BEFORE THE RÉGIE DE L'ÉNERGIE

IN THE MATTER OF:

HYDRO QUÉBEC DISTRIBUTION

Demande du Distributeur relative à l'établissement des tarifs d'électricité pour l'année tarifaire 2007-2008

DOSSIER R-3610-2006

1 November 2006

prepared on behalf of:

l'Association québécoise des consommateurs industriels d'électricité (AQCIE)

Conseil de l'industrie forestière du Québec (CIFQ)

prepared evidence of:

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INTRODUCTION

My name is Robert D. Knecht. I am a Principal and the Treasurer of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. As part of my consulting practice, I prepare analyses and expert testimony in the field of regulatory economics. In Canada, I have submitted expert evidence in regulatory proceedings in Québec, Ontario, Alberta, New Brunswick, Nova Scotia, Manitoba, and Prince Edward Island. In matters regarding Hydro Québec Distribution ("HQD"), I have submitted evidence before the Régie in dockets R-3477-2001, R-3492-2002 (Phases 1 and 2), R-3541-2004, 3563-2005 and R-3579-2005. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. My *curriculum vitae* and a schedule of my expert evidence presented to regulatory tribunals are attached as Exhibit RDK-1.

I was retained by l'Association québécoise des consommateurs industriels d'électricité ("AQCIE") and the Conseil de l'industrie forestière du Québec ("CIFQ") to evaluate the following aspects of HQD's filing:

- HQD's proposed allocation of post-patrimonial generating costs for 2007;
- HQD's proposed allocation of transmission costs for 2007;
- HQD's proposals regarding the allocation of its deferral accounts;
- Implications of post-patrimonial costs for cross-subsidization targets;
- Revenue allocation if alternative treatment of cross-subsidization targets is approved;
- HQD's proposals for increases to the demand and energy charges in Tariff L.

Earlier this year, I participated in the technical committee proceedings relating to the allocation of both generation and transmission costs. I worked with AQCIE/CIFQ to develop its comments on those topics for those sessions. This evidence reiterates many of those comments in the respective sections.

Unfortunately, due to time constraints, this evidence is preliminary, and some of my analysis is incomplete. Completed sections will be provided as soon as they are available. While I do not expect that my primary conclusions and recommendations will be affected by this analysis, I will notify the Régie promptly of any changes.

1. POST-PATRIMONIAL GENERATING COST ALLOCATION

In its decision in the last proceeding, the Régie directed HQD to assemble a technical committee and to review and analyze whether the load pattern and cost causation factors for the post-patrimonial load justified a cost allocation treatment that is different from HQD's "global" or "load factor" method. The Régie expressed the concern that the load profile for the post-patrimonial load may be sufficiently different from the patrimonial load as to justify an alternative, hourly allocation of costs.

In this proceeding, HQD proposes that the global method be applied to both patrimonial and post-patrimonial generation costs. HQD also presents the results from an alternative "average hourly cost" methodology, and compares it to various other analyses prepared in conjunction with the technical committee.

Based on the analysis presented by HQD in both the technical committee and in its current filing, I recommend that the global method be retained for the purpose of allocating all generating costs in this proceeding, for the reasons set forth below.

THE GLOBAL METHOD

By way of background, I note that, in D-2002-221, the Régie determined that the cost allocation methodology for patrimonial energy was implicitly specified by legislative fiat, using HQD's demand-energy "load factor" methodology. That methodology classifies generation costs into (loss-adjusted) energy and demand components based on system load factor, it uses a 300-hour peak allocator for demand-related costs, and it uses annual consumption with no time-of-use differentiation for allocation of energy-related costs. While I (and other parties) submitted evidence in that proceeding (R-3477-2001) that the load factor methodology was inconsistent with cost causation and the historical practices of other Canadian utilities, the Régie determined that the allocation methodology was governed by legislation, and that economics and cost causation were therefore not relevant for those generation costs.

To serve its in-province load, HQD must now use both patrimonial and post-patrimonial energy supplies. It must be assumed that HQD does so on an integrated basis, minimizing overall costs incurred to the extent that it is possible to do so, recognizing the strategic constraints of government policymakers. It is my understanding that HQD simply tries to provide power at the lowest possible cost on an integrated basis given its mix of generation resources, and given the strategic and legal constraints under which it must operate.

For that reason, I concluded that it makes little sense to apply a wildly different cost allocation methodology to post-patrimonial generation costs than that used to allocate patrimonial costs -- it is most logical to apply a single methodology to all generation costs. Moreover, this "global" load factor approach has the advantages of consistency, stability, and simplicity. Finally, this method has the significant advantage that it does not require the use of confidential contract information for post-patrimonial supplies.

Nevertheless, I recognize that the Régie tasked HQD and the technical committee with a review of alternative hourly cost allocation methodologies for post-patrimonial generation costs, and the results of that effort are presented in the current filing. HQD offers a set of algorithms that are, for the most part, similar to that proposed in R-3579-2005 for making these calculations. I believe that HQD has made a heroic effort to accomplish this task, but the approach is necessarily mechanistic and produces post-patrimonial class load profiles that are not a reasonable basis for cost allocation. Moreover, it is likely that other algorithms could be derived for this allocation that would produce different results.

Unfortunately, in its filing in this proceeding, HQD presents its hourly cost allocation analysis as if it were a relatively simple and logical exercise.

Alas, it is not.

The series of algorithms compiled by HQD to allocate patrimonial and post-patrimonial load entitlements is, perhaps, the most complex, judgmental and arbitrary cost allocation methodology in my experience. Moreover, HQD has not or cannot reveal many of the detailed inner workings of the mechanism, making regulatory oversight all but impossible. Thus, while it is painfully lengthy, I review each of the key methodological components of this analysis below.

FIXED VERSUS EVOLVING ENTITLEMENTS TO PATRIMONIAL LOAD

If the global method is rejected, the first step in allocating generation costs is determining each rate class' entitlement to the patrimonial supplies. The key issue in determining this entitlement is whether a fixed or evolving approach should be used. (The "fixed" approach implies a first-come, first-served allocation of the entitlement for each class and perhaps each customer, based on some historical consumption patterns. The evolving approach allows the allocation of the patrimonial load to vary from year to year, depending on the changing mix of domestic load.)

In my evidence in Docket R-3541-2004, I detailed the economic and practical reasons why the evolving methodology is general superior to a fixed entitlement approach. These arguments remain relevant today, though they are not repeated herein. Moreover, while representing Option Consommateurs, Mr. Harper agreed that the evolving approach was consistent with sound economic principles.

Since that proceeding, it appears that the government has adopted an evolving approach, based on Decree 759-2005 and Decree 790-2006, in which each class is assigned (at least approximately) its proportionate share of the patrimonial load in each year.

On this subject, however, it is my understanding that there is a perception that, under this evolving methodology, large industrial customers have been absorbing an increasing share of HQD's load, and that they will continue to do so in the future. This perception is not consistent with the data.

First, from a historical perspective, the share of HQD's total load related to large industrial customers over the past ten years has remained relatively flat, as shown in Figure IEc-1 below. During the 1996 to 2005 period, overall HQD load growth averaged approximately 2.0 percent per year, while residential and large industrial load grew at a slightly lower rate, about 1.9 percent annually. The large industrial share of total load has remained relatively constant, bouncing around between 40 and 42 percent of total load.

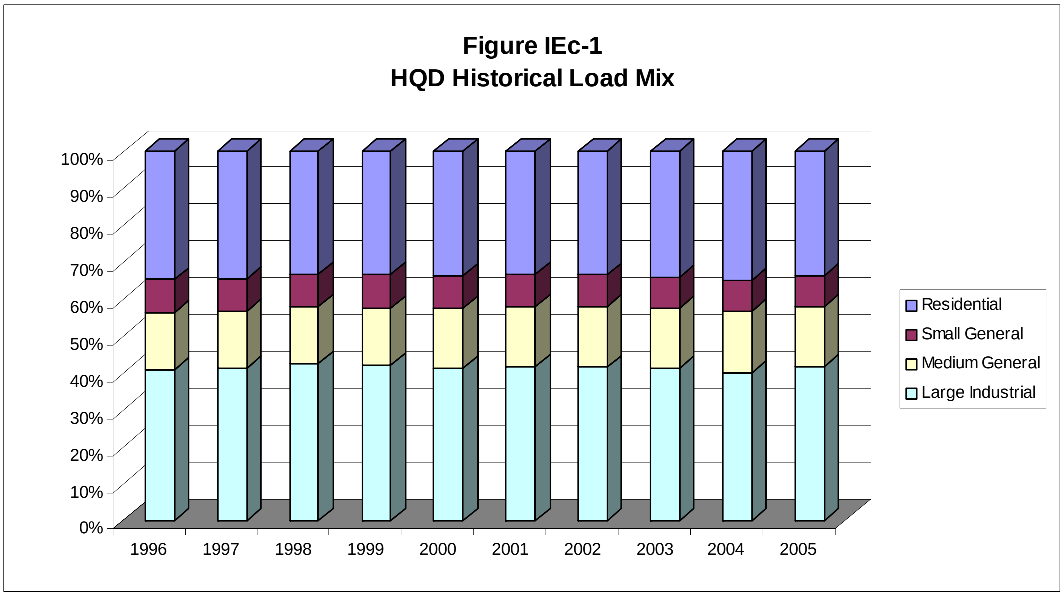

Figure IEc-1
HQD Historical Load Mix

Second, Hydro Québec's strategic plan forecasts have only gradually adjusted to reflect this historical lack of disproportionate large power load growth. As shown in Figure IEc-2 below, the last four strategic plans consistently forecast that large industrial users would experience load growth exceeding that of other rate classes, leading to an increase in the share of load related to large industrial customers. This trend has not materialized. The current strategic plan continues to forecast an increase in the share of load related to large power users, albeit at a much more modest level.

