Nodal pricing and transmission losses

An application to a hydroelectric power system

by

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Summary

Since January 1st, 1997, the wholesale electricity market in the U.S. has been open to competition through FERC Order 888. In order to satisfy the reciprocity requirements which were imposed by FERC to foreign utilities, Hydro-Québec made her transmission grid accessible to third parties. A single flat rate is applied to account for transmission losses; location and time of use play no role.

Hydro-Québec is a hydro based utility and it has very long linear high voltage power lines which link hydro power sites in the north to consumption centres in the south. In this paper, we compare three different methods of incorporating transmission losses into nodal prices for a simplified model of Hydro-Québec electric network: flat rate, linear power loss rates, and quadratic power loss rates. The latter two vary by node and time of use. We estimate that nodal price differences between the flat rate and the quadratic power loss rates can be as large as 27.8% on the producer side and 32.7% on the consumer side. The implications of such price differences for the location of economic activity over the service area could be significant.

Introduction

The on-going restructuration of the electric power industry which is taking place in several countries around the world has brought to the fore topics which had received scant attention in public utilities economics thus far, that is, the governance structure and the pricing of electric power transmission services. Up to the early nineties, electricity was provided by firms which were vertically integrated monopolies and a single organisation, which was subject to government control or regulation, was responsible for generation, transmission, and distribution of electricity over the assigned service area. It is now possible to generate electricity by small natural gas turbines without incurring significant unit cost increases and this possibility has changed the view on the role played by economies of scale at the generation stage, while transmission and distribution kept their natural monopoly features.[1] Technological changes and the public pressure to lower electricity prices undermined the conventional structure of the electric power industry. This led to the privatization of the whole industry in England in 1990 as well as the introduction of competition in electricity generation.[2] Since then, the British model has been adopted with some modifications by several countries.

The opening of electricity generation to competitive market forces first brought the deregulation of the wholesale market, that is, the market between producers on the one hand and local distribution utilities on the other hand. In some cases, this has been followed by partial or even total retail market deregulation. Whatever type of deregulation is being considered, non-discriminatory access to transmission networks must be implemented to reap the benefits of competition. Furthermore prices must be set for transmission services.

Following the path-breaking works of Schweppe et al. (1988) and Hogan (1992), economists have developed optimal transmission pricing rules when the objective is the maximization of social economic surplus subject to production and transmission capacity constraints while taking into account line losses, loop flows, and reliability criteria. The first order conditions associated with the maximization of economic benefits under constraints yield the electricity prices paid by users and received by producers at each node.[3] These prices vary from node to node due mostly to transmission line congestion and losses. The value of a transmission right between two nodes is equal to the price differential between these nodes. For a recent survey of the transmission pricing literature, see Hsu (1997).[4]

The emphasis thus far has been on web like transmission networks which link together load centres and thermal generating stations and which give rise to loop flows. For such networks, there is some discretion in the decision to locate new thermal power plants and important factors in this respect are the load distribution over space, available coal or natural gas supplies, high voltage power line corridors, and environmental concerns. Hydro power stations do not allow for this kind of flexibility and their location is determined by water flows and geography. They may be located at sites which are far away from consumption centres and they require long linear high voltage transmission lines to bridge a link between production and consumption. Hydroelectricity is produced by the energy of falling water. The water, which is stored behind the dams, usually comes from spring runoffs. This is the water which is available to meet demand until the start of the next annual cycle. Import and export from/to interconnected adjacent areas play a critical role in balancing supply and demand over the course of the year. Exchanges take place with neighbours which do not display the same demand patterns.

Imports increase during the peak period and the flows of electricity are reversed in the off-peak period.

Important features of hydro-based electric systems are the water use over the course of the year and the losses over the long linear high voltage power lines. The limits of transmission line capacity are not so significant as in thermal systems since generation and transmission capacities are developed to fit together.[5]

In this paper, we analyse and compare three methods of pricing transmission losses for a hydroelectric power system while taking into account generation and consumption at each node, power exchanges with neighbouring areas, and the available stock of water over the annual cycle. The simple model is applied to Hydro-Québec, a hydro-based utility, which had a total generating capacity of 36841 MW (94.0% hydro) at the end of 1996.[6] The three methods of pricing transmission losses are: single flat rate, which is common to all nodes during the peak and the off-peak period, rates based on linear power losses, and rates based on quadratic power losses. The latter two rates vary by node and time of use.

The development proceeds as follows: section one presents some background information and the topic which is analysed in this paper. In section two, we recall some theoretical considerations on power flows, transmission pricing, and the value of water used to generate electricity. In section three, we present and discuss the results. We show that the three methods of pricing transmission losses lead to different prices at each node; for instance, the price differentials between the single flat rate and the rates based on quadratic transmission losses can be as large as 27.8% from the producer standpoint and 32.7% from the consumer standpoint.

