Uncertainty and Investment in Electricity Generation: The Case of Hydro-Québec[1]

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Abstract

World wide the electricity industry is undergoing a substantial process of restructuring, with an emphasis on the introduction of competition in the generation sector. Competition is ostensibly going to lead to better incentives, both in the use of existing resources and in future investment decisions. One of the main drivers of this new environment will be the increased opportunity for energy sales between what had been, before the introduction of competition, fairly closed markets. These new opportunities may lead to new investments in generation and transmission capacity which will occur in order to take advantage of cost differentials between regions, one of the driving factors in the call for restructuring.

Accounting for some of the underlying complexity of electricity systems, specifically equipment availability and load duration curves, this paper illustrates how uncertainty affects investment in generation. We offer a simple 2-region model to analyse this problem, based on the linear programming model of Chaton (1997). Specifically, we analyse the case where one region has access to four generation technologies, differentiated by cost characteristics as well as construction lead times. A second (neighbouring) region has access to only one of the generation technologies, hence the necessary asymmetry between producing regions. Uncertainty is present in the demand for energy in the first market, as well as in the input fuel prices. Given this uncertainty, and the possibility of electricity sales between regions, we investigate and characterise optimal generation investment in the first market as a function of the problem parameters. The model is calibrated with data from Hydro-Québec and the northeastern United States. This application is particularly interesting and relevant, given the abundance of relatively cheap hydroelectric power in Québec, and Hydro-Québec's self-proclaimed strategic interests in increasing its exports to the northeastern markets. The numerical example illustrates the importance of appropriately modelling the complexity of the electrical system when considering the impacts of restructuring.

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1. Introduction

Worldwide the electricity industry is undergoing a substantial process of restructuring, with an emphasis on the introduction of competition in the generation sector. Competition is ostensibly going to lead to better incentives, both in the use of existing resources and in future investment decisions. One of the main drivers of this new environment will be the increased opportunity for energy sales between what had been, before the introduction of competition, fairly closed markets. These new opportunities may lead to new investments in generation and transmission capacity which will occur in order to take advantage of cost differentials between regions, one of the driving factors in the call for restructuring.

For several reasons, Hydro-Québec presents an interesting case to be examined, in light of these developments. First of all, Hydro-Québec has an abundance of hydroelectric capacity, both developed and undeveloped. Of the 38,825 megawatts (MW) of currently available capacity, 34,632, or 89% is hydroelectric.[4] In terms of energy production, the importance of hydroelectric equipment is even more striking, often accounting for 97% of total annual energy production. Neighbouring systems do not enjoy the same abundance of hydroelectric power, and as a result Hydro-Québec possesses a non-negligible cost advantage in the northeast, as is shown in the table 1.

It is thus of no surprise that Hydro-Québec has for many years been a net exporter of electricity in the northeast.[5] Hydro-Québec expects to increase its exports in the next few years, from 14 to 20 TWh between 1997 and 2002 (Hydro-Québec (1997a)). Part of the rationale for this plan for increasing exports is based on the important restructuring initiatives taking place in eastern Canada and in the northeastern United States. Restructuring plans in Ontario specifically call for increases in transmission capacity with neighbouring utilities in order to increase the possibility of electricity exchanges.[6] In 1998 Hydro-Québec obtained U.S. Federal Energy Regulatory Commission (FERC) approval for access to bulk power markets in the United States. The restructured market in the U.S. is expected to increase opportunities for energy trading, though more in short-term transactions than in the long-term contracts that had previously been the norm.

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[4] Source: Hydro-Québec web site, 27/03/1999, http://www.hydroquebec.com/profil/.

[5] Net electricity exports to the U.S. and neighbouring Canadian provinces fluctuate from year to year. Exports have been as high as 28 TWh (1987), which was equal to over 15% of total production in the province (source: Québec (1998)). A tera watt hour (TWh) is equal to 10^{12} watt hours.

[6] See Ontario (1999).

	Price [a]	Production cost [b]
Québec	5.1	2.5
Ontario	7.9	4.2[c]
New-Brunswick	6.7	3.4[c]
Maine	13.5	10.8[c]
New Hampshire	16.6	7.7
Vermont	13.5	5.7
Massachusetts	14.3	8.6
Rhode Island	14.7	8.8
Connecticut	14.9	8.1
New York	15.7	8.2

Table 1: Average price for all consumers and average production costs of electricity (¢/kWh)

Notes :

(a) 1995 prices are given in 1997 Canadian dollars.

(b) Costs are given in 1997 Canadian dollars.

(c) Information obtained from Hydro-Québec.

Source : Hydro-Québec (1997 a,b)

A particular problem of interest in this context is the optimal planning of investment in generation capacity. Unlike the case in neighbouring restructured markets, Hydro-Québec will retain a monopoly over its production resources. In this context, it makes sense to analyse optimal production investment in the system. In restructured markets this type of decision will obviously be more decentralized in nature (though some level of coordination will undoubtedly be necessary).

Three characteristics of the model make it interesting.

First of all, planning occurs over three periods, with construction of new capacity limited to the first two periods. What makes the three period model both interesting and relevant is the information structure of the problem and the existence of different construction lead times for different production technologies. Uncertainty is present in two planning parameters: 1) the growth rate of domestic demand; and 2) the variable cost of one of the production technologies. Partial information is revealed before production decisions must be taken to satisfy the final market conditions. However, construction decisions are made without full information. Because of the different construction lead times, there exists an option value to waiting for some of the information to be revealed before making some construction decisions.

The second characteristic of note in the model is the inclusion of some of the underlying complexity of electricity systems. Specifically, the model accounts for production equipment availability (as a function of use) within the framework of the load duration curve. Although this makes the model more complex and more challenging to solve, it also, we argue, greatly enhances the realism of the problem.

Finally, the model includes the possibility of imports and exports of electricity, in order to account for increased trading as a result of restructured electricity markets. The modelling of this trading opportunity is greatly simplified. Because of recent developments in combined cycle gas turbines (CCGT), we argue that it is reasonable to assume that in the region of interest natural gas will be the marginal fuel. We therefore peg the import-export price to the (uncertain) cost of natural gas.

The model is calibrated with data from Hydro-Québec and northeastern markets, and the numerical results obtained are discussed in relation to Hydro-Québec's forecasts of increased exports and capacity expansions.

2. The model and data

2.1 The model

The model presented and solved in this paper is a generation investment and production problem with three periods. The choice of three periods is made to reflect short-term and long-term construction projects and the information structure of this type of problem. For the purposes of the paper, one period represents a short-term horizon while two periods represents a long-term horizon. Specifically, we could think that each period has a 4-5 year length.

The model incorporates three essential characteristics of the investment problem:

1) uncertainty on the future returns from the investment;
2) irreversibility (investments are sunk);
3) the possibility of delaying investment, in order to take advantage of new information (option value).