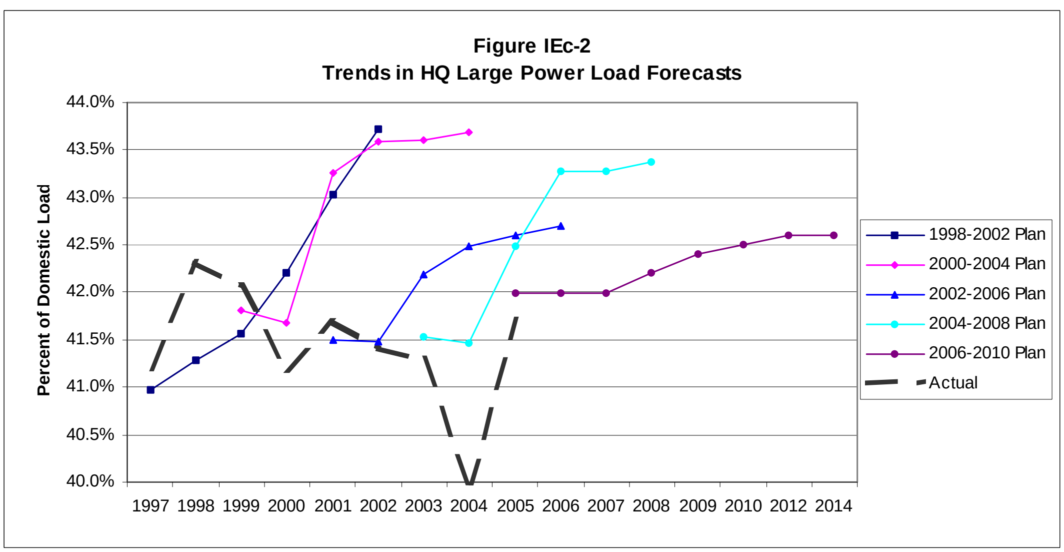

Figure IEc-2
Trends in HQ Large Power Load Forecasts

Thus, there is no evidence that the evolving approach for the entitlement to patrimonial load benefits large industrial customers.

I note also that, while there are likely to be many reasons why expected growth in large industrial manufacturing operations is declining (which vary between industries), it is my understanding that regulatory risk is becoming a serious issue. The AQCIE and CIFQ members are well aware that there is substantial regulatory risk that large industrial customers may face disproportionately large rate increases associated with post-patrimonial cost allocation, and that there are uncertainties and rate risks involving transmission cost allocation and cross-subsidization. Moreover, they are concerned that the post-patrimonial cost allocation issue is now coming before the Régie for the third time without resolution. Generation costs represent, by far, the largest cost component of large industrial customers' electric bills, and electric bills represent a substantial portion of total operating costs for many large industrial firms. Lingering uncertainty about even the allocation method for these costs makes Québec a less attractive location for large industrial companies to make the investments necessary for long-term operation of new and existing manufacturing facilities.

THE PATRIMONIAL LOAD "TAKE"

Once the fixed versus evolving issue is resolved, the next step in a separate allocation of post-patrimonial costs is to forecast when HQD expects to use its patrimonial entitlements. This step is necessary because, while Decree 1277-2001 specifies an hourly entitlement to the patrimonial load for 8760 hours, it does not specify when, during the time of the day or during the season of the year, that HQD is to use those entitlements. Moreover, once HQD specifies its specific hourly "take" for patrimonial load, it implicitly defines its post-patrimonial load shape, which is necessarily the difference between its total load for each hour and the patrimonial load "take" for that hour.

HQD has not provided its workpapers regarding the specifics of how it makes this determination.[1] However, the calculation must necessarily begin with an hourly total load forecast for domestic load, which it presumably builds up from a load forecast for each rate class.

Because HQD's overall load is only slightly higher than its patrimonial entitlement, HQD's "take" must *generally* match its overall load pattern. Nevertheless, HQD has some flexibility for applying its entitlement. The problem of evaluating how HQD will use that flexibility is further compounded by the "skew" between the patrimonial load pattern and HQD's actual load pattern, as the patrimonial load duration curve has a lower load factor than HQD's actual load pattern.

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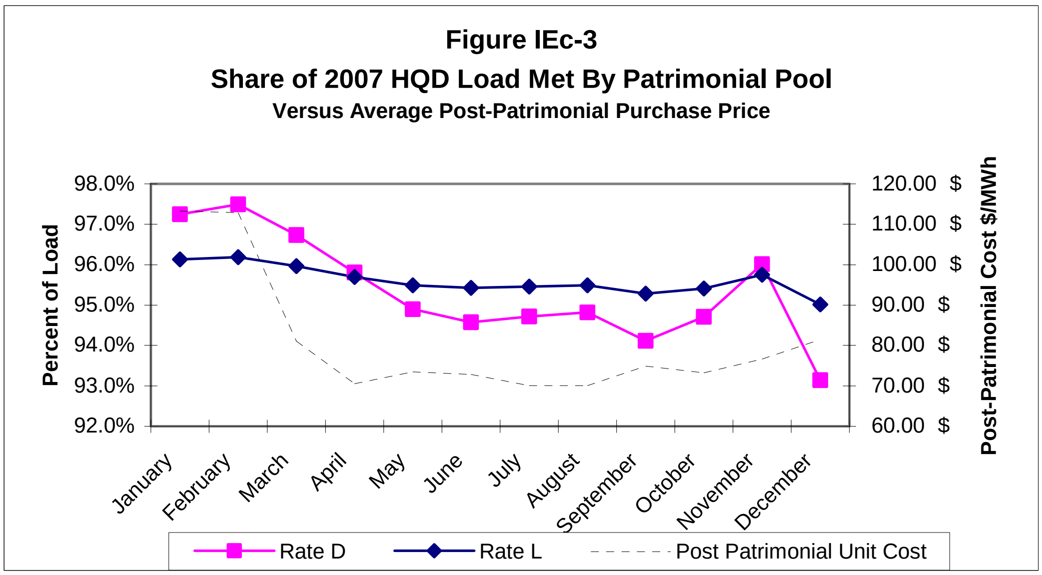
[1] I note that, in 2006, HQD now forecasts that it will be unable to use some 280 GWh of its patrimonial entitlement, which doubtless benefited its supply affiliate which was presumably able to sell that power at market prices. See HQD-4, Document 2, page 9 (English language version). This result suggests that HQD's plan for taking patrimonial load may not necessarily be a good forecast of when it will actually take the patrimonial load, implying that the forecast is suspect as a basis for cost allocation.

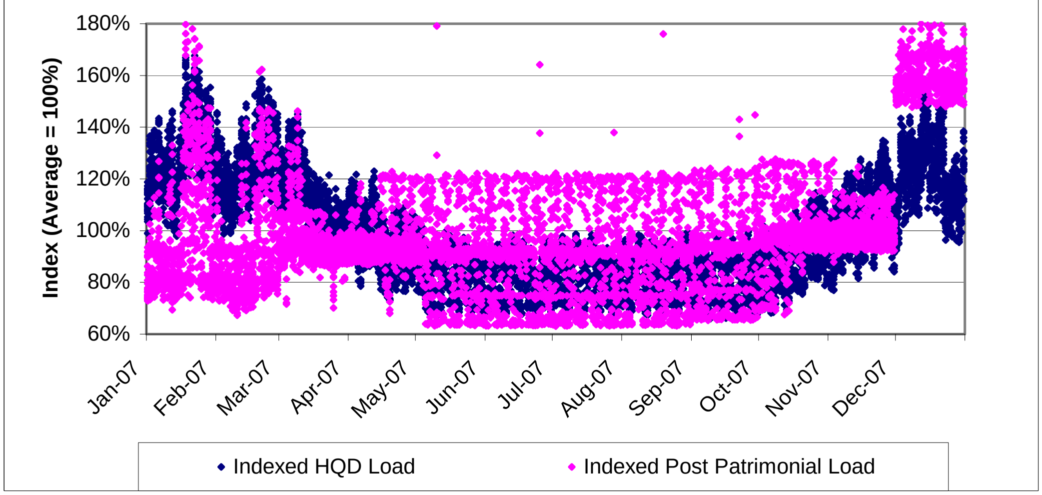
Because HQD does not provide its analysis of how it determines the "take," I can only observe the results. As shown in Figure IEc-3 below, HQD generally proposes to use patrimonial load as a higher percentage of its overall supply in January and February 2007, and to decrease that percentage during the year. This pattern may reflect the general availability of lower cost post-patrimonial power later in the year. However, whatever the algorithm HQD uses is, it results in an unexplained and surprising drop in patrimonial load in December 2007, with a corresponding jump in post-patrimonial load in that month, despite higher post-patrimonial energy costs. Therefore, HQD's does not appear likely that the pattern will remain stable from year to year. As such, it is a poor basis for cost allocation.



Having made this determination, HQD then indicates that the 1 CP load factor is 59.1 percent, compared to the 1 CP overall system load factor of 59.7 percent, suggesting that the post-patrimonial load shape is similar to the total load. This implication, however, is not correct. Not only is the 2007 post-patrimonial load shape not consistent with HQD's load shape, it is also not consistent with load patterns observed at any electric utility (of which I am aware), and it represents an irrational basis for cost allocation

Under its algorithm for 2007, HQD's peak post-patrimonial load is 2,720 MW, compared to average post-patrimonial load of 937 MW. Under tradition 1 CP definition, and if HQD were *really* procuring power to meet, its load factor would be 34.4 percent. The problem is that HQD's calculation is not based on the post-patrimonial load peak -- it is based on its system-wide peak. Thus, as I stated, HQD treats the post-patrimonial supply as part of the integrated system whole. However, if a separate cost allocation methodology is used for post-patrimonial load, then the load pattern should be treated on a stand-alone basis. And, as such, the pattern is very different from HQD's overall load pattern, as shown in Figure IEc-4 below. (Note also the peculiar jump in post-patrimonial load in December 2007.)

Figure IEc-4
Comparison of HQD Total and Post-Patrimonial Load Shapes



Moreover, as was the case last year, HQD's assignment of the patrimonial load results in a post-patrimonial load with a peculiar load shape. Of the top ten hours of post-patrimonial demand in 2007, none occur in winter months, most occur in September, and all occur between 2 and 4 in the morning. Moreover, the post-patrimonial load peak is 2720 MW, and it drops steeply to 2177 MW (a drop of 20 percent) after the first ten highest peaks. This peculiar load shape does not, of course, result from any kind of peak demands in those hours -- it simply reflects HQD's forecast that it will use its very low hourly patrimonial entitlements in those hours. Thus, if HQD were actually procuring post-patrimonial capacity only to meet the post-patrimonial peak, it would implicitly be obtaining its capacity to meet a most unusual peak.

Finally, I observe that the algorithm for the "take" of patrimonial load is not consistent with the theoretical underpinnings of the hourly cost allocation method that HQD offers as its alternative to the load factor method. If HQD did, in fact, incur its post-patrimonial costs on the hourly basis implied by this method, it could substantially reduce the cost to ratepayers by using a different algorithm for assigning patrimonial load to each hour. Under the hourly cost method for post-patrimonial costs pre-supposed by HQD's method, I calculate that a different algorithm for assigning the patrimonial load could reduce HQD's post-patrimonial costs by at least $50 million, or some 8 percent of post-patrimonial costs. And, of course, a different mechanism for assigning the patrimonial load to each hour will result in a different allocation of post-patrimonial load to each rate class.

