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 2006-2007

DOSSIER R-3579-2005

Prepared Evidence of:

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On Behalf of:

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Conseil de l'industrie forestière du Québec (CIFQ)

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1. Introduction and Summary of Conclusions

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 R-3477-2001, R-3492-2002 (Phases 1 and 2), R-3541-2004 and R-3563-2005. 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 is 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 2006;
- HQD's proposed method for establishing base-line cross-subsidy targets;
- The implications of across-the-board rate increases over the next 10 years for revenue-cost ratios.

Based on my review to date, I conclude the following:

- Allocation of HQD's generation costs can be a one-step process (the "global" method) or a three-step process. Under certain very specific conditions, the results of these two approaches produce the identical results. For the current proceeding, I agree with HQD that the global method is the most reasonable approach of the options that have been studied.
- If the global method is not adopted, the generation cost allocation would likely consist of the following three steps:
    - First, the patrimonial load must be assigned to each rate class, using either a rolled-in or incremental approach. For 2006, this step is constrained by Décret 1277-2001, which establishes the overall heritage pool on an hourly basis, and by Décret 759-2005, which implicitly uses a rolled-in methodology for assigning overall annual class volumes to the heritage pool.

- The second step is to allocate heritage pool energy costs to each rate class. For 2006, this step is accomplished by Décret 759-2005, which appears to rely on the traditional HQD load factor algorithm to the heritage pool load, consistent with the cost allocation methodology addressed in R-3477-2001.

- Third, the costs of post-patrimonial energy must be allocated to the various rate classes. In theory, the allocation of post-patrimonial energy costs should reasonably reflect each class' causal contribution to these costs. With the rise in market-based pricing for generation services in neighboring jurisdictions, it may also be reasonable to consider market-based allocation schemes for post-patrimonial energy costs.

- Although the first step in the generation cost allocation process for these proceedings has been effectively mooted by the decree, I reiterate my conclusions from the R-3541-2004 proceedings that the rolled-in methodology is superior to an incremental approach. In that proceeding I indicated, *"[I]ncremental allocation methods for post-patrimonial energy costs are not consistent with cost causation, with basic principles of fairness, or with significant regulatory precedents, and would likely result in complex and contentious allocation analyses."*

- In its decision in the R-3541-2004 matter, the Régie directed that HQD evaluate alternative ways in which post-patrimonial energy costs may be allocated. In this proceeding, HQD proposes that one of the options studied by the generating cost allocation task force ("Alternative A") be a "fall-back" position if its traditional method is not applied to post-patrimonial load. Based on the limited information available, I conclude that this approach not consistent with any traditional method for generation cost allocation, it is not consistent with either cost causation or market pricing principles, and it should not be adopted. While some of the other alternatives considered by the task force may have merit, so little information regarding these methods is presently available that I do not endorse any of them for this year. This evidence lays out general principles that I recommend that the Régie consider, if it chooses to further investigate options for allocating post-patrimonial energy costs.

- HQD's "rolling" methodology for determining base cross-subsidy measures has the advantage of simplicity, but it is conceptually flawed. With each application, HQD should provide a version of the cost allocation study for that proceeding that uses the 2002 baseline methodology for cost allocation.

- Even if there are no changes in class load patterns, shifts in the mix of costs between generation, transmission and distribution will result in changes in class revenue-cost ratios. Over the longer term, the combination of cost shifts will generally cause revenue-cost ratios to migrate toward the cross-subsidization targets. Thus, applying across-the-board rate increases in this proceeding is not an unreasonable strategy.

These conclusions are addressed in this evidence as follows. Section 2 addresses HQD's basic generation cost allocation methodology and its implications for the current proceeding. It also discusses the conditions under which the global method is consistent with the three-step process. Section 3 addresses the various alternatives to the global method that have been suggested, notably Alternative A, and explains why HQD's methodologies for both the allocation of the heritage pool volumes and the allocation of post-heritage costs for 2006 in those scenarios are not appropriate for cost allocation in this proceeding. Section 4 reviews HQD's proposed methodology for developing base cross-subsidy levels, and Section 5 presents my analysis of the longer-term implications for cost mix shifts. Section 6 summarizes my recommendations.

This evidence is based on the analysis completed to date, but remains preliminary due to the time constraints of the process. To the extent that my ongoing analyses result in any additional findings or any modifications to these conclusions, I will provide supplemental evidence to the Régie promptly.

2. HQD's Load Factor Method

In R-3477-2001, the Régie heard evidence regarding HQD's methodology for allocation of generation costs, which, at the time, consisted only of heritage pool costs. For simplicity, I refer to this as the HQD Load Factor Method. In summary, that method essentially consists of the following components:

- All generation costs are classified into energy and demand components, based on the system load factor,[1] implying that overall generation costs are classified as approximately two-thirds energy-related and one-third demand-related.
- Energy costs are allocated to each rate class in proportion to each class' annual kWh consumption, adjusted for losses to derive the each class' annual generation requirements. No effort is made to reflect time-of-use differences in energy costs.
- Demand costs are allocated to each rate class in proportion to each class' contribution to the top 300 hours of system peak demand, also adjusted for class loss factors.

In my evidence in the R-3477-2001 proceeding, I expressed several concerns regarding that methodology. Nevertheless, it is the methodology that Hydro Québec has consistently used

[1] System load factor is the ratio of the average hourly demand for energy over the course of the year divided by some measure of peak demand. The higher the load factor, the "flatter" is the load pattern. For individual rate classes, large industrial process loads exhibit high load factor users, while temperature sensitive residential loads show low load factors.

for allocating costs, it is the methodology used in the development of the Merrill Lynch report,[2] and it is the methodology that the government had at its disposal when it mandated that historical cross-subsidies be retained.

One feature of this methodology is that it requires very little generation cost information. Implementing the methodology requires only that HQD provide the total cost of generation services, as well as the physical parameters for each rate class (energy consumption, loss factors and load factors). With this approach, HQD does not need to provide any information regarding the specific nature of generation costs, nor does it need to provide any details regarding hourly consumption by rate class or hourly variations in energy costs by time of use or season.

The advantages of this method are that it is simple, and that it will reflect changes in class load shape or loss factors. The disadvantages of this methodology are that it is not demonstrably consistent with cost causation, it has never reflected the actual nature of the costs incurred by Hydro Québec, and it cannot reflect any changes in the nature of the costs incurred by HQD in the future. Of course, because HQD declines to provide any specific information about the nature of its post-patrimonial energy costs, it will be difficult to reasonably review and regulate a more complex methodology.

In evaluating this methodology, I begin by applying it on a "global" basis, to all of HQD's claimed generation costs for this proceeding. This analysis is presented in Exhibit RDK-2. As shown, except for errors that are apparently due to rounding, the application of the HQD Load Factor method produces allocated cost results that are virtually identical to HQD's proposal in this proceeding.[3]

I then applied the Load Factor method to the patrimonial and post-patrimonial energy costs separately, using a *pro rata* allocation. In Exhibit RDK-3, I calculated each class' 2006 energy share of the 166.4 TWh heritage pool based on that class' contribution to the total 2006 energy consumption (173.9 TWh). Thus, each class' entitlement to the heritage pool was 95.7 percent of its 2006 forecast consumption. This volumetric allocation produces results that are virtually identical to the class-specific loads shown in Décret 759-2005. (See Exhibit RDK-5 for a comparison of results.) I also assumed that the class-specific load factors and loss factors for the heritage load were the same as those for the overall 2006 load.[4] I then applied the HQD Load

[2] "The Québec Electricity Supply Rate and Options for the Introduction of Competition in Electricity Production," Report to the Ministry of Natural Resources, Government of Québec, Merrill Lynch, January 14, 2000.

[3] AQCIE/CIFQ requested that HQD provide information with sufficient detail to replicate its calculations, but I was not able to exactly match HQD's calculations with the information provided. Based on my analysis to date, it appears that HQD did not provide enough significant digits in its responses to get a perfect match.

[4] This, of course, is a very reasonable assumption. There is no credible way to determine how or why, for a particular class, the post-heritage load is somehow different in characteristics from the heritage load. Even if individual customers were assigned a specific hourly entitlement to the heritage pool, it is likely that some customers would not use their full allotment, and the shortfall would need to be allocated to other customers.

Factor method to these parameters using the heritage pool costs. As shown in Exhibit RDK-3, that approach results in allocated costs that virtually match the costs specified in Décret 759-2005. Note, however, that the system load factor implied by this analysis is 67.7 percent, which is a little different than the heritage pool load factor specified in Décret 1277-2001 of 67.2 percent.[5]

In Exhibit RDK-4, I then allocated the remaining load, again using the HQD's Load Factor methodology. Consumption, peak demand and energy losses are all derived based on the difference between total 2006 levels (in Exhibit RDK-2) and heritage pool levels (Exhibit RDK-3). This approach result implies that the load factors and loss factors for each class are the same for both patrimonial and post-patrimonial loads. Again I applied the HQD methodology, which produced results that are very similar to those reported by HQD in this proceeding.

Exhibit RDK-5 provides a comparison of the global method (Exhibit RDK-2) with the pro rata allocation of the heritage and post-heritage pools (Exhibits RDK-3 and RDK-4). As shown, these two methods produce identical results under these specific conditions. In short, HQD's global Load Factor method is consistent with a method in which the heritage pool is allocated *pro rata*, loss and load factors are identical for heritage and post-heritage load, and the Load Factor methodology is applied to both heritage and post-heritage load.

