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*BEFORE THE*  
**RÉGIE DE L'ÉNERGIE**

*IN THE MATTER OF:*  
**HYDRO QUÉBEC DISTRIBUTION**

**Avis de la Régie de l'énergie sur la distribution d'électricité  
aux grands consommateurs industriels**

**DOSSIER R-3563-2005**

*Prepared Evidence of:*

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Cambridge, Massachusetts

*On Behalf of:*

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

**Conseil de l'industrie forestière du Québec  
(CIFQ)**

*April 2005*

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## 1. Introduction and Summary of Conclusions

Industrial Economics, Incorporated (IEc) 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 implications of industrial load growth on customers of Hydro Québec Distribution ("HQD"). This evaluation is prepared in the context of the Régie's decisions in R-3541-2004 (the "Decision") regarding generation cost allocation and rate design. The aim of this evidence is to identify issues that the Régie may wish to consider as part of the implementation of the Decision. This report, however, presents only implications -- it does not offer any recommendations.

IEc's understanding of the key aspects of the Decision is as follows. Regarding cost allocation, the Decision directs HQD to establish a technical committee and to present a generation cost allocation methodology at the next general rate case. The Decision indicates that the heritage pool should be allocated amongst the rate classes in a way that reflects the heritage pool load shape as specified in the decree 1277-2001. In addition, the Decision indicates that the cost of post-patrimonial energy should be allocated amongst the rate classes that use the post-patrimonial energy.<sup>1</sup> Regarding rate design, the Decision implies that new customers need not be treated differently than existing customers, even if incremental costs are assigned only to incremental load.

By way of comparison, this methodology is substantially different than that employed in British Columbia by BC Hydro. Like Hydro Québec, BC Hydro has a portfolio of low-cost existing generating capacity, but load growth requires it to procure much higher-priced incremental capacity. In that jurisdiction, all loads are treated equally for their eligibility to share in the benefits of a low cost pool of energy. All generation costs, from both low-cost existing assets and higher-cost new assets, are pooled and allocated together on a rolled-in basis. In addition, BC Hydro is in the process of implementing rates for transmission voltage customers with two tiers, for 90 percent of baseload consumption and 10 percent of baseload consumption. The marginal 10 percent of baseload consumption is priced at the cost of new generation, and therefore provides economic incentives for energy efficiency improvements. The remaining 90 percent is priced in such a way as to allow the class to meet its overall revenue requirement as allocated on a rolled-in basis. Nevertheless, it is IEc's understanding that new loads will share equally in the eligibility for the benefits of the low-cost power.

In Québec, many details regarding the implementation of the Régie's recent Decision need to be resolved. This uncertainty makes an analysis of the implications of industrial load growth difficult. Nevertheless, this evidence develops quantitative and qualitative assessments of the implications of increasing industrial load under these rules. On the quantitative front, we

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<sup>1</sup> For the reasons detailed in the IEc evidence filed in R-3541-2004, all consuming customers contribute to the need for post-patrimonial energy. However, we interpret the Decision to base the allocation of post-patrimonial cost only on load that is not specifically recognized as patrimonial load.

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first prepare a “static” analysis of the rate implications of the Decision, on the assumption that the Decision has no impact on HQD’s overall load forecast. In effect, we compute what average class generation rates will be in 2014 under HQD’s current demand forecast, combined with reasonable estimates for load factors, loss rates, and post-patrimonial energy costs.

5           In addition to the quantitative analysis, we present our qualitative assessment of various implications of the Decision, in the context of potential growth in high-load factor industrial load. These assessments include a review of some of the cost allocation issues that the technical committee will need to consider, and the implications of rising and uncertain generation rates on Rate L load growth.