At the beginning of the planning process, in period 0, the utility possesses existing capacity comprised of units of four different technology types. These are large scale-hydro, small scale-hydro, thermal and nuclear.[7] For simplicity, it is assumed that for all technologies capacity is perfectly divisible. These technologies possess decreasing returns to scale because of declining availability as a function of usage. The technologies are differentiated by their variable (running) costs and by their availability factors (a concept to be explained shortly). Historical construction costs of existing equipment are sunk and irrelevant for the construction-planning problem (as well as for the problem of determining the optimal use of existing equipment).

In terms of capacity addition, the same four different types of generation plants are available to the utility.[8] The utility may also import in order to satisfy demand, and export electricity if that is profitable. Of the four available technologies for capacity addition, only the thermal equipment has a “short” construction lead time, meaning that construction takes one period (i.e. less than 5 years). For the three other technologies, construction takes two periods (i.e. 8-10 years). Hence, although construction of any one of the four technologies may be undertaken in period 0 in order to satisfy final demand (period 2), only the thermal equipment can be constructed in period 1 in order to satisfy demand in period 2.

The utility’s problem is to plan capacity additions in periods 0 and 1 in order to meet demand in period 2. For simplicity, we ignore the problem of satisfying demand in periods 0 and 1. Demand in period 0 must be satisfied by existing equipment (and, where possible, imports), and is as such irrelevant for the question of capacity expansion. Although adding demand in period 1 would certainly add realism, it detracts from the tension that we wish to develop between capacity addition in period 0, and in period 1, in a sense to be made clear shortly. Alternatively, we could assume that existing capacity (at the beginning of period 0) is sufficient to meet any projected demand growth during that period. Hence no capacity need be added during period 0 specifically to meet the demand in period 1. This assumption is in fact plausible for many electric systems in the northeast which currently enjoy excess capacity. We also recognise that the problem would be more general if it were solved

[7] This is obviously a simplified categorization. In terms of existing capacity what matters for our modeling purposes is the variable cost and the availability.

[8] For capacity addition, the thermal equipment in question is natural gas fired generation. Combined cycle gas turbines (CCGT) are the most cost-effective units currently under construction.

for consecutive periods. Solving for demand in the third period only is obviously a simplification.

The utility is assumed to be risk-neutral.

The information structure of the problem is as follows. There is uncertainty on two variables, the rate of demand growth in each period and the rate of increase (or decrease) in the variable running cost of the thermal technology. For ease of exposition, in what follows we refer to the price of natural gas as the variable running cost of the thermal technology. Though many factors affect the variable cost, it is clearly highly dependent on this price. In period 0, when the first construction decision is made, demand and the price of natural gas of that period are known with certainty. The possible values of these growth rates, as well as the probabilities of occurrence, for periods 1 and 2 are known at period 0. Demand growth and natural gas price changes affect the original values by a multiplicative factor. For this reason, the arrival of information on demand and natural gas price growth in period 1 reduces (without entirely removing, of course) the uncertainty concerning the final demand level and natural gas price. In period 2 uncertainty is resolved, the final demand and natural gas price are revealed, and the utility makes its production decision (including imports and exports) based on available capacity and parameter values.

The information structure and the decision process are illustrated in the following figure.

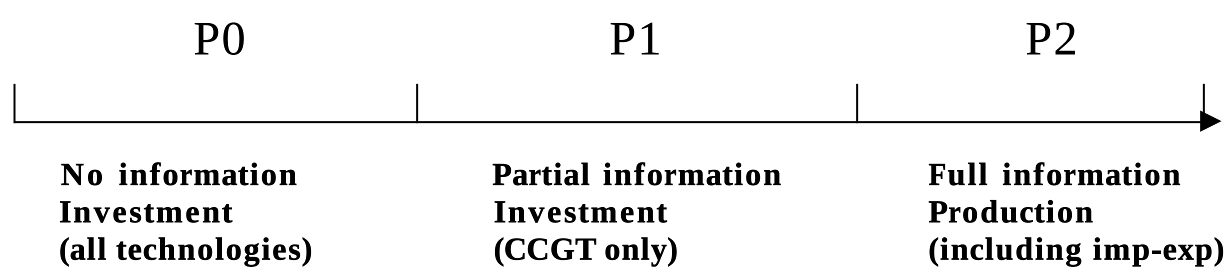

Figure 1: Information structure of the problem

Conceptually, the optimisation problem to be solved by the utility at period 0 is thus:

Min [total expected costs]

Subject to:

1) total supply ≥ total demand

2) installed available capacity ≥ supplied capacity

3) imports + exports ≤ transmission capacity

(plus some model specific constraints)[9]

Where,

Total expected costs = [investment costs period 0] + expected value of [investment costs period 1, given the realisation of uncertain variables in period 1] + expected value of [variable operating costs + costs (imports – exports), given the realisation of uncertain variables in period 2].

The result of this optimisation problem gives one investment decision for period 0, one investment decision for each possible state in period 1 (i.e. for each possible realisation of uncertainty in period 1), and the optimal equipment utilisation for each possible state in period 2, given the investments undertaken in periods 0 and 1. All constraints must be met for each possible state in period 2, i.e. they are not simply met in expectation.

Constraint 3 is straightforward and represents physical limits on transmission capacity. Constraint 1 represents the obligation to serve all demand, i.e. supply is equal to domestic production plus imports and must be greater than or equal to demand. Finally, constraint 2 represents the physical constraint on installed generation capacity, i.e. the actual available capacity. The explicit modelling of equipment availability represented by equation 2 is significant and relevant to the context of the problem at hand.

We now explain the significance of “available” in “installed available capacity” in equation 2. As mentioned in the introduction, the model accounts for production

[9] The formal model which is solved numerically is similar to Chaton (1997), with the addition of another decision period. For ease of exposition, we forego the details of the optimisation problem here. The complete model is provided in the appendix at the end of the paper. The above conceptual description is complete and describes the essence of the problem.

equipment availability (as a function of use) within the framework of the load duration curve. Two concepts are being introduced here: equipment availability and the load duration curve.

In general, electricity generation equipment cannot produce energy 100% of the time. In addition to planned maintenance, generation equipment can fail. Also, in the course of normal operation of an electricity system generation equipment can be non-operating, or used as spinning reserve, etc.[10] The exact availability of different equipment types varies a great deal. Availability depends on many factors, including (but not limited to) its maintenance, usage schedule, etc. Usage is important because, in general, the availability rate (expressed as a % of time that the equipment is available when called upon to generate) declines with usage. This fact is important in the actual planning of generation equipment, and its inclusion in our model is significant and non-trivial.

Since availability is a function of usage, equipment usage must be explicitly modelled. In order to introduce usage, electricity demand has to be explicitely modelled. Electricity demand fluctuates and, though there is a random component to demand, its cyclical nature is evident in daily, weekly and yearly patterns. A typical annual pattern for demand might look like figure 1. In modelling demand and supply, two units of measurement are of interest in this problem. Capacity, which is normally measured in megawatts (MW), indicates the amount of energy that a unit of generation equipment is able to produce at a given time. Energy, which is normally measured in watt-hours (Wh), indicates the total output during a given interval of time. For a unit of equipment, or a group of units, the amount of energy produced in a given period is calculated by multiplying the capacity by the length of the time period.