In my evidence in R-3541-2004, I addressed the issue of allocating generation costs using a "rolled-in approach" versus using an "incremental" approach. If it is re-applied each year, using updated consumption forecasts, this *pro rata* assignment of the heritage pool is consistent with the "rolled-in" approach. Thus, for example, if a large pulp and paper mill closes and Rate L energy consumption declines, the freed-up heritage pool load in the subsequent year would be allocated to all customer classes, and would not be retained by Rate L customers. Under an incremental approach, Rate L would retain its historical entitlement to the heritage pool volume.[6]

In my evidence in R-3541-2004, I listed a number of reasons why the rolled-in method was superior to the incremental approach, as a matter of theoretical economics and regulatory policy. For completeness, my conclusions are summarized below:

Nevertheless, as we shall see, such an arbitrary differentiation of load shapes is a necessary aspect of the three-step process, given the constraints of Décret 1277-2001.

[5] Note that HQD's load factor method measures peak demand as the average of the top 300 hours of consumption. I am not aware of any other electric utility that uses such a large number of hours for allocating peak demand costs. As detailed in my evidence in R-3477-2001, this approach is not consistent with cost causation.

[6] In fact, in a true incremental methodology, each existing customer including the pulpmill would retain its entitlement to its share of the heritage pool, and therefore a closing mill would be able to sell that entitlement when the mill closes.

- All loads, "new" and "old," contribute equally to the need for post-heritage assets. Cost causation cannot distinguish between the decision by a homeowner to build a new residence and the decision by another homeowner not to put in insulation. Both of the loads that result from these decisions contribute to the need for post-heritage supply, and both decisions should face the same price signals.

- The incremental approach inequitably assigns entitlements of low-cost heritage assets to existing customers, violating the fundamental fairness principle that "equals are treated equally."

- The incremental approach may discourage innovation and competition, if new businesses with new loads face higher rates than existing businesses.

- The rolled-in approach is simpler.

- The incremental approach may result in rates that are less stable than the rolled-in approach.

- Significant regulatory precedent in Canada supports the use of the rolled-in approach.[7]

To those reasons, I add the following observations based on my review of HQD's filing in this proceeding:

- Incremental costing will be particularly complex for HQD, in light of the specific hourly nature of the heritage pool as defined in Décret 1277-2001.

- Incremental costing is not consistent with the information available to the government when it specified that historical cross-subsidies be retained. Therefore, adoption of the incremental cost approach should be deemed to be a "methodology change" for the purpose of measuring cross-subsidies. As such, the change will add significant complexity to cost allocation, but will have no material impact on electric rates -- it will simply change the target revenue-cost ratios for each class.

- Décret 759-2005 appears to be consistent with a rolled-in approach for 2006. The decree, however, is a little vague about what will happen in the future. The decree specifies that it applies for setting the rates as per 1 April 2006, but is silent about setting rates thereafter.

[7] Note that regulatory precedent can almost certainly also be found for the incremental approach, and, in general, I do not rely significantly on regulatory precedent for recommendations.

For all of those reasons, I recommend that HQD continue to use the "rolled-in" approach for assigning the heritage pool between the rate classes.

3. Task Force Alternatives

Pursuant to the Régie's decision D-2005-34 (relating to R-3541-2004), a task force evaluated four alternatives for applying post-patrimonial generation cost allocation. In its filing in this proceeding, HQD suggests that, if the global method is rejected, "Alternative A" be applied.

For the reasons explained above, any method that allocates post-patrimonial costs separately must necessarily begin with an allocation of the hourly heritage pool entitlement to each of the various rate classes. In the task force report, HQD presents its methodology for doing so. HQD then used that method for all of the alternatives studied by the task force, and it has presumably also applied that method to the updated 2006 forecast for this application. In the task force report, HQD then applies four different costing methodologies to the resultant class-specific post-patrimonial loads.

3.1 Allocation of Patrimonial and Post-Patrimonial Loads

Allocation of the heritage pool volumes can be performed on either an incremental or a rolled-in basis. If an incremental method is adopted, it will probably be necessary for HQD to perform this allocation only once, thereby establishing each class' permanent entitlement to the heritage pool. (If this approach is adopted, the task force report proposes to use 2006 as the base year, as it avoids certain strike-related disruptions in 2005 and because it anticipated Décret 759-2005.) In that way, each class retains its permanent entitlement to the heritage pool in each hour, based on its share of the 2006 consumption. In effect, the allocation in Décret 759-2005 remains in effect.

If a rolled-in approach is used (and HQD's global method is rejected), it will be necessary to allocate the hourly heritage pool entitlement to each class in each year. In effect, HQD would need to perform the calculations that it performed for 2006 in each year, to reflect the overall changes in each class' entitlement.

Thus, the Régie and the intervenors should scrutinize the HQD method under either circumstance. Of course, if the global method is adopted, it will not be necessary to allocate the hourly heritage pool entitlements.

Unfortunately, HQD has declined to provide the specific methodology it uses to make this allocation, either in algebraic or program format (though it has provided the data for the allocation itself). Based on my review thus far, it appears that HQD has made a valiant arithmetic effort to try to adhere to the constraints of Décret 1277-2001 in conjunction with actual 2006 load patterns. However, the resulting class load profile for post-heritage energy in 2006 does not represent a reasonable basis for allocating costs.

First, it must be recognized that the 2006 post-heritage pool load is not a traditional load for a Canadian electric utility, meaning that allocating costs using traditional methods would not be appropriate. For example,

- For its filing, HQD calculates that its post-patrimonial load will peak at 2 a.m. on September 4, 2006 (2797 MW). If the task force analysis is used, HQD calculates that the post-patrimonial load will peak at 3 a.m. on July 1, 2006 (2514 MW). The post-patrimonial load therefore peaks at a time when both regional demand and market prices for power are relatively low.[8]

- Of the top 100 hours of post-patrimonial demand in HQD's filing, only 20 are in the winter period (October to March), despite the fact that HQD has a sharp winter peak load shape.

- The post-patrimonial load for 2006 is significantly influenced by load growth, with off-season September post-patrimonial load being substantially higher than January post-patrimonial load. The seasonal pattern is therefore not representative of the longer-term post-patrimonial requirements, and it is therefore not reasonable to use a single non-representative year as a cost driver for allocating generation costs.

In short, even the overall post-heritage load has a very unusual load pattern. When viewed at the class level, the implications of HQD's method for allocating post-patrimonial load are even more problematic:

- As a percent of the peak demand for post-patrimonial load, the Rate L load factor is 26 percent, compared to its overall load factor of 84. percent.[9] If HQD's methodology were actually used for system planning, HQD would be procuring peaking capacity to serve these high load factor customers. Such an approach makes no sense in the real world.

- By way of contrast, the post-patrimonial load factor for residential customers, who exhibit much lower overall load factors, is 53 percent. It simply defies common sense

[8] Note also how the relatively small changes between the forecast used by the task force and the current filing result in noticeable shifts in peak periods, suggesting that the HQD method as applied to 2006 is sensitive to small changes in overall load forecast.

[9] Note that these load factors are relatively low because they are "non-coincident" peak loads for large industrial customers (which probably include interruptible loads).

that the load factor for temperature-sensitive rate classes is much higher than that for the high load factor industrial customers.

Thus, I conclude that for 2006, the allocation of post-patrimonial load does not represent a reasonable basis for allocating costs. I should add, however, that these problems appear to be due mostly to the fact that the post-heritage pool is a very small share of the overall load. It is therefore much more influenced by the change in overall system load patterns since Décret 1277-2001, and it is also more influenced by load growth during the year. If HQD's load continues to grow, these problems will gradually become less significant. My review of the 2014 analysis prepared by the task force suggests that the specific problems for 2006 will be less significant by then:

- For 2014, the peak demand for post-patrimonial load is at 4 p.m. on December 20, a date and time that is much more consistent with the overall nature of HQD's system as being sharply winter-peaking.

- Of the top 100 hours in 2014, 91 of them occur in the winter period.

- The post-patrimonial (1CP) load factor for the Rate L class is 99 percent; for the residential class, it is 50 percent. These values are much closer to the underlying nature of the loads than those implied for 2006.

Thus, it is probably not HQD's *methodology* for allocating the heritage pool that creates the anomalies in the 2006 load patterns described above. It is simply that in 2006, the post-heritage pool is so thin that it is not relevant for cost allocation. Thus, while I do not believe that this allocation is reasonable for the current year, it should not be a barrier to changing the methodology in the longer term.

3.2 Allocating Costs to Post-Patrimonial Load

If it is possible to develop reasonable class-specific load shapes for post-patrimonial load, the next problem becomes that of allocating generation costs to those loads. This, of course, looks very much like the problem faced by every other distribution utility, except that other utilities must address this question for their entire loads.

This is not an easy problem to solve, particularly for HQD. For integrated utilities, numerous different methods were developed for generation cost allocation, based on both embedded costs and marginal costs.[10] Most of these methods are substantially more complex

[10] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992.

than HQD's Load Factor method. However, these methods all presuppose that the analyst is aware of the underlying costs for the generation options. When the industry has been unbundled, this underlying cost information may not be available, making it impossible to use those cost allocation methods.