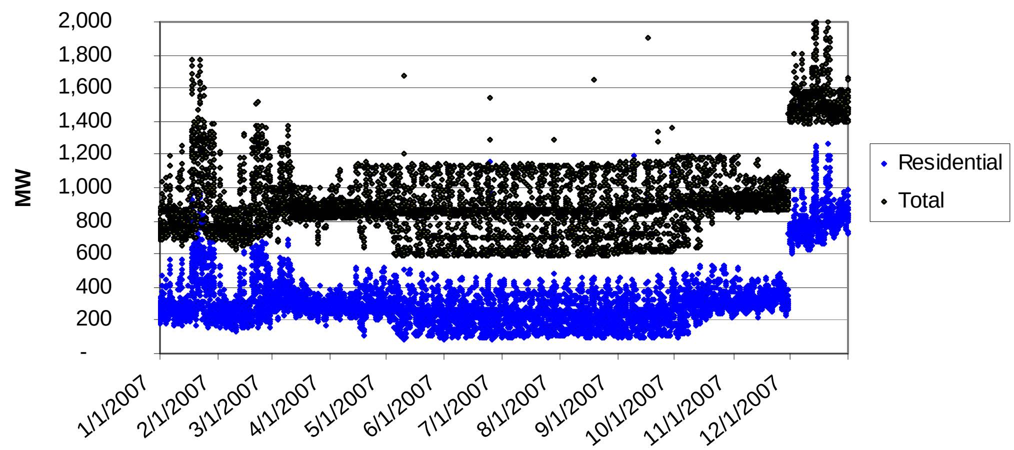
HOURLY CLASS ENTITLEMENTS TO PATRIMONIAL LOAD

Once the hourly total "take" for patrimonial load is determined, it is then necessary to allocate it to each rate class. And, as was the case for total load, the allocation of the patrimonial load implicitly determines the post-patrimonial load shape for each rate class.

HQD's response at HQD-16, Document 3, pages 26 to 27 provides some of the formulae showing how that calculation is made, although that response is incomplete. It is my understanding that this formulation is different than the algorithm that HQD used in last year's proceeding, in that it attempts to dampen the adjustment factors that are used to reconcile the differences between the patrimonial load shape and the actual load shape, on a class-by-class basis.

However, this algorithm also results in a peculiar patrimonial load shape, and correspondingly, unusual post-patrimonial load shape. As shown in Figure IEc-5 below, the Rate D class, for example, experiences a upward jump in post-patrimonial requirements on December 1, 2007. As such, this allocation is also an unreasonable basis for allocating costs.

Figure IEc-5
HQD Post Patrimonial Load Patterns



At least part of the reason for the unreasonable load profiles for post-patrimonial load produced by the HQD algorithms result from (a) the "skew" between the total patrimonial load entitlement from Decree 1277 and the actual HQD load profile, (b) load growth during the year, which tends to produce higher post-patrimonial loads at the end of the year regardless of normal time-of-use fluctuations, and (c) the post-patrimonial load is still a relatively thin slice of the overall system load. Thus, it is possible that, in a number of years, the post-patrimonial load will be less affected by these factors and will not be a completely unreasonable basis for cost allocation. At such time, it may be reasonable to revisit this question.

ALLOCATE POST-PATRIMONIAL COSTS: AVERAGE HOURLY CONTRACT COST METHOD

Once post-patrimonial load shapes for each class are derived, post-patrimonial costs can be allocated to each class using a variety of different methods. As it did last year, HQD again posits the idea of calculating an average generation cost for each hour from each post-patrimonial generation contract, and applies that hourly cost to the post-patrimonial load profiles for each class. In technical committee presentations, HQD correctly observed that this approach is conceptually similar to the "Probability of Dispatch" method briefly cited in NARUC's Electric Utility Cost Allocation Manual.

However, it is important to recognize that the Probability of Dispatch methodology is but one of a wide range of approaches presented in the NARUC manual, and it is not one of the more common ones. As shown in Exhibit IEc-2 attached to this evidence (forthcoming), the Probability of Dispatch method fails to produce reasonable cost allocation results for even the simplest examples. The method necessarily over-allocates costs to high load factor customer classes, and under-allocates costs to classes that disproportionately contribute to system peaks.

Moreover, HQD's procurement decisions for post-patrimonial capacity and energy are influenced by a number of factors beyond only the 2007 post-patrimonial load.

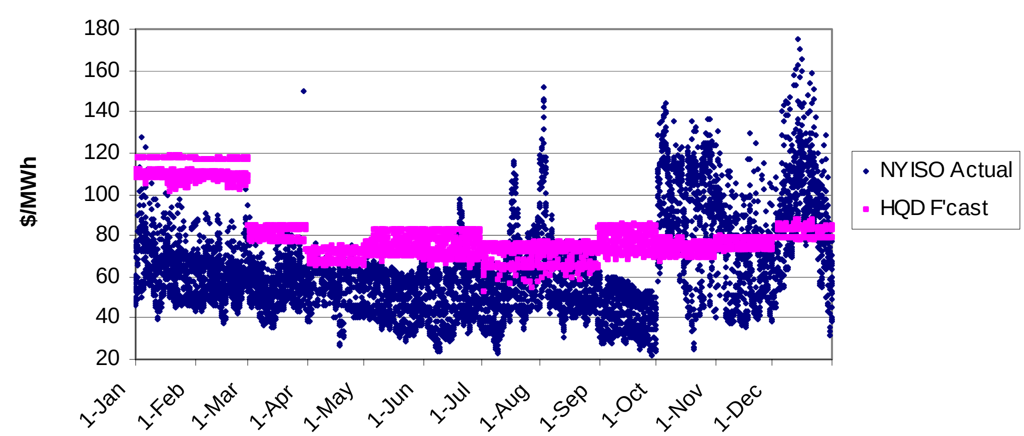
First, they are influenced by the strategic direction for Hydro Québec in total. For example, it is unlikely that if HQD were purchasing power only to meet post-patrimonial load that it would meet such a significant portion through wind capacity. I note that, in Hydro Québec's 2006-2010 strategic plan, HQD's objective regarding its supply sources is to favor renewable energy sources, and that ensuring the full contribution of wind power takes precedence to providing supply at least cost. While this approach may be rational on an integrated system basis, recognizing the patrimonial load supply sources, it would make little sense as applied on an independent basis to post-patrimonial load.

Second, HQD must take a longer-term perspective for developing post-patrimonial supply resources. It must not only meet its 2007 load, but it must develop a longer-term plan for meeting a much higher post-patrimonial load. Thus, unlike the traditional utility cost allocation study which involves a relatively stable load that is met by a set of existing facilities, this hypothetical "Post-patrimonial HQD" utility faces a rapidly growing load with few existing supply sources. If it were even possible to view the "Post-patrimonial HQD" as a stand-alone utility, it would need to be seen as in the midst of a massive transition. As such, cost allocation based on a single year's load profile and the capacity that happens to be in place because it is first to come on stream will likely produce results that are wildly unstable over time. This instability will likely continue until the growth in post-patrimonial load results in a more coherent load shape, and the supply resources become more balanced toward cost optimality.

One sure sign that the hourly cost methodology offered as an alternative by HQD is not reasonable for cost allocation is, as HQD notes, that it implies that there is virtually no seasonal or time-differentiation in average per-kWh electric costs in 2007. For example,

Figure IEc-6 below contrasts HQD's forecast of hourly generation prices for 2007 with the actual locational marginal prices ("LMPs") observed at the NYISO interface with Hydro Québec (the LMPs exclude NYISO demand charges). The NYISO prices exhibit logic seasonal and time-of-use differences, with higher prices in on-peak hours and on-peak seasons. The HQD average hourly post-patrimonial prices exhibit much less volatility, and they are uncorrelated with demand patterns. The only obvious pattern is that HQD will be able to contract for lower average cost power later in the year. This ability, however, is not related to market prices -- it is simply a result of contractual "lumpiness" when applied to a very thin post-patrimonial supply mix.

Figure IEc-6
Comparison of HQD 2007 Hourly and NYISO Actual 2005-2006 Market Prices



I am not aware of any jurisdiction in which costs are allocated such that peak period consumption costs no more to serve than off-peak consumption. Thus, the average hourly cost method fails on both methodological and practical grounds.

DEMAND-ENERGY COST SPLIT

At HQD-11, Document 1, Table 2, HQD presents the results of two alternative approaches (Scenarios 4 and 5), based on a more traditional demand-energy cost classification split. HQD presents this methodology in response to the technical committee comments in favor of a greater recognition of system peak demands (which the hourly cost method fails to address). HQD uses the results of this analysis to argue that this approach produces results that are consistent with the overall load factor methodology.

While this methodology does not produce results that are obviously unreasonable relative to the load factor methodology, I would have methodological concerns regarding the use of this specific approach, should the Régie be considering its adoption.[2]

In this methodology, HQD splits its post-patrimonial costs into demand and energy components. The demand component is determined based on contractual capacity-related costs from two separate post-patrimonial supply contracts, at $80 and $110 per kW for Scenarios 4 and 5 respectively. It applies these demand values to each class' post-patrimonial contribution to the HQD system peak, to derive demand-related costs of $130.0 million and 178.1 million respectively (19.6 percent and 26.8 percent of total post-patrimonial costs). It then applies a 12 cent per kWh to each rate class for its contribution to the top 300 HQD system hours, ostensibly to reflect the cost of providing energy during the system's highest peak periods. The balance of the costs are assumed to be related to energy, and are allocated based on each class' contribution to system energy outside of the top 300 hours.

This approach has a number of suspect assumptions. First, the peak demand costs are based on each class' contribution to the HQD system CP, not the post-patrimonial CP. (As I mentioned earlier, this is consistent with HQD's treatment of its load from an integrated perspective, and not as a standalone post-patrimonial load.) This assumption affects both the magnitude of overall demand costs as well as the allocation. If HQD were to use its post-patrimonial CP, the overall demand component would be much higher (2720 MW), and the allocation between classes for that (very bizarre) CP would be different.

Second, HQD's demand charges are applied only to class loads, with no provision for reserve. This assumption ignores the fact that HQD must procure capacity well in excess of forecast peak demand, particularly for those classes with temperature-sensitive loads and no interruptible customers.[3] Thus, the demand allocators understate actual demand responsibility.