Though interesting and useful for many purposes, the information contained in figure 1 is not immediately useful for the equipment-planning problem of this paper. A more useful presentation, derived from the information contained in figure 1, is the load duration curve, as shown in figure 2.

The load duration curve represents the same information as the annual demand curve, but after a transformation of the data. In both cases the vertical axis measures units of capacity. In the case of the annual demand curve the amount of capacity for each hour of the year is plotted, and the hours of the year are placed chronologically on the horizontal axis. The load duration curve displays this same information, but ordered in decreasing order of the capacity demanded. In other words, for the case of hourly data, with 8760 points on the horizontal axis for the 8760 hours in a year, the first point corresponds to the demanded capacity during the one hour of the year in which capacity demand was the greatest. The second point then corresponds to the

[10] We model equipment availability as binary, i.e. the equipment is either up or down. This ignores questions such as ramping of generation equipment, which is not particularly relevant in this problem and highlights the difference between a long term analysis of equipment investment and a short term analysis of optimal equipment use (or scheduling).

demanded capacity during the one hour of the year in which capacity demand was the next greatest, and so on. For both figures, the area under the curve represents the total energy demand for the year.

The load duration curve offers a simple approach to the problem of optimal planning in generation in a certain environment. This is illustrated in figures 3 and 4 for three technologies. The first figure graphs total cost of each technology as a function of use. The breakpoints on this graph indicate the intervals of time over which it is optimal to use each technology. As is intuitively expected, technologies that are cost effective for high usage, i.e. base-load technologies, have high fixed costs and low variable costs. The converse is true for peak-load technologies. In this simple situation, we can map from figure 3 to figure 4 and immediately see how the different technologies should be optimally used in time as a function of the demand profile given in the load duration curve and the technological parameters of the production technologies. This approach determines the optimal mix of technologies, as well as usage time, though not the exact pattern of equipment usage. There exist two problems with this approach. First of all it does not account for uncertainty. For instance, uncertainty in the cost parameters obviously reduces the usefulness of this straightforward mapping approach. For each set of cost parameter values for figure 3, different mappings are obtained in figure 4. Hence, the optimal levels (in terms of capacity – MW) of each technology will vary. It is also of note that this approach, in its simplest form, assumes no pre-existing production capacity.

Secondly, in the above description of the mapping from figure 3 to figure 4, availability factors of the equipment were ignored. However, as has been argued, availability of equipment is a critical consideration in generation planning and use. Explicitly, incorporating the availability factor is not straightforward in the mapping from figure 3 to figure 4. Figure 3 graphs costs as a function of usage for different technologies, with the implicit assumption of equal sized units of generation for each technology. One way of introducing availability factors is to vary the slopes of the cost curves in figure 3, accounting for increased costs due to decreased availability as usage increases. This approach would work if and only if in the final solution all units of each technology type were used for the same number of hours. Otherwise, the mapping from figure 3 to figure 4 doesn't accurately account for differing availability based on usage.

Hence, because of the presence of uncertainty and availability factors the mapping approach of figures 3 and 4 is unsatisfactory.

The approach proposed in this paper accounts for differing availability based on usage. The approach, which is based on the model developed in Chaton (1997), is sketched here.

As mentioned above, equipment availability is a function of many factors. The availability factor is incorporated into the modelling, with specific reference to the load duration curve. With 100% availability throughout the year (i.e. no downtime), a unit of generation capacity can be modelled as a horizontal band on the load duration curve. The height of the band is simply the capacity of the unit in question. This is illustrated in figure 5, where the unit in question has a capacity of X.

Application of equipment availability is straightforward. If use of the unit for 8760 hours results in an (expected) availability of ϕ%, then in order to have X units of actual available capacity, the utility must use $(1/\phi)$ units of capacity. Figure 6 illustrates this.

Empirically, availability decreases as a function of usage. Hence, if planned usage for a generation unit is reduced from 8760 hours to 5000 hours, then the (expected) availability factor will increase from $\phi1$ (the value for 8760 hours) to $\phi2$ (the value for 5000 hours), where $\phi1 < \phi2$. Hence, the quantity of capacity necessary to effectively deliver X units of available capacity (always in expectation) is less for a demand of 5000 hours than it is in the case of a demand of 8760 hours.

In order to numerically apply the availability factor as described above, the load duration curve must be discretized. The load duration curve is hence segmented into vertical bands where the width of a band equals a number of hours of operation. More bands obviously leads to more precision, but also to more complexity in the numerical resolution. Approximating the load duration curve in this fashion captures the essence of the problem, as illustrated in figure 7.

As mentioned earlier, the possibility of imports and exports is included in the model. Imports are substitutes for generation capacity, while exports are revenue sources. Use of imports and exports will be a function of demand and supply conditions in period 2. The possibility of imports and exports is of course factored into the investment decisions of periods 0 and 1. Since transmission capacity between neighbouring systems limits the levels of imports and exports, an upper bound on the quantity of imports and exports (measured in capacity (MW)) in each band is imposed in the problem. This is obviously an approximation to the real nature of transmission constraints, since it treats transmission capacity somewhat like generation capacity by limiting the amount of transmission within the band. However, the approximation is sufficiently close for the purposes of this paper.

Finally, we make the assumption that between Québec and neighbouring systems there always exists an opportunity to trade in one direction or the other. Trade is modelled from Québec's perspective, i.e. it sells what it wants and buys what it wants (within the transmission constraints). Because the marginal production units in neighbouring systems are assumed to be CCGT, the price of traded energy is pegged as a multiple of the variable cost of these units.

In summary, the problem that is being solved in period 0 is how to minimise the expected cost of meeting demand in period 2. The uncertainty in the problem, in demand growth and fuel price changes, is addressed by minimising expected costs.

Demand can be met with existing capacity, additions of new capacity, and imports. Use of capacity, both existing and new, must respect availability factors which are a function of usage. The optimisation program solves the problem by fitting blocks of capacity into the approximated load duration curve. This approach which accounts for availability as a function of equipment use generates solutions which are much more useful and realistic than the naive mapping approach in figures 3 and 4.

2.2 Data and parameters

We solve the problem with the following parameter values.

	Large-scale hydro	Small-scale hydro	Thermal (CCGT)	Nuclear
Equipment lifespan	**40**	**40**	**25**	**30**
Investment cost (per MW) 1998 $CDN	**2,700,000 a**	**1,350,000**	**1,025,000 b**	**2,800,000**
Variable cost (per kWh) 1998 $CDN	**0.002 c**	**0.002 c**	**0.029 b**	**0.01**
Initial capacity (MW)	**32,000**	**2,600**	**2,500**	**600**
Limits on new capacity (MW)	**15,000 d**	**500 d**	**-**	**-**

Sources:
a: computed using data from the Churchill Falls project (Hydro-Québec).
b: OECD (1998)
c: computed using data from the Great Whale project (Hydro-Québec).
d: computed using data from the Great Whale project (Hydro-Québec).