10           Based on our review, IEC concludes:

- 15           • The algorithm that is used by HQD for allocating generation costs to the various rate classes results in a unit generation cost for Rate L customers that is below system average, because the Rate L loss factor is below average and the Rate L load factor is above system average. However, with the cross-subsidy as mandated by the legislation, generation rates for Rate L customers already exceed both system average generation rates and residential generation rates.
- 20           • If HQD’s load forecast is not affected by the Decision, generation rates for Rate L customers will increase by a substantially larger percentage than other rate classes. Based on conservative assumptions, Rate L generation cost rates will increase by 37.5 percent over the next nine years, compared to increases of 14.8 percent for residential and 11.8 percent for general service customers. The impact of the cost rate increase will be compounded by legislative requirement to maintain historical cross-subsidization revenue-cost ratios. By 2014, if this scenario unfolds, generation rates including the cross-subsidy for Rate L will be nearly 20 percent above system-average.
- 25           • In practice, if industrial customers face rate increases of this magnitude, demand reductions in the form of partial or full plant closures are reasonably likely over the longer term. Any such reductions, however, are nearly impossible to predict, and will occur in large “lumpy” increments.
- 30           • Because the Decision indicates that the incremental costs associated with load growth should not be assigned only to new loads or new customers, all industrial customers’ rates will be subject to the expansion or plant closure decisions of other industrial customers. In addition, because the industrial customers are, under HQD’s forecast, most subject to the costs of post-patrimonial supplies, industrial customers will be most exposed to the volatility of those costs. This cost uncertainty will certainly dampen investment in new industrial facilities in Québec, and may also reduce the maintenance and modernization investments necessary to retain the competitiveness of existing facilities.
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- If plant shutdowns occur, or if the planned growth in industrial load does not materialize, it is likely that HQD will face stranded costs in the form of contractual obligations to purchase power that it does not need. It is unclear which customers will bear these costs, increasing the uncertainty regarding future electricity rates.

5 This evidence has been prepared by and under the direction of Mr. Robert D. Knecht of IEC. Mr. Knecht's *curriculum vitae* and a schedule of his expert testimony in regulatory proceedings are attached to this evidence as Exhibit IEC-5.

## 2. “Static” Analysis of Generation Rates

10 As noted above, the Régie’s Decision in R-3541-2004 indicates that the 166.4 TWh heritage pool should be allocated to the various rate classes in a manner that is consistent with the load pattern specified in Decree 1277-2001. Each rate class’ load in excess of that allocated to the heritage pool is then deemed to be the cause for HQD to incur the cost of new generating supplies. Because HQD’s load forecast anticipates higher load growth in the industrial rate categories than in the rate classes, this decision would tend to assign a disproportionate share of  
15 the costs of incremental capacity to the industrial customers. Therefore, AQCIE/CIFQ asked IEC to estimate the impact of implementing the Decision on each of the rate classes.

There are, of course, several possible ways to interpret the Decision, and there are many details yet to be worked out regarding the decision. Nevertheless, IEC prepared an analysis based on the information that is currently available. The key methodological steps and assumptions in  
20 this analysis are listed below, and the detailed calculations are presented in Exhibits IEC-1 through IEC-4:

1. *Allocate the heritage pool:* For the purpose of this analysis, IEC allocated the 166.4 TWh pool by interpolating between HQD’s forecast consumption in 2004 (from R-3492-2002) and 2005 (from R-3541-2004). This allocation implies an average generation load factor of 68.1 percent, which is slightly higher than the heritage pool load factor of 67.2 percent.<sup>2</sup> To the extent that the Régie eventually determines that the allocation should result in a load pattern that matches the load factor in Decree 1277-2001, the industrial class’ share of the heritage pool would decline. Thus, IEC’s analysis may understate the impact of growth in the industrial load on industrial rates.
2. *Allocate the heritage pool costs:* IEC allocates the heritage pool costs using the HQD generation cost algorithm. This method relies on each class’ load factor and energy loss factor, to derive a unit cost for each class relative to the overall heritage pool average rate. As detailed in R-3541-2004, the heritage pool average rate is 2.767 cents per kWh.

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<sup>2</sup> Note that the load factor, as used in HQD’s generation cost methodology, is based on the top 300 hours of demand over the year. On a single peak basis, the heritage pool load factor is 59.7 percent.

Although the HQD algorithm is a complicated algebraic formula, it is arithmetically equivalent to a traditional generation cost allocation approach.<sup>3</sup>

3. *Calculate the post-patrimonial load for each rate class:* IEC estimated the forecast load for each year from 2005 to 2014 for each rate class based on HQD's load forecasts presented in R-3550-2005. The post-patrimonial "incremental" load is then calculated by subtracting the allocated patrimonial load for each class. Table 1 below summarizes HQD's expected growth in load for the major rate classes:

	Heritage TWh	2014 TWh	Percent
D et DM	54.11	58.57	8%
G	12.17	13.15	8%
M	25.04	26.33	5%
L	50.41	61.78	23%
<b>Total</b>	<b>166.40</b>	<b>184.82</b>	<b>11%</b>
Totals due not add due to exclusion of special contracts and other smaller rate classes. See Exhibit IEC-1 for details.			