Third, HQD confirms that the demand costs are similar to those for a peaking unit. In the cost allocation framework in which demand costs are based on that for a peaking unit, energy costs should generally be allocated based on the marginal cost of supply in each hour. Thus, HQD's arbitrary split of its hours into a very narrow peak period and a very broad off-peak period, each with a simple flat hourly energy cost, understates the time differentiation of energy costs that should be used in this model. As such, this method likely overstates the energy-related costs for high load factor customers. In addition, HQD's choice of a 12 cent per kWh value for the short peak period is, to my knowledge,

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[2] My understanding is that HQD has not proposed that this method be adopted; it uses this method to support the global load factor method.

[3] It is my understanding that HQD includes interruptible demands from Rate L customers in its demand allocators. If these loads can be interrupted, they should not attract any demand costs in this methodological framework.

unsupported. And, as was the case for the demand costs, HQD defines the on-peak hours based on its integrated system peak demands rather than on standalone post-patrimonial load.

In short, while HQD's analysis provides a basis for rejecting the simple hourly cost method, it is "not ready for prime time" as a method for allocating post-patrimonial costs. Moreover, the simplifications inherent in HQD's application of this approach tend to increase costs allocated to high load factor customers. Thus, if anything, a corrected version of this analysis would likely demonstrate that the global load factor method over-allocates costs to the high load factor rate classes.

POST-PATRIMONIAL COST ALLOCATION SUMMARY

I commend HQD for a diligent and serious effort to take on the issue of the allocation of post-patrimonial generation costs. HQD made a good-faith effort in the technical committee proceedings to evaluate a set of options and to present the results of their analysis. While a more serious evaluation of the potential use of market price mechanisms for allocating post-patrimonial generation costs may have been preferred, I understand HQD's reluctance to devote time and resources to analytical efforts that will not be relevant for at least eight to ten years, if ever.

I recommend, on the basis of HQD's analysis presented to the technical committee, that continued use of the load factor methodology for allocating all generation costs through at least 2014 is the preferred approach in light of:

- The legislated mandate for allocating patrimonial costs;
- The agreement amongst HQD and experts for both OC and AQCIE/CIFQ that an evolving entitlement to patrimonial supplies is reasonable, consistent with recent government decrees;
- The unusual shape of the forecast post-patrimonial load, in light of HQD's forecast for its patrimonial load "take;"
- The arbitrary nature of HQD's algorithm for allocating patrimonial load to each class on an hourly basis, and the illogical load shapes it produces in the near term due to the skew in the patrimonial entitlement and the fact that post-patrimonial load remains a relatively small contributor to overall load;
- The conceptual flaws in the average hourly contract cost methodology and contract demand-energy split methodology;
- The confidentiality of post-patrimonial contracts;
- The advantages of reducing regulatory risk faced by business customers in Québec.

2. ALLOCATION OF TRANSMISSION COSTS

In this proceeding, HQD proposes to continue its policy of allocating transmission costs on the basis of a "1 CP" method, consistent with the way that it incurs those costs as billed by its upstream affiliate TransÉnergie. For the reasons explained below, I agree with HQD's proposal for the purposes of this proceeding, at least until TransÉnergie's revenue allocation and rate designs are modified to reflect the cost allocation mechanism approved by the Régie in D-2006-66.

CONTEXT: D-2006-66

In R-3549-2004, the Régie considered the issues of how to allocate TransÉnergie's transmission costs between in-province customers (HQD) and point-to-point service, as well as the issue of designing the rates for both types of customers.

With respect to cost allocation, the Régie determined that transmission costs should be sub-functionalized into generation integration, network, attachment and other interconnection categories. The Régie directed that these cost categories then be classified and allocated as follows:

- Generation Integration and Other Interconnection: These costs are classified into energy and demand components on a 61/39 basis, generally relying on the system 1CP load factor for the classification split. Energy-related costs are to be allocated based on annual energy with no locational or time-of-use differentiation, while the demand costs are allocated on a 1 CP basis.
- High Voltage Network: These costs are classified as 100 percent demand-related and allocated on a 1 CP basis.
- Customer Attachments: These costs are allocated on a customer-specific basis at the transmission level. To the extent that this cost allocation methodology is passed through at the distribution level, the implications are not clearly spelled out in D-2006-66. However, in its filing, HQD proposes to segregate the specific facilities associated with customers who are interconnected at transmission voltage and directly assign the costs to those specific customer classes. HQD further proposes to allocate the balance of these costs on the basis of class primary voltage NCP.

Regarding rate design, however, the Régie decided that it would not rely on the cost allocation methodology, either for determining the overall magnitude of the costs or for designing the rates by which those revenue requirements are collected, at least for the test period. The Régie determined that rates should continue to be based on a flat dollar per kW demand charge for both point-to-point customers and HQD. Moreover, while the cost allocation approach allocated $2,564 million to HQD, the rate design approach established a revenue requirement for HQD of $2,483, some $81 million less than allocated costs.[4] It is also important to recognize that, as a result, the rates paid by HQD are therefore, 100 percent demand-related.

COST CAUSATION FOR HQD – PASSTHROUGH OF TRANSMISSION COST ALLOCATION, OR TRANSMISSION RATE DESIGN

Cost allocation experts generally agree that an electric distribution utility should pass on its regulated transmission costs in the same manner in which they are incurred. For example, if the regulated charges to the distribution utility from the transmission utility are totally based on monthly system peak demand, then transmission costs should be allocated to each rate class based on each class' contribution to monthly system peak demand.

Unfortunately, the inconsistency in the Régie's D-2006-66 decision creates a dilemma for cost allocation analysts at the distribution level. The cost analyst must decide whether to use the Régie's approved transmission cost allocation method to allocate transmission costs at the distribution level, or to use the Régie's approved transmission rate design method to allocate those costs.

The problem arises because transmission rate design, which is what the distribution utility really sees, is not consistent with the cost allocation methodology. If the Régie were to follow its cost allocation principles in setting rates, it would make two significant changes. First, it would require HQD to pay some $81 million more in the test year than it proposes, and second, it would presumably at least begin to start recognizing the energy component of costs by incorporating energy charges in the transmission tariff. However, thus far, the Régie has ordered neither of these changes, and it directs that the revenue requirement and transmission rates be set based on a 1 CP methodology.

The issue of the proper allocation of transmission costs among transmission ratepayers is beyond the scope of this proceeding and this evidence. From the perspective of the distribution company, HQD's actual cost causation is driven by the Régie's rate design methodology, not by its cost allocation approach. The cost allocation methodology is used for neither setting the native load revenue requirement nor for setting the rates. It is therefore irrelevant to HQD. Until that methodology is used to actually set the distributor's revenue requirement and to establish rates, it is a matter that is internal only to TransÉnergie. For example, under D-2006-66, increases in off-peak energy consumption will increase costs that are allocated to native load customers, *but it will not increase the costs that are billed to native load customers.* Therefore, changes in energy use at the distribution level have no causal relationship with transmission costs incurred

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[4] At HQD-11, Document 1, Table 3, HQD indicates that the cost allocation methodology from D-2006-66 assigns $2,564.2 million to native load service, implying a difference of $79 million from the 1 CP method. However, HQD's evidence continues to refer to a $81 million difference. While I do not understand the reason for the difference, I do not believe that it is relevant to this evidence.

by HQD. Thus, for the time being, I recommend that 1 CP be used as the cost allocation method at the distribution level.

However, in the longer term, absent a reversal of D-2006-66, I recognize that the Régie may eventually begin to modify the regulated transmission rates to be consistent with its cost allocation decision. Thus, it is not unreasonable for HQD to begin evaluating the implications of this transition, and for the Régie to develop an understanding of its implications.

THE $81 MILLION PAID BY POINT-TO-POINT CUSTOMERS

As noted above, the Régie has directed that point-to-point customers pay $81 million of the costs allocated to in-province customers. In the technical committee proceedings, HQD posited two alternative approaches for sub-functionalizing that $81 million between the four transmission functions. It offered a proportional approach across all four cost functionalization categories, and it offered an approach in which costs were proportionally functionalized only to the Generation Integration, Network, and Other Interconnection Functions.

The rationale for the first option was presumably simplicity and equity. It provided for a proportional passthrough of the cost discount to all customers equally. The rationale for the second option was presumably that, because point-to-point customers were paying this $81 million, and because they normally do not pay for attachment costs, this credit should not offset the attachment costs.

My recommendation to the technical committee was that any method chosen for assigning this $81 million is arbitrary. The $81 million is a fiction created by the inconsistency in the Régie's decision. Whether it is paid by point-to-point customers or whether Hydro Québec's shareholder absorbs it is irrelevant; it is simply an overall cost credit that has no basis in the physical reality.

For that reason, I agree that HQD's proposal in its filing for a proportional assignment of costs to all four functions is the most reasonable – in that the adjustment to full cost rates will then have a proportional impact on all of the functions.

SUB-FUNCTIONALIZATION AND ALLOCATION OF ATTACHMENT COSTS

While the Régie's decision does not specifically address the allocation methodology for attachment costs (presumably because these are not paid by point-to-point customers), HQD presentation to the technical committee proposed to first split these costs into sub-station costs and costs associated with attaching high voltage customers. The former were then allocated to distribution voltage customers, and the latter are allocated between the high voltage customers in Rates M, L, and special contracts. For allocating the substation costs, HQD proposed two alternatives to the technical committee -- a primary voltage non-coincident peak ("NCP") demand approach, and a number of customers approach.

In my analysis of the technical committee presentation, I agreed with HQD that it is plain common sense to segregate attachment costs between those serving transmission voltage customers and those that serve only distribution voltage customers. Direct assignment of costs, when possible, is preferred to a numerical allocation.

Regarding the allocation of substation costs, I also concluded that a NCP demand allocator is far superior to a customer allocator. Substations are sized to meet peak demands, not number of customers. I am not aware of any jurisdiction that allocates substation costs on a number-of-customers basis. Therefore, although it will allocate more costs to distribution voltage Rate L customers, including some AQCIE/CIFQ members, I recommended that the NCP allocator be used.

HQD apparently agrees with this logic, and its alternative allocation of transmission costs in this proceeding reflects a NCP demand allocator.