Section 1: Context and the topic to be analyzed

1.1 Hydro-Québec: an overview[7]

Since the application in this paper deals with Hydro-Québec, it is appropriate at this stage to know more about this electric utility. Hydro-Québec is a government-owned utility which provides electricity to most users in the province of Québec.[8] In 1996,[9] the vertically integrated utility sold 144.5 TWh to local customers and 19.0 TWh to utilities located outside the province. Total generation, transmission, and distribution losses were 12.3 TWh. Peak demand reached 31245 MW in winter, due to electric heating, and summer months are part of the off-peak period. The available capacity was 36841 MW at year end and the hydro share (34648 MW) was 94.0%.[10] One nuclear plant (675 MW) and a set of fuel oil power plants of various sizes account for the remaining capacity (1518 MW).

The Hydro-Québec network is interconnected with all the adjacent regions: Ontario (1462 MW), New Brunswick (1050 MW), New York (2675 MW), and New England (2300 MW) for a total of 7487 MW. Because some equipment is used jointly by New York and Ontario, the simultaneous capacity is limited to 6337 MW.[11] Peak demands in New York and New England occur over the summer months. If we set aside the purchase of electricity from Labrador, Newfoundland, through a long term contract (65 years), Hydro-Québec buys little electricity from producers located outside the province and the interconnections are used mostly to export power through long term contracts (9.6 TWh) and through short term ones (9.4 TWh). On average, Hydro-Québec has been selling more than 10% of her production to utilities located outside the province.

As it can be seen from Figure 1, very large hydro power sites which are located more than 1000 km in the northern part of the province provide the bulk of the hydro capacity: James Bay on the western side with 14 790 MW and Churchill Falls–Manicouagan-Outardes on the eastern side, with 12 060 MW. Other significant albeit smaller hydro power plants are located in the Trois-Rivières district and on the St. Lawrence River up from Montréal. The bulk of the consumption, as well as exports, takes place in the southern part of the province and 735 kV high voltage power lines, which link production in the north to consumption centres in the south, form the backbone of Hydro-Québec transmission network. There are 11 000 kilometres of such high voltage power lines. Once power reaches the consumption centres, it is transmitted and distributed at lower voltage.

1.2 Transmission pricing

The wholesale electricity market in the U.S. has been open to competition since January 1st, 1997, through FERC Order 888. Following this order, producers, local distribution utilities or any FERC licenced marketers can exchange electricity at market prices. This implies that transmission lines must be open to all interested parties in a non-discriminatory fashion at agreed price schemes.

The pricing of transmission services is giving rise to a large set of complex issues which are related to the nature of the services themselves and which have to be addressed by regulatory commissions. Electricity cannot be stored and it has to be delivered with a high level of reliability when it is requested by customers. A transmission network provides a delicate balancing mechanism between production at some large power stations and load centres which are scattered over wide areas. Important issues are reliability, stability, congestion, and reserve maintenance. Furthermore, transmission rates must provide an acceptable return to grid owners. Transmission rates must also be set to foster the efficient use of available generating equipments and to provide appropriate signals for transmission development.

FERC did not dictate specific pricing schemes with respect to transmission services, but rather it relied upon proposals from interested parties as long as the pricing schemes embodied the general principles of open access to third parties at non-discriminatory rates. Thus far three broad methods have been applied to determine transmission rates: flat rate or average cost pricing, zonal rates which are simply flat rates albeit over smaller areas, and finally nodal prices, which reflect the marginal costs of producing electricity at various nodes over a network. It should be pointed out that transmission line losses have received little attention from regulatory agencies thus far.

Hydro-Québec applied to FERC for a licence to operate as a wholesale marketer in the U.S. market and her application got approved in late 1997.[12] FERC imposed some reciprocity conditions upon foreign applicants which require the latter to open their transmission networks along the lines adopted for the U.S. wholesale market. To satisfy these conditions, Hydro-Québec created a new division, TransÉnergie, which manages all her transmission assets, and the Québec government set the conditions and the rates for the open access to the transmission network.[13] The government chose a single flat rate which is uniform over the whole province for all the time periods. The same approach applies to line losses. In order to have 1kWh delivered by TransÉnergie, the supplier must provide 1.07 kWh for point to point sale whatever are the point in, the point out, and the time period, and 1.05 kWh for grid sale.