4. *Calculate the post-patrimonial average energy cost:* Although HQD is entering various contracts for the supply of post-patrimonial energy, IEC has very little specific information about the costs of those contracts. For this exercise, IEC estimated an average cost of incremental energy based on (a) HQD's evidence in R-3541-2004, (b) HQD's recent press releases regarding wind power costs, and (c) NYMEX futures prices for electric power. As shown in Exhibit IEC-4, the average long-run post-patrimonial energy cost used in this analysis rises from 7.5 cents per kWh currently to 8.1 cents per kWh in 2014. In IEC's view, this is a conservative estimate for future market power costs and probably does not fully reflect the impact of continuing high natural gas prices. Thus, IEC's analysis is conservative and industrial customers must certainly consider the risks that the increases will be substantially higher.
5. *Allocate the post-patrimonial energy cost to post-patrimonial load:* While many allocation methods can be contemplated for this calculation, IEC simply assumed that the HQD algorithm would be applied to the incremental loads and the incremental costs. Further, IEC assumed that the load factors and the loss factors for each rate class'

<sup>3</sup> HQD's formula is equivalent to *classifying* generation costs into energy and demand components based on the average system load factor, and then *allocating* the energy costs based on energy required at the generator for each class and *allocating* the demand costs based on the peak demands at the generator for each class. See IEC report in R-3477-2001, submitted April 2002.

incremental load would be identical to that of the rate class in 2005. Of course, because the industrial class has a disproportionately large share of the incremental load, the average load factor for the incremental load by 2014 is relatively high at 74 percent. As shown in Exhibit IEc-2 (page 10), this allocation produces a range of generation rates in 2014 from 7.4 to 9.5 cents per kWh, around the average of 8.1 cents per kWh.

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6. *Compute average generation rates:* IEC computes average generation rates for each class as a weighted average of the patrimonial and post-patrimonial generation rates.
7. *For comparison purposes, calculate the generation rates using a rolled-in approach.* The Régie rejected the rolled-in approach as in its Decision. This calculation is presented for comparison purposes in Exhibit IEc-3. The allocation methodology is based on the average system-wide generation cost, which is an average of the patrimonial and post-patrimonial energy costs. These costs are allocated using the HQD formula, again assuming that there is no change in class load factor or loss factor over time.
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A summary of the implications of this analysis for the major rate classes is shown in Table 2 below, and the details are shown in the attached Exhibit IEc-2:

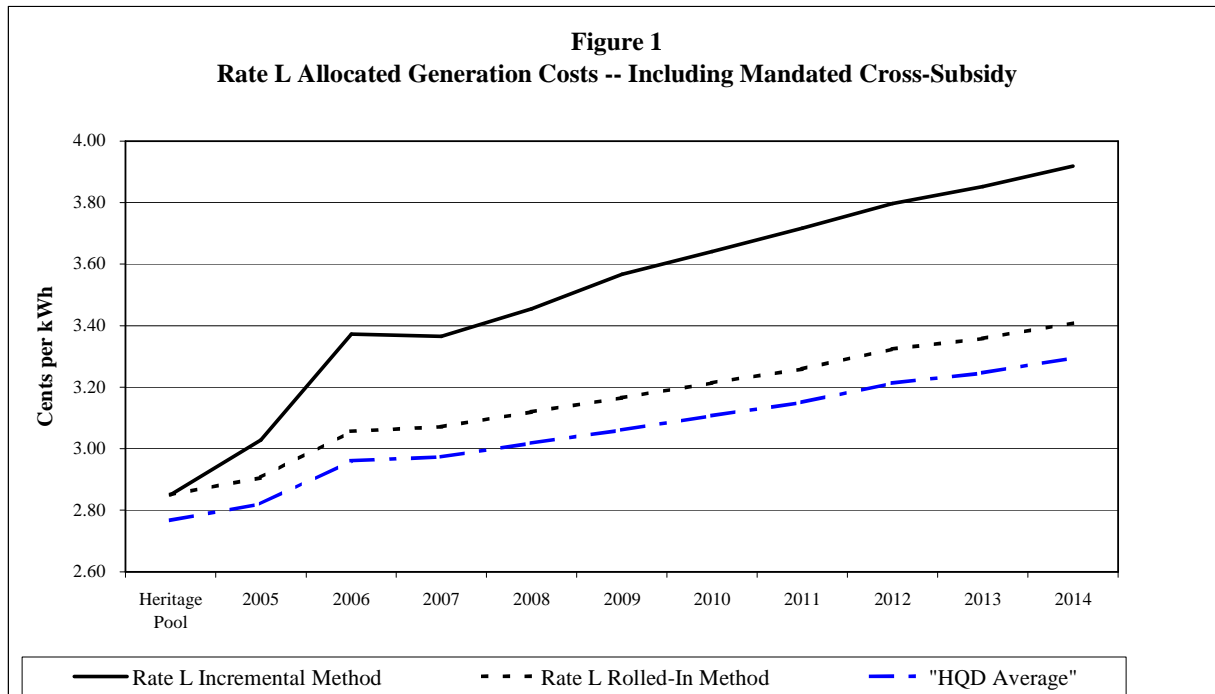
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<b>Table 2</b>				
<b>Generation Cost Rate Implications with</b>				
<b>Industrial Load Growth</b>				
<b>Replacement Power at 8.1 cents per kWh in 2014</b>				
	Heritage Pool (cents/kWh)	Incremental (cents/kWh)	2014 Avg. (cents/kWh)	2014 Avg. % Increase
D et DM	3.2	9.5	3.7	15%
G	2.9	8.6	3.3	15%
M	2.7	8.1	2.9	10%
L	2.5	7.5	3.4	38%
Total	2.8	8.1	3.3	19%
See Exhibit IEc-2, page 10.				

Note that Table 2 presents the cumulative effects of industrial load growth over the nine years. However, as detailed in Exhibit IEc-2, the year-by-year comparison demonstrates that the rate impact on Rate L customers is relatively severe in the near term. This result is caused by two factors. First, according to HQD's documents, it intends to start paying for high-priced wind power before some other sources of lower-cost energy become available. Second, HQD's load forecast shows relatively strong industrial load growth over the next few years, and less growth in the later years of the forecast.

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In graphical form, Figure 1 below shows the generation rate that Rate L customers can expect under incremental pricing and under rolled-in pricing, compared to the system average generation cost. Note that in this figure IEC has added the approximately 16 percent cross-subsidy that Rate L customers are legally obligated to pay to subsidize the residential class under the legislation. As shown in this chart, Rate L customers already pay above system average generation rates for heritage pool load, because of the effect of the mandated cross-subsidy. Under incremental cost allocation methodologies, by 2014, the premium above system average paid by Rate L customers will be approximately 20 percent.



Thus, if HQD's load forecast is not affected by the pricing policies in the Decision, large industrial customers will face average generation rate increases that are about double those of the other rate classes.

One significant cost allocation issue that arises from our review is the logic of matching HQD's post-patrimonial supply contracts with the rate classes whose load is growing. In particular, HQD is contracting for at least 990 MW of wind power, which is roughly one-third of the future capacity needs (see Exhibit IEC-4). Wind capacity can serve as a useful component of an overall portfolio of generation resources. However, the capacity factor for wind generators is quite low (HQD assumes 36 percent), and the cost is relatively high compared to the other generation options HQD has identified. If the costs of wind power were rolled into all rates, the impact of choosing this option would be relatively small. However, because the industrial class is forecast to be the major component of load growth, that class will face the higher costs and lower reliability of the wind resources. Moreover, because industrial demand tends to be

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relatively high load factor, it makes little sense to procure wind power resources in order to serve industrial load.

To the extent that HQD has chosen wind power as a resource for overall portfolio reasons, or for public policy reasons, growth in industrial load may result in industrial customers illogically bearing the higher costs of the wind resources.