IMPLICATIONS OF ALTERNATIVE TRANSMISSION COST ALLOCATION FOR CROSS-SUBSIDIZATION TARGET RATIOS

A significant change in the methodology used to allocate transmission costs is, as HQD's analysis shows, likely to have an impact on target revenue-cost ratios for each class. However, I suggest that there are additional concerns that may need to be resolved before the parties fully understand the implications of these changes. In particular, I recommend that HQD prepare an analysis of the longer-term implications of the proposed methodological change on cross-subsidization indexes, for the following reasons.

First, the Régie has approved HQD's "rolling" method of adjusting revenue-cost ratio targets resulting from methodological changes to cost allocation. However, if transmission rates increase or decrease as a percent of overall costs, a one-time adjustment to the target ratios will either understate or overstate the impact of the methodological change in future years. For example, in this proceeding, HQD calculates the impact of the methodological change on the transmission costs included in this proceeding, excluding both the recovery of the past deferred transmission costs and the recovery of the expected increase in costs associated with the currently ongoing TransÉnergie rate proceeding. For that reason, I encourage the Régie to direct HQD to present results of the longer-term methodological impacts of the proposed change before formally adopting this proposal.

Second, I observe that this change in allocation methodology will lead to more questions regarding whether a change is "methodological" or whether it is related to "price/cost/volume" effects, for the purpose of adjusting target revenue-cost ratios. For example, I note that the Régie in Decision D-2006-66 required TransÉnergie to continue to evaluate its functionalization analyses to ensure accuracy. However, if this analysis results in a significant change in how TransÉnergie functionalizes costs between Generation Integration and Network functions, it is unclear whether any changes resulting from additional analysis will be a methodological change or will be a price/cost/volume change. Thus, until all the cross-subsidization implications of the methodological change are fully analyzed and understood, it is probably prudent to defer making the cost allocation change.

IMPLICATIONS FOR RATES

As I explained above, passing through the Régie's transmission cost allocation methodology implies a significant reduction in the demand component of costs and a significant increase in the energy component of costs. If and when these transmission cost allocation changes are implemented in *transmission* rates and passed on to HQD, the basic principles of *distribution* rate design dictate that these change implies that HQD must re-evaluate the relative levels of its demand charges and its energy charges (for those customer classes with demand charges). HQD has not yet presented any analysis of those implications.

Further, reductions in the coincident peak demand charges that HQD faces from the transmission utility reduces the incentive for HQD to lower its load during its sharp winter peaks. For example, if the D-2006-66 cost allocation were exactly matched in rates, the HQD incentive to shave 1 kW off its coincident peak demand would decline from $69 to $45, because some of the coincident peak demand charge has been replaced by annual energy charges. Thus, if and when the new cost allocation approach is undertaken, HQD should re-evaluate its demand-side management program, particularly its peak-shaving policies, to determine whether they are economically advantageous to its ratepayers in the context of reduced transmission demand charges.[5]

Because none of these factors have been analyzed, I again suggest deferring any proposed change until such time as the implications are fully understood.

TRANSMISSION COST ALLOCATION SUMMARY

I commend HQD for getting a start on the evaluation of the implications of passing through the Régie's transmission cost allocation methodology to distribution rate customers, even though there is no cost causation reason to do so at present. Under the hypothesis that the Régie will eventually develop transmission rates that are consistent with its cost allocation methodology, I recognize that the revised methodology may eventually be passed through to distribution cost allocation. To the extent that this is eventually required by the Régie, I agree with HQD that customer attachment costs should be split between substations and high voltage attachments, and I agree with the use of a NCP allocator for substations costs.

However, until all of the implications of this change are fully evaluated, I recommend that the 1 CP methodology be retained by HQD for allocating its transmission costs to the various rate classes.

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[5] This calculation highlights another aspect of HQD's cost structure that is often overlooked, namely that transmission costs represent a very significant component of costs relative to other electric utilities. While patrimonial generation costs are quite low, they are partly offset by the high transmission costs needed to bring the low-cost power to market. For example, compare the $69 per kW for transmission to the demand costs that HQD estimates for its post-patrimonial generating capacity at $80 to $110 per kW.

I suggest that the key areas requiring attention are the following:

- Resolution by the Régie of the inconsistency in D-2006-66;
- Evaluation of the longer-term implications for cross-subsidization targets resulting from this change;
- Evaluation of the implications for rate design and demand-side management programs associated with this change.

3. ALLOCATION OF GENERATION DEFERRAL ACCOUNT

The Régie permits HQD to recover any variances between its forecast and actual post-patrimonial generation costs. This variance (or deferral) account must then be assigned among the various rate classes in the cost allocation study. In HQD-4, Document 2, HQD proposes to modify the current methodology for disposition of these costs (or credits) from a monthly basis to an annual basis, in an effort to reduce the complexity of the calculations. I have not, at this writing, completed my analysis of this proposal, though I tend to agree with HQD that (a) the allocation of generation deferral accounts should be consistent with the allocation method for generation costs, and (b) that simpler methods, all other factors being equal, are preferred to the more complex approaches. I also agree that continued use of the simpler load factor method for allocating post-patrimonial generating costs will also simplify the allocation of post-patrimonial cost variances.

To the extent that my ongoing analysis of this proposal results in a change in this conclusion, I will notify the Régie promptly and present my analysis.

However, in respect of this proposed change, HQD indicates that the impact of this change on 2007 allocated costs should be treated as a methodological change for the purposes of setting class revenue-cost ratio benchmarks. Based on my preliminary review, I do not agree that it is appropriate to treat this particular methodological change in this manner, in light of the Régie's decision in the last proceeding.

To understand my reasoning, it is useful to recall the purpose for adjusting the benchmark revenue-cost ratios. The Act indicates that the Régie is not permitted to adjust rates in order to modify cross-subsidization among the various rate classes. However, when cross-subsidization is measured, it is measured based on a particular methodology for allocating costs. Thus, at some historical period, a "baseline" level of cross-subsidization has been established. If the methodology for allocating HQD's costs changes, due to better information about cost incurrence, or due to a change of cost allocation philosophy at the Régie, the methodological change would likely affect not only current-year allocated costs but would also affect the baseline cross-subsidization levels.

Thus, the Régie recognized that changes in allocated costs from proceeding to proceeding must be segregated into "price/cost/volume" effects and "methodological" effects. Changes due to methodological effects are used to adjust the baseline cross-subsidization "targets" or "benchmarks" specified by HQD for maintaining baseline cross-subsidization levels at each class.

Moreover, one of the concerns of the parties at the time this adjustment was adopted (including myself) was that, if these adjustments were not made, it would provide an opportunity for advocates to try to "game the system." If methodological adjustments were not made to cross-subsidization targets, an advocate would have the incentive to argue for a cost allocation methodology that was particularly unfavorable to the class he represents at the time the cross-subsidization targets were set, and then reverse its position in subsequent years.

As a hypothetical example, a Rate L advocate might have argued at the time cross-subsidy targets were set that transmission costs should be allocated based on a combination of demand and energy allocators, thereby implying that the class target cross-subsidization level was, say, 110 percent. Once that target was set, the Rate L advocate could then argue for a 1 CP allocator, which, all other factors being equal, would result in a revenue-cost ratio for the class of, say 115 percent. Without an adjustment to the target cross-subsidization ratio, it would be necessary to assign a roughly 5 percent rate decrease to the Rate L class to get it back to its target, even though there was no real change in any cost causation factors.

Nevertheless, to make the most accurate assessment of the methodological impact, it would be necessary to make a direct comparison between the test year and its cost allocation methodology and the baseline year and its associated methodology. As HQD and the Régie recognized, this comparison becomes increasingly difficult with the passage of time. Thus, in the last rates proceeding, it proposed a "rolling" adjustment methodology, such that the adjustment to the target would be based only on the impact of the methodological change between the prior case test year and the current case test year. While I disagreed with that methodology, particularly as it relates to high-cost items such as generation and transmission costs, the single-year rolling approach was accepted by the Régie. However, it is important to recognize that the approximation from the single-year rolling approach is only accurate, *if the impact of the methodological change in one year is reasonably reflective of the impact of that methodological change in every year thereafter*. If the impact is not reasonably consistent from year to year, the rolling methodology will not produce reasonable results regarding the impact of the methodology change.

In respect of this specific methodological change for post-patrimonial generation cost variances, HQD calculates that the impact of this change will be to reduce costs allocated to the large industrial customers by some $40.8 million. Based on HQD's analysis presented in HQD-11, Document 1, Tables 5 and 7, this change appears to be the primary contributing factor to an increase in the large industrial cross-subsidization benchmark revenue-cost ratio from 117.1 percent to 117.9 percent. Under HQD's rolling approach, the large industrial target is now increased by that 0.8 percent forever, regardless of the impact of this methodological change in any future year.

However, this is a very different kind of methodological change than, say, changing the transmission cost allocation methodology. HQD will incur transmission costs every year, and they will be more-or-less stable from year to year. Thus, the impact of a methodological allocation change in one year may reasonably approximate the impact in future years. In contrast, however, the generation variance account can be expected to swing substantially from year to year, with both positive and negative values. It is most unlikely that this methodological change will have a consistent impact from year to year. It is much more likely that, in some years, this change will result in an increase in the revenue-cost ratio for a particular class of customers and, in some years, it will reduce the revenue-cost ratio for those customers.

Thus, under HQD's rolling methodology for measuring the impact of methodological changes, it would be better to treat this particular change as a price/cost/volume effect, unless HQD can specifically establish that the impact of this methodological change will be consistent from year to year.

4. CROSS-SUBSIDIZATION AND POST-PATRIMONIAL COSTS

At HQD-12, Document 1, pages 63 to 66, HQD indicates that the Régie has requested that parties comment on the standard used by HQD for measuring cross-subsidization among the various rate classes, in light of the exhaustion of heritage pool electricity. To date, the Régie has agreed with HQD's revenue-cost ratio method, in which target cross-subsidies are based on a ratio of class revenues to allocated costs.

In response to that directive, HQD offers an alternative to the existing methodology in which the rate increases for each rate class would be set based on the increase in per kWh allocated cost for that rate class, as measured from test year to test year. (I assume that the impacts of cost allocation methodological changes would be excluded from that adjustment, much as they are from target revenue cost ratios in the existing method.) As shown in HQD-12, Document 1, Table 30, rigid adherence to this methodology between 2006 and 2007 would require a substantially larger rate increase for residential customers than for business customers.