Table 1: Production technology parameters:

The functions used in this paper to estimate equipment availability, as a function of usage, depend on two parameters, scheduled maintenance and unscheduled failure. These two failure rates operate multiplicatively, giving rise to a quadratic function.

$$F_i(H) = \alpha_i + \beta_i H + \gamma_i H^2$$

Where H refers to the number of hours of operation and the index i refers to a specific equipment type. F(H) is thus a function which maps from the number of hours that an equipment is called on to be available to the % of time that the equipment will actually be available when used. See Chaton (1997) for details and parameter estimates for various production technologies. The equipment availability values are provided in the following table.

hours	Large-scale hydro	Small-scale hydro	CCGT	Nuclear
8760	80,07%	77,07%	68,80%	73,12%
8000	83,80%	80,80%	72,27%	74,58%
7000	88,00%	85,00%	76,24%	76,53%
6000	91,40%	88,40%	79,52%	78,52%
5000	94,00%	91,00%	82,11%	80,54%
4000	95,80%	92,80%	84,01%	82,60%
3000	96,80%	93,80%	85,23%	84,69%
2000	97,00%	94,00%	85,76%	86,81%
1000	96,40%	93,40%	85,60%	88,97%

Table 2: equipment availability parameters for the model

Economic parameters:

The model uses a real discount rate of 5%.

Demand parameters:

In modelling demand, the following parameters are used. The number of bands used is determined by the numerical procedure for solving the problem. In our solution we use 6 bands to represent the last 8700 hours of the year, with each band having a width of 1450 hours. The first 60 hours of the load duration curve, the extreme peak makes up the 7^{th} (left-most) band. The minimum demand, i.e. height A in figure 8, is 13,000 MW. The maximum height, save the extreme peak, is 24,500 MW and is identified as height B in the figure. These are the values for the base year, i.e. at period 0, and gives a total energy demand of 173 TWh, consistent with Hydro-Québec's current demand level. These values are increased for periods 1 and 2 as demand grows. The height of the extreme peak, C in the figure, is obtained as a multiple of height B. For the purposes of this paper, we assume that C equals 130% of the height of B, giving 31,850 MW. Again, this is consistent with Hydro-Québec's current winter peak levels. Recall that the extreme peak is a short duration event, representing only 60 of the 8760 hours in the year.

The demand growth factor, in the base case, is applied to both points A and B. Hence, the load duration curve grows uniformly. The peak value obviously grows in the same way since it remains a multiple of point B. In the sensitivity analysis we examine other types of growth scenarios.

Import/Export price:

Natural gas-fired thermal units are expected to be the marginal units on neighbouring systems. For simplicity, we model the price of imports and exports as a multiple of variable cost of these units (which is principally the price of natural gas). The multiple used in the base case is 1.3. Hence, in order to satisfy demand the utility can import energy at a cost of 1.3 times the prevailing price of natural gas. Conversely, with excess capacity the utility can sell energy at a price of 1.3 times the prevailing price of natural gas. In both cases, a constraint bounds the maximum amount of imports and exports (initially) at 6,337 MW. This constraint reflects physical constraints in transmission capacity between Québec and neighbouring jurisdictions.[11] No exports are permitted during the extreme peak, i.e. during the 60 hours of the year in which the level of demand is highest, in order to reflect the system operating constraints during peak hours.

Uncertainty:

The uncertainty, both for demand growth and gas price changes, is assumed to be multiplicative.

In order to simplify the numerical solution of the model, we restrict the range of uncertainty and limit values of demand growth and gas price changes to two possible values. We will refer to these values as low and high demand growth, and low and high gas prices, respectively. Without loss of generality, we assume that the same values for these parameters apply to the variables in period 1 and in period 2 in the base case.

Low demand growth (Low-D): 10%
High demand growth (High-D): 15%

Low gas price (Low-P): -10%
High gas price (High-P): 10%

There are therefore 4 possible states of nature in period 1, and 16 possible states of nature in period 2.

3. Numerical results

The problem is solved using the GAMS software program on a Pentium PC. This section presents the results of the optimisation program.

For each set of parameter values the optimisation program provides the following results:

1) investment in each technology type in period 0;

[11] There are of course multiple transmission lines linking Hydro-Québec's system to neighbouring provinces and states. For the purposes of this paper we consider a single transmission constraint.

2) investment in each technology type in period 1, for each of the four states of nature which may be realised in period 1;
3) optimal equipment use, imports and exports for each of the sixteen states of nature which may be realised in period 2.

Except where they are of particular interest, we do not provide information on optimal equipment use, and focus rather on the investment decisions. The investment decisions are presented in tables indicating the time of the investment (P0 or P1) and the capacity invested in each equipment type. Note that the tables include four columns for the investment decision in P1, since there are four possible outcomes (combinations of the demand growth and fuel price growth parameters).

3.1 Base case:

	P0	P1	P1	P1	P1
		Low-D Low-P	Low-D High-P	High-D Low-P	High-D High-P
Large-scale hydro	0	0	0	0	0
Small-scale hydro	0	0	0	0	0
CCGT	0	0	0	399	399
Nuclear	0	0	0	0	0

Table 4: Base case results (MW of investment)

As seen in the table, no investment occurs in period 0. In period 1 a moderate amount of investment occurs in thermal equipment, but only in the high demand realisations.

The above results are not very surprising, given that we are using parameter values that are chosen to describe the current situation in Québec. Hydro-Québec is presently in a situation of comfortable capacity margins. The demand growth parameters which are used (low = 10%, high =15%) are fairly low, considering that they represent compounded growth for periods representing 4-5 years. So, if demand growth between period 0 and period 1 has been low, it is optimal for the utility to choose not to undertake any investment.

Given that demand does not grow very much, it is also not surprising that what little investment is undertaken is made in thermal equipment. In order to better understand the rationale for this investment, it is useful to present more data from the optimisation problem.

Imports and exports are, as expected used in the optimal production schedule of the 16 possible realisations in period 2. The utility imports energy in 4 of the 16 realisations, these being the 4 in which demand growth is high in both periods. For the 12 other realisations the optimal production schedule calls for exports in period 2. In both cases, imports and exports, the transmission constraint is binding. This indicates, as expected, the potential interest in expanding transmission capacity.

This pattern of imports and exports is consistent throughout the sensitivity analysis which follows.

3.2 Sensitivity analysis:

The objective of this paper is not to forecast exact levels of capacity additions, but rather to gain a better understanding of how uncertainty on certain parameters can affect an optimal investment path. In what follows we introduce different changes to the parameter values in order to explore the sensitivity of the solution. Without changing the demand parameters, it is obvious that capacity additions will, all else being equal, be relatively modest. The parameter sensitivity is nonetheless interesting in light of Hydro-Québec's stated export objectives.