Further, not only are the underlying cost data not available, HQD treats the specifics of its post-patrimonial contracts as confidential. However, even if the details of the specific contracts were available to the intervenors, I recommend against using the billing determinants in those contracts for cost allocation purposes. While it would be very tempting to classify all costs billed to HQD on a demand basis as demand-related, and to classify all costs billed to HQD on an energy basis as energy-related (perhaps even by hour), that approach is simply incorrect. Those billing determinants reflect only the desires of the parties to the contracts (possibly relating to risk-sharing or desirable performance incentives), but they do not reflect cost causation.

A practical example demonstrates the problem. In Pennsylvania, several electric distribution utilities are putting their entire annual loads out for bid. The loads include all residential, commercial and industrial customers, for on-peak and off-peak, and for all seasons of the year. The terms of the contract will specify that the supplier will charge a constant dollar per MWh for all supply provided. If we were to use the contracts' billing determinants for cost allocation, all rate classes would then pay the same dollar per MWh charge for all load. However, while this might reflect cost causation for the very short term during which the contract is in place, over the long term, it is sending the wrong price signals. Clearly, the bid for any supplier will reflect the load patterns of all of the different customers, simply averaged together. If, for example, these utilities separately listed the high load factor industrial loads and the lower load factor residential loads, the bids for the two load would certainly diverge, reflecting the very different unit cost to serve each class.

What makes this problem more difficult for Hydro Québec is that customers do not have the option to shop for power. In Pennsylvania, if the distribution utility does not set the generation prices correctly, the customers who are being overcharged can simply opt out of utility service and purchase power on the market. In time, the rates for the remaining customers would necessarily move toward market levels. In Québec, however, there is no market mechanism to insure that prices are set reasonably.

Nevertheless, the theoretically best solution would be to allocate post-patrimonial generation costs to each rate class in a way that matches as closely as possible the costs that the class would incur if the power needed to serve that class were purchased separately on the market.[11] HQD could certainly attempt to allocate costs in this manner, relying on market prices

[11] In theory, due to the benefits of diversity, it would be less expensive to serve the combination of two different customer classes than to serve each one independently, if the classes peak at different times and the load shapes exhibit more diversity. In fully developed markets, these benefits may be exploited by suppliers, who can bid on loads for more than one class, or who may bid on diverse loads at different distribution utilities.

in New York or Ontario, and applying hourly prices to class-specific hourly loads. However, it has not done so, nor did it propose to do so as part of the task force effort.

Thus, we are faced with the problem of trying to evaluate whether any of the methods reviewed by the task force are consistent with either cost causation or market prices, without any detailed information about either costs or market prices. What is needed is a sound theoretical framework against which the proposed methods of HQD can be evaluated. To that end, I attempted to evaluate HQD's proposals relative to a simple yet powerful methodological framework.

That methodology can be summarized as follows. It can be mathematically demonstrated that, for an optimally configured generation system, the entire revenue requirement for that system can be recovered through the combination of a capacity charge based on the cost of a peaking unit (including reserve) and an energy charge based on the marginal energy cost for each hour of operation, applied to the total load in that hour.[12] That is, the demand costs are based on the fixed costs of a peaking unit, and the energy costs vary by time of use and reflect the marginal cost of the last unit dispatched on the system.

This methodology then implies that the cost allocation scheme for such a utility would be to allocate peaker-related capital costs to all rate classes based on their contribution to system peak demand, and to allocate energy costs on an hourly basis to each rate class based on the marginal cost of energy in that hour. For lack of a better name, I will refer to this as the Peaker/MC method. Note that, in this method, the marginal cost in each hour applies to all energy consumed in that hour, even the energy that was generated using lower marginal cost generating sources. Thus, for example, during system peak hours, all consumption would be allocated the high marginal cost of the peaking unit, even though base and intermediate load plants also operate during that hour.

This methodology elegantly recognizes the nature of cost tradeoffs in generation planning. A utility that evaluates how to serve its overall load shape recognizes that it can meet its load with a variety of different generation options. Baseload plants, generally nuclear or coal-fired units, exhibit relatively high capacity-related costs and low fuel costs. Peaking plants, such as gas-fired combustion turbine units, exhibit the reverse cost structure, with relatively low capital costs but very high fuel costs. In between lie other types of capacity, "intermediate" units, which exhibit capacity and energy costs that lie in between the baseload and peaker extremes. Baseload plants are less costly if they run for a relatively large number of hours over the course of the year; peaker units are economical when they are needed to serve only relatively short peak periods. With this cost structure, it is relatively easy to compute a "break-even" point for each unit relative to the next technology, in terms of the number of hours of operation needed to make the unit economically viable.

[12] See, for example, Optimal Pricing and Investment in Electricity Supply, An Essay in Welfare Economics, Turvey, Ralph, The MIT Press, 1968.

Thus, for example, a breakeven analysis between an intermediate load unit and baseload unit might indicate that, if the unit will operate more than 60 percent of the hours in the year (5256 hours), that the baseload unit will be less expensive. Under 60 percent, the intermediate load unit is less expensive. Using the breakeven capacity factors, it is then possible to derive the optimal amount of generating capacity of each type is optimal for this utility, given the utility's load duration curve.[13] A graphical depiction of this methodology is shown in Exhibit RDK-6.

This analysis shows the implications for generation cost allocation. The traditional approach for generation cost allocation is the "fixed-variable" method, in which all capacity costs are allocated based on peak demand and all variable costs are allocated based on annual energy. It is often argued that the fixed-variable method does not recognize that the utility incurs extra capacity costs for baseload units, in order to reduce its energy costs. These analysts then argue that the cost allocation study should re-classify some of the baseload fixed costs as "energy-related," and allocate them accordingly. Other analysts respond that the cost tradeoff works both ways. That is, while the utility incurs baseload capital costs to reduce fuel costs, the utility also incurs higher fuel costs from peaker units in an effort to reduce capacity costs.

The advantage of the Peaker/MC method is that it does indeed recognize both aspects of this cost tradeoff. By allocating only costs related to peaker units on a peak demand basis, the higher fixed costs of baseload units are not allocated on that basis, thereby recognizing the "capital for fuel" tradeoff. Low load factor customers thereby avoid the substantial allocation of baseload capacity costs associated with the fixed-variable method. Similarly, the Peaker/MC method allocates fuel costs based on the marginal costs in each hour, thereby assigning higher fuel costs to peak periods, in which the low load factor classes contribute disproportionately to the load. It therefore also recognizes the "fuel for capital" aspect of the generation planning framework.

Finally, the Peaker/MC method is much more consistent with the way that unregulated electricity markets now function. Energy prices vary on an hourly (or even five-minute) basis, often with significant differences between on-peak and off-peak prices. If the generation market is competitive, economic theory indicates that these energy costs reflect the marginal cost of the last unit dispatched. Moreover, the high peak period hourly prices apply to all of the load in the peak hours, much in the same way the Peaker/MC approach allocates costs.

Of course, in the real world, utilities are not optimally configured. Neither the Peaker/MC method nor the use of market prices will produce cost allocations that exactly total a distributor's actual revenue requirement. As with any marginal cost studies, some adjustment mechanism would be needed to adjust the allocated costs to equal the revenue requirement. Nevertheless, this conceptual framework is useful for evaluating HQD's four alternatives.

[13] The "load duration curve" is simply the hourly demands of the utility, ranked from highest hour to lowest hour. HQD uses load duration curves in its heritage pool allocation method.

Under Alternative A, it is my understanding that HQD takes the cost of each particular post-patrimonial generation option and allocates it to each hour of the year based on the kWh generated by that unit in each hour. For hours where the plant is not operating, no costs are assigned. HQD prepares this analysis for each post-patrimonial generating supplier, and computes a weighted average hourly cost for each hour. (At this stage, intervenors are permitted to see the results of the analysis.) HQD then multiplies each class' hourly load by the weighted average price, to derive the Alternative A allocated generation costs.

This approach is clearly inconsistent with the Peaker/MC method. Consider an off-peak period in which baseload capacity is the marginal unit being dispatched. The Peaker/MC method would set a price equal only to the marginal cost of the baseload unit (as would a market mechanism in a competitive market). However, in HQD's method, the capital-related costs for the baseload unit are being assigned to these off-peak hours, setting the cost for that hour higher than it should be. Similarly, for peak hours, HQD's method includes all the costs of baseload and intermediate load plants in the *weighted average* price for those hours, thereby understating the cost of peak hours relative to Peaker/MC or market methods. Finally, HQD's method fails to recognize capacity costs at all, as no costs are allocated on a peak demand method.

Therefore, relative to a theoretically accurate methodology, HQD's Alternative A inappropriately shifts costs *away* from those customers who contribute disproportionately to peak demands (the low load factor customers), and *toward* the customers who contribute disproportionately to off-peak demands (high load factor customers). This method is therefore not consistent with cost causation; it is not consistent with how markets function; and I recommend that it be rejected.

In Alternative B, HQD applies its traditional "Load Factor" method to the post-patrimonial load. But for the adjustment to exactly match the heritage pool loads defined in Décret 1277-2001, this approach would result in allocations identical to the global method. (HQD confirms this conclusion; see HQD-12, Document 1.1, page 10, lines 1 to 8.) As detailed in my evidence in R-3477-2001, this method is not consistent with cost causation, and, in fact, does not even recognize the specific nature of HQD's costs at all. For a variety of reasons, this method appears to be unfairly biased against high load factor classes relative to traditional cost allocation methods. Nevertheless, based on the analysis presented by HQD in this proceeding, it is less inequitable than Alternative A. While I do not recommend the adoption of this methodology for the long term, particularly if an incremental approach to generation cost allocation is adopted, it is the least unreasonable of the alternatives that are "on the table."