As I understand this alternative, HQD's proposal would essentially shift the cross-subsidy benchmark from a revenue-cost ratio basis to a subsidy per kWh consumed basis. That is, rather than having the target cross-subsidization for the residential class be, say, 81 percent, it would be, say, $16.00 per MWh. In effect, the entire residential class load would continue to receive the same subsidy per kWh consumed that it did in the historical baseline year, but that value would not increase if costs rose faster than load growth. (Under the existing methodology, the subsidy values per kWh consumed tend to increase over time, as costs are increasing faster than load growth.)

In the R-3492-2002 proceedings, I presented evidence that evaluated the implications of three different measures of cross-subsidy: the revenue-cost ratio approach (the current method), the unit subsidy approach (which is similar to HQD's suggested alternative in this proceeding) and the dollar subsidy approach. Under the last option, a fixed baseline dollar cross-subsidy from each class is established, and it does not change with either volume growth or unit cost growth. Without repeating the arguments that I presented in that proceeding, I concluded that a fixed dollar subsidy approach would cause the least amount of distortion to cost causation and would be the least inequitable of the options.

While I believe that the analysis presented in that evidence remains relevant today, I also recognize that my recommendation was not adopted by the Régie.

In those proceedings, however, the issue of the impact of high-cost post-patrimonial energy was not explicitly considered. Because each class faces a different "mix" of costs, the potential impact of sharp increases in post-patrimonial costs. In Exhibit IEc-3, I constructed a simple example showing the impact of a 5 percent across-the-board load growth, met by increases in post-patrimonial energy supplies. For illustrative purposes, the example presented in the exhibit assumes that per-kWh transmission and distribution costs remain the same. As shown in that example, the across-the-board load growth will result in noticeably higher rate increases for the large power customers under the currently approved methodology for setting benchmark cross-subsidy targets. If the existing methodology is rigidly followed, the 5 percent load growth scenario will require an increase of 6.5 percent for large industrial customers, compared to a 3.7 percent increase for residential customers. Moreover, the subsidy to the residential class will increase from $950 million to $1,041 million, and the per-unit subsidy to that class will increase from $16.03 per MWh to $16.74 per MWh. Similarly, the subsidy provided by large industrial customers will increase by about 10 percent, and the per-kWh subsidy will increase by about 5 percent.

Thus, if HQD experiences disproportionate increases in its post-patrimonial generation costs, the currently approved cross-subsidization metric will compound the impact on those customers who are already most exposed to those increases, namely the large power customers. Moreover, it will result in substantial increases in subsidies provided to the residential customers, on both a per-kWh and total dollar basis.

From a theoretical standpoint, there is no perfect way to set a baseline for cross-subsidization. All three of the methods that have been considered have advantages and disadvantages -- none is perfect. Any consideration of whether a rate increase for a particular class has an undue impact on cross-subsidization is a matter of judgment. Since there is no perfect solution, I recommend that, for evaluating proposed rate increases, the Régie begin to consider not only the trends in revenue-cost ratios, but the Régie should also consider trends in per-kWh subsidies, and total dollar subsidies.

As a very rough estimate of the impact of considering these alternative measures, I attempted to construct a time-line for all three metrics, similar to that presented in HQD-11, Document 4, Table 54. That analysis is attached as Exhibit IEc-4, although it must only be considered an approximation at this writing.

As that analysis shows, if the 2006 to 2007 changes are considered, the results in that exhibit tend to support HQD's analysis, which indicates that if only the one year is considered, the residential class would need to face the largest rate increase in 2007 to maintain its historical per-kWh cross-subsidy, while the large power customers would face the smallest increase.

However, when evaluated over the longer term, the exhibit suggests that, as measured by per-kWh or even dollar value subsidies, the residential class has experienced a noticeable increase in the subsidy received, but that the subsidy increase has come primarily from the small general and medium sized customers.

5. TARIFF DESIGN FOR RATE L

In HQD's last rate proceeding, the Régie approved an "across-the-board" rate increase for all rate classes of 5.3 percent. However, several high load factor industrial customers were unpleasantly surprised to find that their actual rate increase was somewhat higher than the "across-the-board" figure. This differential rate increase within the rate class occurred because HQD has been following a policy of increasing the energy charge for large industrial customers by a greater percentage than it increases the demand charge. HQD proposes to do so again in this proceeding, by assigning a 1.5 percent increase to the Rate L demand charge and a 3.6 percent increase to the Rate L energy charge. (Increases to the demand-related voltage discounts are similar in magnitude to the demand charge increase, ranging from 1.6 to 1.9 percent.)

For the purposes of this proceeding, HQD's proposal for differentiated increases should be rejected, and an "across-the-board" increase applied to all existing Rate L tariff charges. For the next proceeding, I recommend that HQD consult with its Rate L customers to evaluate whether decreasing the energy charges is appropriate, and to investigate alternative innovative approaches for Rate L tariff design that will better encourage conservation and load leveling.

I make this recommendation for several reasons.

First, on a cost basis, HQD's cost allocation study segregates costs into demand and energy components. As a general rule, utilities tend to match the revenue earned from demand charges with allocated demand costs, and match the revenue earned from energy charges with energy-related costs. Some utilities will set demand charges modestly below allocated demand costs, in recognition that the individual customer peak does not always match up with the coincident peak measure used in the cost allocation study. The need for this adjustment is less appropriate for HQD, because it already uses such a broad peak (300 hours) for allocating the demand-related portion of generation costs in the load factor method.

It is therefore reasonable to compare the energy-related costs assigned to Rate L with the revenues generated by the energy charges, as well as to compare demand-related costs with revenues from demand charges. However, HQD is the only utility in my experience that is not required to provide a "proof-of-revenue" analysis for its rate design, showing its present and proposed tariff charges, its test year billing determinants, and the present and proposed revenues associated with each specific tariff charge. As such, it is not easy to exactly determine the energy-related revenues for Rate L.

Nevertheless, Table IEc-1 below shows my derivation of the estimated energy-related costs assigned to Rate L on a per kWh basis. The only energy-related costs allocated to Rate L are those associated with generation costs. Based on HQD's load factor method, approximately 67.2 percent of generation costs are energy-related. The balance of generation costs, as well as all transmission and distribution costs, are demand-related

TABLE IEC-1 COMPARISON OF RATE L ENERGY COSTS AND ENERGY CHARGES	
HQD Generation Costs ($mm)	$4,971.2
Energy Component of Generation (300 CP)	67.2%
HQD Energy-Related Generation Costs ($mm)	$3,341
Rate L Share of Energy	25.8%
Rate L Energy Costs ($mm)	$861.6
Rate L Consumption (GWh)	45,708
Rate L Unit Energy Cost (cts/kWh)	1.89
Rate L Revenue/Cost Ratio	115.6%
Cost-Based Rate L Energy Charge (cents/kWh)	2.18
HQD Proposed Energy Charge (cents/kWh)	2.84

Thus, HQD is proposing to set the energy charge for Rate L some 30 percent higher than energy-related costs. As such, this proposal is not justified on a cost basis.

In addition, by assigning disproportionate increases to the energy charge, HQD is reducing the incentive for large industrial customers from maintaining a level load. Under HQD's tariff, the energy charge is the same regardless of whether it is a peak period or an off-peak period, or whether it applies to a customer with a very high load factor or to a customer with a more temperature sensitive peak demand. The demand charge, by contrast, applies only to the customer's peak demand. Thus, by proposing disproportionate increases to the energy charge, HQD encourages less efficient behavior by Rate L customers.

Finally, I note that other jurisdictions, notably British Columbia, have already explored more innovative approaches for rate design for large industrial customers designed to create incentives for efficient use of a low-cost heritage pool. I recommend that the Board encourage HQD to begin to seriously evaluate innovative rate design proposals for large industrial customers, for its next base rates case.

CONCLUSIONS AND RECOMMENDATIONS

Based on my analysis completed to date, my recommendations are as follows:

- Allocate all generation costs based on HQD's load factor method;
- Allocate transmission costs the way they are incurred by HQD, on a 1 CP basis;
- If the proposed change to the allocation of generation deferral costs is adopted, treated the impact of the change as a price/cost/volume effect for the purpose of setting cross-subsidization targets;
- In recognition of the transition to a post-patrimonial generation environment, the Régie should measure the cross-subsidization implications of the proposed revenue allocation based on three different indicators: revenue-cost ratios, subsidy per kWh consumed, and dollar subsidies;
- For the purposes of this proceeding, adjust all Rate L tariff charges and credits by the same percentage;
- Encourage HQD to explore more innovative Rate L tariff designs for the next rates proceeding.

EXHIBIT IEc-1

CURRICULUM VITAE AND

EXPERT TESTIMONY SCHEDULE

OF

ROBERT D. KNECHT

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than twenty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. In addition, as Treasurer of IEc since 1995, Mr. Knecht is responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans. Mr. Knecht's consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.
- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.
- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.
- As part of international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.
- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.
- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-00061493	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corporation	September 2006	Pennsylvania Office of Small Business Advocate	Rate of return, load forecasting, cost allocation, revenue allocation, rate design, revenue decoupling.
R-00061398	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	August 2006	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-00061365	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Merger savings, cost allocation, revenue allocation, rate design.
R-00061519	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
R-00061518	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
A-125146	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Southern Union Company	June 2006	Pennsylvania Office of Small Business Advocate	Public benefits of proposed sale of PG Energy to UGI; asset management agreement.
R-00061355	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2006	Pennsylvania Office of Small Business Advocate	Gas supply and hedging plan; procedural issues
R-00061296	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2006	Pennsylvania Office of Small Business Advocate	Gas procurement and procedural issues.
R-00061246	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2006	Pennsylvania Office of Small Business Advocate	Gas procurement; unaccounted for gas retention rates
2005-002 Refiling	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	February 2006	New Brunswick Public Intervenor	Cost allocation, rate design
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	December 2005	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design for POLR supplies.
R-3579-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2005	AQCIE/CIFQ	Generation cost allocation; cross-subsidization; revenue allocation
2005-002	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	August 2005	New Brunswick Public Intervenor	Cost allocation, rate design
R-00050538	Pennsylvania Public Utility Commission	PG Energy	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement diversification