3.2.1 Fixed costs - hydro:

There exists a small amount of undeveloped small-hydro capacity in Québec. In addition, there are a certain number of old small-hydro stations in Québec. In the late 1980's and early 1990's, at a time when Hydro-Québec forecast capacity shortfalls, the Government of Québec and Hydro-Québec put in place a program to privatise many disaffected small-hydro stations and develop new stations. This program eventually was ended as a result of lower than expected demand growth in the early 1990's.

In the base case no construction of small-hydro. It is interesting to analyze under what conditions small-hydro might become economically interesting in the optimal investment portfolio. In order to examine this question we modify the fixed cost of small-hydro. In the base case small-scale hydro has a unit construction cost of 1,350$. The following table shows how the investment decisions as the construction cost of small-scale hydro decreases. The changes are limited to investments in CCGT in period 2 (as in the base case) and in small-scale hydro in period 1. No other investment decisions change qualitatively with respect to the base case (imports/exports, etc). Note that the investments in CCGT that are given in the table occur for the same realisations as in the base case, that is for the high-demand scenarios (for both low and high gas prices).

Small-scale hydro cost	1,350$ (base case)	800$	780$	700$
Small-scale hydro (invest in P1)	0	0	379	380
CCGT (invest in P2)	399	399	0	0

Table 5: sensitivity results for fixed costs of small-scale hydro (MW)

As indicated in the table, the cost of small-scale hydro has to fall by over 42% before this technology begins to be of interest in the investment profile. At this point, small-scale hydro completely takes over from CCGT. At the outset, these types of drops in cost appear unlikely. Under the current demand and cost parameters it therefore appears unlikely that small-scale hydro could displace CCGT in future investment projects in Québec.

We also considered cost reductions for the large-scale hydro technology. A 33% drop in this cost, from 2,700$ to 1,800$ per unit, produced no changes from the base case. Given the fact that any future development of large-scale hydro will be on sites that are further away from demand centres, and less cost-effective than existing sites, it appears highly unlikely that cost decreases of this magnitude are likely. What is probably more likely is that increased environmental concerns might lead to increased costs of hydro projects, both small and large. Ceteris paribus, this would make hydro projects even less interesting than they are at present.

3.2.2 Fixed costs - CCGT:

This section looks at the impacts of changes in the cost of the thermal technology, CCGT. The fixed cost of CCGT in the base case is 1,025,000$ per unit. It is well known that technological developments over the last decade have greatly increased the efficiency of this technology, and reduced costs.

Investment in CCGT is, perhaps a little surprisingly, relatively insensitive to variations of the fixed cost of construction. Qualitatively, the results of the base case, investment only in CCGT and only in period 2 remain unchanged. As the following table illustrates, the size of the investment varies with the fixed cost, though not by large amounts.

All other investment decisions in the base case are unchanged.

CCGT cost	700$	900$	1,025$ (base case)	1,400$	1,800$
High-demand Low-price	399	399	399	361	361
High-demand High-price	580	399	399	399	361

Table 6: sensitivity results for fixed costs of CCGT (MW)

As expected, as the cost of CCGT falls eventually it becomes optimal to invest more in this technology. What is not expected, and certainly counterintuitive in the above table, is that investment increases in the high-price scenario (price of natural gas). It is not intuitive to think that decreases in fixed costs would lead to more investment, when the variable cost is higher.

The explanation of the above result goes back to the optimal utilisation of the production units in time, as illustrated in the load duration curve. Although more capacity is added in the high-price scenario than in the low-price scenario, the capacity is used less in the high-price scenario than in the low-price scenario. As a result, variable costs are lower in the former than in the latter. Greater capacity in CCGT introduces more flexibility in utilisation, hence enabling the producer to reduce variable costs, which is of more value in the scenario of high gas prices.

This counterintuitive investment profile does in fact minimise total expected costs.

3.2.3 Availability factors:

Availability factors change for many reasons, such as technological advances, improved maintenance and environmental constraints. The impacts on the results of changing availability factors are all as expected.

1) Reducing availability of large-scale hydro increases investment in small-scale hydro in period 0 and in CCGT in period 2.

It is relevant to investigate the impact of decreases in the availability factors of hydro units. Hydro-Québec’s reservoirs are currently at relatively low levels. Whether or not this situation will persist, and how it will affect future planning decisions is the subject of (intense) debate. Clearly though, if reduced reservoir levels impose a reduction in the availability of large-scale hydro units, additional investments in small-scale hydro and in CCGT may be necessary.

The availability of large-scale hydro is reduced as follows:

hours	Large-scale hydro - Modified availability	Large-scale hydro - Original availability
8760	75,07%	80,07%
7000	83,00%	88,00%
6000	86,40%	91,40%
5000	89,00%	94,00%
4000	90,80%	95,80%
3000	91,80%	96,80%
2000	92,00%	97,00%
1000	91,40%	96,40%

The impact of this change on the investment profile is:

	P0	**P1**	**P1**	**P1**	**P1**
		Low-D Low-P	**Low-D High-P**	**High-D Low-P**	**High-D High-P**
Large-scale hydro	0	0	0	0	0
Small-scale hydro	500	0	0	0	0
CCGT	0	119	120	1,917	1,917
Nuclear	0	0	0	0	0

Table 7: sensitivity results for availability of large-scale hydro

Hence, lower availability of large-scale hydro leads to more CCGT in period 1, but also to investment in small-scale hydro in period 0 (the maximum investment in small-scale hydro is undertaken, given the constraint on undeveloped capacity). The reduction in availability therefore has a qualitative impact on investment, illustrating the significance of accounting for load profiles and equipment utilisation. If the availability reduction is less than what is illustrated here, investment only in CCGT in period 1 remains the optimal option.

2) Reducing availability of small-scale hydro increases investment in CCGT, without any other qualitative changes to the base case.

Since many small-scale hydro projects are run of the river, or at best possess little storage capacity, changes in availability factors are not brought about by the same conditions as in the case of large-scale hydro. Growing environmental awareness has an impact of the availability of small-scale hydro projects. Many of these projects are located close to recreational sites and the joint management of these sites and the hydro production impose constraints on availability. It is thus possible that increased pressures on small-scale hydro projects result in reduced availability, and hence lead to increased investment in other technologies.

3) Increasing availability of CCGT reduces investment in CCGT, without any other qualitative changes to the base case.

Not surprisingly, when the thermal generation equipment has increased availability the investments necessary in this equipment are reduced. Since in the base case investment occurs only in this equipment, no other changes occur in the program. This equipment is utilised in basically the same way, except that it is available a higher % of time when called upon.