1.3 The analysis

In this paper, we focus on three methods to set nodal prices in order to take into account line losses: a flat rate for the whole network as it is currently applied by TransÉnergie, rates based on linear power losses, and finally rates based on quadratic power losses. Only two time periods are considered: peak and off-peak. Furthermore, we incorporate one important feature of the hydroelectric system under consideration which is the balancing mechanism associated with electricity import and export. However, our analysis does not rely on an integrated optimizing model and therefore we do not compute the optimal power flows between nodes in order to maximize either social economic surplus or the value of the available stock of water. Rather we take as given total hydro power generation and electricity use at different nodes as they occurred in 1996 and the constant transmission loss (%) as it is specified under current regulation and we analyse how nodal prices vary when they are adjusted to embody the three ways of incorporating transmission losses. The main purpose of the analysis is to shed some light on the limitations associated with the current flat rate for transmission losses.

Since we focus mainly on transmission losses, we neglect some other elements which have attracted the attention thus far in the economic literature on transmission pricing, namely, congestion and loop flows. These two elements of transmission are not so important for hydro-based electric networks when hydro power sites are located far from consumption centres.[14]

Section 2: Some theoretical considerations

Although the theoretical literature on optimal nodal pricing of transmission services is now well developed, a small number of applications which embody these principles have been implemented so far.[15] Furthermore very few studies have dealt with the implications of different transmission pricing methods. One exception is Green (1998), who applies the optimizing approach to the England and Wales electric system while taking into account transmission capacity constraints and line losses under four pricing regimes of transmission services: nodal pricing which is taken as the first best case, one uniform price for consumers and nodal prices for producers, nodal prices for consumers and one uniform price for producers, and finally, uniform prices for both consumers and producers. Congestion and transmission line losses are the major factors which lead to price differences between the northern area which is a net supplier and the southern area where the bulk of the load occurs. Let us recall briefly some theoretical considerations which are germane to our analysis.

2.1 Power flows

The basis for the calculation of power flows is the direct current (DC) model.[16] This model is based on two assumptions. First, only active power flows are considered. Second, line losses are computed separately from the computation of transmitted power. DC power flows are computed from net generation:

$$P = H\ (Y\text{-}d)$$

where: Y = the vector of generation at each node;

d = the vector of demand at each node;

H = the transfer matrix;

P = the vector of power flows between nodes.

The transfer matrix need not be defined explicitly in the case of a linear transmission network as the one studied here. This simple model will be described in section 3.1. Actually the elements of the H matrix can readily be interpreted by inspection of the model as it is done in the next section.

2.2 Nodal pricing

We do not apply an optimizing routine, rather we take consumption and production in each region as given and we compute the nodal prices under the three methods of incorporating transmission losses. Our starting point is the nodal pricing rule as presented in Hsu (1997) when it is simplified by removing generation and transmission capacity constraints:[17]

$$\rho_k(t) = \lambda(t) + \lambda(t) \bullet \frac{\partial L\left[\vec{P}(t)\right]}{\partial d_k(t)} \tag{1}$$

where: $\rho_k(t) =$ the electricity price for delivery and purchase at node k and time t;

$\lambda(t) =$ system lambda at time t. It is the marginal cost of the highest cost production unit which is located at the swing node;

$L\left[\vec{P}(t)\right]=$ total line losses associated with a vector of power flows $\vec{P}(t)$ over the set of lines;

$d_k(t)$ = demand at node k and time t.

Using the same assumptions as before, equation (1) can be rewritten in the following way (Schweppe et al., 1988):

$$\rho_k(t) = \lambda(t) - \lambda(t) \bullet \sum_i \frac{\partial L_i[P_i(t)]}{\partial P_i(t)} H_{ik}(t) \qquad (2)$$

where: $L_i[P_i(t)]$ = line losses over line i at time t;

$P_i(t)$ = power transmitted over line i at time t (MW);

$H_{ik}(t)$ = line indicator from the swing node to node k at time t. It takes value +1 or –1 according to the direction of power flows, or 0 if line i does not link the swing node to node k.

The three methods of incorporating explicitly transmission line losses into nodal prices at each time period are:

iii. One flat rate:

$$\rho_k(t) = \lambda(t) \bullet [1 + c(t)] \qquad (3)$$

where: c(t) = loss factor at time t (%).

iv. Rate based on linear power losses:

$$\rho_k(t) = \lambda(t) - \lambda(t) \bullet f(t) \sum_i D_i H_{ik}(t) \qquad (4)$$

where: f(t) = line loss per km at time t (MW/km);

D_i = length of line i (km).