### 3. Qualitative Considerations and Implications

The Decision implies that rates will be set on an average cost basis, even if the cost allocation assumption is that the customers whose load is increasing are the ones that cause the class to be assigned the higher post-patrimonial generation costs. This rate design philosophy will have implications for load growth in several ways, discussed in this section.

The key issue is that disproportionate industrial *load* growth will result in disproportionate industrial *price* growth. This higher growth in electricity prices may very well apply to all industrial customers, which will therefore affect the investment and operational behavior of all industrial customers. Moreover, because the magnitude of the rate impact will depend on the behavior of individual industrial customers, the industrial class will face fairly significant uncertainty about where future rates will go.

#### a. Industrial Price Elasticity of Demand

As detailed above, growth in industrial load in conjunction with the Decision will result in a significant rate increase for electric power to domestic industrial customers. An economist will conclude that this increase in price will necessarily result in a reduction in the demand for electricity, below the level that would occur in the absence of the price increase. A key consideration for the Régie, particularly when evaluating the rates for a state-owned utility, is the magnitude of this demand response.<sup>4</sup>

Economists address the question of the magnitude of this demand response to price with the concept of "the price elasticity of demand," or in its common short form, "price elasticity."

The price elasticity of demand is defined as the ratio of the percentage change in demand to the percentage change in price. For example, if HQD's electricity demand declines by 3 percent as a result of a price increase of 6 percent, the price elasticity is -0.5.

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<sup>4</sup> In the R-3492-2002 proceeding, IEC presented a report regarding the nature of the industrial demand for electric power, and how it reacts to jurisdictional rate increases. That description remains accurate, and this section is very similar to the IEC report in that proceeding. AQCIE/CIFQ requested that this evidence be placed on the record in these proceedings.

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Unfortunately, the concept of price elasticity is often over-simplified. A price increase for a particular good has two effects on customers. First, the economic attractiveness of substitute products is increased. For example, increasing the price for beef will increase the economic attractiveness of pork and chicken. The more similar the characteristics of the available substitute, the larger will be the substitution response. Second, the price increase will have an effect on consumer income. To the extent that the customer cannot substitute alternative products, the customer must continue to purchase the higher-priced good. However, the higher prices eat deeper into the customer's income, and he cannot afford to purchase as much of the good as he did before the price increase. Thus, the demand reaction to a price change has both a substitution effect and an income effect.<sup>5</sup>

In considering what the price elasticity of demand is for electricity consumption, it is necessary to understand the nature of the demand for electricity. Electricity is a nearly ubiquitous commodity in modern society, used in all sectors of the economy and for a wide variety of purposes. As such, the various different uses of electricity all have different demand patterns and price elasticities. However, we can reach a few generalizations about the nature of the demand for electric power:

- Electric power is not consumed directly. It must be used in some form of appliance or capital equipment to provide any useful service to the customer. Thus, to some extent, capital goods and electric power are what economists call "complementary" goods, in that they are consumed together.
- Over the longer term, however, capital can be a substitute for electric energy. If electric prices rise, consumers may, over time, replace their existing equipment with more energy efficient equipment. In addition, consumers may replace existing capital equipment with capital equipment that uses a lower cost fuel.
- Because of the need for capital, the near-term response to a change in electricity demand is relatively limited. For residential customers, the near term response is basically one related to the income constraint -- thermostats get turned down and heating load declines. (We also see some "substitution" in the form of more sweaters!) However, in the longer term, the price response is much greater as the capital stock turns over and capital is substituted for electric energy, or a change in capital increases the potential for fuel switching.
- For some uses, electricity has very limited substitution possibilities, particularly in the residential and small commercial sectors. Few (but not zero) substitutes are available for refrigeration, lighting, air conditioning, electric motor appliances, etc. Thus, demand for residential electricity for those uses tends to be relatively price inelastic.

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<sup>5</sup> Note that this is a price-related effect on the consumer income constraint -- it is different from the demand response to a change in income. Higher income generally leads to increased demand for goods, measured by a concept known as the income elasticity of demand. In most cases, demand has a positive income elasticity and a negative price elasticity.

