Newfoundland an Labrador
Board of Commissioners of Public Utilities

Newfoundland Power
2008 General Rate Application

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On Behalf of
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1 INTRODUCTION

Newfoundland Power ("NP") filed its 2008 General Rate Application ("2008 GRA") with the Board of Commissioners of Public Utilities ("Board" or "PUB") on May 10, 2007.

The Government of Newfoundland and Labrador appointed Thomas Johnson as the Consumer Advocate ("CA") to represent the interests of consumers in connection with the 2008 GRA. The CA has asked me as an economist who has specialized in the theory and practice of economic regulation for over 25 years to provide assistance to the Board by preparing evidence that addresses the following issues.[1]

1. NP's proposed changes in regulatory mechanisms used to mitigate its risk related to power purchase costs. NP is proposing to:
   - eliminate of the Purchased Power Unit Cost Variance Reserve Account;
   - introduce a Demand Management Incentive Account; and
   - introduce an Energy Supply Cost Variance component in the Rate Stabilization Clause.
2. The low level of productivity improvement expected in the test year relative to NP's recent productivity performance.
3. The regulatory treatment of Other Post Employment Benefits (OPEBs).
4. NP's proposals with respect to the disposition of its regulatory deferral accounts.

My evidence is divided into four additional sections. Section 2 deals with NP's proposed changes in regulatory instruments related to the Company's power purchase costs. Section 3 examines NP's productivity performance. Section 4 addresses the options available to NP for dealing with the treatment of OPEBs for regulatory purposes. Section 5 considers the options for disposing of the balances in NP's regulatory deferral accounts. My conclusions and recommendations on these issues appear at the end of each section.

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[1] My curriculum vitae appears as Appendix A. Also see www.era-inc.ca.

2 Proposed Changes to NP's Power Purchase Costs Risk Mitigation Mechanisms

NP's 2008 GRA includes three proposed changes to the regulatory instruments used to mitigate the Company's risk associated with variances from forecast in its power purchase costs.

- Discontinuance of the Purchased Power Unit Cost Variance Reserve ("PPUCVR" or "Unit Cost Reserve")[2]
- Introduction of a Demand Management Incentive Account[3]
- Inclusion of a Energy Supply Cost Variance component in the Rate Stabilization Clause[4]

The effect of these three proposals, taken together, is to transfer to customers all of the energy-related PPUCVR risk while continuing to maintain the existing division of demand-related risk between the Company and customers.

These changes appear to be inconsistent with the objectives of the Board as they were described in Order No. P.U. 44(2004), which is the order that approved both (i) the introduction of a demand and energy rate to be charged NP by Hydro and (ii) the reserve that was ultimately implemented as the PPUCVR.

This section is divided into three subsections. The first summarizes my understanding of the way in which the PPUCVR operates. The second subsection reviews my understanding of the purpose of the changes introduced by Order No. P.U. 44(2004). The third summarizes the combined effect of the three proposals and the fourth subsection presents my conclusions.

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[2] NP, 2008, GRA, Section A. Application, page 3. See item 13 (a).
[3] NP, 2008, GRA, Section A. Application, page 3. See item 13 (b).
[4] NP, 2008, GRA, Section A. Application, page 4. See item 16 (a). Also see Exhibit 12, page5.

2.1 PURCHASED POWER UNIT COST VARIANCE RESERVE

As NP's 2008 GRA evidence states "In Order No. P.U. 44 (2004), the Board approved the establishment of a reserve as part of its approval of a demand and energy wholesale rate."[5] In order to implement this decision, the Board approved in Order No. P.U. 35 (2005) "the definition of the Purchased Power Unit Cost Variance Reserve Account … for inclusion in Newfoundland Power's System of Accounts to be effective for 2005."[6] The approved methodology for this account was set out in Schedule "A" of the order.[7] Schedule "A" states:

> *The Purchased Power Unit Cost Variance will be determined annually in the following manner:*
>
> *1. A variance factor will be determined by calculating the per kilowatt-hour difference between (a) the forecast unit cost of purchased power per kilowatt-hour, and (b) the normalized actual unit cost of purchased power per kilowatt-hour.*
>
> *2. The variance factor so determined will be multiplied by the normalized actual energy purchases for the year, in kilowatt-hours, to determine the Purchased Power Unit Cost Variance.*

The unit costs of purchased power (forecast and normalized actual) are each calculated by dividing the relevant total cost of purchased power by the quantity of purchased power. The unit cost of purchased power is also referred to in NP's 2008 GRA evidence as the Average Supply Cost.[8] Variances in the Average Supply Cost will reflect:

a) the variance between the forecast and actual billing demand[9], and

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5 NP, 2008 GRA Evidence, page 40, lines 15-16. Also see footnote 126 at page 88.

6 Order No. P.U. 35(2005), page 3 lines 3-5.

7 Schedule "A" was updated by Order No. P.U. 38(2005) and Order No. 8(2007). These orders quantified the Reserve Deadband for 2006 and 2007 respectively "to reflect adjustments to the demand and energy rates from Newfoundland and Labrador Hydro during the three-year rate phase-in period approved by the Board in Order No. P.U. 44(2004)" (P.U. 35(2005) Schedule "A", p. 2). The calculation methodology for the PPUCVRA was not altered by these orders. Also see CA-NP-21, Attachment C.

8 See NP 2008 GRA Evidence, footnote 135 at page 91.

9 Billing Demand, as defined in Hydro's rate schedules, Order No. P. U. 8(2007), Schedule A.

"Billing Demand"

In the Months of January through March, billing demand shall be the greater of:

(a) the highest Native Load less the Generation Credit, beginning in the previous December and ending in the current Month; and

(b) the Minimum Billing Demand.

b) the variance between the forecast and normalized actual number of kilowatt-hours purchased in the year.

A variance between the forecast billing demand and the actual billing demand will have an impact on the Average Supply Cost provided that the percentage variance in the billing demand is not equal to the percentage variance in the kWhs of power purchased. For example,

- if actual billing demand and actual purchases both exceed their respective forecasts by 1%, the effective demand charge per kWh would be equal to the effective demand charge that is implicitly embedded in rates;
- if actual billing demand increases by 1% more than the change in actual purchases, the effective demand charge per kWh would be 1% higher than the effective demand charge that is implicitly embedded in rates; and
- if actual billing demand decreases by 1% more than the change in actual purchases, the effective demand charge per kWh would be 1% lower than the effective demand charge that is implicitly embedded in rates.

The variance between the forecast and normalized actual number of kilowatt-hours purchased in the year will also have an impact on the Average Supply Cost because the Newfoundland and Labrador Energy Charge was restructured from a flat per-kWh charge to a block structure commencing in 2005.[10] The energy charge for 2007 was approved in Order No. P.U. 8(2007):

Energy Charge:

First 250,000,000 kilowatt-hours... @ 3.246 ¢ per kWh

In the Months of April through December, billing demand shall be the greater of:
(a) the Weather-Adjusted Native Load less the Generation Credit, plus the Weather Adjustment True-up; and
(b) the Minimum Billing Demand.
"Minimum Billing Demand" means ninety-nine percent (99%) of:
NP's test year Native Load less the Generation Credit.

[10] In Order No. P.U. 14(2004) the Board found that the implementation of a demand and energy rate for NP's holesale power purchases from Hydro was appropriate. Order No. P.U. 44(2004) approved the in concept reserve mechanism that was defined and implemented by Order P.U. 35(2005).

All excess kilowatt-hours.. @ 8.805 ¢ per kWh

Under this rate structure for the energy charge, the Marginal Energy Charge is significantly higher than the average energy charge. As a result, variances between the forecast and normalized actual number of kilowatt-hours purchased in the year will impact on both the Average Energy Charge and the Average Supply Cost.

Variances between the forecast and actual number of kWhs purchased will occur as a result of variances in:

- the number of customers, and
- the average use per customer.

The impact of variances due to variances in the number of customers and the average use per customer on the Average Energy Charge are identical. However, the net impact on the Company due to the difference between NP's Marginal Revenue and its Marginal Supply Cost of Sales is dependent on the class of customer experiencing the variance in number of customers and/or use per customer. Further, because General Service Rates 2.2, 2.3 and 2.4 have a declining block rate structure, increasing average use per customer in those classes will result in lower Average Revenue.

The Purchased Power Unit Cost Variance Reserve Account (PPUCVRA) approved by the Board included a Reserve Deadband. Hence, under the PPUCVRA methodology NP is at risk for variances from forecast up to 1% in the effective unit cost of power.

2.2 ORIGINS OF THE UNIT COST RESERVE

NP's Evidence discusses the Unit Cost Reserve at pages 88-89 of its evidence. The Company states in footnote 126 that:

> *Conceptually, through the use of unit costs, the reserve provides an incentive for the Company to influence demand conservation by its customers. Commencing in 2008, the Company is proposing that a substantially similar mechanism, called the Demand Management Incentive, replace the Unit Cost Reserve.*[11]

[11] NP 2008 GRA Evidence, footnote 126, page 88.

This characterization of the Unit Cost Reserve is repeated in the Company's response to CA-NP-20 (a).

> *Purchased Power Unit Cost Variance Reserve*
>
> *The Purchased Power Unit Cost Variance Reserve (the PPUCVR) provides an incentive to the Company to undertake reasonable initiatives to minimize peak demand. Providing an incentive to the utility to reduce peak demand on the system to potentially avoid future system expansion is understandable to customers. Savings that result from such initiatives are consistent with the provision of least cost service to customers.*

These statements appear to confuse the purpose of the Unit Cost Reserve with the purpose of the demand and energy rate that was introduced in 2005. It is the rate design for Hydro rates (i.e., the demand and energy rate) that creates an incentive for the Company to influence demand conservation by its customers. The Unit Cost Reserve actually reduces this incentive.

Interestingly, the description of the Unit Cost Reserve that is provided in NP's response to CA-NP-80 avoids this confusion.

> *The establishment of a reserve account was approved with the demand and energy wholesale rate in 2004. The Purchased Power Unit Cost Variance Reserve Account (the "Reserve Account") limits the impacts on the Company of variability in the forecast average cost of purchased power to one percent of test year demand costs. A one percent variance in billing demand will cause a variance in purchased power costs from that reflected in customer rates by approximately $520,000. This provides a meaningful demand management incentive to undertake reasonable initiatives to minimize peak demand.*

However, even this description appears to be incomplete in that it implies that the demand and energy wholesale rate and the Unit Cost Reserve were dealing exclusively with providing an incentive to reduce billing demand and not energy purchases.

The Board clearly addressed the incentive role of the demand and energy rate and the effect of the reserve which was to provide a transitional risk mitigation mechanism.