This way of incorporating line losses is based on the fictious assumption of linear line losses:

$$L_i^l(t) = f(t)D_i P_i(t) \tag{5}$$

where: $L_i^l(t)$ = linear line losses over line i at time t.

iii. Rate based on quadratic power losses:

$$\rho_k(t) = \quad \lambda(t) - \lambda(t) \bullet 2\frac{R(t)}{|V|^2}\sum_i D_i P_i(t) H_{ik}(t) \tag{6}$$

where: R(t) = line resistance per km at time t (Ohms/km);

V = voltage (kV).

This last way of incorporating line losses is based on the quadratic equation determining the power loss through heat:

$$L_i^q(t) = \frac{R(t)}{|V|^2} D_i P_i^2(t) \tag{7}$$

where: $L_i^q(t)$ = quadratic line losses over line i at time t.

We can see the effect of the marginal loss on the nodal price in equation (6). The line resistance is made to vary with time because we have different loss factors for the peak and the off-peak period.

2.3 Value of water

The node which has the highest marginal cost is taken to be the swing node. For a thermal system, it is fairly easy to rank the power stations in terms of their marginal operating costs. Hydro power stations are different in this respect and their operating cost is almost nil; however the electricity which can be generated is constrained by the available water which is stored in the reservoirs. The relevant factor is the opportunity cost of water. Since import provides the marginal supply during the peak period, import is taken to be the swing node at that period. This also determines the opportunity cost of water since the producer should be indifferent between importing electricity and generating it by his own hydro power station. For the off-peak period, the opportunity cost of water is the same as in the peak period if the producer is maximizing the value of the available water. The James Bay node which corresponds to the last large hydro power site which has been developed in the province of Québec is taken to be the swing node in the off-peak period in the empirical analysis which follows.

Section 3: The simplified network and the empirical results

In this section, we present the results which are obtained when we apply the three nodal pricing formulas, as they were introduced in the previous section, to a simplified model of the 735 kV transmission network of Hydro-Québec for 1996. Several assumptions have to be made in order to go from a highly complex hydro power network as it is shown in Figure 1 to a simplified model which can be analyzed without the help of a large scale simulation model, while preserving the main characteristics of the network which are: long linear high voltage power lines from the north (generation) to the south (consumption), the line losses under peak and off-peak use, the availability of water over the annual cycle, and the interconnections with the adjacent areas in the southern part of the province. Now we describe the main assumptions in this respect.[18]

3.1 A simplified network

i. From administrative districts to nodes

Hydro-Québec high voltage transmission network is simplified in such a way that each node corresponds to an administrative district (or a set of administrative districts) linked by power lines. In this way, the model represents power exchanges between the districts. Table 1 shows the relationships between Hydro-Québec administrative districts in 1996 and the nodes in the simplified model and Figure 2 provides a graphical representation of the nodes, the lines, their length,[19] and the direction of power flows.[20]

ii. The transmission network and power losses

We assume that there is no congestion over the whole network and that all the lines have the same voltage which is 735 kV. As it can be seen from equation (3), the loss factor, c(t), varies with time. During the peak period, losses are taken to be 7.0% of the load. This is the loss factor for point to point delivery under the current transmission rates in Québec. During the off-peak period, losses are taken to be 5.0% of the load. This last figure is the loss factor for grid sale under the current regulation. The line loss per km in the linear loss model, f(t), and the line resistance per km in the quadratic loss model, R(t), vary with the time period, but not with the lines. Total losses are the same under the three different ways of incorporating losses into nodal prices. The supplier which is located at the swing node (the marginal producer) compensates for power losses.

iii. Demand

There are two time periods: peak which lasts 300 hours and off-peak which lasts 8460 hours. Demand is constant within each period. Off-peak demand is adjusted so that Hydro-Québec annual sales match the sum of peak and off-peak demands. The district (node) shares of consumption within each period are the same as the annual shares. Table 2 shows the 1996 actual electricity sales by district[21] and Table 3 provides the corresponding computed figures during the peak and the off-peak period. It can be seen that the largest electricity sale occurs in the Montréal district (63.4%) followed by the Québec district (24.9%).

iv. Power generation, import/export, and transfer

Table 2 shows the installed generating capacity by district. The nuclear station (675 MW) is considered to be a must-run unit in both periods.[22] The thermal stations are assumed to operate at maximum capacity during the peak period and to be shut down during the off-peak period. The hydro power stations are assumed to have the same load factor (55.4%) and the off-peak load factor is computed in such a way that the weighted sum of the peak and off-peak load factors matches the annual load factor.

