BEFORE THE

RÉGIE DE L'ÉNERGIE

IN THE MATTER OF:

HYDRO QUÉBEC

**ALLOCATION DU COÛT DE FOURNITURE
DE L'ÉLECTRICITÉ PATRIMONIALE
PAR CATÉGORIE DE CONSOMMATEURS
POUR LES ANNÉES 2001 ET 2002**

REQUÉTE R-3477-2001

Evaluation of Intervenor Proposals

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On Behalf of:

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L'association des industries forestiéres du Québec (AIFQ)

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Introduction

AQCIE/AIFQ asked Industrial Economics, Incorporated (IEc) to review the reports and interrogatory responses of the other intervenors in this proceeding. This document presents the results of our review.

Expert Report of M. Jacques Fontaine, on behalf of Stratégies Énergétiques and Groupe STOP (SÉ-GS)

In summary, M. Fontaine makes two recommended modifications to Hydro Québec's calculations of generation cost rates by class:

- The peak period for developing the demand cost allocator should be based on 100 hours, rather than the 300 hours proposed by Hydro Québec and the 1 CP methodology recommended by IEc;

- The loss factor for allocating demand costs should be based on the loss factor during the peak period, rather than the average loss factor used by Hydro Québec. While M. Fontaine uses a different method for estimating loss factors than that used in the IEc report, the results of his analysis are directionally similar to ours.

Peak Demand Definition

The goal of defining the peak demand period is to identify which rate classes contribute to the need to incur that portion of costs that are demand-related. As detailed in the IEc report, demand costs are generally proportional to the amount of capacity required.

M. Fontaine's primary basis for recommending a 100 hour peak period is that it is consistent with the expected average hours per year of operation for peaking capacity. Unfortunately, the average hours per year of operation (or average utilization) of peaking capacity is irrelevant for demand cost causation.

Attached are three exhibits related to generic generation planning concepts, that demonstrate why the utilization of peaking units is not relevant for demand cost causation.[1] The figure labeled Exhibit 1 shows how utility planners theoretically attempt to optimize the type of generating capacity in capacity planning. Exhibit 1 shows a typical "load duration curve" for a utility, in which hourly load is sorted from highest to lowest and plotted for all hours of the year. (The exhibit depicts hours only up to 4,000, although the graph extends to 8,760.)

[1] These figures were prepared by IEc as part of work done in respect of generation cost allocation at Ontario Hydro in 1995, but are representative of the basic economic theory for optimal generation planning for all electric utilities.

In that exhibit, three generic types of capacity are assumed: baseload, intermediate, and peaking. The cost structure for these types of generator range, respectively, from high to low fixed costs, and low to high variable costs. (For example, baseload plants have high fixed and low variable costs.) Baseload plants have overall lower costs if operated for many hours per year; peakers have lower overall costs if operated for relatively few hours per year. Thus, for each pair of capacity choices, there is "break-even" level of hours for the year, above which one generator is more economical and below which the other generator is more economical.

In Exhibit 1, the break-even rate between peaking capacity and intermediate load capacity is about 850 hours per year. That is, if a generation planner is trying to decide whether to construct a peaker or an intermediate load unit, he should choose the peaker if it will run less than 850 hours per year. Similarly, the break-even utilization between intermediate and baseload is approximately 3,300 hours.

To determine the optimal mix of capacity, the generation planner determines the capacity required to meet the load at the break-even utilization levels. The optimal capacity level for each type of plant is derived from the MW value of the load duration curve at the various break-even points. In that exhibit, optimal baseload capacity is a little over 16,000 MW. Intermediate load capacity is approximately 3,000 MW (the 19,000 MW intersection point less the baseload capacity), and peaking capacity of at least 5,000 MW. (Note that peaking capacity would also need to be added to meet the system reserve requirement, above the expected peak demand level.)

The average hours per year of operation in this exhibit depends both on how much peaking capacity is in place and the shape of the load duration curve during the peak period. Consider Exhibit 2. If the utility has 10,000 MW of peaking capacity (5,000 to operate and 5,000 to provide the necessary reserve), one half of the peaking capacity will not operate at all. The rest will operate somewhere between 0 hours and 850 hours per year. In this example, the average operation is roughly 150 hours per year.

However, the average hours of operation is based on the shape of the load duration curve, but the need for capacity, which drives the demand costs, is based only on the peak demand.

Imagine a modified version of Exhibit 2, in which the load duration curve does not decline nearly as steeply as it does, but still intersects the break-even point at 19,000 MW. In that case, the need for capacity would remain the same, but the average number of hours of operation would increase. Similarly, if the load duration curve were "peakier," and declined much more steeply (but retained the same intersection point), the average hours of operation would decline, but the need for capacity would be the same.

In short, the number of hours of operation of peaking capacity is largely determined by the shape of the load during peak periods. The magnitude of the capacity required to serve that load is determined only by the peak demand. Thus, demand costs are determined by the peak, and are unaffected by the shape of the load below the peak.