3.2.4 Demand:

Three types of modifications are applied to the demand. The first change is on the rate of growth of demand without changing the profile of demand, i.e. the shape of the load duration curve. The other two changes keep the demand growth rates of the base case but apply them in different ways to the original demand and therefore result in modified forms of the load duration curve. The three changes are:

1) increasing the growth rates;
2) increasing the peak level, keeping the base level fixed;
3) increasing only the level of base demand, keeping the peak level fixed.

1) increasing the growth rates:

With higher growth rates the investment in CCGT is higher in period 2, as expected. What is interesting though is that even with a total growth rate over the two periods of 60%, the profile of investment in the base case does not change. At this level of growth the investment in CCGT jumps to 9,650 MW (as opposed to 399 MW in the base case). Hence, given the parameters used here, CCGT appears to be the technology of choice for capacity expansion independent of the rate of growth of demand.

2) increasing the peak level, keeping the base level fixed:

If the demand growth (base case values) is only applied to the peak level (24,500 MW in the base case), meaning the load duration curve becomes more peaked, optimal investment in CCGT in period 1 drops to zero. This makes sense since applying demand growth only to the peak level implies less total energy demand than in the base case. Under current market conditions, it appears unlikely that the load duration curve would evolve in this direction.

3) increasing only the level of base demand, keeping the peak level fixed:

If the demand growth (base case values) is only applied to the base level (13 000 MW in the base case), meaning the load duration curve becomes flatter, no investment is optimal in period 1. This result, which isn't at all surprising and highlights the value of initiatives that might reduce the peak to base ratio in the demand, and flatten the load duration curve. Given the importance of hydro capacity in Québec, it is not surprising that a flattening of the load duration curve leads to this change in optimal investment. Current Hydro-Québec tariff structures base prices on average costs, even though the long-run marginal cost of hydro capacity is increasing and above average cost. This numerical result confirms calls for a reassessment of Hydro-Québec's tariff structures (see, for instance, Bernard and Doucet (1999) or Bernard and Chatel (1985)).

3.2.5 Natural gas prices:

Decreases in natural gas prices produce no changes in the optimal investment profile. Even when gas prices fall, the variable cost of existing large-scale hydro is so small that it isn't worthwhile to invest in new CCGT in order to displace existing production capacity. The result obviously might be different if existing generation equipment included coal-fired capacity.

Moderate increases in natural gas prices actually increase the optimal level of investment in CCGT, the counterintuitive result of section 3.2.2 above. However, the qualitative nature of the investment path remains unchanges.

3.2.6 Transmission capacity constraint:

The value of the transmission constraint was relaxed. The original value was in effect approximately 6,337 MW. Interestingly these changes had no qualitative effect on the investment profile, and only marginal quantitative effects on the investment in CCGT. As the transmission constraint was relaxed imports and exports increased, but the constraint was no longer binding. This type of change could be used to address the issue of optimal investment in transmission capacity.

4. Conclusions

Competition in northeastern energy markets, resulting in part from restructuring of the electricity industry, will undoubtedly have an impact on investment decisions in the generation sector. The method of analysis proposed in this paper incorporates two critical aspects of the decision, uncertainty and equipment availability. We have argued that our treatment of these factors is both relevant and important.

The results obtained have been interpreted in light of current market activity in the northeast, and in terms of Hydro-Québec's plans and strategies. One broad conclusion that can be reached at this point is that Hydro-Québec's strategy, of increased energy exports, may not be realistic, given available information on market conditions. Given the current cost of CCGT, which are likely to be the marginal units in most neighbouring systems, it may be difficult to justify large investments in large-scale hydro projects based on export opportunities.

The model that we have presented also leads to a number of interesting questions regarding strategic considerations in investment in the context of this market. For instance, in the case of a network industry such as electricity, how do cost advantages affect first-mover advantages and subsequent investment in capacity. This type of question, which might be critical in a better understanding of the evolution of this market, will be addressed in future research.

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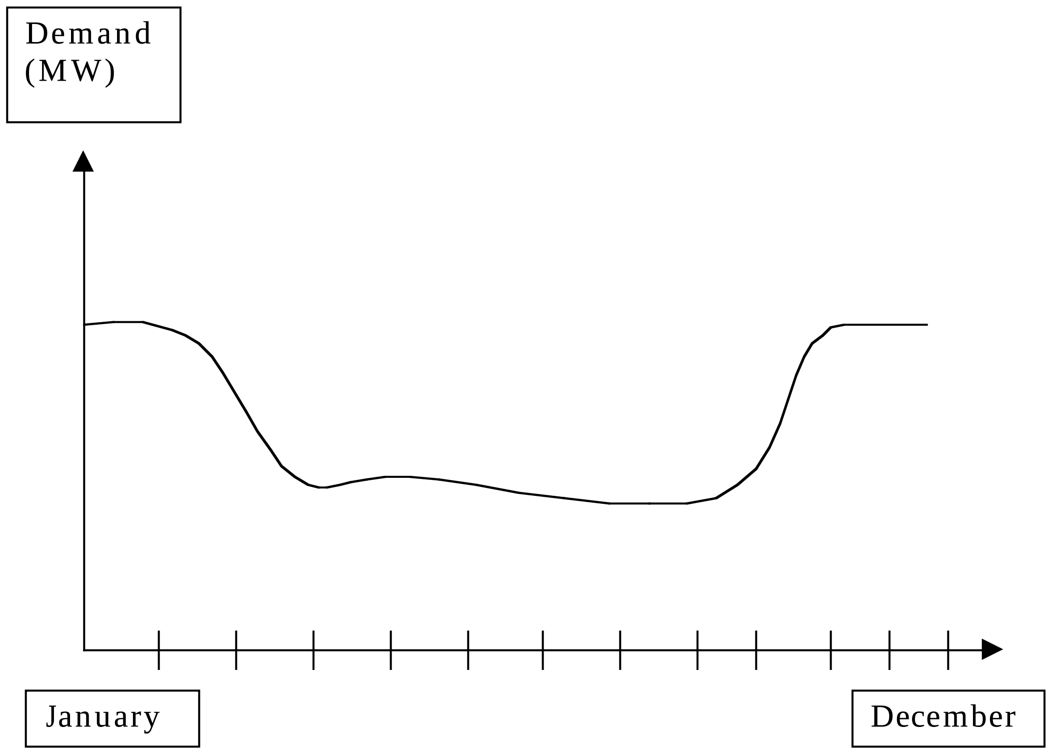