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-00050540	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging, retention rates, sharing mechanism
R-00050340	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging and diversification.
R-3563-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	April 2005	AQCIE/CIFQ	Generation cost allocation; industrial demand response
R-00050264	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, risk hedging, financing costs in the gas cost rate.
R-00050216	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2005	Pennsylvania Office of Small Business Advocate	Gas supply procurement and forward pricing policies.
EB-2004-0542	Ontario Energy Board	Union Gas Limited	March 2005	Tribute Resources Inc.	Cost allocation and rate design for service to embedded storage pools.
R-00049884	Pennsylvania Public Utility Commission	Pike County Light and Power (Gas Service)	January 2005	Pennsylvania Office of Small Business Advocate	Fair rate of return, cost allocation, class revenue assignment.
R-00049656	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	December 2004	Pennsylvania Office of Small Business Advocate	Fair rate of return, uncollectibles costs, automatic rate adjustments, cost allocation, rate design.
R-3541-2004	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2004	AQCIE, CIFQ	Allocation of post-patrimonial generation costs.
C-20031302	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	July 2004	Pennsylvania Office of Small Business Advocate	Customer assistance program funding and cost allocation.
R-049255	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	June 2004	Pennsylvania Office of Small Business Advocate	Transmission and distribution cost allocation, rate design, automatic distribution increases.
P-042090 et al.	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2004	Pennsylvania Office of Small Business Advocate	Collections and universal service cost issues.
RP-2003-0203	Ontario Energy Board	Enbridge Gas Distribution	May 2004	Vulnerable Energy Consumers Coalition et al.	Cost allocation, rate design for pipeline and storage costs
R-049157 P-042090	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2004	Pennsylvania Office of Small Business Advocate	Cash receipts reconciliation clause

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-049108	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2004	Pennsylvania Office of Small Business Advocate	Uncollectible cost responsibility for standby charges
Application 1306819	Alberta Energy and Utilities Board	ENMAX Power Corporation	January 2004	Calgary Industrial Group Calgary Building Owners	T&D cost allocation, rate design, ratepayer equity funding
R-3492-2002 Phase 2	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2003	AQCIE, CIFQ	Rate policy, cross-subsidization
R-038168	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	July 2003	Pennsylvania Office of Small Business Advocate	Cost allocation, deficiency assignment, rate design, pension cost reconciliation, rate of return
R-3492-2002 Phase 1	Régie de l'Énergie, Québec	Hydro Québec Distribution	January 2003	AQCIE, AIFQ	Cost allocation; maintenance of historical cross-subsidization
M-021612	Pennsylvania Public Utility Commission	Philadelphia Gas Works	September 2002	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, cost allocation, rate unbundling
R-027385	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms.
1250932	Alberta Energy and Utilities Board	Aquila Networks Canada (Alberta) Ltd.	July 2002	Senior Petroleum Producers Association	Distribution plant and cost allocation, rate design.
R-027204	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms, rate design
R-3477-2001	Régie de l'Énergie, Québec	Hydro Québec Distribution	May 2002	AQCIE, AIFQ	Classification/allocation of generation costs, subject to constant unit cost constraint.
1248859	Alberta Energy and Utilities Board	ESBI Alberta Limited	March 2002	IPPSA	Transmission congestion management principles
R-016378	Pennsylvania Public Utility Commission	Philadelphia Gas Works	August 2001	Pennsylvania Office of Small Business Advocate	Cost of gas; commodity price forecasting
R-016179	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2001	Pennsylvania Office of Small Business Advocate	Recovery of CAP costs; PGC treatment of pipeline credits
R-005277	Pennsylvania Public Utility Commission	PFG Gas Inc. and North Penn Gas Company	November 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design.
R-3443-2000	Régie de l'Énergie, Québec	Société en commandite Gaz Métropolitain	November 2000	Industrial Gas Users Association (ACIG)	Tariff unbundling

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
990005	Alberta Energy and Utilities Board	ESBI Alberta Limited	November 2000	IPPSA	Location-based credits for transmission rates
R-005119	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, weather normalization
R-994788	Pennsylvania Public Utility Commission	PFG Gas, Inc. and North Penn Gas Company	February 2000	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994785	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corp.	December 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994783	Pennsylvania Public Utility Commission	PG Energy, Inc.	November 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
99005	Alberta Energy and Utilities Board	ESBI Alberta Limited (Transmission Administrator)	September 1999	IPPSA	Transmission tariff cost allocation, rate design, industry restructuring
RE95080	Alberta Energy and Utilities Board	Alberta Power Limited	December 1998	Independent Power Producers Society of Alberta and SPPA	Electric industry restructuring, rate unbundling, cost allocation and rate design.
RE95081	Alberta Energy and Utilities Board	TransAlta Utilities Corporation	November 1998	IPPSA and Senior Petroleum Producers Assn.	Industry restructuring, cost allocation, rate design.
Expansion Feasibility Test	Public Utilities Board of Manitoba	Centra Gas Manitoba	August 1998	Simplot Canada Limited	Expansion feasibility and customer contribution methodology
R-984280	Pennsylvania Public Utility Commission	PG Energy, Inc.	August 1998	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue deficiency assignment, rate design
EO97070455	New Jersey Board of Public Utilities	Atlantic City Electric Company	February 1998	New Jersey Board of Public Utilities	Industry restructuring, audit of unbundled rates
R-973981	Pennsylvania Public Utility Commission	Allegheny Power (West Penn Power)	January 1998	Pennsylvania Office of Small Business Advocate	Industry restructuring, cost unbunding, cost allocation, and rate design.
R-973954	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	August 1997	Pennsylvania Office of Small Business Advocate	Restructuring, stranded costs, market price forecasting, cost allocation, and rate design.
1996 Electric Utility Tariff Applications	Alberta Energy & Utilities Board	TransAlta Utilities, Alberta Power Edmonton Power, Grid Company of Alberta	October 1996	Independent Power Producers Society of Alberta (IPPSA)	Industry restructuring; transmission cost allocation and rate design.

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-963612	Pennsylvania Public Utility Commission	PG Energy, Inc.	October 1996	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal.
R-953444	Pennsylvania Public Utility Commission	Trigen-Philadelphia Energy Corp.	November 1995	Pennsylvania Office of Small Business Advocate	Steam energy cost rate -- direct and rebuttal.
R-953406	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	October 1995	Pennsylvania Office of Small Business Advocate	Weather normalization, cost allocation and rate design.
R-953297	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Gas Division)	May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and surrebuttal.
R-943271	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	April/May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal
EBRO 488	Ontario Energy Board	Natural Resource Gas Limited	November 1994	Natural Resource Gas Limited	Customer classification, cost allocation and rate design.
RE92071	Alberta Public Utilities Board	Alberta Power Limited	November 1994	Independent Power Producers Society of Alberta	Cost allocation and rate design for export transmission service.
R-942986	Pennsylvania Public Utility Commission	West Penn Power Company	August 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design.
R-932862	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Electric Division)	March 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct, rebuttal and surrebuttal.
EBRO 485, and Generic Direct Purchase Hearings	Ontario Energy Board	Consumers' Gas Company, Ltd.	August 1993,September 1993.	Canadian Independent Gas Marketing Association	Classification and allocation of marketing and administrative costs.
Hearings for Cost of Service and Rate Design	Nova Scotia Utility and Review Board	Nova Scotia Power, Inc.	May 1993	Bowater Mersey Paper Company, Ltd.	Classification of bulk power costs, rate design for interruptible service and other rate design issues.
Generic Hearing #4	Board of Commissioners of Public Utilities, New Brunswick	New Brunswick Power Corporation	November 1991	Large Power Users Group	Review of cost allocation and rate design.
EBRO-473	Ontario Energy Board	Consumers' Gas Company, Ltd.	October 1991	Ontario Energy Board Staff	Cost allocation and rate design

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
EBRO-470	Ontario Energy Board	Union Gas, Ltd.	February 1991	Ontario Energy Board Staff	Cost allocation and rate design; evaluation of load shifting study.
Rate Area Boundaries Hearings	Prince Edward Island Public Utilities Commission	Maritime Electric Co., Ltd.			February 1991
EBRO-467	Ontario Energy Board	Centra Gas, Ltd.	January 1991	Ontario Energy Board Staff	Cost allocation and rate design for technology, cogen and bypass.
Arbitration Hearings	Arbitrator	ARINC, Inc.	July 1990	ARINC Inc.	Cost allocation and rate design for aircraft to ground data communications service.
EBRO-462	Ontario Energy Board	Union Gas, Ltd.	January 1990	Ontario Energy Board Staff	Seasonal cost allocation study, and allocation of costs to export markets.
NSPC-857	Nova Scotia Board of Commissioners of Public Utilities	Nova Scotia Power Corp.	February 1989	Interruptible industrial customers	Cost allocation and rate design of interruptible electric service.

EXHIBIT IEc-2

CONCEPTUAL ANALYSIS OF HQD'S HOURLY GENERATION COST ALLOCATION METHODOLOGY

[forthcoming]

EXHIBIT IEc-3

IMPLICATIONS OF POST-PATRIMONIAL LOAD AND COST GROWTH FOR RATE INCREASES UNDER ALTERNATIVE CROSS-SUBSIDIZATION METRICS

EXHIBIT IEc-3
Impacts of Post-Patrimonial Cost Growth on Average Class Rate Increases
Under Alternative Cross-Subsidization Benchmarks.