> *The intent of implementing a demand and energy rate to NP is to incorporate the proper price signals in the wholesale rates so that NP can respond appropriately to reduce its costs and ultimately the costs imposed on the system by increasing load growth. The Board is concerned that the effect of NP's proposals to mitigate revenue instability will actually mute the price signal that the demand rate is*

intended to send, and result in no incentive for NP to take any action to reduce its demand costs.[12]

The Board clearly viewed the Unit Cost Reserve as a temporary measure that would be used to mitigate NP's risk during a three-year transitional period (2005 to 2007). My reading of the order suggests that while the intent of the Board was that the PPUCVR should be eliminated after 2007, the purpose of eliminating it would be to eliminate this measure for mitigating NP's risk. The purpose of the transitional period was to give NP adequate time to adapt to the new rate structure and adopt measures within its control to manage the unit cost risk by introducing measures to moderate demand and energy purchases so that it would be able to profit more generously from the incentive. The point was addressed at page 13 of the order:

The Board is inclined to accept the positions of both Hydro and the Consumer Advocate that NP's proposals to limit its financial risk undermine the principal objective and rationale for the wholesale demand and energy rate. The Board acknowledges, however, that, at least for the period of the phase-in of the demand and energy rate, NP will be adjusting to this new rate structure. In light of this the Board is prepared to put in place a temporary reserve to be reevaluated in the context of the actual experience and results of the demand and energy rate structure. The reserve will be based on the proposal put forth by NP but will not be subject to automatic refund/recovery provisions as proposed by NP. Rather the Board will retain the discretion to determine the disposition of the reserve, taking into account NP's response to the demand and energy rate to reduce system peak.[13]

The Board's view that, subject to the relief provided during the transition period, NP should enjoy an incentive that reflects in full Hydro's marginal costs was also clearly stated in the Board order:

It is noted that, while NP believes the level of the initial demand charge proposed by Hydro is reasonable, NP states that there is insufficient justification to increase the demand charge in the wholesale rate to 100% of embedded demand costs by January 1, 2007. The Board does not agree with NP's position. The intent of the wholesale demand charge is to reflect a proper price signal in rates to NP of demand costs imposed on the system. This can only happen with a demand charge that is designed to recover 100% of embedded demand costs. The Board has accepted the proposal for a phase-in of the demand charge over a three-year period as described above. The Board acknowledges that the initial rate will only

[12] Order No. P.U. 44(2004), page 12.
[13] Order No. P.U. 44(2004), page 13.

> *recover 70% of these costs; however, once the phase-in to 100% recovery is completed, a proper price signal to NP will be in place. The Board will also have the benefit at that time of more information, in the form of a marginal cost study from Hydro and the benefit of two years experience, to satisfy itself that the $6.64 per kW per month continues to be a reasonable rate. The Board continues to be of the view that a proper price signal, reflecting 100% of the demand costs, is imperative as an incentive to NP and its customers to engage in load management practices.*[14]

The Board also made it clear that in its view the incentive that was introduced by the demand and energy rate structure constituted an opportunity for NP and should not be viewed as a factor that increased the Company's risk in a manner that justified a claim that customers should compensate NP for higher risk.

> *Hydro has agreed to put at risk a portion of its revenue to provide NP with an incentive to reduce its peak demand. If NP does not take advantage of this incentive, the additional risks are its own and the costs of such inaction should not be automatically passed to its customers.*[15]

In the years following the decision, the NP and Fortis Inc. Annual Reports characterize the Unit Cost Reserve as a risk mitigation mechanism rather than an incentive. For example, NP provided this summary of the issue in its 2005 Annual Report (page 31):

> ***Purchased Power Cost:*** *In December 2004, the PUB approved a revised wholesale rate for the electricity Hydro sells to the Company. The inclusion of peak billing demand as a determinant in the wholesale rate increases the risk of volatility of purchased power cost due to difficulty in forecasting peak billing demand.*
>
> *In conjunction with implementation of the new purchased power rate structure, the PUB approved a temporary reserve that will help limit the volatility in purchased power cost caused by variances between the actual unit cost of purchased power (per kWh) and the forecast unit cost of purchased power (per kWh) during the three-year phase-in period beginning in 2005. The purchased power unit cost reserve includes a pre-tax threshold amount for 2006 of +/-$714,000 and 2007 of +/-$840,000. A purchased power cost variance caused by a difference between the actual unit cost of purchased power (per kWh) and the forecast unit cost of purchased power (per kWh), in excess of the threshold amount, will be transferred to or from the reserve. The PUB has retained discretion as to disposition of the reserve, taking into account Newfoundland Power's response with respect to energy conservation and demand management.*[16]

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[14] Order No. P.U. 44(2004), page 9.
[15] Order No. P.U. 44(2004), page 13.
[16] NP, 2005 Annual Report, page 31. A similar discussion also appears in the 2006 Annual Report at page 41.

The role of the Unit Cost Reserve was similarly described in the Fortis Inc. Annual Report:

> *At Newfoundland Power, other regulatory liabilities include a PUB-approved purchased power unit cost variance reserve to limit variations in the cost of purchased power associated with the implementation of a demand and energy wholesale rate structure, effective January 1, 2005. Operation of the reserve limits purchased power cost volatility within a range approved by the PUB. The balance in reserve is reviewed by the PUB each year for disposition at their discretion. In the absence of rate regulation, fluctuations in purchased power cost would be recorded in earnings in the period in which they occurred.*[17]

It is also important to note that while the focus of Order No. P.U. 14(2004) was on the reduction of billing demand, which would result in the most significant avoided costs for Hydro in the future, it also recognized that the demand and energy rate would create an incentive for NP to seek to moderate both billing demand and energy purchased by its customers.

> *Looking ahead, the extent of the forecast variances (positive or negative) will depend to a large extent on the accuracy of NP's forecasting, and also on the manner in which NP responds to the wholesale demand and energy rate, including retail rate design innovations and load management programs.*[18]

Load management programs reduce both demand and energy purchases and therefore will, if pursued diligently and effectively, reduce both billing demand and the average supply cost by reducing purchases of higher cost, second tier, energy. In fact, it would seem to me that the rate design for Hydro's wholesale supply to NP approved in Order No. P.U. 14(2004) had two distinct and explicit incentives.

- The demand charge created an incentive to moderate billing demand
- The two-tier energy price, with the second tier reflecting the full marginal cost of energy created the correct price signal for encouraging efficient load management programs to reduce NP's total energy purchases on behalf of its customers.

[17] Fortis Inc, 2006 Annual Report, page 109.
[18] Order No. P.U. 44(2004), page 12.

If it were not for the implications of the Minimum Billing Demand feature of Hydro's wholesale rates for NP, which are discussed below, the implications of this review of the origins of the Unit Cost Reserve would be quite clear: the intended objectives of introducing the demand and energy price structure, along with the two-tier energy structure that establishes a marginal supply cost for NP that reflects Hydro's marginal cost of production would best be achieved by eliminating the transitional Unit Cost Reserve as was originally intended, without replacing it with either the Demand Management Incentive or the Energy Supply Cost Variance component in the Rate Stabilization Clause. Introducing these mechanisms has the effect of reducing NP's incentive to pursue programs that reduce billing demand (in the case of the Demand Management Incentive) and completely eliminate the incentive to reduce monthly energy use. These changes would therefore run directly against the direction established by Order No. P.U. 14(2004).

IMPLICATIONS OF THE MINIMUM BILLING DEMAND

One complicating factor is the continued existence of the Minimum Billing Demand which is defined to equal 99% of "NP's test year Native Load less the Generation Credit."[19] The Minimum Billing Demand was established for the benefit of Hydro.

> *Hydro has also proposed that a minimum billing demand of 99% be approved to provide NP with an incentive to enter into demand-related initiatives that could reduce demand below the test year forecast, and also to limit its risk as it moves out of a revenue stabilized environment. Both the Consumer Advocate and EES Consulting have recommended that the minimum billing demand be set at 98% as proposed by Hydro in its 2003 general rate application. The Board notes Hydro's position that the increase in the proposed minimum billing demand is as a result of the Board's order reducing Hydro's return on equity for rate setting purposes to 5.83% from the 9.75% proposed. Hydro states that because of this lower return on equity it should also carry a reduced risk. The Board notes that a minimum billing demand of 99% will result in potential savings to NP of approximately $588,000 in 2005, which will increase to approximately $840,000 per year in 2007 once the full demand charge is implemented. The realization of these savings by NP will depend*

[19] Order No. P.U. 8 (2007), Schedule A, page 2.

> *on the extent to which NP can reduce its demand levels through load conservation efforts.*[20]

This Minimum Billing Demand limits the potential reward to NP for reducing demand. NP's proposal to introduce a Demand Management Incentive with a 1% deadband would achieve symmetry in terms of the variance from forecast billing demand that would be to the Company's account. The asymmetry that would exist without the deadband provides a rationale for either:

1. Removing the Minimum Billing Demand in the Hydro rate structure,
2. Adopting the Demand Management Incentive as proposed by NP that has a 1% deadband that limits both the positive and negative variances that are not recoverable from customers to 1% of test year billing demand, or
3. Adopting a demand management incentive with a larger deadband (e.g., 2%) and adjusting the Minimum Billing demand at the next Hydro rate hearing so that it is consistent with the deadband (e.g., 98% of test year Billing Demand).

The first option would be more consistent with the Board's discussion of the issues in Order No. P.U. 44(2004), however, a change to Hydro's rates can only be addressed in the context of a Hydro rate proceeding during which the impact on Hydro would be a consideration. The problem with the second option is that it provides an incentive to avoid achieving improvements over test year billing demand of more than 1%, which would be contrary to the intent of Order No. P.U. 44(2004). The third option could be used to strengthen the incentive while ensuring that the risk for NP is symmetric.

Further in light of the following comment of the Board in Order No. P.U. 44(2004) it may be appropriate to revisit these issues at a later date when the Board has had an opportunity to review the Conservation and Demand Management Potential Study that NP is participating in with Hydro.

> *NP did not provide any evidence with respect to the specific actions that it may take with respect to load management for its customers, the associated costs of such*

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[20] Order No. P.U. 44(2004), page 10.

programs, and the expected outcomes in terms of potential load reduction. As a result the Board is not able to make a definite finding on whether the proposed demand rate along with the 99% billing demand is a meaningful incentive for NP to implement load management programs. However, the Board is satisfied that Hydro's proposed rate structure with a 99% billing demand is a reasonable starting point for implementation of a wholesale demand energy rate to NP. While both EES and the CA recommended that a 98% minimum billing demand be approved, the Board accepts Hydro's position that its proposal does result in risk of under recovery of its costs, depending on the success of NP's load management efforts.[21]

Of course, since there is no minimum energy charge, the same rationale does not exist to adopt NP's proposed Energy Supply Cost Variance component in the Rate Stabilization Clause.

2.3 THE OVERALL IMPACT OF NP'S PURCHASED POWER COST VARIANCE PROPOSALS

The Company's response to CA-NP-21 recognizes the linkage between the three proposed regulatory instruments dealing with variances in its purchased power costs.

III. Proposed Mechanism Changes

In this Application, Newfoundland Power is effectively proposing to modify the PPUCVR reserve mechanism to make it explicitly related to demand management. Further information, including a detailed description of the proposed Demand Management Incentive Account is provided in Volume 1, Customer Operations, pages 41 – 42, and Exhibit 4.

The Application also proposes a modification to the Rate Stabilization Clause to ensure recovery of prudently incurred energy supply costs related to the cost of production at Hydro's Holyrood Thermal Generating Station. Further information regarding the proposed change is provided in Volume 1, Finance, Section 4.5.1, pages 122 – 124 and Exhibit 12.

Taken individually, the impact of each of the three proposals is as follows.

- **Elimination of the Unit Cost Reserve:** Would remove the risk mitigation for variance in unit costs in excess of the deadband for both demand-related and normalized energy related variances in power purchases. This change would result in the most direct price signal and strongest incentive for NP to minimize both billing demand and energy purchases.

[21] Order No. P.U. 44(2004), page 11.

- **Introduction of the Demand Management Incentive**: Would reintroduce the Unit Cost Reserve incentive, but limit it to demand-related variances in unit cost that are within the 1% deadband. This change would result in the retention of the existing demand-related incentive, and convert it from a transitional measure into an on-going mitigation of the incentive.
- **Introduction of the Energy Supply Cost Variance component in the Rate Stabilization Clause:** Would eliminate NP's exposure to normalized energy-related unit cost variances. This change would eliminate the existing incentive for NP to pursue energy related demand management initiatives.[22]

2.4 CONCLUSIONS REGARDING NP'S POWER PURCHASE COSTS RISK MITIGATION MECHANISMS

The stated objective of Order No. P.U. 44(2004) to create a price signal that reflects Hydro's marginal costs is as relevant today as it was in 2004. In fact, the importance of maintaining an incentive for NP to pursue load management efforts has increased in recent years as oil prices have risen, driving up the marginal supply cost of power purchased from Hydro. Furthermore, increasing societal concerns about global warming add to the urgency of the incentives the Board had the foresight to introduce in 2004.