Figure 1: Annual demand curve

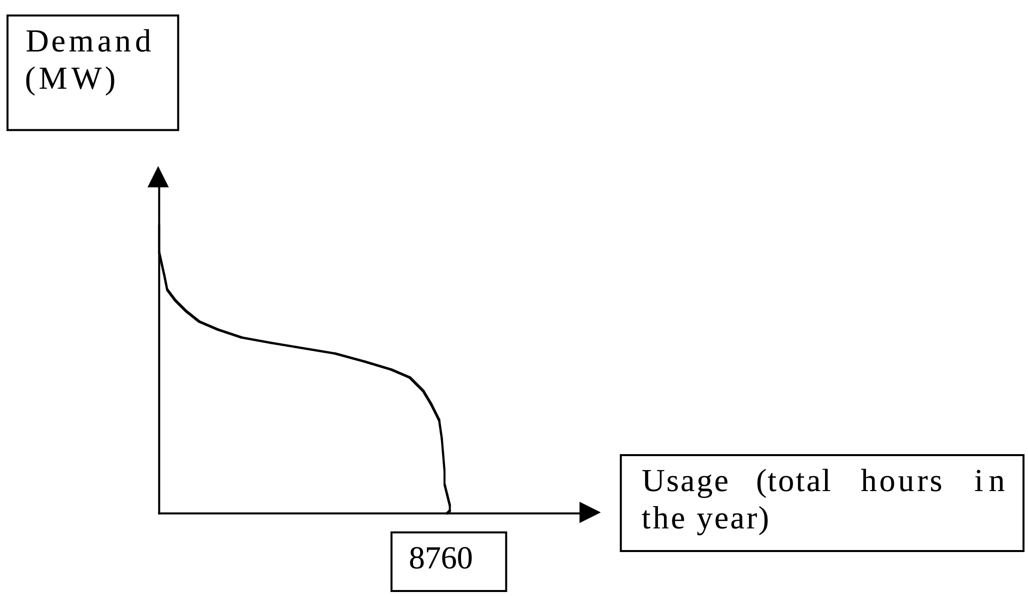

Figure 2: Load duration curve

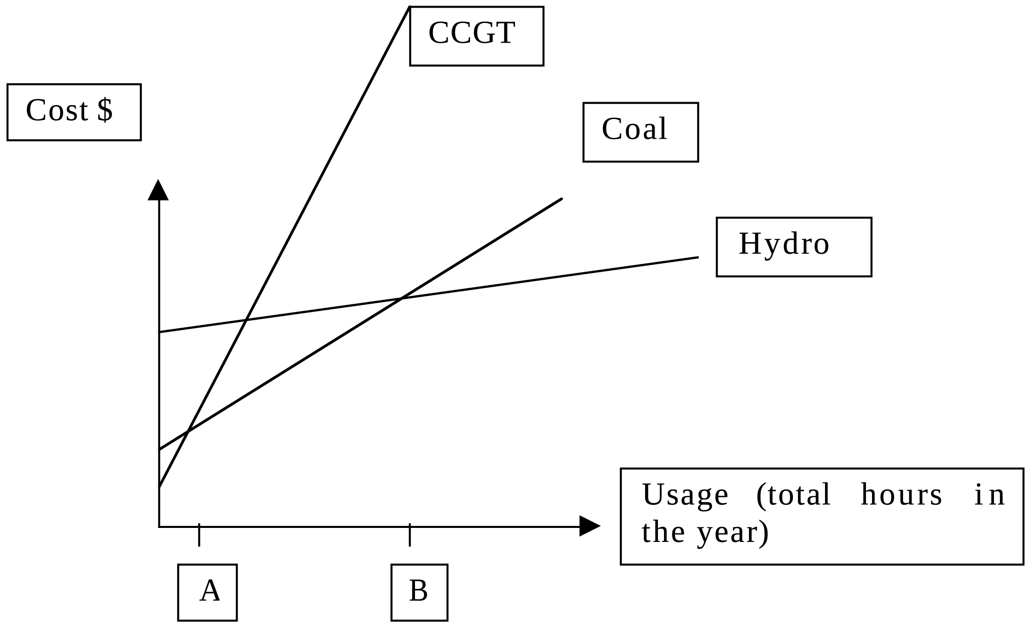

Figure 3: Equipment cost as a function of utilisation

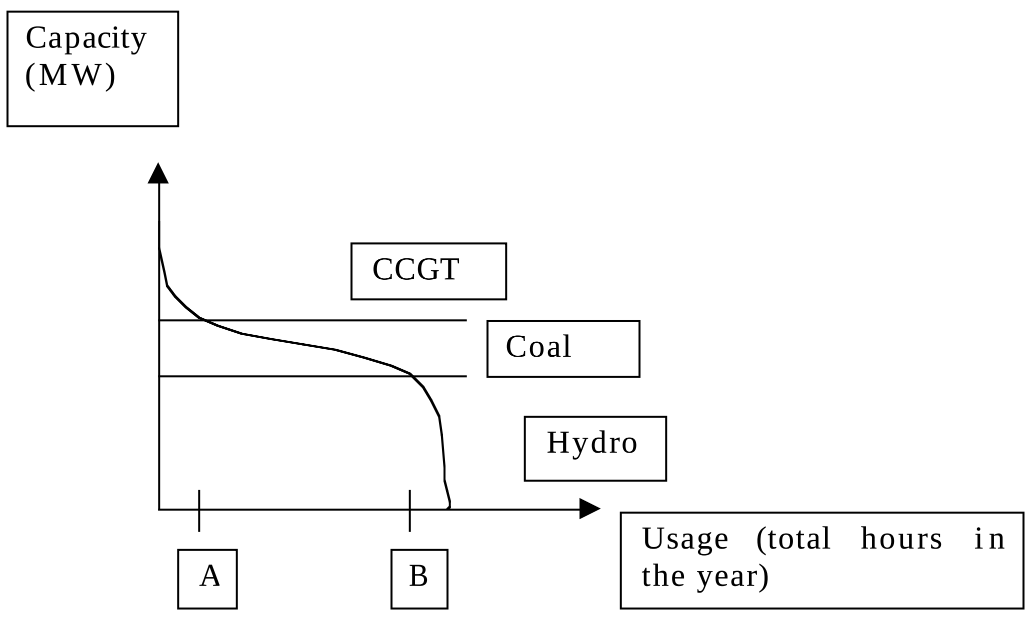

Figure 4: Load duration curve with equipment utilisation

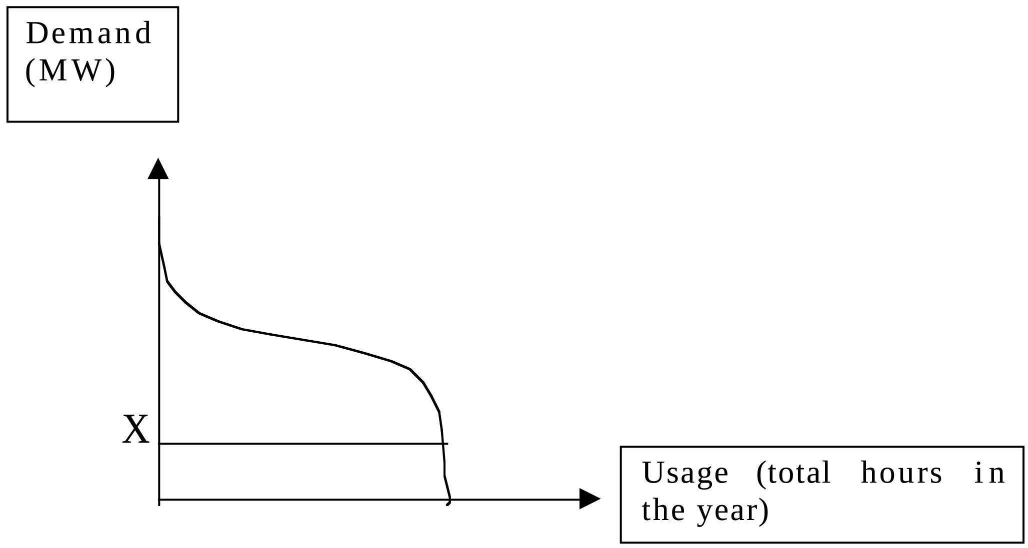

Figure 5: Load duration curve with a horizontal band of height X, representing capacity of X.