Import during the peak period is set at 500 MW before losses at price $40/MWh.[23] Export during the off-peak is a residual so that generation plus import equal sales within the province plus export. Table 3 shows the peak and the off-peak production as well as the net supply by node, and Table 4 displays the power transfer over the power lines.

v. System lambda or marginal production cost

The system lambda, which is the marginal production cost, is the import price ($40.00/MWh) during the peak period. This also determines the opportunity cost of water at James Bay as it was presented in Section 2. So the opportunity cost of water at James Bay in the peak period is equal to the import price once power losses to the Montréal node are taken into account for the two nodes. This also determines the system lambda in the off-peak period since James Bay is then the swing node.[24]

3.2 Empirical results

Total losses are the same under the three pricing methods and they are equal to the losses as they are computed under the current regulatory regime. Table 5 provides the peak and the off-peak spot prices at each node ($/MWh) when import is the swing node in the peak period and James Bay is the swing node in the off-peak period. We can see the direct effects of power line losses related to length by looking at the peak nodal prices of James Bay (long distance) ($35.57/MWh) and import (short distance) ($40.00/MWh) vis-à-vis Montréal ($40.26/MWh) under the linear power loss rates. We can also observe the effects of quadratic power line losses in comparison to linear power line losses by looking at the peak nodal prices of James Bay: $28.88/MWh for the former and $35.57/MWh for the latter.

Table 6 shows the spot prices under linear and quadratic power losses relative to the flat rate (producer price). It can be seen that the nodal spot price differentials can be quite large. For a producer which is as far away as James Bay, the difference is 11.1% under linear power losses and 27.8% under quadratic power losses. The relative differences with respect to the consumer price, i.e. 42.80 MWh, are larger. For instance, it is 32.7% at the James Bay node under the quadratic power losses.

No profit is generated under the single flat rate when all sales (including losses) and all purchases are realized at constant prices at each node.[25] The price spread (%) is exactly equal to the loss (%). We do not have the zero profit result for the two other pricing methods. The linear loss rates yields a loss of $ 268 000 per year when demand and production, including the losses, receive the prices displayed in Table 5. The quadratic power loss rates generate an annual profit of 253 million $. The latter amount falls short of the total revenue requirements for TransÉnergie which were estimated by Gouvernement du Québec (1997) to be 2260 million $. This implies that some other ways to finance the capital invested in the transmission network need to be implemented to go along with the nodal prices which are presented in Table 5.[26]

Conclusion

Bernard and Doucet (1999) argued that the average cost pricing of transmission services can lead to misleading price signals for large hydro-based power networks which have long linear high voltage transmission lines between hydro power sites and consumption centres. However they failed to incorporate any information on the empirical significance of this effect. Here we use a simplified model of Hydro-Québec network to compute the nodal prices when line losses are the main factor leading to nodal price differences. Losses are incorporated in nodal prices through three methods, i.e. flat rate, linear power loss rates, and quadratic power loss rates. In this simple model, linear power loss rates and quadratic power loss rates are estimated to display significant differences relative to the single flat rate. Although the model is quite simple, it has been specified to represent a good first order approximation of reality. Our preferred representation of line losses appears in the quadratic line loss nodal prices. These are the prices which should enter into the producer decision with respect to new power site location. Our results indicate that the current flat rate provides erroneous price signals. Line losses are real economic losses and they should be properly reflected into prices paid to producers and prices paid by consumers.