NP's proposals dilute the incentives that were established in 2004 at a time when it would be consistent with that decision to strengthen them. As the Board recognized in 2004, the incentives that it adopted at that time created an opportunity for NP to profit by taking positive action to reduce both peak demand and energy purchases. Consumers will also benefit both financially and environmentally from any success that NP has in limiting the requirement to generate power from Hydro's oil-fired Holyrood Thermal Generating Station.

[22] NP's response to CA-NP-217 indicates that NP's rationale for introducing the Energy Supply Cost Variance Account is to reduce the frequency of rate cases in the future since customer growth itself will be a driver of future revenue requirement shortfalls since there is a marginal contribution shortfall. Why avoiding rate cases justifies removing the load management incentive is not explained.

It is therefore recommended that the Board increase the incentive for NP to pursue load management programs by:

1. **replacing the PPUCVR with the proposed Demand Management Incentive;**

2. **rejecting NP's proposal to introduce Energy Supply Cost Variance component in the Rate Stabilization Clause; and**

3. **reconfirming the position of the Board in Order No. P.U. 44(2004), that "If NP does not take advantage of this incentive, the additional risks are its own and the costs of such inaction should not be automatically passed to its customers."**

In addition, in order to advance the evolution of the load management incentives introduced in Order No. P.U. 44(2004), it is recommended that the Board make it clear that it intends to continue on the path that it set out on at that time by:

4. **reviewing the existing Minimum Billing Demand in Hydro's Utility Rate with a view to reducing the minimum to something less than 99% of test year billing demand; and**

5. **adjusting the deadband in the Demand Management Incentive mechanism to correspond to any change in the Minimum Billing Demand in Hydro's Utility Rate.**

These latter recommendations will have to be implemented through an order in the next Hydro rates case.

3 NP'S ACTUAL AND FORECAST PRODUCTIVITY TREND

NP sets out its actual and forecast operating costs for the period 2002 to 2008 in Table 5 of its evidence.[23]

Table 5
Operating Costs
2002 to 2008F
($000s)

	2002	2003	2004	2005	2006	2007F	2008F
Operating Costs	*48,804*	*49,506*	*49,102*	*49,111*	*48,691*	*49,099*	*49,573*

Figure 1 below shows the percentage change in NP's operating cost per customer in both current and constant dollars.[24] During the period 2003 through 2008 the only years in which NP's operating costs increased on a per customer basis was in 2003 and

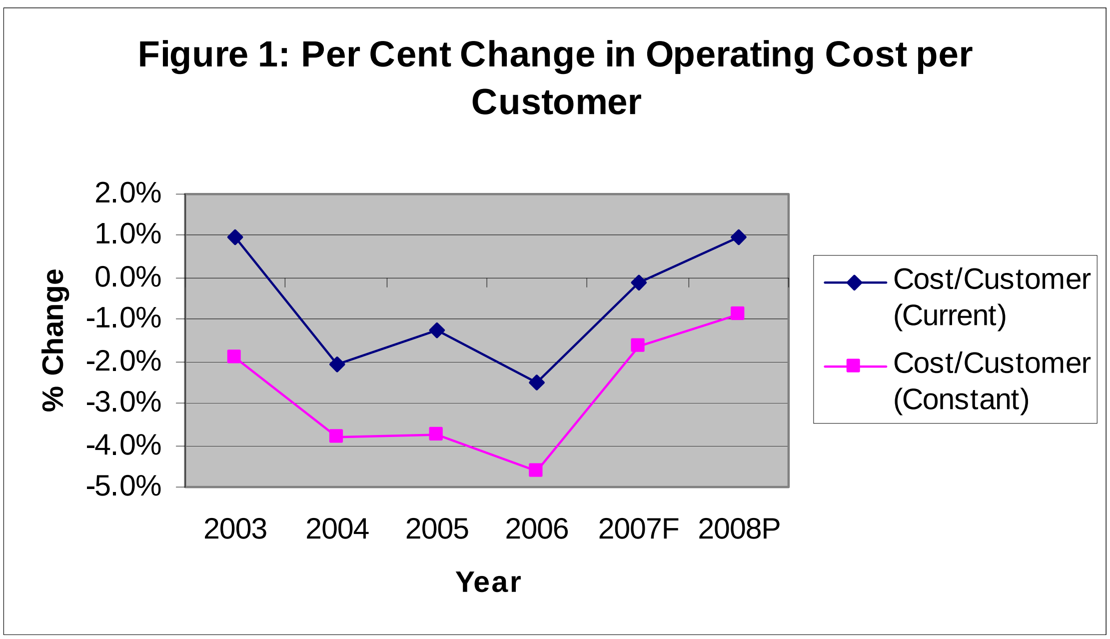

Figure 1: Per Cent Change in Operating Cost per Customer

2008. During the intervening years NP has been able to achieve productivity gains that have reduced operating costs in current dollars (i.e., not adjusted for inflation). Further, the productivity gains for the three years 2004 through 2006 kept the trend line in

[23] NP 2008 GRA Evidence, Table 5, page 13.
[24] Figure 1 was derived using the number of customers and consumer price index provided by NP in its response to CA-NP-27.

operating costs per customer at about -4% in constant dollars (i.e., adjusted for inflation).

NP has demonstrated its ability to achieve on-going productivity improvemetns. At the same time, it highlights the possibility that the opportunities to achieve productivity gains are not fully reflected in NP's operating cost forecast. This is a reasonable expectation given NP's approach to pursuing productivity initiatives as described in its response to CA-NP-61.

> *Q. Please provide copies of all reports and studies in the possession or control of NP pertaining to its staffing levels and/or staff productivity that has been generated from 2004 to the present time.*
>
> *A. There have been no formal studies, reviews or reports pertaining to staffing levels and/or staff productivity completed by or on behalf of Newfoundland Power from 2004 to present.*
>
> *Newfoundland Power assesses opportunities for organizational change or restructuring as opportunities arise and synergies are identified. Restructuring opportunities since 2004 have been provided through early retirement programs, re-assignment of responsibilities, and staff re-deployment. Formal studies have not been part of this process.*

This response suggests that productivity initiatives at NP are not part of a systematic long term planning process. The implication is that at NP, as in most organizations, productivity gains are achieved when management focuses its efforts on finding savings as a means of improving shareholder returns. It raises the question of whether at the time of preparing the 2008 operating cost forecast for NP's application, it was simply too early to identify the full spectrum of opportunities to reduce operating costs.

Furthermore, it must be hoped that the significantly lower productivity anticipated for the 2008 test year, which is subject to a GRA, is not attributable to the fact that productivity gains included in the forecast would be captured in rates for the benefit of customers rather than be to the benefit of shareholders, as was the case in 2004 through 2007, which were non-GRA years. These questions arise because nothing on the record explains why the productivity gains that NP has achieved since its 2003 GRA cannot be repeated in the coming years. In fact, NP's discussions in its Annual Reports and

Quarterly Reports,[25] as well as in its 2008 GRA Application would appear to be more suggestive that it pursues productivity opportunities on a consistent and on-going basis.

3.1 CONCLUSIONS REGARDING NP'S PRODUCTIVITY TREND

NP has an solid track record in terms of its ability to achieve sustained productivity improvements. In constant dollar terms, operating costs per customers were reduced by an average of about 4% in each of the three historic years since NP's last GRA (i.e., 2004, 2005 and 2006). Since NP's forecast for the 2008 test year does not reflect a continuation of this productivity trend, the Board could establish a productivity target for 2008 that recognizes NP's proven ability to make continuous productivity gains.

While it may be unduly onerous to expect NP to maintain productivity performance that is consistent with the 2004 to 2006 period permanently, it may not be unreasonable to expect the company to maintain a level of operating cost in 2008 that is no higher than its 2007 expected operating costs. This target could be established by approving an operating budget for 2008 that is $474,000 below the operating cost budget as filed by NP. The $474,000 adjustment could be viewed as a global productivity target, which would leave it to NP to determine how best to achieve this productivity gain. The financial consequences of adopting this target are shown in the responses to CA-NP-29 and CA-NP-30.

It is therefore recommended that the Board approve a level of 2008 operating costs for rate-setting purposes that is equal to the 2007 forecast of operating costs as shown on line 18 (Sub total) of Exhibit 1.

[25] For example, NP's discussions in the Productivity sections of its Quarterly Regulatory Reports for 02/05, 03/05, 04/05. 01/06, 02/06, 03/06, 04/06, and 01/07, which appear in the response to CA-NP-8, are suggestive of a process of continuous productivity improvement.

4 REGULATORY TREATMENT OF OTHER POST EMPLOYMENT BENEFITS

As NP notes in its evidence, "[i]n Order No. P.U. 19 (2003), the Board ordered the Company to file a report with its next general rate application which addresses the use of the accrual method as an alternative to the existing accounting treatment for OPEBs." In response to this direction, NP has filed at Volume 2, Tab 4, *A Report on Employee Future Benefits* ("OPEBs Report"). In addition, NP has filed under Volume 2, Tab 5 an Actuarial Valuation of OPEBs at December 31, 2006 which contains a report prepared by Mercer Human Resource Consulting entitled *Report on Non-Pension Post Retirement Benefit Expense for the Fiscal Year Ending December 31, 2006 Under CICA Section 3461* ("Mercer Report").

The OPEBs Report states:

> *Newfoundland Power effectively recognizes OPEBs costs on a cash basis whereby the annual expense is equal to the related retirement allowances and insurance premiums actually paid in the year (the "Cash Method").[1] Newfoundland Power recognizes pension costs using the accrual method (the "Accrual Method").*[26]

The OPEBs Report then outlines NP's proposal for transitioning from the Cash Method to the Accrual Method for regulatory (i.e., rate-setting) purposes commencing with the 2008 test year.

> *In this Application, Newfoundland Power proposes to:*
>
> *1. adopt the Accrual Method of accounting for OPEBs costs for regulatory purposes commencing in 2008;*
>
> *2. tax-effect all of its employee future benefits costs, represented by OPEBs expense and pension expense, for regulatory purposes commencing in 2008; and*
>
> *3. defer consideration of the Transitional Obligation of $34.1 million until its next general rate proceeding.*

[26] NP 2008 GRA Evidence, Volume 2, page 1.

NP's proposal is discussed at pages 7-11 of the Grant Thornton Report to the Board ("GT Report").[27] With respect to NP's proposal to adopt the accrual method of accounting for OPEBs costs for regulatory purposes in 2008, the GT Report states:

> *Based upon our review of this issue, we believe that the Company's proposal of using the accrual method for accounting for other future employee benefits is consistent with the Company's treatment of pension costs, both of which are provided similar treatment for financial reporting purposes under Canadian GAAP (CICA 3461). In addition, as noted above, this treatment is consistent with Newfoundland and Labrador Hydro.*[28]

While this summation confirms that the proposed treatment is consistent with Canadian GAAP, it does not address a number of regulatory considerations that are appropriate for the Board to consider in evaluating the merits of adopting the accrual method for OPEBs costs at this time. In particular, it is important for the Board to recognize that:

- it would not be inconsistent with generally accepted regulatory principles or practices for the Board to defer the adoption of the accrual method for accounting for OPEBs cost for regulatory purposes; hence the cash method remains acceptable for regulatory purposes; and
- it may not be in the public interest to adopt the accrual method for accounting for OPEBs costs for regulatory purposes given that the additional revenue that would be received by NP as a result of this change in accounting methodology provides no benefit to customers.