For the purposes of 2006, it is my understanding that Alternatives C and D are not "on the table," as HQD has either rejected them as unreasonable or believes that they require additional study. Nevertheless, I briefly compare them to the Peaker/MC and market methods below.

It is my understanding that, under Alternative C, post-patrimonial costs are split into demand and energy components based on contract terms. HQD indicates that this methodology is consistent with that proposed by FCEI in R-3541-2004. However, in that proceeding, Mr. Mikkelsen was careful to note:

> *"This classification would follow from the contract parameters for the post-heritage energy* ***(recognizing that it is likely that the cost characteristics of the generating units are likely to be reflected in the contract terms.)"*** (emphasis added)

As I explained earlier, however, contract terms often do not reflect the underlying cost characteristics.[14] Moreover, without any specific cost information from HQD, it is impossible to evaluate whether the billing determinants in these contracts reflect costs in any way at all, on either a demand-energy basis or on a time-of-use basis. For example, it is very possible that the energy charges in these contracts simply represent an average of the energy costs incurred by the supplier, whereas their actual costs may vary significantly between on- and off-peak periods. As in the case of my example from Pennsylvania, the contract terms may simply reflect the requirements of the buyer. Thus, absent a much more thorough understanding of the nature of the new supply contracts and the underlying cost data, I do not recommend that this method be adopted.

For Alternative D, as I understand it, HQD splits its post-patrimonial costs into "cycle-related" costs and other costs (which presumably reflects baseload unit costs). These separate costs are then used to derive hourly energy costs, similar in concept to that in Alternative A, but recognizing the different nature of low load factor and high load factor customers. HQD describes the method as arbitrary, and I have insufficient information regarding the details of this method to compare it to the Peaker/MC method. This approach appears to be an attempt to recognize the dual nature of the cost tradeoff, but without additional detail, I can suggest only that it not be adopted without additional study.

Thus, I conclude that while HQD's methodology for allocating the heritage pool to the rate classes on an hourly basis may be reasonable, it produces a load pattern for post-heritage consumption by rate class for 2006 that is nonsensical for cost allocation purposes. Further, HQD's proposed alternatives to the global approach, particularly Alternative A, are not consistent with either cost causation principles or with the results that a competitive market

[14] For example, in New Brunswick, where the distribution utility purchases generation services from two generating companies (all provincially owned) under power purchase agreements ("PPAs"), the PPA billing determinants are not related to either the underlying costs or to the established method for allocating generation costs.

would produce. As such, for the purposes of 2006, I do not disagree with HQD's basic proposal to continue to use the Load Factor method, applied on a global basis.

For the future, the issue of rolled-in versus incremental methods (for the purpose of allocating the heritage pool volumes) remains indeterminate. Décret 759-2005 is inconclusive regarding the future -- the government may issue a new decree every year, or the allocation for base year 2006 in Décret 759-2005 may continue beyond the year-ending March 31, 2007, or the responsibility for allocating heritage pool volumes may fall on the Régie. For the reasons I have presented, if this responsibility remains that of the Régie, I recommend continued use of the rolled-in method for allocating heritage pool assets. For 2006, however, that issue is essentially moot.

Nevertheless, in the future, if the post-patrimonial load for each rate class begins to take on a reasonable load shape for purposes of cost allocation, the Régie may wish to encourage HQD to continue to evaluate alternatives for allocating the post-patrimonial costs beyond the basic Load Factor method. If so, I encourage the Régie to recommend that HQD evaluate methods that reflect market prices, either those explicitly determined from neighboring jurisdictions or those derived from marginal cost analyses, as the most reasonable basis for allocating post-patrimonial costs.

4. Defining Base Cross-Subsidy Levels

Unlike most regulators, the Régie is constrained by legislation in its ability to move rates for individual classes in line with allocated costs. §52.1 of the Loi sur la Régie de l'energie (the Act) states in part:

> *"The Régie shall not modify the rates applicable to a class of consumers in order to alleviate the cross-subsidization of rates applicable to classes of consumers."*

In R-3492-2002 (Phase 1), HQD proposed that the metric used for defining the level of cross-subsidy should be the revenue-cost ratio for each rate class.[15] This measure is simply the ratio of the all of the revenues generated by each class to the costs allocated to the class. Classes

[15] In my evidence in R-3492-2002, I described some of the illogical implications of using the revenue-cost ratio as a measure of cross-subsidization. I retain my view that this metric is not consistent with sound regulatory economics principles, in that it will produce rate impacts upon individual rate classes that are not related to any changes in costs or usage patterns by the class. Nevertheless, it is my understanding that this is the metric approved by the Régie and I therefore rely on it in this evidence.

whose revenue-cost ratios exceed unity (100 percent) are providers of the cross-subsidy; classes whose revenue-cost ratios fall below unity are recipients of the cross-subsidy.[16]

For those years in which HQD's overall revenues are not equal to costs, the revenue-cost ratios for each class are "normalized" by multiplying the unadjusted class revenue-cost ratios by the overall ratio of HQD costs to HQD revenues. This adjustment insures that the average of the adjusted revenue-cost ratio for each class is unity.

Note also that, as a matter of basic arithmetic, it will likely be impossible for the Régie to exactly maintain revenue-cost ratios for each rate class. Because of the "mix effect" of different rate classes, exactly maintaining revenue-cost ratios for each class will almost certainly not produce overall revenues exactly equal to HQD's costs. Thus, some adjustments in class revenue-cost ratios will be necessary even if the goal is to maintain constant revenue-cost ratios.

Nevertheless, the basic concept of maintaining historical cross-subsidization levels, pursuant to the Act and consistent with the use of the revenue-cost ratio metric, is to establish a "base" level of revenue-cost ratios for each rate class, and then to set rates that hold class revenue-cost ratios at or near those base levels. The base period for establishing these cross-subsidy targets has been set at 2002.[17] On a weather-normalized basis, that base year implies target revenue-cost ratios as follows:

- Residential 80.7 percent
- Small Commercial: 128.1 percent
- Medium Commercial 130.1 percent
- Large Industrial 116.3 percent

However, as HQD recognizes, there are four generic reasons why revenue-cost ratios may change. First, HQD may change its cost allocation methodology. Second, the underlying mix of costs may change. For example, relatively large increases in generation costs relative to distribution costs will, all other factors being equal, cause revenue-cost ratios for the large industrial class to decline. That occurs because large industrial customers' overall allocated costs are disproportionately related to generation costs relative to the other rate classes. The

[16] As detailed in my evidence in R-3492-2002 (Phase 1), this definition of cross-subsidy is not consistent with theoretical economics. Nevertheless, it represents the common usage of the term in utility regulatory proceedings, and I accept this practical definition for the purposes of this evidence.

[17] The use of 2002 as a base year therefore includes, in the base, the significant increase in cross-subsidy from the large industrial class that occurred between the cross-subsidy level in place when the Act was passed and 2002.

third reason that can cause revenue-cost ratios to shift is changes in the cost causation determinants. For example, if the load factor for small commercial customers improves, all other factors being equal, that class' revenue-cost ratio will increase. Finally, revenue cost ratios can be affected by differential rate increases between the classes. If the residential class experiences a below-average rate increase, all other factors being equal, its revenue-cost ratio will decline.

For the purpose of establishing base cross-subsidy levels, it is necessary to "factor out" the effects of methodological changes. Therefore, it is reasonable to segregate the impacts on revenue-cost ratios into "methodological" impacts and "price/cost/load" effects (as HQD proposes). This procedure is necessary to avoid perverse incentives for establishing the original base. As recognized in the R-3492-2002 proceedings, if adjustments for methodological changes were not made, it would have been in the parties' interest in 2002 to advocate for unfavorable methodologies for their constituencies, and then reverse their positions in future proceedings. Such gamesmanship would seriously distort efforts to accurately and consistently allocate costs based on cost causation principles.

In this proceeding, HQD offers a proposal for making the "methodology change" adjustment to the target revenue-cost ratios. I describe HQD's proposal as a "rolling" method. In each year, HQD will compare the results of the cost allocation study for that specific year based on the approved methodology to the results based on the approved methodology from the previous year. The change in revenue-cost ratios for each class between these two simulations will be added to the base revenue-cost ratio target to establish the adjusted target.

For example, if the Board approves the methodology proposed by HQD in this proceeding for allocating costs, HQD will calculate the 2006 revenue-cost ratio using the 2006 methodology for the residential class as 81.6 percent. It will also simulate the 2006 study, using all 2006 costs and all 2006 cost causation factors, but using the *2005* methodology. This produces a revenue-cost ratio for residential customers of 81.4 percent. Therefore, the methodology change between those two scenarios is 0.2 percent, the amount that will be added to the previous year's target revenue-cost ratio.

While this approach has the advantage of simplicity, it contains a critical assumption that may not be appropriate, particularly for large cost items like generation and transmission. *HQD's methodology implicitly assumes that the total permanent impact of a methodological change on class revenue-cost ratios will all occur in the year in which the change is made.* While this assumption may not be unreasonable for some cost items, it quickly falls apart for others. If there are significant changes over time in the costs that are affected by the methodology change, it is wrong to assume that the cumulative impact of the methodology change occurs in only one year.