Figure 1

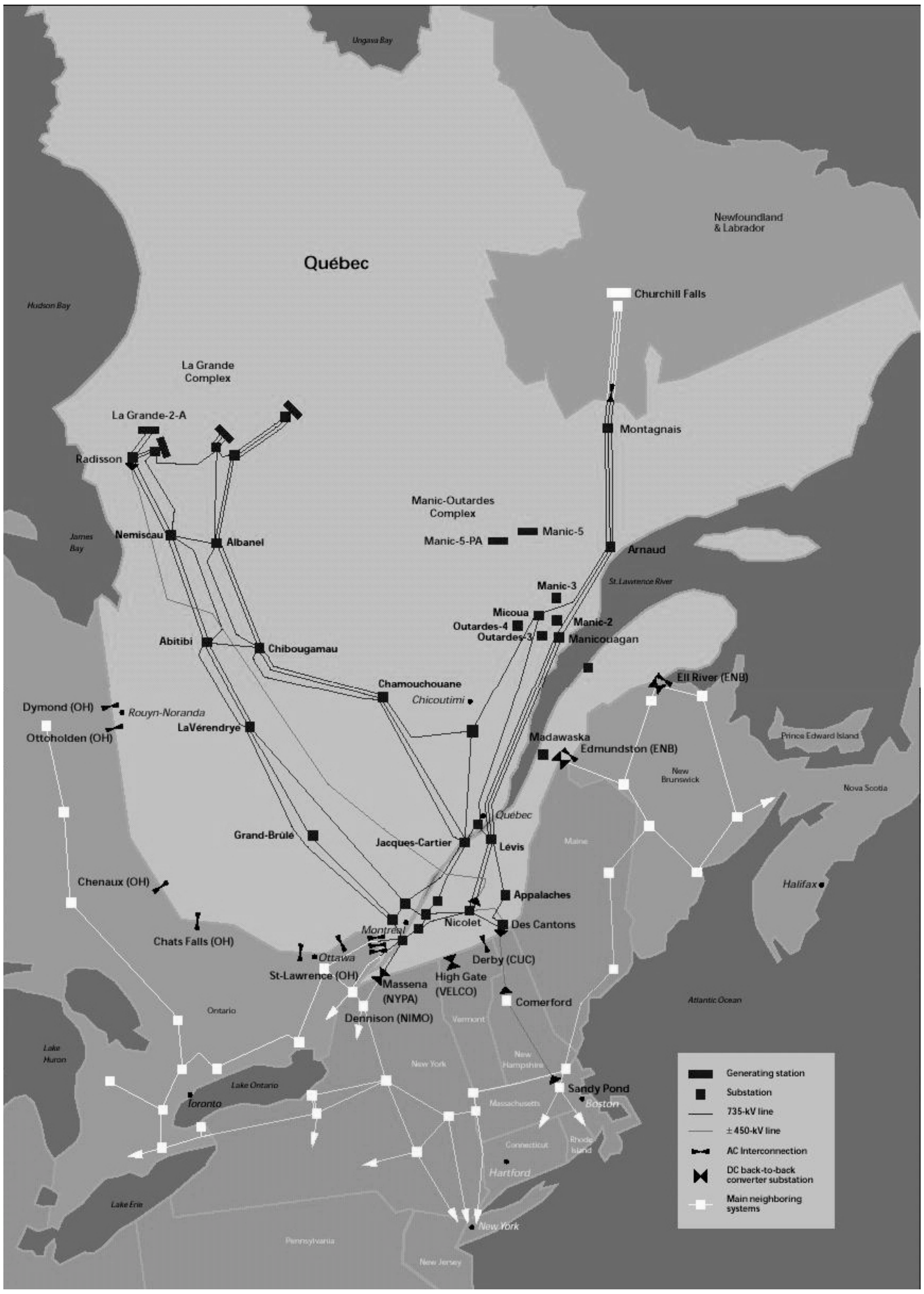
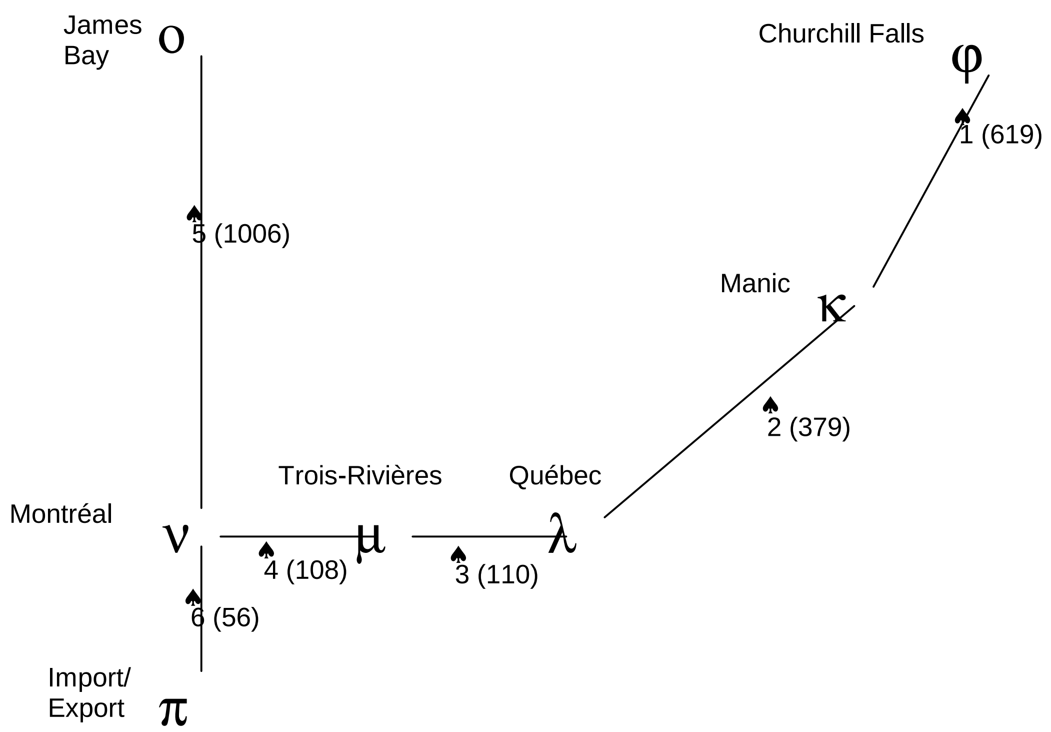