4.1 THE CASH METHOD IS ACCEPTABLE FOR REGULATORY PURPOSES

Order No. P.U. 19 (2003) makes it clear that in directing "NP to propose a plan at its next general rate application for moving towards the accrual method of accounting for employee future benefits as recommended by CICA" the Board was of the view that it was to be considered as a possible alternative, not as a preferred alternative.

[27] Grant Thornton, Board of Commissioners of Public Utilities Financial Consultants Report, Newfoundland Power Inc., 2008 General Rate Application, July 27, 2007.
[28] GT Report, page 8.

> *Grant Thornton also reviewed NP's proposal and concluded that NP's proposal of using the cash basis for accounting for other future employee benefits is acceptable. (Grant Thornton Report-NP 2003 GRA, pg. 8/1-2)*
>
> *In addressing this proposal the Board is cognizant of the fact that in Order No. P.U. 7 (2001-2002) it approved NLH's proposal to adopt the accrual method of accounting for other employee future benefits in accordance with GAAP. However as part of its proposal, NLH did not propose to recover from ratepayers the actuarial accrued balance of other employee future benefits of $21,200,000, proposing instead to write-off this balance against prior period earnings. In the case of NP the additional cost to ratepayers of moving to the accrual method is in the order of $4,100,000 in each of 2003 and 2004. To avoid rate impact on consumers the Board is prepared to accept NP's proposal to continue with using the cash basis for recognizing expenses for other employee future benefits.*
>
> *The Board is concerned about the potential liability for employee future benefits and is of the view that NP should explore using the accrual method of accounting for these benefits. The Board recognizes that there are significant transitional obligations associated with this change in accounting policy but once the transitional obligation has been met these costs should decrease. NP should continue to monitor its obligations with respect to employee future benefits and corresponding regulatory practice. The Board will direct NP to propose a plan at its next general rate application for moving towards the accrual method of accounting for employee future benefits as recommended by CICA. <u>The Board emphasizes such a plan should be presented to the Board as an alternative to the existing method and should address the transitional impact with a view to fulfilling NP's obligation to its employees while at the same time moderating its impact on rates.</u> The Board will then be in a position to consider this alternative accrual method and its specific impacts at the next hearing. [Emphasis added.]*

NP's evidence clearly demonstrates that both the accrual and cash methods of accounting for OPEBs costs are acceptable for regulatory purposes.

- Section 3461 of the CICA Handbook, which addresses the treatment of both defined benefit pension costs and OPEBs costs for financial reporting purposes, became effective for NP January 1, 2000.[29] Nevertheless, as NP explains:

  > *the CICA Handbook effectively permits rate-regulated entities such as Newfoundland Power to recognize costs under methods other than the Accrual Method. For this reason, Newfoundland Power's use of the Cash Method to recognize OPEBs costs is currently in compliance with GAAP.*

  There has been no change in accounting requirements since NP's last GRA that affects the on-going acceptability of the cash method.

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[29] OPEBs Report, op. cit. footnote 7 at page 3.

- NP surveyed 26 regulated Canadian utilities in 12 jurisdictions with respect to their OPEBs accounting policy for financial reporting and Regulatory purposes. The results for 24 of these are reported in Table 2 of the OPEBs Report.[30] One quarter of the utilities surveyed use the cash method.

- The evidence of NP's expert John Browne clearly supports the view that the Board must balance the competing regulatory objectives and principles in determining whether it is in the public interest to adopt the accrual method for OPEBs costs at this time.

> *It should be noted that Section 3461 establishes what is required under GAAP which sets out financial statement accounting and reporting requirements. However GAAP is designed for financial reporting purposes, not rate setting. Although it often provides useful guidance for regulators in setting rates, regulators can and do deviate from GAAP where they believe it is appropriate in setting just and reasonable rates.*
>
> *Although NP adopted accrual accounting for financial reporting purposes in accordance with GAAP, it continued to recognize its OPEB expense on a cash basis for regulatory purposes. The main reason for maintaining the cash basis was the impact on rates from a change to the accrual method.*
>
> *In a report prepared for NP's last general rate application ("GRA"), I wrote:*
>
>> From the perspective of the principle of intergenerational equity, the accrual method for recovering OPEB costs is preferable to the pay-as-you-go method proposed by NP. However, the NP proposal is a practical approach that recognizes the impact of dealing with the transition from one method to the other.
>
> *In its decision following that application, the Board accepted the continued use of the cash basis:*
>
>> *To avoid rate impact on consumers the Board is prepared to accept NP's proposal to continue with using the cash basis for recognizing expenses for other employee future benefits.*[31]

[30] Appendix A to the OPEBs Report lists 26 utilities. The total number of utilities is only 24 in Table 2.
[31] John T. Browne Consulting, Newfoundland Power, Regulatory Accounting Issues Related to 2007 (sic) Rate Application, May 4, 2007, page 4.

4.2 THE IMPACT ON CUSTOMERS OF ADOPTING THE ACCRUAL METHOD

NP evidence shows that adopting the accrual method at this time will increase its 2008 revenue requirement forecast by $9.4 million.[32] This revenue requirement increase consists of the $6.4 million increase in Net OPEBs Expense, the related tax effect of an additional $3.4 million, and a $0.4 million offset due to the rate base effects.

NP's proposal to "tax-effect all of its employee future benefits costs, represented by OPEBs expense and pension expense, for regulatory purposes commencing in 2008" mitigates this impact; however, the overall 2008 revenue requirement increase is still $7.2 million.[33] This $7.2 million increase represents 30% of the increase in the revenue requirement from rates that NP is seeking for the 2008 test year.[34] Put differently, the $7.2 million increase in the revenue requirement results in a rate increase of 1.6%.

This rate increase is being driven by an accounting change that will have no impact on the operating budget of NP and therefore, will not result in any operational benefit for customers.

The primary impact of this accounting change is that it will increase NP's cash flow. OPEBs differ from NP's defined benefit pension plan in that its pension plan is funded, while its OPEBS are not.[35] The cash flow resulting from using the accrual method for pension benefits is used to fund the pension plan; the cash flow resulting from using the accrual method for OPEBs will be retained by NP and used to reduce debt. This is why adopting the accrual method for OPEBs will result in a slightly lower return on rate base. NP will also directly benefit from this additional cash flow in that its financial ratios will be improved. Put simply, the company's cash flow will be improved, all other things being equal, making it a less risky investment for both debt and equity investors.

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[32] OPEBs Report, op.cit., Table 5, page 7.
[33] OPEBs Report, Table 9, page 12 and NP 2008 GRA Evidence, Table 32, page 81.
[34] As per NP 2008 GRA Evidence, Ex. 9, the change in revenue requirement from rates is $23.951 million.
[35] John Browne states at page 3 of his evidence: "Unlike pension plans, companies generally do not fund their OPEB plans. As a result, they have no interest income on plan assets and tend to have an accrued benefit liability. This liability represents the difference between what has been expensed and what has been paid out."

From the customers' perspective, it is not difficult to understand that the rates they pay need to generate the cash necessary to fund the company's pension plan. If pension cost were not recovered in rates on the same basis as the pension plan is funded the company would have to borrow money to meet its obligation to fund the pension plan. However, the same logic does not apply to OPEBs costs. It is less obvious that rates should reflect the accrual of OPEBs when there is no funded OPEB plan and, as a consequence, the additional cash that will be generated as a result of adopting the accrual approach will simply result in NP receiving more cash, while not making a corresponding payment.

This difference between the cash requirement for a funded pension plan and the cash requirement for unfunded OPEBs may justify adopting the same policy as the federal government employs in its income tax rules.

> *The Income Tax Act (Canada) requires that the computation of current income tax reflect the Cash Method of accounting for OPEBs, i.e. only retirement allowances and insurance premiums actually paid are tax deductible.*[36]

Using this analogy "only retirement allowances and insurance premiums actually paid" should be recognized for rate-setting purposes and recovered from customers.

Transitional Matters

NP is proposing to defer consideration of the OPEBs Transitional Obligation of $34.1 million. The intent is to transition to the accrual method in a "measured"[37] way. It is important to recognize, however, that once the Board makes a decision to adopt the accrual method of accounting for OPEBs for regulatory purposes, it will be extremely difficult to avoid maintaining consistency by recovering in rates this additional $34.1 million.

Of course, just as the proposed increase in OPEBs expense of $6.4 million in 2008 will have a revenue requirement impact of $9.4 million, so too will the impact of collecting an additional $34.1 million in rates for the Transitional Obligation result in a revenue

[36] OPEBs Report, footnote 1 at page 1. Also see NP 2008 GRA Evidence page 79, lines 2-8.
[37] OPEBs Report, page 2.

requirement impact closer to $48.5 million since it is an accrual of OPEBs expenses that are not tax deductible.[38] This amount, if it had been requested as a recovery in the 2008 test year would have required an additional rate increase of about 10.5%, although the proposal to tax-effect these costs should reduce the impact to something in the order of 8%. While the percentage increases needed to recover the transitional obligation in future years will be somewhat lower because the base revenue requirement will be higher, the recognition of the Transitional Obligation can be expected to drive rate increases that will be significant unless they are spread over several years.

The comments made above with respect to recognizing the increase in OPEBs expense as a result of adopting the accrual method apply equally to the recovery of the Transitional Obligation.

- The increase in rates reflects an accounting change and will have no operational benefits for customers.
- The additional cash is not required to fund a "OPEBs Plan". Instead it will simply represent an increased cash flow to NP that it can use to reduce its debt, pay dividends or dispose of as it wishes. It will not be set aside in a segregated account, comparable to a pension plan, to provide the funds to meet its future OPEBs obligations.

4.3 CONCLUSIONS REGARDING THE TREATMENT OF OPEBS

The evidence indicates that the case for recognizing OPEBs using the accrual method is no more compelling at this time than it was when the Board last addressed the issue and decided not to adopt the accrual method.[39] As is so often the case, the regulatory principles that need to be taken into account are in conflict. Concern about intergenerational equity indicates that the accrual method should be adopted at some

[38] The $48.5 million assume the effects will be proportional to the effect of the increase in net OPEBs expense as set out in Table 5 of the OPEBs Report.

[39] Order No. P.U. 19 (2003).

point in time. On the other hand, the impact on customers at a time when rates have been increasing much more quickly than inflation suggests caution.

The responses to CA-NP-17 and CA-NP-16 provide an interesting comparison of the rate increases that had been faced by NP's customers in the years prior to Order P.U. P.U. P.U. 19(2003) when this issue was last addressed and the increases experienced in the past few years.

Table 1 in the response to CA-NP-17 presents the rate increases during the period 1999 to 2003.

Table 1
Rate Changes: 1999 to 2003
(percent)

	1999	***2000***	***2001***	***2002***	***2003***	***Total***
Newfoundland Power	*1.2*	*0.7*	*-*	*-0.6*	*-0.2*	*1.1*
Newfoundland and Labrador Hydro	*-*	*-*	*-*	*3.7*	*-*	*3.7*
RSP/RSA/MTA	*1.1*	*-1.1*	*-0.2*	*-0.1*	*2.0*	*1.7*

Table 1 in the response to CA-NP-16 presents the actual and requested rate increases for the period 2002 to 2008.[40]

Table 1
Rate Changes: 2002 to 2008
(percent)

			July 1						
	2002	***2003***	***2004***	***2005***	***2006***	***2007***	***2007***	***2008***	***Total***
Newfoundland Power	*-0.6*	*-0.2*	*-*	*-0.5*	*-*	*-0.5*	*-*	*5.3*	*3.4*
Newfoundland and Labrador Hydro	*3.7*	*-*	*5.3*	*-*	*-*	*3.1*	*-*	*-*	*12.6*
RSP/RSA/MTA	*-0.1*	*2.0*	*4.5*	*5.2*	*4.8*	*-2.5*	*-2.9*	*-*	*11.1*

In light of the significant rate increases that have been approved in recent years, the case for avoiding another increase that is more than double the current inflation rate would appear to be much stronger than it was in 2003.