The most significant example for this issue is generation costs. Base cross-subsidization targets rely on the assumption that HQD's Load Factor methodology applied to all generation costs (both at the time of the passage of the Act and at the time the Régie set base cross-subsidization targets). Therefore HQD logically recognizes that any change to the allocation of generation costs should be recognized as a methodological change, rather than a price/cost/load change. (See HQD-14, Document 3, page 65, IR-10.)

However, consider the hypothetical scenario in which HQD does change to a very different methodology for allocating post-patrimonial costs. Under HQD's method, the impact of this methodological change will be determined in only one year, presumably a year in which post-patrimonial costs are small compared to heritage pool costs. The impact of the methodology change on revenue-cost ratios in that year will be relatively small. But going forward, as post-patrimonial energy costs grow, the cumulative impact of this methodological change will likely get larger each year. However, HQD's method will not be able to reflect the cumulative effect of the impact -- it will reflect only the impact of the methodology change in the first year. Thus, for a critical aspect of HQD's cost allocation methodology, its proposal for evaluating the impact of methodological changes will fail to recognize the full impact of those changes.[18]

Because it is not obvious whether there have been, or will be in the future, other types of costs that may be differentially affected by methodological changes from year to year, I recommend that the Régie direct HQD to continue to provide, as closely as possible, a cost allocation study for the current year based on the original 2002 base year methodology. While I recognize that this approach is administratively more difficult than HQD's proposal, it is necessary to ensure that the cumulative effect of methodological changes are properly accounted for.

One final note on this subject is in order. In 2006, HQD is showing a methodological adjustment that increases the target revenue-cost ratios for all classes. (See HQD-12, Document 3, page 13, Table 2.) This type of impact should not be typical -- it is much more logical that methodological changes result in target increases for some rate classes and decreases for others. The anomalous result in this case is due to the transfer of two customers out of Rate L and into the Special Contracts class. At present, it appears that this occurs because the customers who were transferred out were historically providing a below average cross-subsidy. With the change, the remaining Rate L customers thereby exhibit a higher revenue-cost ratio target. At present, I am not proposing any adjustment to the proposed methodology. Nevertheless, it is my understanding that AQCIE/CIFQ may pursue additional information regarding this impact on the remaining Rate L customers as the hearings progress, and some adjustment may be necessary.

[18] I recognize that HQD proposes to avoid this specific problem by continuing to use the global method of cost allocation for generation costs. Nevertheless, this particular problem demonstrates that HQD's proposal has a methodological flaw, that may apply to other costs.

5. Implications for Cost Shifts

In this proceeding, HQD proposes to apply an across-the-board increase to all rate classes. As a result of increases in post-patrimonial generation costs, this proposal will result in a revenue-cost ratio for large industrial customers that exhibits a 2.6 percent divergence from target.[19]

That is, under proposed rates, the large industrial class will provide a cross-subsidy equal to 14.4 percent of its allocated costs, rather than the 17.0 percent adjusted base target.[20] While the divergence from the other rate classes is relatively modest, the concern may arise that the mandatory cross-subsidy from large industrial customers is being permitted to decline.

The decline in the large industrial revenue-cost ratio is due primarily to the relatively large increase in post-patrimonial generation costs in 2006. While it is likely that the post-patrimonial share of generation costs will increase, HQD expects that the unit cost of post-patrimonial costs will decline in future years. Moreover, the relative increase in transmission and distribution costs over the longer term may tend to shift costs in the other direction. Recognizing these trends, AQCIE/CIFQ requested that I prepare an analysis of the implications of these trends for allocated costs over the longer term, assuming that across-the-board rate increases continue to be applied and that there are no major changes in cost causation parameters.

A draft version of that analysis is presented in Exhibit RDK-8. As shown in this analysis, the longer term trends generally reflect a convergence of revenue-cost ratios toward target levels, without the need for differentiated rate increases. Based on this analysis, and recognizing the rate stability and customer acceptability advantages of consistent across-the-board rate increases, HQD's proposal for this proceeding is not unreasonable.

[19] Note also that the decline in large industrial revenue cost ratios results from increases in both customer service and primary distribution system costs. (See Exhibit RDK-7 for a summary of the revenue and cost changes between 2005 and 2006, consistently using the 2005 cost allocation methodology.) Customer service cost increases (about $13 million) are related to a very large jump in overall HQD energy efficiency costs (Table 25B in the cost allocation study) plus the allocation of Rate BT costs. Distribution cost increases (about $9 million) are related to a combination of increases in HQD's overall primary distribution system costs, plus a noticeable decline in the NCP load factor for primary voltage Rate L customers. The distribution cost impact should not be passed on to Rate L transmission voltage customers, because they do not use the distribution system. While I do not address this rate design issue in this evidence, HQD may need to increase its voltage discount factors, particularly if these trends continue.

[20] As detailed above, this base target may require adjustments to reflect cumulative impacts of methodology changes and possibly for the outward transition of Rate L customers to the special contracts class. For the purposes of this section, I use HQD's proposal without adjustment.

6. Summary of Recommendations

Based on the foregoing analysis, my recommendations to the Régie in this matter (and at this writing) are as follows:

- HQD's proposal to use a rolled-in methodology for allocating the heritage pool volumes to the various rate classes for 2006 should be approved, because it is consistent with sound utility practice and with Décret 759-2005;
- HQD's proposal to allocate post-patrimonial costs using its traditional Load Factor method, as part of the overall global cost allocation methodology, is the best alternative available for 2006 and should be adopted;
- HQD's "Alternative A" for allocating post-patrimonial generating costs is not consistent with cost causation or market pricing principles, and it should not be adopted;
- If the Régie decides to pursue alternative methods for allocating post-heritage costs, it should direct HQD to evaluate methods that are consistent with the Peaker/MC theoretical framework or with market pricing principles;
- HQD's "rolling" methodology for adjusting cross-subsidy targets will not correctly measure the cumulative impacts of methodology changes, and should be replaced with the consistent use of the base-year methodology;
- HQD's proposal to implement across-the-board rate increases for the next several years is not inconsistent with the goal of maintaining revenue-cost ratios that are reasonably constant.

Evidence Prepared By:

Robert D. Knecht

18 November 2005

Date

EXHIBIT RDK-1

CURRICULUM VITAE AND EXPERT TESTIMONY SCHEDULE

ROBERT D. KNECHT

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. As Treasurer of IEc, 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 recent 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 the New Jersey Board of Public Utilities, Mr. Knecht audited the cost and rate unbundling, cost allocation and rate design aspects of the industry restructuring filing of an investor-owned electric utility.
- For the U.S. Department of Justice, Mr. Knecht participated in an evaluation of the economic damage claims of a large forest products concern, in a breach of contract lawsuit. Mr. Knecht's analysis included a review of the economic claims of the plaintiff, and an evaluation of settlement alternatives.
- For the Independent Power Producers Society of Alberta and the Senior Petroleum Producers Association, Mr. Knecht provides analysis and recommendations regarding electric industry restructuring strategies. Mr. Knecht also provided expert testimony with respect to industry restructuring, cost allocation, rate unbundling methodologies and rate design.
- For a major South American iron ore mining company, Mr. Knecht assembled and managed an international team of consultants to review and evaluate the company's strategic plan. Mr. Knecht oversaw the development of recommendations in the areas of markets, the resource base, development of the resource, processing operations and finance.

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.

Regulatory Economics

Mr. Knecht consults and provides expert testimony in the field of regulatory economics, focusing primarily on issues of industry restructuring, cost allocation and rate design. His clients include both utilities and the consumers, competitors, and regulators of public utilities. Representative assignments are listed below.

- For the Independent Power Producers Society of Alberta and the Senior Petroleum Producers Association, in a variety of regulatory proceedings, analysis and expert testimony regarding electric industry restructuring, market power mitigation, stranded cost determination, cost allocation, rate unbundling and tariff design for transmission and distribution utilities.
- Participation in an audit of the electric industry restructuring filing of the Atlantic City Electric Company, for the NJ Board of Public Utilities, evaluating the company's rate unbundling filing.
- For the Pennsylvania OSBA, evaluation of all aspects of the electric industry restructuring filings of Pennsylvania Power & Light and West Penn Power, focusing on impacts to customers in general and small businesses in particular.
- Analysis and expert testimony regarding system expansion and related customer contribution requirements of Centra Gas Manitoba, for a large industrial customer.
- For the Industrial Gas Users Association, analysis and expert testimony of the cost unbundling methods of Gaz Metropolitain.
- Analysis and expert testimony of cost allocation and rate design practices of the three major Ontario natural gas distribution utilities over several years, on behalf of the Ontario Energy Board staff and the Canadian Independent Gas Marketing Association.
- Cost allocation and rate design study and expert testimony for a small Ontario gas distribution utility.
- Analysis and litigation support regarding accounting, financial and capacity planning procedures of New Brunswick Power Corporation, and presentation of expert testimony on cost allocation and rate design, in a series of generic regulatory hearings, on behalf of a group of large industrial customers.
- Analysis of the cost allocation and rate design procedures of Consumers' Gas, Ltd., for the Canadian Independent Gas Marketing Association.
- Analysis of the cost allocation and rate design procedures of the three major Ontario natural gas utilities, for the staff of the Ontario Energy Board.
- Economic analysis and modeling of U.S. Postal Service proposals for allocation of peak load labor and equipment costs in 1987 and 1990, for the American Newspaper Publishers Association.
- Evaluation of the cost allocation and cost recovery procedures of a domestic telecommunications firm providing aircraft to ground data communications.
- Assessment of alternative methodologies for defining the electric rate classes of Maritime Electric Corporation, for the Prince Edward Island Ministry of Energy and Forestry.