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- The price elasticity of industrial demand for electricity tends to be higher than that for residential or commercial demand in both the short-term and the long-term, for a variety of reasons. As discussed in more detail below, these include the greater ability of industrial customers to substitute alternative fuels at locations facing a price increase, greater ability to move manufacturing output to locations not facing a price increase, and reductions in product output related to loss of business to competitors who do not face the price increases.
  - 10 • The breadth of the impact of a price change is a significant determinant of the price elasticity. A very broad price increase, such as a national tax on all forms of energy, will result in a much smaller percentage demand response than a narrow price increase, such as a provincial price increase in electric power only. The hypothetical tax on energy has a much lower elasticity because substitution possibilities are much smaller -- the price increase cannot be avoided by switching to alternative fuels and the price increase cannot be avoided by relocating business operations to other provinces. Thus, it is difficult to put a precise figure on the likely elasticity response to the increases that would result from near-term industrial load growth. Moreover, as noted above, any such response will be much greater in the longer term than the near term.

20 Demand for electric power in the industrial sector, particularly in relatively low electric cost locations such as Québec, has some additional characteristics that are important to recognize. These include:

- For the most part, industrial electricity consumption is associated with massive capital investment. Thus, future electricity consumption is directly related to (a) investment in new industrial facilities, and (b) re-investment in existing industrial facilities.
  - 25 • Because Québec has historically been a location with relatively low electric rates, a large share of industrial load is related to processes that require low-cost electric power. Therefore, from an industrial customer's perspective, it is nonsensical to compare HQD industrial rates with those in Boston, New York and Chicago. For similar reasons, electricity costs represent a fairly significant percentage of the operating costs of many of HQD's industrial customers.
  - 30 • The prices for industrial commodities produced by most of HQD's industrial customers are set on world markets -- HQD industrial customers cannot easily pass on electricity cost increases to their customers unless electric rates are rising by similar amounts everywhere.
  - 35 • In the short run, industrial facilities continue to operate if their short-term variable costs are lower than both (a) the market price for the commodity being produced, and (b) the short-term variable cost of an alternative production location. If an industrial plant is operating at low margin, a price increase could potentially cause the plant to close quickly. Moreover, over the longer term, industrial plants require capital
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investment that must also be recovered from operating margin. Increases in electric energy costs will reduce the margins earned by industrial companies, and will therefore also reduce the ability of these companies to recover future capital investment costs.

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- To continue in regular operation, industrial facilities require regular maintenance capital, as well as infrequent major upgrades or refurbishments. Facilities that do not receive regular capital investment are implicitly being phased-out by industrial companies. Thus, the long term level of industrial demand is determined significantly by the capital budgeting processes of industrial companies. In particular, many of these companies compare the relative attractiveness of numerous locations around the globe for the investment of their capital budgets.
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- Industrial firms consider many factors when evaluating capital budgeting alternatives. However, in IEC's experience, the important factors include the relative performance of various locations based on (a) historical profitability (or cash flow) of existing operations, (b) potential future profitability of operations, and (c) the security of the investment climate. Increasing electric rates, particularly resulting from a change in public policy, will have a deleterious effect on all of these factors.
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- A price increase to industrial customers will have a short-term effect and a long-term effect. The short-term effect will be related to near-term reductions in plant output due to the reduction in the plant's international competitiveness. In some circumstances, a price increase can lead to a plant being closed or mothballed. In the longer term, the price increase will reduce the actual and potential future profitability of the plant, which in some cases will lead to reduced maintenance capital investment and eventually plant closure. In addition, electricity price increases will reduce future investment in new plant and equipment.
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In summary, industrial customers are generally the most price elastic market served by electric utilities, particularly when faced with localized price increases. While it is difficult for an outside consultant to say that a price increase will result in any near term plant closures or significant reductions in load in the near term without intimate knowledge of the economics of a specific plant, a wide variety of economic and econometric analyses confirm that load reductions will take place.

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Any reductions in industrial load will likely be associated with unfavorable implications for overall Québec economic activity and employment, including both the direct and indirect (“multiplier”) effects. Other AQCIE/CIFQ witnesses address these general economic effects.

35      b. *Uncertainty*

In addition to the direct effects, the potential for industrial rate increases arising from industrial load growth has indirect effects as well. Because industrial electricity rates will

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essentially be determined by the rate of growth of electricity demand of a relatively small number of customers, there is significant uncertainty about where rates are headed. If the expected load growth does not materialize, electric rates will presumably not increase because the industrial class is not causing the need for new capacity. However, if load growth exceeds expectations, industrial electric rates will rise much faster.