Certainly if the requested 5.3% rate increase where being driven by increases in necessary operating costs, the cost of service principle would make it necessary for the

[40] Also see NP 2008 GRS Evidence, Table 4, page 4.

Board to accept the increase as necessary to ensure that NP has a reasonable opportunity to earn its allowed return. However, the OPEBs issue is an accounting change that will have no impact on NP's ability to earn its allowed return. The primary impact of adopting the accrual method for recognizing OPEBs expenses for rate setting purposes is that NP's cash flow and financial ratios will improve.

On balance, it would seem appropriate at this time to give more weight to the rate impact of adopting the accrual method for recognizing OPEBs cost for regulatory purposes than to the principle of intergenerational equity.

It is therefore recommended that the Board reject NP's proposal to adopt the accrual method for recognizing OPEBs cost for regulatory purposes at this time.

5 REGULATORY DEFERRAL ACCOUNTS

The GT Report provides an excellent summary of NP's proposals with respect to the disposition of the various regulatory deferral accounts.[41] The discussion of NP's proposal to amortize two revenue deferral accounts (2005 Unbilled Revenue and Municipal Tax Liability) and two cost recovery deferral accounts (Depreciation and Replacement Energy) over a five-year period makes the following observation:

> *… the five year amortization of the regulatory deferrals will reduce pro forma revenue requirements by $5,108,000 in the 2008 test year and $1,150,000 from 2009 to 2012. Alternatively, a three year amortization period would reduce the revenue requirement by $5,875,000 in 2008 and $1,917,000 from 2009 to 2010 thus providing a quicker return to ratepayers.*

The GT report then notes without comment the three regulatory principles that the evidence of JT Browne focuses on in his evidence for the company: cost of service standard, intergenerational equity and rate stability,[42] although JT Browne also addresses the regulatory principle of financial integrity.

The difference between a three-year and a five-year amortization period does not appear to be dramatic in terms of any of these principles. If anything, the shorter time period may well be slightly preferable.

- **Cost of service standard:** NP will recover these costs under either amortization period.
- **Intergenerational equity:** These costs relate to past period; hence, recovering them in rates earlier will better respect intergeneration equity than recovering them later.
- **Rate stability:** The impact of the amortization period on rate stability depends on the rate increases that will be required absent the recoveries. Higher recoveries during periods of large rate increases will tend to improve rate stability.

[41] GT Report, page 12-14.
[42] NP 2008 GRA Evidence, Volume 3: Expert Evidence, Tab 2.

- **Financial integrity:** Financial integrity will not be significantly affected by the choice of amortization period, although a shorter amortization will slightly reduce NP's cash flow.

5.1 Conclusions Regarding Regulatory Deferral Accounts

The primary regulatory principle that is relevant to determining the amortization period for the balances in the regulatory deferral accounts is the impact the alternatives have on rate stability. Given the rather modest difference between the three-year and five-year amortization periods in terms of the percentage rate increase required by NP, the rate stability issue might best be considered in the context of the overall trend in rates.

Consistent with the discussion of the rate increases faced by NP's customers in recent years in the preceding section, it may be appropriate for the Board to utilize every lever at its disposal to limit the rate increase in the 2008 test year and the immediately following years.

It is therefore recommended that the Board approve a three-year amortization period for the balances in the regulatory deferral accounts identified above.

Appendix A

CURRICULUM VITAE

JOHN D. TODD

January 2007

elenchus
Research Associates

PERSONAL INFORMATION - JOHN D. TODD

Born: Oshawa, Ontario, March 20, 1950

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Education:	M.B.A.	University of Toronto, 1975 (Economics and Management Science)
	B.A.Sc.	University of Toronto, 1972 (Electrical Engineering)

Founder of Elenchus Research Associates Inc. (ERAI)

ERAI was established as a unit within ECS (see below) in 2003. In 2004, ERAI was spun off as an independent consulting firm. There are presently thirteen ERAI Consultants and Associates: Bruce Bacon, Bob Cappadocia, James Cochrane, Philippe Dunsky (Montreal), Fred Hassan, Bayu Kidane, Judy Kwik, Kim McKenzie, Stephen Motluk, Terry Rochefort (Calgary), John Todd, Cecil Vincent and John Wolnik. Web address: www.era-inc.ca

Founded the Canadian Energy Regulation Information Service (CERISE) in 2002

CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. (Staff are Keith Bryan, Alfredo Bertolotti, Rachel Chua and Diana Henderson.)
Web address: www.cerise.info.

Founded Econalysis Consulting Services, Inc., (ECS) in October, 1980

There are presently four ECS consultants: Bill Harper, Roger Higgin, Cristina Romanelli (Montreal), Brigid Rowan (Montreal), Tim Turner and James Wightman. Web address: www.econalysis.ca

Areas of Expertise:

John Todd has specialized in government regulation for 30 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest have included energy, telecommunications, housing and the financial industry. John has assisted counsel in approximately 200 regulatory proceedings and provided expert evidence in over 70 hearings. His clients include regulated companies, producers and generators, competitors, customers groups, regulators and government.

Prior Employment:

1978-80	Ontario Economic Council, Research Officer (Government Regulation)
1973-78	Research Assistant, Univ. of Toronto, Faculty of Management Studies
1972-73	Bell Canada, Western Area Engineering

Regulatory/Legal Proceedings

Provided expert evidence and/or assistance to the applicant or another participant for:

Before the Ontario Energy Board

2006 - Cost Allocation Review (EB-2005-0252)
- Transmission Revenue Requirement Adjustment Mechanism (EB-2005-0501)
- Second Generation Incentive Regulation Mechanism (EB-2006-0088-0089) (Capital Investment Factor)

2005 - Sub-metering Review (EB-2005-0317) (Evidence: Comments on Staff Discussion Paper on Sub-metering)
- Union Gas Rate Hearing (Evidence: Evaluation of Avoided Cost Methodology)

2004 - Enbridge Gas Distribution 2005 Rates (RP-2003-0203) (Evidence: Determining the Fair Rate of Return for a 15-Month Period) (Evidence: Stand-alone System Supply Costs)

2003 - Generic Proceeding on Electricity Distributor Boundary Changes (RP-2003-0044) (Evidence: The Benefits of Competition in the Electrical Distribution Sector)
- Union Gas Limited, 2004 Rates (RP-2003-0063) (Evidence: Monthly Demand Charge for Brighton Beach Power Station (with Paula Zarnett))

2002 - Union Gas Limited, 2003 Rates (RP-2002-0130/EB-2002-0363) (Evidence: Review of Union's Delivery Commitment Credit (with Joyce Poon))

2001 - Union Gas, Further Unbundling of Rates (RP-2000-0078) (Evidence: Regulatory Framework and Cost Responsibility)
- Hydro One Networks, Cost Allocation and Rate Design for RP-2000-0023 (Evidence: Cost Allocation Model (with Bruce Bacon))

1999 - Propose Electric Distribution Rate Handbook (Evidence: Comments on Staff Proposals)
- Standard Supply Service Code, (RP-1999-0040) (Evidence: Comments and Alternate Proposal)
- Enbridge, Year 2000 Rate Application (RP 1999-0001)
- Enbridge, Performance Based Regulation Application (EBRO 497-01)
- Enbridge, Ancillary Service Separation & Rental Wind Down (EBO 179-14/15)

1998 - Consumers Gas, 1999 Test Year Rates Application (EBRO 497)
- Union Gas, Separation of Ancillary Services (EBO 177-17)

1997 - Town of Aurora, Franchise Renewal (EBA 795)
- Union Gas, Customer Information System (EBO 177-15)
- Legislative Change (EBO 202)
- System Expansion Generic Hearing (EBO 188)
- Consumers Gas, 1998 Test Year Rates Application (EBRO 495)
- Ten Year Market Review Working Group
- Union Gas/Centra Gas Amalgamation Application

1996 - Union Gas/Centra Gas, 1997 Rates Application (EBRO 493/494)
- Consumers Gas, 1997 Test Year Rates Application (EBRO 492)
- Ontario Hydro, Review of 1997 Rates (HR-24)

1995 - Ontario Hydro, Review of 1996 Rates (HR-23)
- Consumers Gas, 1996 Test Year Rates Application (EBRO 490)
- Union Gas, 1996 Test Year Rates Application (EBRO 486)
- Union Gas/Centra Gas, Shared Services Hearing (EBRO 486/489)

1994 - Centra Gas, 1995 Test Year Rates Application (EBRO 489)
- Ontario Hydro International Hearing (EBRLG - 36)
- Ontario Hydro Corporate Restructuring and 1995 Rates (HR-22)
- Consumers' Gas, 1995 Test Year Rate Case (EBRO 487)

1993 - Joint Hearing on Direct Purchase Issues (EBRO 474-B/476/483/484/485) (Evidence: Return-to-System Policies for Ontario LDCs)
- Centra Gas, 1994 Test Year Rates Application (EBRO 483/484)

Regulatory/Legal Proceedings (cont'd)

1993 - Consumers' Gas, 1994 Test Year Rate Case (EBRO 485)
- Union Gas, 1994 Test Year Rate Case (EBRO 476-03)
  (Evidence: Equity Effects of Union's Depreciation Study)

1992 - Consumers' Gas, 1993 Test Year Rate Case (EBRO 479)
- Union Gas, 1993 Test Year Interim Rate Increase (EBRO 476)

1991 - Consumers' Gas, 1992 Test Year Rate Case (EBRO 473)
  (Evidence: Direct Purchase Issues)
- Union Gas, Application for Rates and Cost of Gas (EBRO 462)
- Centra Gas, 1992 Test Year Rates Application (EBRO 474)
  (Evidence: Direct Purchase Issues)

Before the Canadian Radio-television and Telecommunications Commission

2006 - Review of Price Cap Framework (PN 06-5)

2001 - Implementation of Price Cap Regulation for Québec-Téléphone & Télébec (PN 01-36)
  (Evidence: Designing a Consistent Price Cap Regime)
- Price Cap Review (PN 01-37)
  (Evidence: The Second Generation Price Cap Regime)
- Recovery of 2000 and 2001 Income Tax Expense (PN 00-108)
  (Evidence: Appropriate Recovery of MTS Income Tax Expense)

2000 - Scope of Price Cap Review (PN 00-99)
- Sunset Rule for Near-Essential Facilities (PN 00-96)
- Access to Municipal Property in the City of Vancouver (PN 99-25)
- Review of Contribution Collection Mechanism (PN 99-6)
  (Evidence: Review of Contribution Collection Mechanism)
- Review of Direct Connection Charges

1999 - Review of Frozen Contribution Rate Policy (PN 99-5)
  (Evidence: Comments on the Frozen Contribution Rates Policy)
- High Cost of Serving Areas (PN 97-42)

1998 - Local Number Portability Start-up Costs (PN 98-10)
- Competition in the Provision of International Telecommunications Services (PN 97-34)

1997 - Implementation of Price Caps (PN 97-11)
- Review of Joint Marketing Restrictions (PN 97-14/97-21)
- Forbearance from Regulation of Toll Services Provided by Dominant Carriers (96-26)
- Regulation of Telecom Services Offered by Broadcast Carriers (PN 96-36)