Québec
Newfoundland & Labrador
Churchill Falls
La Grande Complex
La Grande-2-A
Radisson
Montagnais
Manic-Outardes Complex
Manic-5
Manic-5-PA
Arnaud
Nemiscau
Albanel
Manic-3
Micoua
Outardes-4
Outardes-3
Manic-2
Manicouagan
Abitibi
Chibougamau
Eel River (ENB)
Chamouchouane
Chicoutimi
Dymond (OH)
Rouyn-Noranda
Ottoholden (OH)
LaVérendrye
Madawaska
Edmundston (ENB)
Grand-Brûlé
Jacques-Cartier
Québec
Lévis
Chenaux (OH)
Appalaches
Nicolet
Des Cantons
Chats Falls (OH)
Montréal
Ottawa
Derby (CUC)
St-Lawrence (OH)
Massena (NYPA)
High Gate (VELCO)
Comerford
Dennison (NIMO)
Sandy Pond
Boston
Toronto
Hartford
New York
Halifax
Generating station
Substation
735-kV line
± 450-kV line
AC Interconnection
DC back-to-back converter substation
Main neighboring systems

Figure 2

A SIMPLIFIED VERSION OF QUÉBEC ELECTRIC POWER NETWORK



node

f line

( ) line length in km

Table 1

RELATIONSHIP BETWEEN HYDRO-QUÉBEC ADMINISTRATIVE DISTRICTS IN 1996
AND NODES IN THE SIMPLE MODEL

Node		
Number	**Name**	**Administrative District in 1996**
1	Churchill Falls	
2	Manic	Manicouagan
3	Québec	Montmorency Saguenay[a]
4	Trois-Rivières	Mauricie[b]
5	Montréal	Saint-Laurent Richelieu Laurentides
6	James Bay	La Grande Rivière Saguenay[b]
7	Export/Import	External markets

a) Consumption only
b) Production only

Source: Hydro-Québec (1997b)

Table 2

SALES AND GENERATING CAPACITY

Node		Electricity sales		Generating capacity[a] (MW)			
Number	**Name**	**GWh**	**Share (%)**	**Hydro**	**Thermal and Nuclear**	**Total**	**Share (%)**
1	Churchill Falls	0	0.0	5428	0	5428	14.8
2	Manic	10690	7.8	8599	0	8599	23.5
3	Québec	34386	24.9	0	0	0	0.0
4	Trois-Rivières	0	0.0	1636	1103	3339	9.1
5	Montréal	87403	63.4	3252	801	3453	9.4
6	James Bay	5353	3.9	15 698	162	15 860	43.2
7	Export/Import[b]	-	-	-	-	-	-
Total		**137 832**	**100.0**	**34613**	**2066**	**36679**	**100.0**

a) December 31, 1996.
b) Electricity imports and exports are described in the text.

Source: Hydro-Québec (1997b)

Table 3

PEAK AND OFF-PEAK OF DEMAND AND PRODUCTION BY NODE (MW)

Node		Peak			Off-peak		
Number	**Name**	**Demand**	**Production**	**Net**	**Demand**	**Production**	**Net**
1	Churchill Falls	0	4177	4177	0	2820	2820
2	Manic	2278	6617	4339	1190	4467	3277
3	Québec	7271	0	-7271	3799	0	-3799
4	Trois-Rivières	0	2362	2362	0	1524	1524
5	Montréal	18513	3303	-15 210	9673	1689	-7984
6	James Bay	1139	12 242	11 103	595	8155	7560
7	Export/Import	0	500	500	3398	0	3398
Total		**29 201**	**29 201**	**0**	**18 655**	**18 655**	**0**
Power losses		-	2044[a]	-	-	933[b]	-

a) Compensated by import.
b) Compensated by James Bay.

Table 4

POWER TRANSFER (MW)

Power line	Peak	Off peak
1	4177	2820
2	8516	6097
3	1245	2298
4	3607	3822
5	11103	7560
6	500[a]	3398[b]
Total	**29 148**	**25 995**

a) Import
b) Export

Table 5

PEAK AND OFF-PEAK SPOT PRICES AT EACH NODE ($/MWh)

Node		Flat rate[a]		Linear power loss rate		Quadratic power loss rate	
Number	**Name**	**Peak**	**Off-peak**	**Peak**	**Off-peak**	**Peak**	**Off-peak**
1	Churchill Falls	40.00	40.00	34.59	35.01	33.70	30.84
2	Manic	40.00	40.00	37.98	36.65	36.28	32.03
3	Québec	40.00	40.00	39.24	37.66	39.50	33.60
4	Trois-Rivières	40.00	40.00	39.76	37.94	39.64	33.77
5	Montréal	40.00	40.00	40.26	38.24	40.03	34.05
6	James Bay	40.00	40.00	35.57	35.57	28.88	28.88
7	Export/Import	40.00	40.00	40.00	38.38	40.00	34.18

a) This is the producer price. The consumer price is $42.80/MWh.