Therefore, IEc concludes that M. Fontaine's conclusion in respect of the 100 hour peak period is not consistent with economic cost causation.

Loss Factor

M. Fontaine proposes that a separate loss factor be used for allocating demand-related costs, based on the loss factor that applies to peak period demand. Based on a brief review of M. Fontaine's workpapers, we conclude that he estimates peak period loss factors using the following methodology:

$$LP_i = LE_i * P_T/E_T$$

where:

LP is peak period loss factor
LE is average loss factor (from Hydro Québec)
P is peak demand
E is average demand
i represents each rate class
T represents the heritage pool

IEc is not familiar with this methodology for estimating class-specific loss factors, but we do not have the technical support on which M. Fontaine relied to review. For the reasons detailed in the IEc report, we believe that class specific loss factors are more a function of class specific load factor, than system wide load factor used by M. Fontaine,[2] based on the formula used in the UNCA report.[3] We note that M. Fontaine's method produces class peak period loss factors that are directionally consistent and reasonably similar in magnitude to those that result from the methodologies applied in the IEc report.[4]

Nevertheless, we conclude that both the IEc and Fontaine analyses are estimates, and we reiterate our recommendation that Hydro Québec develop peak period loss factors by rate class.

[2] The ratio P_T to E_T in M. Fontaine's formula is the inverse of the system load factor.

[3] This report was submitted in response to Hydro Québec interrogatory 10.4, labeled Exhibit 23.

[4] This similarity can be seen by comparing the 300 CP loss factors in Fontaine Tableau 7 at page 21 with the loss factors shown in Exhibit 12 of the IEc report.

Expert Report of M. Pierre Lasserre
Observations of Action Réseau Consommateur and Féderation des Associations Coopératives D'Économie Familiale du Québec (ARC-FACEF), now d/b/a De L'Union des Consommateurs (UC)

Based on IEc's review, we conclude that the primary recommendations of these two documents in respect of Hydro Québec's methodology for generation cost rates are as follows:

- M. Lasserre proposes that a "scarcity factor" be included in the Hydro Québec formula. The scarcity factor is based on a number of factors, but the distinction between classes is the relative rate of load growth over the past several years.

- UC endorses the use of an 80 percent energy, 20 percent demand classification split in the cost allocation algorithm.

Scarcity Factor

UC observes that its recommendations in this matter are guided by equity (or fairness) considerations. IEc has two comments on that assertion.

- IEc agrees that "fairness" is a well-established criterion for rate design. However, IEc suggests that considerations of equity be reflected in the rate design process, and not at the cost allocation stage. To the extent practicable, the cost allocation stage should reflect economic cost causation.

- Unfortunately, each individual's sense of fairness can vary considerably, both from person to person and from circumstance to circumstance. For example, an individual may believe that it is fair for people to pay for the services that they require. That same individual, however, may feel that it is not fair to charge higher health insurance premiums to less healthy individuals. For that reason, "fairness" in utility rate design usually refers to "avoidance of undue discrimination." This criterion generally requires that similarly situated customers be treated similarly.

UC and M. Lasserre allege that the relatively higher load growth in the industrial rate classes is encouraged by the HQ formula, that the industrial class is using energy in a wasteful manner, and that the industrial class is implicitly exporting the low cost power and reaping the profit, by converting the power into products and exporting those products. Neither document offers any analysis of whether an increase in rates to the industrial classes would result in only a reduction in these referenced profits, or whether the increase would also result in a reduction in industrial output and employment.

UC also argues that increasing load for the industrial class reduces its per-unit costs under the HQ formula. This assertion is incorrect. To reach this conclusion, UC assumes that an increase in average industrial load will have no corresponding increase in industrial peak demand. This assumption has no logical basis. An industrial customer cannot reasonably be assumed to be able to significantly increase its consumption of power without increasing consumption in the peak period.[5] Thus, it would be much more reasonable to assume that load growth in the industrial class would also increase peak demand.[6] As demonstrated in IEc's report, however, increasing industrial load at constant load factor will *increase unit costs for all rate classes*, with the largest effect on industrial customers.

M. Lasserre opines that the heritage pool represents a scarce resource of low cost energy, and that the relative contribution of each rate class to exhausting that capacity should be reflected in higher rates. To reflect that scarcity, M. Lasserre has developed a "scarcity factor" to be included in the Hydro Québec cost rate algorithm.

The scarcity factor is based on a combination of (i) the difference between the market price for power[7] and the legislated price for the 165 TWh heritage pool, (ii) the percentage of the 165 TWh heritage pool that is being consumed, and (iii) the ratio of the average demand growth rate for each rate class to the average growth rate for the pool.