1996 - Scope of Contribution (PN 96-19)
- Bell Canada, Business Rate Restructuring (PN 96-13)
- Price Cap Regulation and Related Issues (PN 96-8)
  (Evidence: Evidence addressing the design of the price cap system)
- Local Interconnection and Network Component Unbundling (PN 95-36)
  (Evidence: Mechanisms for Collecting Contribution)
- AGT, General Rate Application
- Local Services Pricing Options (PN 95-49/95-56)
  (Evidence: Mechanisms for Pursuing the Goal of Universally Available Basic Telephone Service in Low-Penetration Exchanges)

1995 - Review of Phase II (PN 95-19)
- Regulatory Framework for Ontario Independent Telephone Cos. (PN 95-15)
- Split Rate Base Hearing (PN 94-52, 94-56 and 94-58)
  (Evidence: Applicability of the Decision 94-19 Regulatory Framework to MTS)
- Review of the Quality of Service Indicators (PN 94-50)
- Review of the Regulatory Framework of Teleglobe Canada Inc. (PN 95-11)
- Bell SYGMA Hearing (PN 94-53)

Regulatory/Legal Proceedings (cont'd)

1994 - Regulatory Framework
(Evidence: A Proposed Regulatory/Structural Alternative)
- Maritime Tel, General Rate Increase
- Island Tel, General Rate Increase
- BC Tel, General Rate Increase
- AGT, General Rate Increase
- Northwestel, General Rate Increase (paper hearing)
- Bell Canada, General Rate Increase
- Teleglobe, Annual Construction Program Review (paper hearing)
- New Brunswick Tel, Annual Construction Program Review (paper hearing)

1992 - Bell Canada - 1992 Annual Construction Program Review
- AGT - 1992 Annual Construction Program Review

1991 - Bell Canada - 1991 Construction Program Review

1990 - Maritime Telegraph & Telephone, Review of Revenue Requirement 1990-91
(Evidence on the impact of modernization)
- Island Telephone Company, Review of Revenue Requirement 1990-91
(Evidence on the impact of modernization)
- Review of Cable Television Regulations
(Evidence on alternative forms of regulation)

Before the Public Utilities Board of Manitoba

2005 - Manitoba Public Insurance, 2006 General Rates Application
(Evidence: Rate Stabilization Reserve and Related Issues)

2003 - Centra Gas Manitoba, 2003/04 General Rate Application,
(Evidence: Comments on the Future Regulatory Methodology)

2002 - Manitoba Hydro, Rate Status Update
(Evidence: Manitoba Hydro's Financial Requirements and Proposed Curtailable Rate Program, with William Harper)
- Manitoba Hydro, Integration Proceeding
(Evidence: Assessment of Manitoba Hydro/Centra Manitoba Integration, with William Harper)

2001 - Manitoba Public Insurance, 2002 General Rate Application
(Evidence: Rate Stabilization Issues)
- Centra Gas Manitoba, Primary Gas Rates
(Evidence: Centra Gas Manitoba's Rate Setting Methodology)

2000 - Centra Gas Manitoba, Rate Management
- Manitoba Public Insurance, 2001 General Rate Application
(Evidence: MPI's Rate Stabilization Reserve Surplus)
- Manitoba Hydro, Surplus Energy Program

1999 - Centra Gas Manitoba, Western T-Service and Agency Billing and Collection Service
(Evidence: Assessment of the Proposals of the Company)
- Manitoba Public Insurance, 2000 General Rate Application
(Evidence: Rate Stabilization Reserve Risk Analysis)
- Manitoba Hydro Purchase of Centra Manitoba
(Evidence: Implications for Rates and the Regulatory Regime)

1998 - Centra Gas Manitoba, Rates Flowing from Board Order 79/98
- Manitoba Public Insurance, 1999 General Rate Application
(Evidence: Rate Stabilization Reserve, Allocation of Costs and IT Expenditures)
- Centra Gas Manitoba, Feasibility Cost Assumptions Application
(Evidence: Comments on Centra's Proposed Changes to the Feasibility Test)
- Centra Gas Manitoba, 1998 Test Year General Rate Application
(Evidence: Comments on Centra's Proposed Customer Information System)

1997 - Centra Gas Manitoba, Ste. Agathe Franchise Application

Regulatory/Legal Proceedings (cont'd)

1997 - Manitoba Hydro, Review of ISE/DFH/SESS Programs
- Manitoba Public Insurance, 1998 General Rate Application
- Centra Gas Manitoba, Continuation of Shared Services Application

1996 - Centra Gas Manitoba, 1997 General Rate Application
- Centra Gas Manitoba, Cost of Service and Rate Design Review
- Generic Hearing on the Role of the LDC in Manitoba
(Evidence: The Future Role of Centra Manitoba in the Supply of Natural Gas)
- Manitoba Hydro, General Rate Application, 1996 and 1997

1995 - Centra Gas Manitoba, Price Management and Direct Purchase Issues
- Application of the Gladstone, Austin Natural Gas Co-op Ltd.
- Manitoba Hydro, Review of Prospective Cost of Service Study (GRA)
(Evidence: Comments on the Prospective COSS Methodology)

1995 - Manitoba Hydro, Dual Fuel Heating and Industrial Surplus Energy Rates
- Centra Gas Manitoba, Rural Expansion/Brandon Facilities Upgrade Hearings
- Centra Gas Manitoba, 1995 General Rate Application
(Evidence: Review of Centra's Weather Normalization Methodology)

1994 - Centra Gas Manitoba, Rural Expansion Hearing
(Evidence: Rural Mains Expansion Feasibility Test)
- Centra Gas Manitoba, Future Test Year Application
(Evidence: Comparison of the Future and Historic Test Year methods of RB-ROR regulation)
- Manitoba Hydro, General Rate Application, 1994 and 1995

1993 - Centra Gas Manitoba, Inc. 1994 General Rate Application
- Manitoba Telephone System, Interconnect Hearing
- Manitoba Telephone System, 1993 General Rate Application

1992 - Manitoba Telephone System, 1992 General Rate Application
(Evidence: The appropriate debt ratio for a crown corporation)
- Manitoba Hydro, General Rate Application, 1992
- Centra Gas Manitoba, Inc. General Rate Application

1991 - Manitoba Telephone System, General Rate Application, 1991
- Centra Gas Manitoba, Inc. Application for Interim Refundable Rate Increase

1990 - Manitoba Hydro, Major Capital Projects
(Evidence: Hydro's 1000MW Ontario Sale and system planning risks)
- ICG Utilities (Manitoba) Ltd., Generic Hearing on Rate Setting
(Evidence: Implications of using a future versus historic test year)

Before the British Columbia Utilities Commission

2006 - British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement Appl.

2005 - Insurance Corporation of British Columbia, Financial Allocation Workshop
- FortisBC, General Rates Application
(Evidence: Review of FortisBC Performance under PBR, 1996 to 2004) with S. Motluk

2004 - Insurance Corporation of British Columbia, Financial Allocation Methodology
(Evidence: Review of ICBC's Financial Allocation Methodology, with ICBC)

2002 - Pacific Northern Gas West and Northeast, General Rate Application.

2001 - Utilicorp Networks Canada (formerly West Kootenay Power), Annual Review, 2001

2000 - Pacific Northern Gas, 2000-01 General Rate Application (negotiated)
- West Kootenay Power, Annual Review, 2000

1999 - Centra Gas BC, 2000-02 Rates Application (negotiated)
- BC Gas, Market Unbundling Group (Report to the BCUC)
- West Kootenay Power, 2000-02 Rate Application (negotiated)
- Pacific Northern Gas, 1999-00 General Rate Application (negotiated)
- Annual Reviews of WKP and BC Gas
- West Kootenay Power, Transmission Access Application

Regulatory/Legal Proceedings (cont'd)

1998 - BC Gas, Southern Crossing Pipeline Application (Revised)
- Pacific Northern Gas, 1998-99 Revenue Requirement/Rate Design
  (Evidence on PNG′s Cost of Service Methodology)

1997 - BC Gas, Southern Crossing Pipeline Application
  (Evidence on the impact of ratepayer risks related to the SCP due to developments in the competitive environment in the natural gas sector)
- Annual Reviews of WKP and BC Gas.
- West Kootenay Power, Cost of Service and Rate Design (negotiated settlement)

1997 - Pacific Northern Gas Shared Services
- Retail Access and Unbundling Tariff Hearing (suspended)
  (Evidence on the impact of market restructuring on costs and rates)

1996 - BC Gas - 1996 Rate Design (negotiated settlement)
  (Alternative Methods for Allocating Distribution Mains Costs to Customer Classes)
- BC Gas - 1996-1997, Revenue Requirement & IRP (negotiated settlement)
- West Kootenay Power - Brilliant Generating Station Transactions
- West Kootenay Power - General Rate Application/IRP (negotiated settlement)

1995 - Generic System Expansion Hearing
- BC Gas - General Rate Application (negotiated settlement)

1994 - BC Hydro, 1994 Rate Increase Application
- West Kootenay Power, 1994/95 Rates and Integrated Resource Plan
  (Evidence: Review of WKP's Integrated Resource Plan)

1993 - BC Hydro, 1993 Rate Increase Application
- BC Gas, Rate Design Hearing
  (Evidence: Analysis of BC Gas' cost studies and their use in setting rates)
- BC Gas - General Rate Application (settled and withdrawn prior to hearing)
- Generic Hearing into the New Provincial Domestic Natural Gas Supply Policy

Before the Régie de l’énergie

2001 - Hydro Québec, Transmission Rates (R-3401-98)
  (Evidence: HQT’s Transmission Tariff Rate Design Methodology, with B. Bacon)
- Inclusion of Operating Costs in the Gasoline Price Floor Set By the Régie
  (Evidence: Review of Principles) (Régie File R-3457-2000)

2000 - SCGM Unbundling of Tariffs (R-3443-2000)
  (Evidence: SCGM’s Unbundling Tariff Proposal, with R. Higgin)
- Gazifère, Rates (R-3446-2000)
  (Evidence: Cash Working Capital and Other Issues, with G. Morrison)

1999 - Operating Costs Borne by Gasoline or Diesel Fuel Retailers (R-3399-98)
  (Evidence: Methodology for Determining Operating Costs)
- Small Hydro Within Hydro Quebec’s Resource Plan (R-3410-98)
  (Evidence: Determining the Purchase Price for Small Hydro)
- Gazifère, Year 2000 Rate Case
  (Evidence: Assessment of Cost Allocation and Revenue Sharing Proposals)

1998 - Hydro Québec, Rate-Setting Methodology Under s. 167 of the Régie de l’énergie Act.
  (Evidence: Recommendations on Regulatory Framework)
- Hydro Québec, The Role of Wind Power in the Quebec Energy Portfolio
  (Evidence: Issues Related to Establishing a Set-Aside)

Regulatory/Legal Proceedings (cont'd)

Before the Alberta Energy and Utilities Board

2001 - Generic, Gas Rate Unbundling (2001-093)
(Evidence: Canadian Experience and Approaches)
- Generic, Gas Cost Recovery Rate Methodology (2001-040)

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

2006 - Newfoundland Power, 2007 Amortization and Cost Deferrals Application
2005 - Newfoundland Power, 2006 Accounting Policy Application
(Evidence: Assessment of Newfoundland Power's Proposals)

Before the National Energy Board

1999 - BC Gas, Southern Crossing Project

Before the Ontario Securities Commission

1985 - Securities Industry Review
(Evidence: Industry structure and the form of regulation)
1983 - Role of Financial Institutions in the Securities Industry
(Evidence: Discount Brokerage and the Role of Financial Institutions)
1982 - Institutional Ownership of, and Diversification by, Securities Dealers
(Evidence: The impact of foreign and institutional entry)
1981 - The Unfixing of Brokerage Commission Rates
(Evidence: The impact of price competition on the securities industry)

Before the Ontario Telephone Services Commission

1992 - Review of Rate-of-Return Regulation for Public Utility Telephone Companies.
(Evidence: The need for OTSC regulation of municipal public utility telcos)

Before the Ontario Municipal Board

1995 - Appeal of Boundary Expansion by Lincoln Hydro Electric Commission
(Affidavit prepared on the tests for boundary expansions)
1992 - Evidence dealing with the *Rental Housing Protection Act, 1989*

Before the Supreme Court of Ontario

1990 - Challenge of the *Residential Rent Regulation Act (1986)* under the *Canadian Charter of Rights and Freedoms*
(Evidence: The impact of rent regulation on Ontario's rental housing market)

Before the Saskatchewan Court of Queen's Bench

1993 - Evidence regarding market dynamics and competition policy.