Regulatory Economics (continued)

- Evaluation of the cost allocation and rate design procedures of the Nova Scotia Power Corporation, for a group of interruptible electricity consumers, and in a later proceeding, for a large industrial customer.
- Assessment of a proposed class-specific, risk-adjusted rate of return methodology for natural gas distribution utilities, for the staff of the Ontario Energy Board.
- Preparation of rebuttal analysis regarding management prudence in the construction of the River Bend Nuclear Generating Station, for Gulf States Utilities.

Economic Consulting

Mr. Knecht's practice includes the application of economics, finance and decision analysis theory to practical problems facing businesses, law firms and government. His assignments include industry and company planning, market forecasting, policy analysis and economic damage assessment. Representative assignments are listed below.

- For the US Department of Justice Civil Division, analysis of economic damages and participation in settlement negotiations associated with alleged breach of contract involving long-term timber supply contracts between the U.S. government and a large forest products company in Southeast Alaska.
- For the Electric Power Research Institute, analysis and adaptation of models that compute the economic costs of environmental externalities associated with electric generating stations.
- Economic, market and cost analysis for a team of international consultants preparing a restructuring study of the Polish steel industry, in conjunction with the World Bank.
- Economic and policy analysis for a U.S. engineering firm preparing a strategic planning study for the state-owned steel company in Venezuela.
- For the U.S. Environmental Protection Agency, evaluation of the impact of Clean Air Act amendments on major industrial facilities that are closing or are threatened with closure.
- Econometric analysis of world steel consumption patterns for a major international iron ore producer.
- Litigation support services relating to the business planning activities of a major West Coast construction and fabrication concern, in a fraudulent conveyance lawsuit.
- Review and analysis of direct and rebuttal evidence regarding economic damages to recreational activities, for the U.S. Department of Justice.
- Decision analysis and calculation of economic damages in an ERISA discrimination lawsuit, for a major domestic manufacturing company.
- Financial, econometric and strategic planning analyses for an international engineering firm, engaged in the preparation of a strategic plan for the steel industry of Nigeria.

Economic Consulting (continued)

- Economic analysis and econometric modeling of import behavior in the domestic carbon steel and wire rope markets, for hearings before the U.S. International Trade Commission.
- Financial analysis and damage assessment for a major domestic law firm, in support of a major anti-trust suit involving the potential construction of a coal slurry pipeline.
- Economic analysis of imports of iron ore pellets into the U.S., for a major international iron ore producer.
- Construction of an economic model of domestic metallurgical coke demand, for the U.S. Environmental Protection Agency.
- Econometric analysis of energy demand, by energy type, region and sector, and management of a sectoral supply-demand model of energy production and use.

Management Consulting

Mr. Knecht has also provided management consulting services to various basic industrial clients, focusing primarily on planning and decision-making. Representative assignments are listed below.

- Competitive dynamics analysis of the world iron ore industry and preparation of strategic recommendations for a major South American mining company.
- Task leader in a management audit of a New Jersey natural gas local distribution company.
- Development of a strategic plan and various business plans for a domestic specialized producer of carbon and alloy steel bars.
- Economic analysis and financial modeling of labor and employee benefits costs for a large integrated steel producer. Preparation of recommendations for labor relations and bargaining strategies.
- Analysis for the restructuring of the marketing function of a large domestic manufacturing company, including market segmentation analysis, field interviews and competitor comparisons.
- Market survey and analysis of the domestic hot finished seamless steel tube markets, for a U.S. producer.
- Strategic and business plan development for a major Polish steel producer.

December 2004

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
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
R-00050540	Pennsylvania Public Utility Commission	PPL Gas Utilties, Inc.	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.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
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	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
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.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
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
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

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
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.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
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.
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.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN UTILITY REGULATORY PROCEEDINGS

Docket #	Regulator	Utility	Date of Testimony	Client	Topic of Testimony
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, Province of 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
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	Prince Edward Island Department of Energy and Forestry	Customer classification by geographical area.
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 RDK-2
ALLOCATION OF PATRIMONIAL AND POST-PATRIMONIAL GENERATION COSTS
GLOBAL METHOD

Test Year 2006 -- Total Load

	Consumption at Meter (GWh)	Loss Factor	Energy Losses (GWh)	Consumption at Generator (GWh)	Peak Demand at Gen. (MW)	Load Factor at Generator	Calculated Unit Cost (cents/kWh)	Calculated Allocated Costs ($mm)	HQD Proposed Alloc. Costs	Percent Difference
D and DM	56,188	9.2%	5,169	61,357	14,801	47.3%	3.54	1,986.3	1,985.8	0.0%
DH	4	9.2%	0	4	1	45.7%	3.59	0.1	0.1	-23.9%
DT	2,597	9.2%	239	2,836	409	79.2%	2.96	76.8	76.8	0.0%
Residential	***58,789***	***9.2%***	***5,409***	***64,197***	***15,211***	***48.2%***	***3.51***	***2,063.2***	***2,062.7***	***0.0%***
G and fixed	12,862	9.2%	1,183	14,045	2,559	62.7%	3.18	409.5	409.4	0.0%
G9	1,108	8.9%	99	1,207	202	68.2%	3.09	34.2	34.2	0.0%
M	26,836	8.5%	2,281	29,117	4,247	78.3%	2.95	791.4	791.1	0.0%
Lighting	556	9.2%	51	607	84	82.5%	2.92	16.3	16.2	-0.3%
General Service	***41,362***	***8.7%***	***3,614***	***44,976***	***7,092***	***72.4%***	***3.03***	***1,251.4***	***1,250.9***	***0.0%***
L	47,049	5.5%	2,588	49,637	5,958	95.1%	2.72	1,279.3	1,280.1	0.1%
H	10	6.8%	1	11	2	61.0%	3.14	0.3	0.3	-4.6%
Special Contracts	26,656	5.2%	1,386	28,042	3,248	98.6%	2.69	716.3	716.5	0.0%
Large Industrial	***73,715***	***5.4%***	***3,974***	***77,689***	***9,208***	***96.3%***	***2.71***	***1,996.0***	***1,996.9***	***0.0%***
Total	**173,866**	**7.5%**	**12,997**	**186,863**	**31,511**	**67.7%**	**3.05**	**5,310.6**	**5,310.5**	**0.0%**
							Check ==>	***5,310.6***		

Notes:
1) Load Factor total is derived at the generator per HQD formula.
2) Loss Factor total is derived from consumption per HQD formula.
3) Total generation costs are based on HQD-12, Document 2, page 15, column 10.
4) Energy consumption, peak demands and loss factors derived from HQD-14, Document 3, Annexe 2.

EXHIBIT RDK-3
ALLOCATION OF HERITAGE GENERATION COSTS
PRO-RATA ASSIGNMENT; TRADITIONAL HQD LOAD FACTOR METHOD

Test Year 2006 -- Heritage Load

	Pro-Rated Consumption at Meter (GWh)	Loss Factor	Energy Losses (GWh)	Consumption at Generator (GWh)	Peak Demand at Gen. (MW)	Load Factor at Generator	Calculated Unit Cost (cents/kWh)	Calculated Allocated Costs ($mm)	Allocated Costs per Decree 759	Percent Difference
D and DM	53,775	9.2%	4,947	58,723	14,165	47.3%	3.20	1,721.8	1,722.0	0.0%
DH	4	9.2%	0	4	1	45.7%	3.25	0.1	0.1	-18.4%
DT	2,485	9.2%	229	2,714	391	79.2%	2.68	66.6	66.6	0.0%
Residential	***56,264***	***9.2%***	***5,176***	***61,441***	***14,558***	***48.2%***	***3.18***	***1,788.5***	***1,788.7***	***0.0%***
G and fixed	12,310	9.2%	1,132	13,442	2,449	62.7%	2.88	355.0	355.0	0.0%
G9	1,060	8.9%	94	1,155	193	68.2%	2.80	29.7	29.6	-0.2%
M	25,684	8.5%	2,183	27,867	4,065	78.3%	2.67	686.0	686.1	0.0%
Lighting	532	9.2%	49	581	80	82.5%	2.65	14.1	14.1	0.1%
General Service	***39,586***	***8.7%***	***3,459***	***43,045***	***6,787***	***72.4%***	***2.74***	***1,084.8***	***1,084.8***	***0.0%***
L	45,029	5.5%	2,477	47,505	5,702	95.1%	2.46	1,109.0	1,109.0	0.0%
H	10	6.8%	1	10	2	61.0%	2.85	0.3	0.2	-12.5%
Special Contracts	25,511	5.2%	1,327	26,838	3,109	98.6%	2.43	621.0	620.0	-0.2%
Large Industrial	***70,550***	***5.4%***	***3,804***	***74,354***	***8,813***	***96.3%***	***2.45***	***1,730.2***	***1,729.2***	***-0.1%***
Total	**166,400**	**7.5%**	**12,439**	**178,839**	**30,158**	**67.7%**	**2.77**	**4,603.5**	**4,602.7**	**0.0%**
							Check ==>	***4,603.5***		