	Sales GWh	- - - - - - - - - - - - - *Revenue Requirement (Costs) $mm* - - - - - - - - - - - - - Patrimonial	Post-Patrimonial	Transmission	Dist'n and Other	Total	Revenues $mm	Normalized R/C Ratio	Normalized $ Subsidy	Normalized $/MWh Subsidy	Unit Revenue Increase
2007 Baseline Conditions											
Domestique	59,232	1,798	259	1,263	1,706	5,026	4,076	81.1%	(950)	$ (16.03)	
Petite Puissance	14,620	400	58	228	356	1,042	1,282	123.1%	240	$ 16.44	
Moyenne Puissance	27,129	698	101	337	266	1,401	1,841	131.5%	441	$ 16.24	
Grande Puissance	45,567	1,074	155	427	59	1,715	1,983	115.7%	269	$ 5.89	
Total	**146,548**	**3,970**	**572**	**2,255**	**2,387**	**9,183**	**9,183**	**100.0%**	-	$ -	
Source:	*(1)*	*(2)*	*(2)*	*(3)*	*Calc.*	*(4)*	*(5)*	*Calc.*			
Future Scenario: Constant Revenue-Cost Ratio Approach (Currently Approved Method)											
Domestique	62,194	1,798	558	1,326	1,791	5,473	4,432	81.0%	(1,041)	$ (16.74)	3.7%
Petite Puissance	15,351	400	124	240	374	1,138	1,398	122.9%	260	$ 16.96	4.0%
Moyenne Puissance	28,485	698	217	354	279	1,547	2,030	131.3%	484	$ 16.97	5.2%
Grande Puissance	47,845	1,074	333	448	62	1,917	2,214	115.5%	297	$ 6.21	6.5%
Total	**153,875**	**3,970**	**1,232**	**2,367**	**2,506**	**10,075**	**10,075**	**100.0%**	-	$ -	4.6%
Future Scenario: HQD Proposed Unit Cost Increase/Normalization Approach											
Domestique	62,194	1,798	558	1,326	1,791	5,473	4,476	81.8%	(997)	$ (16.03)	4.6%
Petite Puissance	15,351	400	124	240	374	1,138	1,389	122.1%	252	$ 16.39	3.2%
Moyenne Puissance	28,485	698	217	354	279	1,547	2,009	129.9%	462	$ 16.23	3.9%
Grande Puissance	47,845	1,074	333	448	62	1,917	2,201	114.8%	283	$ 5.92	5.7%
Total	**153,875**	**3,970**	**333**	**2,367**	**2,506**	**10,075**	**10,075**	**100.0%**	-	$ -	4.5%
Future Scenario: Constant Unit Subsidy Approach											
Domestique	62,194	1,798	558	1,326	1,791	5,473	4,476	81.8%	(997)	$ (16.03)	4.6%
Petite Puissance	15,351	400	124	240	374	1,138	1,390	122.2%	252	$ 16.44	3.2%
Moyenne Puissance	28,485	698	217	354	279	1,547	2,009	129.9%	463	$ 16.24	3.9%
Grande Puissance	47,845	1,074	333	448	62	1,917	2,199	114.7%	282	$ 5.89	5.6%
Total	**153,875**	**3,970**	**333**	**2,367**	**2,506**	**10,075**	**10,075**	**100.0%**	-	$ -	4.5%
Future Scenario: Constant Dollar Subsidy Approach											
Domestique	62,194	1,798	558	1,326	1,791	5,473	4,523	82.6%	(950)	$ (15.27)	5.7%
Petite Puissance	15,351	400	124	240	374	1,138	1,378	121.1%	240	$ 15.66	2.3%
Moyenne Puissance	28,485	698	217	354	279	1,547	1,987	128.5%	441	$ 15.47	2.8%
Grande Puissance	47,845	1,074	333	448	62	1,917	2,186	114.0%	269	$ 5.61	5.0%
Total	**153,875**	**3,970**	**333**	**2,367**	**2,506**	**10,075**	**10,075**	**100.0%**	-	$ -	4.5%

Scenario Definition	Load Growth	Post-Pat Cost	Unit Trnsmsn Cost Gr	Unit Dist'n Cost Growth
Domestique			0.0%	0.0%
Petite Puissance			0.0%	0.0%
Moyenne Puissance			0.0%	0.0%
Grande Puissance			0.0%	0.0%
Total	5.0%	$ 90.00		

Sources:
(1) HQD-12, Document 5, page 3, Ventes
(2) HQD-11, Document 4, Table 9A
(3) HQD-11, Document 4, Table 7
(4) HQD-11, Document 4, Table 1
(5) HQD-12, Document 1, Table 28, Normalized to equal total cost

EXHIBIT IEc-4

TRENDS IN ALTERNATIVE CROSS-SUBSIDIZATION METRICS

Exhibit IEc-4
Historical Trends in Alternative Cross-Subsidization Metrics

	Sales	*Revenue*	*Cost*	*Normalized R/C Ratio*	*Normalized Unit Subsidy*	*Normalized $ Subsidy*
2002 Non-normalized						
Residential	52,969	3,230.8	4,377.1	80.2%	$ (16.37)	(867.3)
Small General	13,859	1,079.2	952.2	123.1%	$ 15.89	220.2
Medium	24,361	1,470.5	1,223.4	130.6%	$ 15.36	374.1
Large Power	45,171	1,746.1	1,623.9	116.8%	$ 6.04	273.0
Total	**136,360**	**7,526.6**	**8,176.6**	**100.0%**	**$ -**	**-**
2002 Normalized						
Residential	52,969	3,281.0	4,396.4	80.7%	$ (15.99)	(847.2)
Small General	13,859	1,078.7	952.0	122.6%	$ 15.51	214.9
Medium	24,361	1,470.3	1,223.1	130.0%	$ 15.08	367.4
Large Power	45,171	1,746.7	1,624.6	116.3%	$ 5.86	264.9
Total	**136,360**	**7,576.7**	**8,196.1**	**100.0%**	**$ 0.00**	**0.0**
2003 Normalized						
Residential	55,544	3,359.7	4,386.3	80.4%	$ (15.48)	(859.8)
Small General	13,863	1,078.7	930.2	121.7%	$ 14.57	202.0
Medium	25,301	1,542.1	1,239.2	130.6%	$ 15.00	379.4
Large Power	47,937	1,874.9	1,689.6	116.5%	$ 5.81	278.4
Total	**142,645**	**7,855.4**	**8,245.3**	**100.0%**	**$ -**	**-**
2004 Approved						
Residential	55,432	3,578.5	4,426.3	80.8%	$ (15.30)	(848.3)
Small General	13,967	1,133.8	928.8	122.1%	$ 14.67	204.9
Medium	25,967	1,643.6	1,260.7	130.4%	$ 14.74	382.7
Large Power	48,767	1,964.4	1,703.4	115.3%	$ 5.35	260.7
Total	**144,133**	**8,320.3**	**8,319.2**	**100.0%**	**$ 0.00**	**0.0**
2005 Approved						
Residential	57,447	3,700.2	4,577.3	81.1%	$ (15.03)	(863.7)
Small General	14,356	1,170.0	974.3	120.5%	$ 13.93	200.0
Medium	26,282	1,655.0	1,289.4	128.8%	$ 14.14	371.6
Large Power	52,241	2,116.8	1,832.4	115.9%	$ 5.59	292.1
Total	**150,326**	**8,642.0**	**8,673.4**	**100.0%**	**$ -**	**-**
2005 with 2004 Method						
Residential	57,447	3,700.2	4,583.6	81.0%	$ (15.13)	(869.2)
Small General	14,356	1,170.0	972.9	120.7%	$ 14.04	201.6
Medium	26,282	1,655.0	1,286.3	129.2%	$ 14.27	375.1
Large Power	52,241	2,116.8	1,832.4	116.0%	$ 5.60	292.5
Total	**150,326**	**8,642.0**	**8,675.2**	**100.0%**	**$ 0.00**	**0.0**
2006 Approved						
Residential	58,976	3,960.8	4,914.3	81.6%	$ (15.35)	(905.1)
Small General	14,640	1,247.2	1,025.0	123.2%	$ 16.22	237.4
Medium	26,890	1,763.5	1,372.2	130.1%	$ 15.35	412.9
Large Power	47,059	2,000.3	1,770.0	114.4%	$ 5.41	254.8
Total	**147,565**	**8,971.8**	**9,081.5**	**100.0%**	**$ 0.00**	**0.0**

Exhibit IEc-4
Historical Trends in Alternative Cross-Subsidization Metrics

2006 with 2005 Method							
Residential	58,976	3,902.7	4,916.6	81.4%	$	(15.47)	(912.4)
Small General	14,640	1,227.2	1,025.6	122.8%	$	15.95	233.5
Medium	26,890	1,734.6	1,372.3	129.7%	$	15.15	407.4
Large Power	47,059	2,207.7	1,993.6	113.6%	$	5.77	271.5
Total	**147,565**	**9,072.2**	**9,308.1**	**100.0%**	**$**	**(0.00)**	**(0.0)**
2007 Proposed							
Residential	59,224	4,164.1	5,025.9	81.1%	$	(16.03)	(949.5)
Small General	14,665	1,310.2	1,042.0	123.1%	$	16.41	240.6
Medium	27,407	1,880.8	1,400.7	131.4%	$	16.07	440.5
Large Power	45,716	2,026.4	1,715.3	115.6%	$	5.87	268.4
Total	**147,012**	**9,381.5**	**9,183.9**	**100.0%**	**$**	**0.00**	**0.0**
2007 Proposed with 2006 Method							
Residential	59,224	4,164.1	5,113.6	81.4%	$	(16.04)	(949.8)
Small General	14,665	1,310.2	1,063.6	123.2%	$	16.81	246.5
Medium	27,407	1,880.8	1,436.5	130.9%	$	16.21	444.2
Large Power	45,716	2,026.4	1,767.1	114.7%	$	5.67	259.1
Total	**147,012**	**9,381.5**	**9,380.8**	**100.0%**	**$**	**0.00**	**0.0**

Evolution of Cross-Subsidy Benchmarks (Based on HQD-11 Table 54)

	Residential Class				**Small General**			
	Revenue-Cost Ratio		Per-MWh Subsidy	Dollar Subsidy	Revenue-Cost Ratio		Per-MWh Subsidy	Dollar Subsidy
2002 Basis	80.2%	$	(16.37)	(867.3)	123.1%	$	15.89	220.2
2002 Method	0.5%	$	0.38	20.1	-0.6%	$	(0.38)	(5.3)
2005 Method	0.1%	$	0.10	5.5	-0.2%	$	(0.11)	(1.6)
2006 Method	0.1%	$	0.12	7.3	0.4%	$	0.27	3.9
2007 Method	-0.3%	$	0.01	0.3	-0.1%	$	(0.40)	(5.9)
2007 Targets	80.6%	$	(15.77)	(834.0)	122.7%	$	15.26	211.3

	Medium Power				**Large Power**			
	Revenue-Cost Ratio		Per-MWh Subsidy	Dollar Subsidy	Revenue-Cost Ratio		Per-MWh Subsidy	Dollar Subsidy
2002 Basis	130.6%	$	15.36	374.1	116.8%	$	6.04	273.0
2002 Method	-0.5%	$	(0.27)	(6.7)	-0.5%	$	(0.18)	(8.1)
2005 Method	-0.3%	$	(0.13)	(3.4)	0.0%	$	(0.01)	(0.4)
2006 Method	0.4%	$	0.20	5.5	0.8%	$	(0.36)	(16.7)
2007 Method	0.5%	$	(0.13)	(3.7)	1.0%	$	0.20	9.3
2007 Targets	130.6%	$	15.02	365.7	118.0%	$	5.70	257.0

Notes:
1) Revenue and cost values are based on Exhibit HQD-11, Document 4, Table 54
2) Sales figures are loss-adjusted (generator basis), based on historical cost allocation studies Table 11 as available.
3) This analysis is not precise at this writing, but should provide a reasonable estimate of the trends.