Commercial Arbitrations

2006 - Disputed Power Purchase Agreement (PPA)
2004 - Evidence on the interpretation of a Gas Purchase Agreement (GPA)

Non-Hearing Processes (Task Forces, Lawsuits and Arbitrations)

2006 - Workshop on Regulatory Methodology for the Government of Vietnam (electricity regulator, Ministry of Energy and state-owned enterprises) with Marie Rounding
2004 - Vitamin Price Fixing
- Allocation of debt related to separation of electric utilities
2001 - BC Gas, Second Generation Performance Based Regulation Negotiation
- Telecommunications Industry, Price Cap Review Negotiation
1999 - PBR Task Force (Electricity), Ontario Energy Board
- Market Unbundling Group (BC Gas), British Columbia Utilities Commission
- Western Supply Transportation Service (Centra Gas Manitoba), Manitoba PUB
1998 - Market Design Task Force, Ontario Energy Board
1997 - Ten Year Market Review, Ontario Energy Board

Facilitation Activities

2004 - Ontario Energy Board, Review of Further Efficiencies in the Electricity Distribution Sector (RP-2004-0020) (with IBM Consulting)
- Visioning Session: Structural Review of an association of Ontario electric LDCs
- Business Plan Visioning Session with the Board of Directors of an Ontario electric LDC.
2000 - Ontario Energy Board, Distribution Access Rule Task Force.

Other Regulatory Issues Researched for Clients

2006 - "Review of Potential Regulatory Cost Measures" (a Report for the OEB)
- "Survey of Regulatory Cost Measures" (a Report for the Ontario Energy Board)
- "Designing an Appropriate Lost Revenue Adjustment Mechanism (LRAM) for Electricity CDM Programs In Ontario"
- Small Hydro PPA Terms and Conditions
- Ontario Electricity Supply Mix
- Mitigation of Regulatory Risk for Utilities
2005 - Regulatory Benchmarking
- Cross-jurisdictional Survey of Regulatory Efficiency
- Renegotiation of Municipal Franchise Agreement

Regulated Industries: Papers and Research Projects

- *Report on the Effects of Separating Hydro One's Transmission and Distribution Functions.*
- *Report on Hydro One Privatization Options.*
- *The Impact of Complete Deregulation on Market Efficiency of the Gas and Electric Industry in Alberta Post-2005 Assuming Current Market Dominance.*
- *Analysis of a Possible Equity Infusion for Ontario Hydro: Potential Implications for Financing Costs.*
- *Volatility in the Ontario Electricity Market, by ECS with Snelson International Energy.*
- *An Assessment of Price Volatility in the Ontario Electricity Market.*
- *Analysis of MTS Privatization Plan*.
- *Comments on the Issues Identified in the December 1995 Working Paper of the Advisory Committee on Competition in Ontario's Electricity System*, A submission on behalf of The Power Workers′ Union.
- *Telecommunications Municipal/Franchise Tax Design Options* (with Dr. E. Slack).
- The Implications of Phase III Costing for the Rates and Toll Settlements of Independent Telephone Companies (with Andrew Roman).
- Submission to the Department of Communications (Canada) (August 1990): *Towards Competition in Telecommunication and Cable TV Services: A Single Switched Broadband Distribution Facility* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).
- Submission to the Department of Communications (Canada) (May 1990): *Fibre Optic Networks: Facilitating Competition in Telecommunication and Television Services for the Benefit of All Users* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).
- Submission to the CRTC concerning cable television regulation on behalf of the Public Interest Advocacy Centre (with Carmen Baggaley).
- Analysis of financing alternatives for Toronto Hydro's 13.8 kV conversion program for the City of Toronto Parks and Recreation Department.
- Analysis of the MacEachen White Paper on "Inflation and the Taxation of Personal Investment Income" for the Ontario Economic Council.
- Submission to the Parliamentary Committee commenting on the April 1985 Finance Green Paper, "The Regulation of Financial Institutions: Proposals for Discussion" prepared on behalf of the Public Interest Research Centre.

Financial Markets: Papers and Research Projects

- Analysis of the potential consumer benefits from insurance retailing by financial institutions in Canada for the Public Interest Research Centre.
- Development of a financial model for projecting the financial implications of alternative corporate structures.
- Developed model for projecting cash flows for a major land development project.
- Analysis of the impact on the capital markets of changes to the investment rules for public sector pension funds for the Task Force on the Investment of Public Sector Pension Funds (with Prof. John Bossons).
- Review of the OSC proposals and alternatives for relaxing ownership restrictions in the securities industry prepared for the Ontario Securities Commission for submission to the Premier's Office (with Prof. Tom Courchene).
- Analysis of the Impact of Opening the Ontario Securities Market on the Economy of Toronto for a major Canadian securities dealer.
- Response to the December 1984 "Interim Report of the Ontario Task Force on Financial Institutions" for Consumer and Corporate Affairs (Canada).
- Report on functional integration in the Canadian financial services sector for the Australian Merchant Bankers' Association.
- Analysis of the Canadian and American Experience with Partially Negotiable Brokerage Commission Rates for the Australian Merchant Bankers Assoc.
- Served as a North American contact for the Office of Fair Trading (United Kingdom) providing information on developments in the debate over unfixing of brokerage fees, entry of banks into securities dealing and related matters.
- Development of a computerized package for analyzing the effects of alternative tax systems on business investment. Prepared for the Ontario Government reference to the Ontario Economic Council to study a separate personal income tax for Ontario.
- "An Analysis of the Use of Component Internal Rates of Return for Fund Performance Measurement" for Canadian National Investments.
- Analysis of Canadian Stock Market Data (development of a computer package for evaluating investment portfolio efficiency).
- Redesign and periodic updating of the financial, analysis methodology for Alfred Bunting and Co.
- Developed an APL computer package for teaching Business Finance concepts.

Housing: Papers and Research Projects

- Potential Impact of Rent De-Control on Selected Markets in Ontario
- Review of the Ontario Auditors analysis of the cost of social housing.
- *Future Social Housing Delivery Opportunities in Metro Toronto*.
- Development of a model for projecting core need households to 2011.
- Analysis of the City of Toronto's approach to the valuation of certain properties developed under the *Rental Housing Protection Act, 1989*.
- *Security of Tenure Issues Pertaining to Co-operative Housing*.
- *Rent Regulation in Ontario*, a report prepared as expert Evidence for a Charter of Rights challenge of Ontario's system of rent regulation (with W.T. Stanbury).
- Feasibility study of enhancements to long term housing forecasting models (demographic factors) with David Foot.
- Feasibility study of enhancements to long term housing forecasting models (economic factors).
- Review of the housing situation in the Greater (Toronto) Metropolitan Region in 1988 and the next decade for the Ontario Ministry of Housing.
- Treatment of the Assisted Rental Program under rent regulation for the Ontario Ministry of Housing.
- Alternatives for implementing of the chronically depressed rent provision of the Residential Rent Regulation Act, 1986.
- Projected rental housing requirements to 1996, by unit rent level for Ontario Ministry of Housing.
- Analysis of the effects of the Canadian Home Ownership Stimulation Program on housing starts for Canada Mortgage and Housing Corporation.
- Energy Efficiency of New Housing (with Peat, Marwick and Partners and Scanada Consultants Limited) for Canada Mortgage and Housing Corporation.
- A Model of Supply and Demand in the Market for Housing for the Ontario Ministry of Housing.
- Several publications and presentations shown in the Academic Profile (see below).

Other Areas: Papers and Research Projects

- Economic analysis of the market impact of the merger of two Canadian trucking companies in the context of the Competition Act.
- Assisted a Joint Task Force of the Ontario Ministries of Social Services and Health to develop a cost project model of alternative long term health care delivery systems.
- Study of Tax Incentives for Film and Television (joint project with Dr. E. Slack) for the Canadian Film and Television Association.
- Economic Analysis of Tax Incentives for the Film Industry (joint project with Dr. E. Slack) for the Department of Communications.
- Economic Impact of Cultural Institutions for Ontario Association of Art Galleries with the Ontario Federation of Symphony Orchestras and the Toronto Theatre Alliance.
- Economic Impact of Art Galleries' Expenditures on their Local Communities for the Ontario Association of Art Galleries.
- Developed a case study of the potash pro-rationing scheme invoked by the Saskatchewan government for the Faculty of Management Studies, Univ. of Toronto.
- Analysis of Regional Municipality of Niagara financial information for the Niagara Region Review Commission.
- Analysis of Ottawa/Carleton regional government's financial information, and comparison with other regional governments, using the MARS database (with Dr. E. Slack).
- A Dynamic Simulation Model of the North York Secondary School System for Planning for Declining Enrolment for the Ontario Institute for Studies in Education, Department of Educational Planning (with Dr. S. Padro).
- Development of an extension to the Limits to Growth World III Model incorporating commodity prices, technology, disaggregated regions and energy resources into the model.
- Development of a computer program for solving the Dynamic Transportation Problem (with Professors Sethi and Bookbinder at the Faculty of Management Studies, University of Toronto).

Presentations

- "Low-Income Energy Plan for Peterborough City & County", 2006 LIEN-AHAC Conference
- "The "Deregulated Retail Energy Sector in Ontario", Toronto Association of Business Economists, Oct. 2003.
- "Other Approaches to Rate Regulation", CAMPUT Annual Meeting, Sept. 2003.
- "Price Projection: Will the Rate Freeze be Revenue Neutral?" at Canadian Institute Conf., The Impact of Ontario's New Electricity Market on Large Power Consumers Jan. 2003.
- "Managing Energy Price Risk: Impact of Market & Regulatory Developments on Price Risk Management", Canadian institute Conference, Toronto, October 21, 2002.
- "Location Based Marginal Pricing: Will it Happen?" Ontario Energy Contracts, Insight Conference, Toronto, October 1, 2002.
- "The Evolution of the North American Energy Market" Canadian Gas Association Executive Conference, Vancouver, June 2002.
- "Alternate Dispute Resolution: Can Everyone Win?" Canadian Gas Association Breakfast, Whistler, British Columbia, May 7, 2002.
- "Incentive Regulation and Commodity Competition Impacts on Quality of Service & Rates", CAMPUT Regulatory Educational Conference, Whistler, BC, May 7, 2002.
- "Energy Deregulation Developments and Impacts on the HVACR Industry", HRAI's 33rd Annual Meeting, August 23-25, 2001 Huntsville, Ontario.
- "Natural Gas Delivery Regulation in Canada", HRAC Conference on Natural Gas in Nova Scotia, Halifax, Nova Scotia, August 25, 1999.
- "Licensing as a Regulatory Approach" Thirteenth Annual CAMPUT Regulatory Educational Conference, Saint John, New Brunswick, May 4, 1999.
- "The Impact of Restructuring Electricity Markets on Customers", West Kootenay Power 1998 Annual Conference, The Dawn of Customer Choice, Kelowna, B.C., Dec. 2, 1998.
- "Gaining Access to the Retail Customer", *Electricity Competition in Ontario, New Rule, New Opportunities, New Players* (Canadian Institute Conference), Toronto, Oct. 1998.
- "The Future: Mega-BTU Inc.?" (Plenary session) Twelfth Annual CAMPUT Regulatory Educational Conference, Banff, Alberta, April 27, 1998.
- "Protecting Low Income Consumers' Access: Lessons Learned From Other Countries," Twelfth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 26-27, 1998.
- "Competition: What happens downstream of the meter?" (Plenary) Eleventh Annual CAMPUT Regulatory Educ. Conference, Whistler, B.C., May 6, 1997.
- "Brokers, Marketers and the Public Interest" Eleventh Annual CAMPUT Regulatory Educational Conference, Whistler, B.C., May 6, 1997.
- "Separation of Gas Supply, Merchant Functions & Other Alternatives," Tenth Annual CAMPUT Regulatory Educ. Conf., Niagara-on-the Lake, May 1, 1996.
- "The Impact of Deregulation on the Public Interest," Tenth Annual CAMPUT Regulatory Educational Conference, Niagara-on-the Lake, April 30, 1996.