Notes:
1) See Exhbit RDK-2 notes.
2) Energy levels are pro-rated from Exhibit RDK-2 to heritage pool.
3) Load factors and loss factors are set equal to Exhibit RDK-1

EXHIBIT RDK-4
ALLOCATION OF POST-HERITAGE GENERATION COSTS
DIFFERENCE FROM PRO RATA -- TRADITIONAL HQD LOAD FACTOR METHOD

Test Year 2006 -- Post-Heritage Load

	Consumption at Meter (GWh)	Loss Factor	Energy Losses (GWh)	Consumption at Generator (GWh)	Peak Demand at Gen. (MW)	Load Factor at Generator	Calculated Unit Cost (cents/kWh)	Calculated Allocated Costs ($mm)	Allocated Costs per HQD ($mm)	Percent Difference
D and DM	2,413	9.2%	222	2,635	636	47.3%	10.96	264.5	263.8	-0.2%
DH	0	9.2%	0	0	0	45.7%	11.12	0.0	0.1	302.1%
DT	112	9.2%	10	122	18	79.2%	9.17	10.2	10.2	-0.3%
Residential	***2,524***	***9.2%***	***232***	***2,757***	***653***	***48.2%***	***10.88***	***274.7***	***274.1***	***-0.2%***
G and fixed	552	9.2%	51	603	110	62.7%	9.87	54.5	54.4	-0.2%
G9	48	8.9%	4	52	9	68.2%	9.57	4.6	4.5	-1.2%
M	1,152	8.5%	98	1,250	182	78.3%	9.14	105.4	105.1	-0.3%
Lighting	24	9.2%	2	26	4	82.5%	9.07	2.2	2.2	1.7%
General Service	***1,776***	***8.7%***	***155***	***1,931***	***305***	***72.4%***	***9.38***	***166.6***	***166.2***	***-0.3%***
L	2,020	5.5%	111	2,131	256	95.1%	8.43	170.3	171.1	0.4%
H	0	6.8%	0	0	0	61.0%	9.75	0.0	0.1	116.5%
Special Contracts	1,145	5.2%	60	1,204	139	98.6%	8.33	95.4	95.8	0.4%
Large Industrial	***3,165***	***5.4%***	***171***	***3,336***	***395***	***96.3%***	***8.40***	***265.8***	***267.0***	***0.5%***
Total	**7,466**	**7.5%**	**558**	**8,024**	**1,353**	**67.7%**	**9.47**	**707.1**	**707.3**	**0.0%**
							Check ==>	***707.1***		

Notes:
1) See notes in Exhibit RDK-2 and RDK-3.
2) Energy levels are the difference between Exhibit RDK-2 and RDK-3.
3) Peak demands are the difference between Exhibit RDK-2 and RDK-3, making load factors for each class the same.
4) Losses are calculated as difference between Exhibit RDK-2 and RDK-3, making loss factors constant for each class.

EXHIBIT RDK-5
ALLOCATION OF HERITAGE AND POST-HERITAGE GENERATION COSTS
COMPARISON OF TRADITIONAL HQD METHODOLOGIES

	Heritage Volume Comparison			***HQD Proposed Allocation (c/kWh)***			***One-Step (cts/kWh)***		***Two-Step Traditional Allocation (c/kWh)***			
	Decree 759	*Pro-Rata*	*Difference*	*Patr.*	*Post-Patr.*	*Total*	*Total*	*Percent*	*Patr.*	*Post-Patr.*	*Total*	*Percent*
D and DM	53,782	53,775	0.0%	3.20	10.97	3.53	3.54	0.0%	3.20	10.96	3.54	0.0%
DH	3	4	16.9%	3.10	10.61	4.46	3.59	-19.6%	3.25	11.12	3.59	-19.6%
DT	2,486	2,485	0.0%	2.68	9.19	2.96	2.96	0.0%	2.68	9.17	2.96	0.0%
Residential	***56,271***	***56,264***	***0.0%***	***3.18***	***10.89***	***3.51***	***3.51***	***0.0%***	***3.18***	***10.88***	***3.51***	***0.0%***
G and fixed	12,312	12,310	0.0%	2.88	9.89	3.18	3.18	0.0%	2.88	9.87	3.18	0.0%
G9	1,061	1,060	-0.1%	2.79	9.57	3.08	3.09	0.3%	2.80	9.57	3.09	0.3%
M	25,687	25,684	0.0%	2.67	9.15	2.95	2.95	0.0%	2.67	9.14	2.95	0.0%
Lighting	532	532	0.0%	2.65	9.17	2.93	2.92	-0.3%	2.65	9.07	2.92	-0.3%
General Service	***39,592***	***39,586***	***0.0%***	***2.74***	***9.39***	***3.02***	***3.03***	***0.0%***	***2.74***	***9.38***	***3.03***	***0.0%***
L	45,021	45,029	0.0%	2.46	8.44	2.72	2.72	-0.1%	2.46	8.43	2.72	-0.1%
H	9	10	6.3%	2.65	9.06	3.29	3.14	-4.5%	2.85	9.75	3.14	-4.5%
Special Contracts	25,507	25,511	0.0%	2.43	8.34	2.69	2.69	0.1%	2.43	8.33	2.69	0.1%
Large Industrial	***70,537***	***70,550***	***0.0%***	***2.45***	***8.40***	***2.71***	***2.71***	***0.0%***	***2.45***	***8.40***	***2.71***	***0.0%***
Total	**166,400**	**166,400**	**0.0%**	**2.77**	**9.47**	**3.05**	**3.05**	**0.0%**	**2.77**	**9.47**	**3.05**	**0.0%**

Notes:
1) See Exhibits RDK-2, RDK-3, RDK-4.

Exhibit RDK-6
Optimal Generation Planning Example

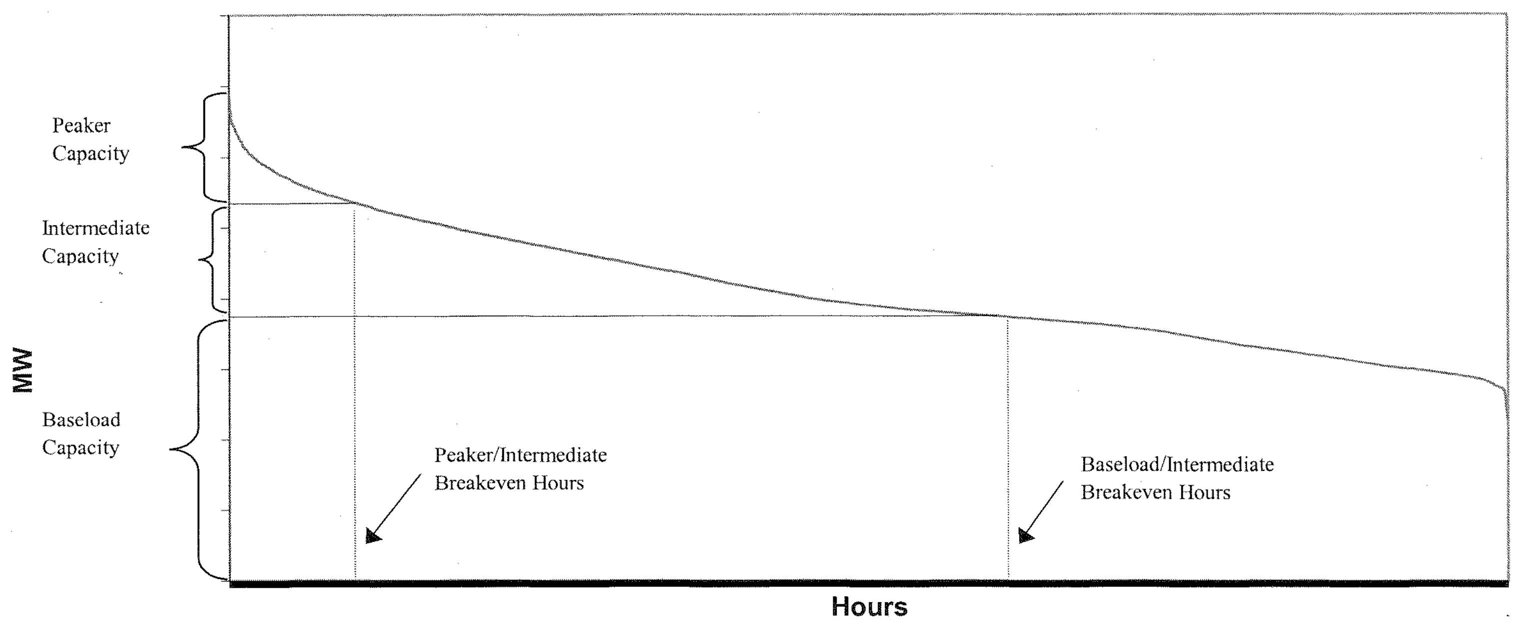

EXHIBIT RDK-7
ANALYSIS OF "METHODOLOGICAL" CHANGES IN RATE L/H IN 2006

RATE L Plus RATE H	*2005 with 2005 Method*	*2006 with 2005 Method*	*Percent*	*Per MWh Percent*	*Unit Increase ($/MWh)*
Sales Volume (GWh)	52,241	53,341	2.11%		
Generation Costs ($mm)	1,314.4	1,451.6	10.44%	8.2%	$ 2.05
Transmission Costs ($mm)	439.9	442.0	0.48%	-1.6%	$ (0.13)
Distribution Costs ($mm)	23.7	27.9	17.72%	15.3%	$ 0.07
Customer Service ($mm)	31.5	44.0	39.68%	36.8%	$ 0.22
Return ($mm)	23.0	28.0	21.74%	19.2%	$ 0.08
Total Costs ($mm)	1,832.5	1,993.5	8.79%	6.5%	$ 2.29
Unit Cost ($/MWh)	$ 35.08	$ 37.37	6.54%		
Revenue $mm	2,116.8	2,207.7	4.29%	2.1%	$ 0.87
Unit Revenue ($/MWh)	$ 40.52	$ 41.39	2.14%		
Adjustment Factor	100.4%	102.6%			
R/C Ratio	115.9%	113.6%			
Cost Mix					
Generation	71.7%	72.8%			
Transmission	24.0%	22.2%			
Distribution	1.3%	1.4%			
Customer Service	1.7%	2.2%			
Return	1.3%	1.4%			
Total	100.0%	100.0%			