For example, HQD forecasts industrial load growth at about 1.4 percent per year for the next decade. If, however, industrial load grows at 2.5 percent per year, the industrial generation rate will increase by some 62 percent, compared to the 38 percent that it will grow under HQD's forecast, and to the zero percent associated with no industrial load growth. Thus, industrial customers will face a wide range of possible future electric rates, making business planning for Québec operations more uncertain.

As a general rule, industrial investors much prefer certainty to higher risk. To the extent possible, many industrial corporations will engage in both physical and financial hedging strategies to reduce risk. In this case, however, because the risk is related to the behavior of other parties as well as regulatory risk, it cannot be hedged. As such, we believe that industrial corporations will make decisions based on some combination of base case and worst case scenarios. Because the worst case scenarios in Québec involve the potential of very large increases in rates, the uncertainty effect will tend to increase the elasticity of industrial electric demand.

*c. Lumpiness, and Stranded Costs*

The preceding discussion suggests that near-term load growth in the industrial sector, if it materializes, will result in significantly higher industrial electricity rates. These higher rates, and even the expectation of these higher rates, will lead over the longer-term to industrial demand reductions. As noted, however, it is impossible to predict how such demand reductions will occur. They may simply manifest themselves as less load growth than Hydro Québec currently anticipates. Or, load may grow in the near-term on the basis of decisions made in the past, to be followed by plant shutdowns in the future.

In either event, any such demand reductions are likely to be "lumpy." Large industrial facilities in Québec consume a great deal of power. By way of comparison, HQD's forecast industrial sector growth is roughly 1000 MW. An aluminum smelter in Québec can use on the order of 600 MW. A typical thermo-mechanical pulping operation in Québec can use about 100 MW. Thus, one or two major plant closures can have a significant impact on the future demand for capacity.

The risk, of course, is that plant closures will likely result in stranded costs for HQD. HQD is currently contracting for power based on the expectations built into its load forecast. If this load growth does not materialize, HQD will likely face substantial fixed costs associated

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with those contracts, for capacity that it does not need. While it is not clear at this stage who will bear these stranded costs, it is likely that it will be some or all of HQD's ratepayers.

#### 4. Summary

5 This report presents an overview of the major implications of increasing industrial load for all Rate L customers, in the framework of the Régie's decision in R-3541-2004. As detailed herein, the load growth in the industrial sector that is currently forecasted by HQD will lead to average industrial generation rates that substantially exceed system average over the next decade.

10 The expectation of this increase in rates, combined with substantial uncertainty regarding regulatory policy and the actions of other large customers, will discourage investment in large industrial facilities in Québec. Over the longer-term, this potential disinvestment will likely lead to reduced economic activity and the potential for large plan closures. However, it is impossible to predict whether or when any such closures will occur. If such shutdowns occur sooner rather than later, there is a reasonable chance that HQD will face stranded costs associated with purchasing incremental generating capacity that it does not need.

*Evidence Prepared By and Under the Direction of:*

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Robert D. Knecht

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Date

**EXHIBIT IEc-1**

**IMPACT OF RISING INDUSTRIAL LOAD ON ALLOCATED GENERATION COSTS**

**LOAD GROWTH AND ALLOCATION PARAMETERS**

**EXHIBIT IEc-2**

**IMPACT OF RISING INDUSTRIAL LOAD ON ALLOCATED GENERATION COSTS**

**YEAR-BY-YEAR INCREMENTAL GENERATION COST ALLOCATION**

**EXHIBIT IEc-3**

**IMPACT OF RISING INDUSTRIAL LOAD ON ALLOCATED GENERATION COSTS**

**YEAR-BY-YEAR ROLLED-IN COST ALLOCATION**

**EXHIBIT IEc-4**

**IMPACT OF RISING INDUSTRIAL LOAD ON ALLOCATED GENERATION COSTS**

**ESTIMATED COST OF POST-PATRIMONIAL ENERGY**

**EXHIBIT IEc-5**

***CURRICULUM VITAE* AND EXPERT TESTIMONY SCHEDULE**

**ROBERT D. KNECHT**