Presentations (cont'd)

- "Marketing to Low and Moderate Income Consumers in the New Competitive Market: Lessons Learned From Other Industries," Tenth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 22, 1996.
- "Where Should We be Going?" OEB Ten Year Market Review Workshop, Jan. 31, 1996.
- "Restructuring the Electrical Power Industry in Ontario" for the Board of Directors of Ontario Hydro on behalf of the Power Workers' Union, August, 1995.
- "A New Vision for Ontario's Electric Demand/Supply Future" panel presentation, Opening Plenary Session of the Canadian Independent Power Conference, Toronto, Dec. 1993.
- "Trends in Rental Housing Affordability by Income Level in Ontario" presented at the 1992 meetings of the Canadian Economics Assoc., Charlottetown, PEI.
- "An Evaluation of Rent Regulation as an Instrument for Meeting the Housing Needs of Renters in Ontario," presented to the Ontario Standing Committee on General Government, August, 1991.
- with S.W. Hamilton (Sept 1990) "Housing and the Regulatory Environment", a paper presented at the Housing Young Families Affordability Symposium, (Vancouver: Canadian Housing and Renewal Association/Canada Mortgage and Housing Corp.)
- "New Telecommunications Technologies: Who Pays? Who Benefits?" presented at the 1990 (June) meetings of the Canadian Economics Assoc., Victoria, B.C.
- with W.T. Stanbury, (1989) "Rent Controls as a Prisoner of War Game", Canadian Real Estate Research Bureau, Faculty of Commerce and Business Administration, University of British Columbia, #89-ULE-019.
- "The Implications of Rent Regulation for Housing Market Models" presented at 1989 (June) meetings of the Canadian Economics Association, Quebec City.
- "Price Caps - An Alternative to Rate of Return Regulation?" at the Canadian Association of Members of Public Utility Tribunals/Centre for the Study of Regulated Industries, Annual Regulatory Studies Training Programme, McGill University, May 14-18, 1989.
- "Living with Rent Regulation in Ontario" at the 35th North American meetings of the Regional Sciences Association, Toronto, November 1988.
- "A Survey of the Research of the Thom Commission," at *Rent Control: The International Experience*, John Deutsch Institute Roundtable, Queen's University, September, 1987.
- Invited address on "Forecasting the Regulatory Environment of Financial Institutions" sponsored by the University of Michigan - Flint as the 1985 paper for their annual *Lectures on the American Economy and the Business Community* series.
- "Collapsing Barriers Between Banking and Other Financial Institutions" at the 1984 Canadian MBA Conference, McMaster University.
- The economic impact of cultural activities for conferences of National Museums of Canada, Canadian Conference on Heritage Resources, Canadian Museums Association, Ontario Association of Art Galleries, and Ontario Federation of Symphony Orchestras.

Publications

Refereed Books and Monographs:

- with W.T. Stanbury (February 1990) *Rent Regulation: The Ontario Experience*, (Vancouver: The Canadian Real Estate Research Bureau).
- with W.T. Stanbury (January 1990) *The Housing Crisis: The Effects of Local Government Regulation*, (Vancouver: The Laurier Institute).
- with T. Courchene and L. Schwartz (October 1986) *Ontario's Proposals for the Canadian Securities Industry*, Observation No. 29, (Toronto: C.D. Howe Inst.).
- (1983) *Price Competition in the Canadian Securities Industry: A Test Case of Deregulation*, (Toronto: Ontario Economic Council).
- with G.F. Mathewson (1982) *Information Entry and Regulation in Markets for Life Insurance - Part II Overview and Policy Implications*, (Toronto: Ontario Economic Council).

Refereed Articles:

- with W.T.Stanbury (1990) "Landlords as Economic Prisoners of War", *Canadian Public Policy*, XVI no.4.
- with G.D. Quirin and S.P. Sethi (1977) "Market Feedbacks and the Limits to Growth", *INFOR*, Vol. 15, No. 1.

Other Publications:

- (1992) *Technology, Competition and Cross-subsidization in the Canadian Telecommunications Industry*, (Ottawa: Public Interest Advocacy Centre).
- (April 1990) *Paying for What You Need: Technological Advances and Competition in Telecommunications*, (Ottawa: Public Interest Advocacy Centre).
- with Andrew Roman and Robert Horwood, (1989) *Insurance Retailing by Financial Institutions in Canada*, (Ottawa: Public Interest Research Centre).
- with Douglas G. Hartle (1983) "The TAX-2 Model and Results" in *A Separate Personal Income Tax for Ontario: An Economic Analysis*, Special Research Report, (Toronto: Ontario Economic Council).
- (1982) "Commentary" in *Inflation and the Taxation of Personal Investment Income: An Analysis and Evaluation of the Canadian 1982 Reform Proposals* (edit. D.W. Conklin), Special Research Report (Toronto: Ontario Economic Council).

Teaching

1989	Economics of Housing, Scarborough College, University of Toronto
1979-85	Engineering Economy, Faculty of Engineering, University of Toronto
1982-85	Computerized Business Systems (B.A. Program), and Management Information Systems (M.B.A.), Canadian School of Management
1979	Introductory Economics at St. George Campus, University of Toronto
1977-79	Economic Principles at Erindale College, University of Toronto
1980-85	Scuba diving instruction for Basic Diver, Sport Diver, Assistant Instructor and Instructor courses (National Association of Underwater Instructors).

Research Management

1983-87: Research Director: Commission of Inquiry Into Residential Tenancies.
Directing a staff of four in-house researchers on various background studies on Ontario's housing market and the literature related to rent regulation. Managed thirty external projects on topics related to the housing market and rent regulation.

1978-80: Research Officer: Ontario Economic Council.
Research was conducted in the areas of regulation of the securities industry, mineral resource taxation policy, and Federal-Provincial energy policy.
Other duties included managing ten external research contracts on topics in regulation and directing the work of research assistants.

Other Activities

- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Participation on behalf of OCAP in consultative processes related to direct purchase and integrated resource planning in the Ontario natural gas industry.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Former Chairman of the Board of Directors of the Festival of Canadian Theatre.
- Articles in the editorial section of the Financial Times of Canada on policies for reforming Ontario's system of rent regulation (June 1990) and federal proposals regarding bank directorships (February 1991).
- Numerous appearances on CBC radio and television commenting on competition, regulation and mergers in the Canadian economy.
- Refereed articles and research studies for *Canadian Public Policy*, *Queen's Quarterly* and Consumer and Corporate Affairs, Canada.
- Several organizations have been assisted in developing their research agendas, writing submissions to government on economic issue, or in other advisory capacities. Clients include the Public Interest Research Centre (topics include airline deregulation, Via Rail, telephone solicitation, Bell Canada's rate structure, frequent flyer programs, price cap regulation, and home equity conversion), Ontario Association of Art Galleries (arts funding and economic impact), Public Affairs Management, Inc., City of Toronto, Parks and Recreation Department, and Goldfarb Consultants.

Clients

Private Sector Companies

Alfred Bunting & Co.
BC Gas Utilities Limited
Buttcon Ltd.
Canadian National Investments
Comdisco Canada Inc.
Devon Canada
EnCana
Enbridge Gas Distribution
Enron Trade and Capital Canada
Fine Line Communications Ltd.
Fuji Electric (Tokyo)
Great West Life Assurance Co.
Hydro One Networks Inc.
McLeod Young Weir
Ontario Hydro Services
Shulman Communications Inc.
Star Produce
The Morassutti Group
Wirebury Connections Inc.
Auto Haulaway Inc.
BC Rail
Canavest House Ltd.
Chatham-Kent Energy
Coral Energy
Direct Energy
ENERconnect
EnCana Corporation
Financial Times of Canada
FortisBC
Goldfarb Consultants
Highmark Properties
Insurance Corp. of British Columbia
New Brunswick Power (Disco)
Ontario Power Generation
Sithe Canada
Terasen Gas
Union Gas Limited

Industry and Other Associations

Association for Furthering Ontario's Rental Development
Australian Merchant Bankers' Association
Canadian Business Telecommunications Alliance
Canadian Film and Television Association
Canadian Independent Telephone Association
Canadian Museums Association
Cornerstone Hydro Electric Concepts
Electricity Distributors Association
Manitoba Keewatinowi Okimakanak
Ontario Association of Art Galleries
Ontario Energy Association
Ontario Federation of Symphony Orchestras
Power Workers' Union (CUPE 1000)
Toronto Theatre Alliance

Clients (cont'd)

Consumers' Associations

Alberta Council on Aging
Alert on Welfare
British Columbia Old Age Pensioners' Association
Canadian Pensioners Concerned
    (Nova Scotia Division)
Consumers Association Of Canada
    (National)
    (Manitoba Branch)
    (Alberta Branch)
    (Northwest Territories Branch)
Consumers Fight Back Association
Council of Senior Citizens' Organizations
Co-operative Housing Association of Ontario
Federated Anti-Poverty Groups of British Columbia
Action réseau consommateurs (formerly La Fédération
    Nationale des Associations de Consommateurs du Québec)
Manitoba Society for Seniors
The National Anti-Poverty Organization
Newfoundland Consumer Advocate
Nova Scotia League for Equal Opportunities
Ontario Coalition Against Poverty
Option Consommateurs
PEI Council for the Disabled
PEI Senior Citizens Federation
People on Welfare for Equal Rights
Public Interest Research Centre
Rural Dignity of Canada
Rural Dignity, PEI Chapter
Senior Citizen' Association
Social Action Commission

Counsel for Consumers' Associations

British Columbia Public Interest Advocacy Centre
Legal Aid Manitoba, Public Interest Law Centre
Public Interest Advocacy Centre (Ottawa)

Clients (cont'd)

Government

Federal
Canada Mortgage and Housing Corporation
Canadian Conference on Heritage Resources
Consumer and Corporate Affairs (Canada)
Department of Communications (Canada)
Director of Investigation and Research, Combines Investigation Act
St. Lawrence Seaway Authority

Provincial
Alberta Department of Energy
Commission of Inquiry into Residential Tenancies
Niagara Region Review Commission
Ontario Economic Council
Ontario Energy Board
Ontario Institute for Studies in Education, Department of Educational Planning
Ontario Ministry of Community and Social Services
Ontario Ministry of Health
Ontario Ministry of Housing (Corporate Policy and Planning; Rent Review Policy, Housing Field Operations)
Ontario Securities Commission
Ontario Task Force on the Investment of Public Sector Pension Funds
Ottawa/Carleton Region Review Commission
University of Toronto

Other
City of Calgary Electrical System
City of Peterborough
City of Toronto, (Telecom; Housing; Parks and Recreation)
Manitoba NDP Caucus
Office of Fair Trading (United Kingdom)
Toronto Harbour Commissioners
Four municipally operated public utility telephone system