Notes:

1) Energy efficiency increase ($23.5 mm overall) increases customer service by $6.5 mm
2) Rate BT allocation increases customer service by $6.2 mm ($27 mm overall)
3) Distribution cost increase due to combination of:
   Significant increase in primary system demand costs
   Decrease in NCP load factor for large industrial class (2.1% inc. load; 14.6% inc NCP)

EXHIBIT RDK-8
DRAFT: IMPLICATIONS OF LONG-TERM COST SHIFTS ON REVENUE-COST RATIOS

	2006	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
Residential									
Sales Volume (GWh)	58,788	59,200	59,614	60,031	60,451	60,875	61,301	61,730	62,162
Revenue	3,902.7	4,047.9	4,198.5	4,354.8	4,516.8	4,684.9	4,859.2	5,040.0	5,227.6
Generation Cost	2,062.7	2,096.8	2,145.9	2,195.8	2,235.5	2,281.2	2,333.9	2,377.0	2,426.2
Transmission Cost	1,187.5	1,542.0	1,361.9	1,378.9	1,401.8	1,396.1	1,379.1	1,379.6	1,394.1
Distribution/Service Cost	1,667.3	1,770.2	1,835.4	1,890.4	1,942.0	1,976.5	2,000.3	2,032.7	2,058.6
Total Cost	4,917.5	5,409.0	5,343.2	5,465.1	5,579.4	5,653.8	5,713.3	5,789.2	5,878.8
Adjustment Factor	102.8%	108.4%	103.2%	101.7%	100.0%	97.7%	95.2%	93.0%	91.0%
R/C Ratio	81.6%	81.1%	81.1%	81.0%	80.9%	80.9%	81.0%	80.9%	81.0%
Small Commercial									
Sales Volume (GWh)	14,526	14,531	14,808	14,953	15,081	15,143	15,336	15,364	15,490
Revenue	1,227.2	1,264.5	1,327.2	1,380.4	1,434.0	1,483.1	1,547.1	1,596.4	1,657.8
Generation Cost	459.8	464.3	480.9	493.4	503.1	511.9	526.8	533.7	545.4
Transmission Cost	213.8	275.8	246.5	250.3	254.8	253.1	251.4	250.2	253.1
Distribution/Service Cost	351.5	370.7	389.0	401.8	413.4	419.5	427.0	431.7	437.7
Total Cost	1,025.1	1,110.8	1,116.4	1,145.5	1,171.3	1,184.5	1,205.1	1,215.6	1,236.2
Adjustment Factor	102.8%	108.4%	103.2%	101.7%	100.0%	97.7%	95.2%	93.0%	91.0%
R/C Ratio	123.1%	123.4%	122.7%	122.5%	122.4%	122.3%	122.2%	122.1%	122.1%
Medium Commercial									
Sales Volume (GWh)	26,836	26,846	27,357	27,625	27,862	27,976	28,333	28,385	28,618
Revenue	1,734.6	1,787.3	1,876.0	1,951.2	2,026.9	2,096.3	2,186.7	2,256.4	2,343.2
Generation Cost	791.1	798.9	827.4	849.0	865.7	880.8	906.3	918.3	938.4
Transmission Cost	313.3	404.1	361.2	366.7	373.4	370.8	368.4	366.6	370.9
Distribution/Service Cost	267.2	281.8	295.7	305.4	314.2	318.9	324.6	328.1	332.7
Total Cost	1,371.6	1,484.9	1,484.3	1,521.1	1,553.3	1,570.5	1,599.3	1,613.0	1,642.1
Adjustment Factor	102.8%	108.4%	103.2%	101.7%	100.0%	97.7%	95.2%	93.0%	91.0%
R/C Ratio	130.1%	130.5%	130.5%	130.4%	130.4%	130.3%	130.2%	130.1%	129.9%
Large Industrial									
Sales Volume (GWh)	47,059	47,076	47,973	48,443	48,858	49,059	49,684	49,774	50,183
Revenue	1,966.7	2,026.4	2,127.0	2,212.3	2,298.2	2,376.8	2,479.3	2,558.4	2,656.8
Generation Cost	1,280.4	1,293.0	1,339.1	1,374.1	1,401.1	1,425.6	1,466.8	1,486.2	1,518.8
Transmission Cost	391.9	505.5	451.8	458.7	467.1	463.9	460.8	458.6	464.0
Distribution/Service Cost	96.1	101.4	106.4	109.8	113.0	114.7	116.7	118.0	119.7
Total Cost	1,768.4	1,899.9	1,897.3	1,942.7	1,981.2	2,004.2	2,044.4	2,062.9	2,102.5
Adjustment Factor	102.8%	108.4%	103.2%	101.7%	100.0%	97.7%	95.2%	93.0%	91.0%

EXHIBIT RDK-8
DRAFT: IMPLICATIONS OF LONG-TERM COST SHIFTS ON REVENUE-COST RATIOS

	2006	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*
R/C Ratio	114.4%	115.6%	115.7%	115.8%	116.0%	115.8%	115.4%	115.3%	115.1%
Special Contracts, BT, LD/LP									
Sales Volume (GWh)	27,147	27,147	27,147	27,147	27,147	27,147	27,147	27,147	27,147
Revenue	824.4	890.8	868.5	880.2	889.7	895.7	901.6	907.7	917.6
Generation Cost	600.4	606.1	616.0	625.9	632.8	641.2	651.5	658.9	667.9
Transmission Cost	206.4	266.1	233.4	234.7	236.9	234.3	229.9	228.4	229.2
Distribution/Service Cost	17.6	18.6	19.1	19.5	19.9	20.1	20.2	20.4	20.6
Total Cost	824.4	890.8	868.5	880.2	889.7	895.7	901.6	907.7	917.6
Total HQD		174,800	176,900	178,200	179,400	180,200	181,800	182,400	183,600
Total Sales Volume (GWh)	174,356	174,800	176,900	178,200	179,400	180,200	181,800	182,400	183,600
Patrimonial (GWh)	166,400	166,400	166,400	166,400	166,400	166,400	166,400	166,400	166,400
Post-Patrimonial (GWh)	7,956	8,400	10,500	11,800	13,000	13,800	15,400	16,000	17,200
Post-Patrimonial Cost ($/MWh)	$ 94.72	$ 77.80	$ 76.50	$ 78.90	$ 79.20	$ 81.90	$ 82.70	$ 85.00	$ 86.10
Revenue	9,655.6	10,016.9	10,397.3	10,778.8	11,165.6	11,536.9	11,973.9	12,358.9	12,802.9
Generation Cost	5,194.4	5,257.0	5,406.8	5,534.5	5,633.1	5,733.7	5,877.1	5,963.5	6,084.4
Transmission Cost	2,312.9	2,990.0	2,654.0	2,688.0	2,732.0	2,714.0	2,686.0	2,677.0	2,704.0
Distribution/Service Cost	2,399.7	2,536.5	2,643.1	2,723.2	2,796.8	2,839.3	2,878.9	2,914.7	2,950.6
Total Cost	9,907.0	10,783.5	10,703.8	10,945.8	11,161.9	11,287.0	11,442.0	11,555.2	11,739.0
Index for Dist'n Cost	2,544.0	2,689.0	2,802.0	2,887.0	2,965.0	3,010.0	3,052.0	3,090.0	3,128.00
Adjustment Factor	102.8%	108.4%	103.2%	101.7%	100.0%	97.7%	95.2%	93.0%	91.0%

Assumptions:
1) Special contracts volume remains constant.
2) Special Contracts, Rate BT and LD/LP excluded from revenue cost ratio adjustments
3) Residential load growth is set at 0.7 percent per year, per HQD-12 Document 1 page 14
4) Other class load growth is allocated proportionately from total (which is sourced from HQD-14 Document 1, page 30).
5) Generation cost f'cast assumes heritage cost of $4603.5 million, plus post-patr. cost applied to post-patr. volumes (HQD-14, Document 1, page 30)
6) Transmission cost forecast is based on HQD-14, Document 1, page 32.
7) Distribution and customer sevice cost forecast is based on HQD-14, Document 1, page 32, using index because costs could not be reconciled.
8) Class cost increase equals volume increase and unit cost increase, for each cost category.