic efficiency* through market prices. No carbon tax or tradable permit system are involved in these scenarios. Of course, such carbon tax or cap-and-trade systems would further increase the value of trading electricity across Canada.

Export and Transmission Issues

The export of electricity is only possible if enough interconnections exist between provinces. Table 8 shows that not only do these interconnections exist; they are already used to export *within Canada* between 12% and 69% of the total electricity exports. However, paradoxically, current interconnections to Alberta and Ontario only represent between 10% and 20% of the export capacity of the four provinces discussed here. This reflects the fact that very limited investment has been done to increase provincial trade. To some extent, these limited capacities "protect" high market prices in market-based provinces.

Table 8: Exports from British Columbia, Saskatchewan, Manitoba and Quebec, 2006

	Exports to All Canadian Provinces (TWh; % of total)	Total Exports (TWh)	Interconnection Capacity (MW; % of total)		Total Export Capacity (MW)
BC	1.05 (17%)	6.15	to Alberta	800 (20%)	3,950
SK	1.34 (69%)	1.94	to Alberta	75 (10%)	725
MB	2.19 (12%)	14.47	to Ontario	275 (10%)	2,800
QC	3.56 (23%)	15.28	to Ontario	1,372 (12%)	11,352

If only new transmission lines were built to export the electricity available through consumption reductions (10% reduction scenario), a total investment of less than $8.5 billion would be needed, as shown in Table 9 for the four provinces.

Table 9: Estimated Investment in Transmission Capacity to Export All Energy Saved to Alberta and Ontario

	Distance between "regional centroids", km (EC, 2005)	Additional possible exports under the 10% consumption reduction scenario, TWh (from Table 6)	Required transmission capacity if lines are used at 50%, MW	Estimated construction cost at $1,113/MW/km (EC, 2005)
BC (to AB)	620	6.91	1,577	1,104,878,578
SK (to AB)	543	2.01	459	281,676,619
MB (to ON)	1,155	2.32	531	692,427,775
QC (to ON)	1,155	21.52	4,915	6,414,858,850
Total			**7,482**	**8,493,841,823**

Results in Table 9 are based on standard assumptions made in transmission planning (see also EIA (2002) for similar transmission investment cost estimates). It is interesting to note that the total long-term investment is less than the total single year subsidy given to consumers in the four provinces.

Institutional Obstacles

Even if estimates presented in this paper could change for higher or smaller figures, depending on different assumptions, the economic and environmental gains would remain in all cases (unless transmission costs become extremely prohibitive or new, cheap, technologies become available). It is therefore interesting to try to understand which obstacles prevent the better outcome to be obtained. Five obstacles are identified, most likely in decreasing order of importance.

1. *Electricity is under provincial jurisdictions*. As there is no central leader or coordinator in Canada for electricity markets, no one feels responsible to implement an electricity sector structure that would generate economic and environmental gains in the society.

2. *Consumers in regulated provinces want to keep low prices*. As market prices would prevail in BC, Manitoba and Québec, consumers in these provinces would face price increases. This prospect creates high resistance.

3. *Electricity producers in market-based provinces want to protect their market share*. In Alberta and Ontario, increased trade would directly reduce the market share of current electricity generators, which could only lose in a more integrated market. The irony of this situation is that a Canada-wide competitive electricity market could be blocked by the initial promoters of competition in Canada.

4. *Lack of financial environmental rewards*. No adequate incentive to reduce GHG emissions exists, as no Federal plan creates economic rewards to export electricity from low-emitting power sources.

5. *Possible social opposition to transmission capacity upgrades*. As for any new major investment project, resistance of local groups complicates their implementation.

All of these obstacles could be removed with some political will and/or clever economic mechanisms to convince “losers” to accept change in the electricity sector. For instance, direct lump sum payments to electricity consumers in regulated provinces could be made, so that they could directly cash some of the benefits of the new structure (instead of seeing provincially-owned electricity companies suddenly multiplying their profits).

Conclusion

Canada is becoming a world leader in energy. Its fossil fuel resources are extremely important and managed under a market system that works–if we ignore the absence of an adequate environmental framework to deal with greenhouse gas emissions. In electricity, market incentives are mostly absent, with a heavy reliance on inefficient average-cost pricing structures. This regulation maintains electricity prices at a low level and creates market distortions preventing significant economic and environmental gains to be made. First, current shareholders of regulated electricity companies do not obtain the full return on their investment because they accept much lower prices than what the market would bare. Second, these economic losses (taking the form of high electricity consumption in regulated provinces) create the need in other provinces to rely on more fossil fuel to generate electricity. Indeed, under a Canadian system where market prices and trade would be used to their full extent, significantly more hydropower could be exported.

The estimate provided in this paper for the total loss for shareholders (subsidy to consumers) is about $10 billion per year, before valuing GHG emissions. Trading electricity under market prices would allow CO_2-equivalent emissions to be reduced by up to 57,000 kilotonnes–which would represent almost a third of the Kyoto reduction effort (from 2005 emission levels). Only reasonable transmission investments are involved in these scenarios.

If some important institutional obstacles have been identified, the scope of the benefit is too large to think they are insurmountable. Economic and environmental gains will hopefully be proven once again as strong incentives to induce change.

Endnotes

[1] These provinces are British Columbia, Saskatchewan, Manitoba, Ontario, Québec, New Brunswick and Newfoundland and Labrador. Alberta also has important publicly-owned companies (by municipalities), along with private companies. Nova Scotia and Prince Edward Island are the only two provinces solely relying on investor-owned companies in the electricity sector. See Pineau (2007) for more details.

[2] The Maritime Provinces (Nova Scotia, New Brunswick and Prince Edward Island) and Newfoundland and Labrador are not fully covered in this paper due to scope limitations.

[3] New Brunswick, however, has a bi-lateral contract system, where prices are not regulated and where there is no open hourly spot market (NBSO, 2007).

[4] This is the main forecast of the "heritage reference price" (BCUC, 2003), which serves as the reference energy price to bill electricity consumers in BC.

[5] Capacities shown in Table 1 and Figures 2 and 3 are "nameplate" capacities, not available 100% of the time. At any given moment, some capacity is unavailable, due to water level, maintenance or other technical reasons.

[6] However, if price in Saskatchewan was rising, electricity consumption would decrease and emissions would also decrease. This possible consequence is ignored in the analysis.

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