In respect of M. Lasserre's proposed scarcity factor, we note that the approach is novel, but the basic economic issue that this mechanism purports to address applies to many utilities. This issue is that, in the long run, new load costs more to serve than existing load -- that is, the incremental cost of service is higher than the average current cost of service. In a competitive market, all consumers would pay the incremental cost of service, but a regulated utility sets rates based on average costs. Thus, the price signals for regulated utilities are economically inefficient, since increases in load will not provide sufficient revenues to recover incremental costs.

Various schemes have been developed for utilities to address this issue, including marginal cost of service studies, contribution requirements for new customers, and demand-side management/integrated resource planning schemes. M. Lasserre's proposal, however, is very different from all of these techniques.

In our view, M. Lasserre's argument rests on the assumption that each rate class has some legislated entitlement to a proportionate share of the low cost pool. Thus, he proposes to discourage (through cost allocation) any class from increasing its relative share of the pool. There are a couple of problems associated with this approach. First, this proposal smacks of "vintaging," in which existing customers implicitly have greater rights to low cost power than new customers. This conflicts with the basic economics principle that all load contributes

[5] Note that this conclusion is equally true for a long peak period such as the 300 hour period advocated by Hydro Québec and UC, as well as for a single CP. Since an industrial customer is unable to predict when the single CP will occur, there is no easy way to turn off its consumption in that hour.

[6] Please see also IEc's response to HQ interrogatory 7.1.

[7] M. Lasserre uses 6.79 cents per kWh in his analysis as the market price for power. We are confused about his reference to 14 cents per kWh as the price of power in the northeast United States, however. Over the past twelve months, ISO New England reports energy prices that vary from about 4 to 8 cents (Canadian) per kWh, averaging around 5 cents per kWh. Thus, even M. Lasserre's 6.79 cent per kWh value appears to substantially exceed the opportunity cost of exporting power to New England, at recent market prices.

equally to causing the incremental costs to be incurred. While new load may result in incremental costs being incurred, a reduction in existing load could avoid those costs. Thus, all customers contribute equally to the "scarcity." It makes little sense to provide lower cost rates to one group of customers, because a reduction in load in that class is as valuable as a reduction in the rate of growth of load in another class.

A second problem with M. Lasserre's proposal is that it penalizes *all load* in the higher-growth industrial class, and not only the *new load* in the industrial class. Even if it can be argued that new load causes "scarcity costs," it would make more sense to apply the scarcity charge only to new customers, be they industrial or residential. (This is the conceptual argument for customer contribution requirements, such as those that are now before the Alberta Energy and Utilities Board in respect of transmission grid capacity.)

Finally, IEc notes that if the legislature had intended to establish inherent rights to a share of the 165 TWh heritage pool for each rate class, it would and could have done so explicitly. Instead, it simply established a pool of terawatt hours that would be subject to a fixed average unit cost. It did not establish that all customers within a particular rate class should pay higher or lower rates depending on whether or not new customers or new loads were added within their rate class.

In addition, we note that the UC analysis appears to contain a number of numerical flaws (e.g., system average prices do not appear to average to 2.79) and the method for computing class average load growth appears to be flawed in that it is not weather normalized.

Demand/EnergyClassification

UC proposes that costs be classified as 80 percent energy, 20 percent demand, based on a report prepared by M. Co Pham. Although AQCIE/AIFQ requested this report in interrogatories, UC filed only a summary of the report without backup. Thus, IEc cannot fully evaluate the merits of the proposal. We note that the UC document cites several conclusions from the Co Pham report:

- M. Co Pham concludes that the pattern of use is relatively constant from winter to summer workdays to weekends. We simply do not agree with this conclusion for the overall heritage pool load, in light of the load profiles shown in HQD, Document 1, Annexe 2, which show a dramatic peak for the large residential load in winter periods. Also, as Hydro Québec's documents show, the load factor for the heritage pool at a 300 hour peak is 67.7 percent; at a one hour peak, it is 61.1 percent. This difference indicates a very pronounced and narrow peak period, which drives overall capacity requirements.

- UC notes that M. Co Pham argues that equipment and system costs are included in the demand factor only for occasional capacity expansion costs. IEc is unaware of any jurisdiction that defines demand costs so narrowly. Demand-related costs are not occasional costs -- demand-related costs are costs that vary with total capacity required (and, therefore, peak demand).

- UC cites a relatively high and rising system load factor (of around 60 percent) as evidence of a large energy component in the system driven by increasing industrial load. IEc agrees that, for an optimally configured generation system, the energy-related share of total costs is likely to be higher for systems with higher load factors. However, in IEc's experience, system load factors of 60 percent are not unusually high. We note that the current load factor in Alberta approaches 80 percent.

As noted in the IEc report, we agree that a fixed-variable cost classification methodology is not appropriate for Hydro Québec. Further, any other classification scheme will be somewhat arbitrary. For that reason, it is difficult to develop an economic argument other than that presented in our report -- that is, set the split based on the historical practices of Hydro Québec and those of other Canadian electric utilities. On that basis, the UC proposal is well outside the range of the practices of all the Canadian utilities that we reviewed.