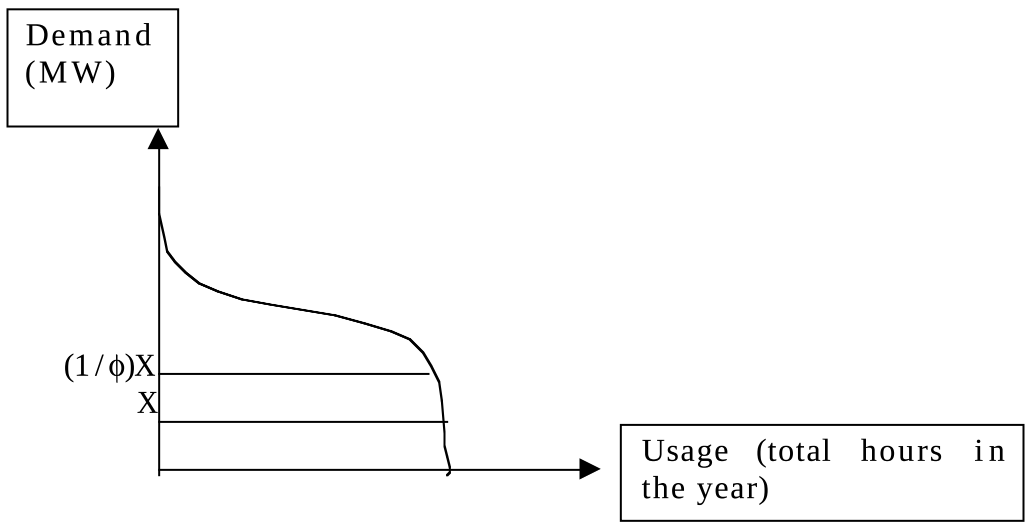

Figure 6: Load duration curve with two horizontal bands overlaid: one of height X for desired capacity, the second of height $(1/\phi)X$, for the capacity necessary to deliver X.

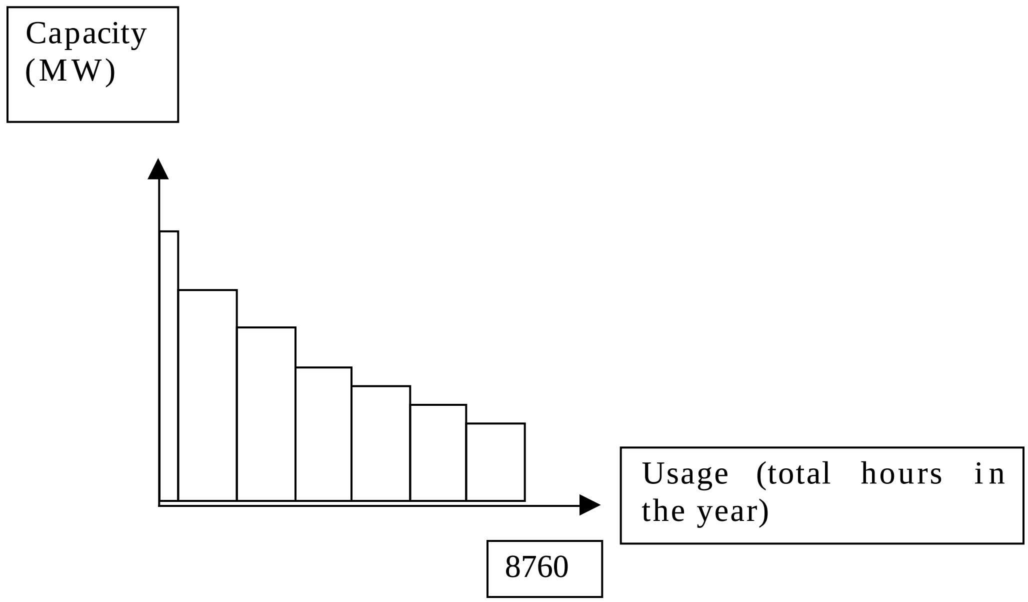

Figure 7: Approximated load duration curve

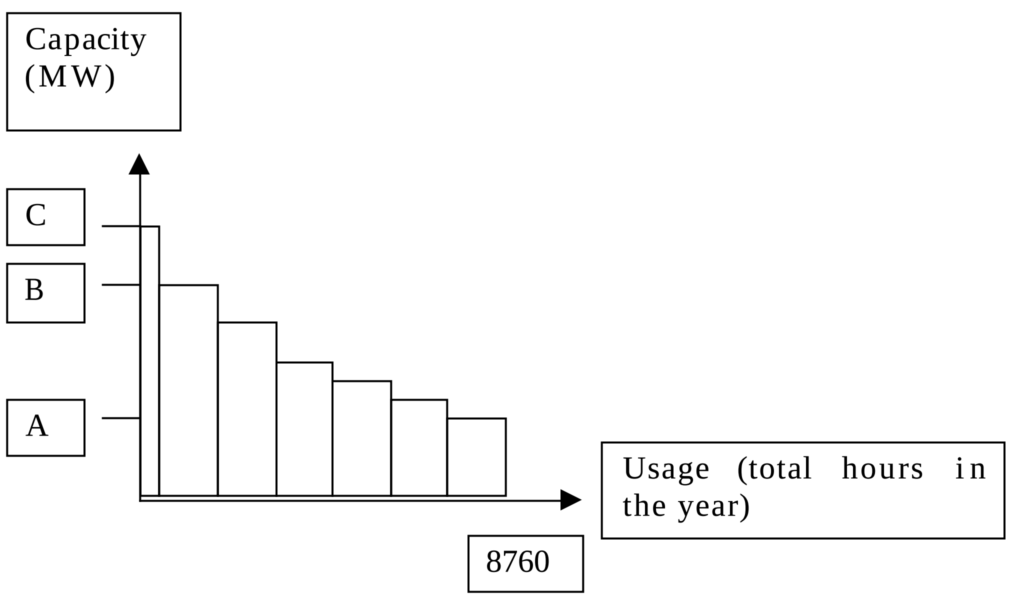

Figure 8: Demand levels A, B and C in the approximated load duration curve