Table 6

SPOT PRICES AT EACH NODE RELATIVE TO THE FLAT RATE PAID TO PRODUCER (%)

Node		**Linear power loss rate**		**Quadratic power loss rate**	
Number	**Name**	**Peak**	**Off-peak**	**Peak**	**Off-peak**
1	Churchill Falls	86.5	87.6	84.2	77.1
2	Manic	93.7	91.6	90.7	80.1
3	Québec	98.1	94.1	98.8	84.0
4	Trois-Rivières	99.4	94.8	99.4	84.4
5	Montréal	100.6	95.6	100.1	85.1
6	James Bay	88.9	88.9	72.2	72.2
7	Export/Import	100.00	95.9	100.00	85.4

Notes

1. For an early investigation of the empirical evidence on the extent of economies of scale in electricity generation, see Joskow and Schmalensee (1983).

2. Although there were earlier experiments in some countries such as Chili, the British policy change is considered to be the benchmark into the new era of electricity market deregulation. See papers in Gilbert and Kahn (1996).

3. A node is a consumption centre, a producer or set of producers, or a set of high voltage power lines that meet at one point.

4. See also papers in *Journal of Regulatory Economics* (1996) and *Utilities Policy* (1997).

5. The limits of the interconnections with adjacent regions may still be significant.

6. More information on Hydro-Québec will be provided in section one.

7. The information presented in this section comes from Hydro-Québec (1997a,b).

8. Besides Hydro-Québec, there are nine municipal distribution services which purchase electricity from the latter. Furthermore, private producers owned and operated 3864 MW (96% hydro) mostly for their own use.

9. The most recent year for which district consumption and production data are available is 1996.

10. This includes the 5428 MW hydro power plant located at Churchill Falls in Labrador, Newfoundland. Through a long term contract, Hydro-Québec gets nearly all the output from this plant.

11. The effective export capacity is of the order of 5500 MW, while the effective import capacity is of the order of 4500 MW.

12. Up to that point Hydro-Québec was selling electricity at border points.

13. Gouvernement du Québec (1997).

14. Besides Hydro-Québec, British Columbia Hydro and Manitoba Hydro are two other Canadian utilities which have transmission networks linking hydro power sites located far from consumption centres.

15. Exceptions are the Pennsylvania – New Jersey – Maryland area in the U. S. and New Zealand.

16. The DC label is related to the history of this industry. It refers to the time when power flows were obtained from a miniature model of the actual transmission network under investigation; this miniature model was using direct current (DC).

17. See equation (14) in Hsu (1997) and set γ_{QS} and μ_{QS_i} equal to zero.

18. The detailed information with respect to the computation of consumption and production at each node appears in Guertin (2000).

19. The approximative distances in km between substations have been provided by TransÉnergie: line $\vec{1}$, Churchill-Manicouagan (619 km); line $\vec{2}$, Manicouagan-Lévis (379 km); line $\vec{3}$, Lévis-Nicolet (110 km); line $\vec{4}$, Lévis-Boucherville (Montréal) (108 km); line $\vec{5}$, LG2-Chénier (Montréal) (1006 km); line $\vec{6}$, Châteauguay (Montréal)-Massena (New-York) (56 km).

20. The Matapedia district is left out because it includes the Gaspé Peninsula and a set of small isolated networks which are scattered outside the region served by the main network. It represents less than 0,5% of generation capacity and 4% of annual sales.

21. There are no electricity sales in the Trois-Rivières district because they were recorded in the Montréal and the Québec districts in 1996.

22. Its load factor was 94.4% in 1996.

23. All figures are in Canadian dollars.

24. In an optimizing model designed to maximize the value of water, the peak and the off-peak opportunity costs of water would be the same at all hydro power plants if each hydro power site has enough storage capacity. Furthermore, the opportunity costs of water at all power sites would be equal once the power line losses are taken into consideration. Here we do not have these results because we try to approximate actual sales and generation by district and also because our network is a gross simplification of the real network.

25. In that sense, the flat rate does not lead to a pure nodal pricing system since we do not have identical prices for power sold and purchased at a given node.

26. Green (1998) arrives at the same conclusion.

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