Newfoundland and Labrador
Board of Commissioners of Public Utilities

Newfoundland Power
2010 General Rate Application

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On Behalf of
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August 21, 2009

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1 INTRODUCTION

Newfoundland Power ("NP") filed its 2010 General Rate Application ("2010 GRA") with the Board of Commissioners of Public Utilities ("Board" or "PUB") on May 28, 2009.

The Government of Newfoundland and Labrador appointed Thomas Johnson as the Consumer Advocate ("CA") to represent the interests of consumers in connection with the 2010 GRA. The CA has asked me as an economist who has specialized in the theory and practice of economic regulation for over 30 years to provide assistance to the Board by preparing evidence that addresses the following issues:[1]

1. The role of the existing and proposed regulatory mechanisms in the context of NP's multi-year regulatory regime
2. NP's proposed Pension Expense Variance Deferral Account ("PEVDA")
3. NP's report on the Demand Management Incentive Account ("DMIA")
4. The regulatory treatment of Other Post Employment Benefits ("OPEBs")
5. NP's proposed treatment of its gain on sale of the Kenmount Road property

My evidence is divided into five additional sections that deal with the five issues listed above. My conclusions and recommendations on these issues appear at the end of each section.

[1] John Todd's curriculum vitae is available at www.era-inc.ca.

2 REGULATORY MECHANISMS FOR THE MULTI-YEAR REGIME

The regime that the Board relies on to regulate NP includes a number of regulatory mechanisms that facilitate the multi-year regime that has become the established norm for NP. The role of these regulatory mechanisms within the multi-year regime was discussed at some length during the 2008 GRA. The issue has also been revisited in a number of responses to RFIs in the current proceeding.[2] Essentially, the regulatory mechanisms reduce the need for frequent GRAs by using deferral accounts to pass through any variances in specified costs between the level of costs embedded in rates in a GRA year and the level of costs actually incurred in subsequent non-GRA years. Since year-over-year increases in these costs factors are recovered automatically by means of the deferral accounts, the Company is held whole whether or not rates are changed by means of a GRA.

The existing multi-year regime serves two purposes that are similar to the incentive regulation and performance based regulation regimes that have been adopted in some other jurisdictions: they reduce regulatory cost by reducing the frequency of GRAs and they provide an incentive for the Company to pursue productivity gains in the non-GRA years. It is my understanding that the productivity incentive that is inherent in the multi-year regime was a consideration in the Board's decision to reject the recommendation of the CA during the 2008 GRA to adopt an explicit productivity adjustment. As the Board order in that proceeding noted:

> *Also despite discussing the merits of incentive based regulation (i.e. price cap and PBR) and how it operates elsewhere, the evidence does not justify the application of new incentive mechanisms to the multi-year cost of service regulation legislated in this jurisdiction. (Order P.U. 32(2007), p. 42)*

Any shortening of the multi-year cycle (from three to two years or annually, for example) will clearly compromise both benefits: regulatory costs will not be avoided and the incentive to reduce costs in the absence of a GRA that rebases rates to current forecast cost levels will be reduced or eliminated.

[2] For example, see the responses to CA-NP-20, 21, 442 and 444.

Over the years the Board has introduced and modified deferral accounts that serve to reduce or eliminate the Company's exposure to cost variances that relate to cost factors that are beyond its control. The Rate Stabilization Account, Weather Normalization Reserve, the Energy Supply Cost Variance Clause and the Conservation Cost Deferral Account are examples of regulatory mechanisms that remove the risk of non-recovery of costs incurred during non-GRA years. As a result of these regulatory mechanisms, NP bears minimal risk in relation to its power costs, which can vary significantly due to weather factors, Hydro's rates and fuel costs, and other factors that are beyond management's control.

The Automatic Adjustment Formula ("AAF") is another feature of the regulatory regime that was designed to enable NP to recover costs in a flexible manner that recognizes changing circumstances without requiring the company to file a GRA.

The proposed PEVDA which, if approved by the Board, will limit the variability of pension expense due to changing assumptions, is another regulatory mechanism that would reduce NP's exposure to cost variances that could drive the need for a GRA. (The PEVDA is addressed in section 3, below.)

It may be noted that in general deferral/variance accounts serve three distinct purposes:

- First, variance accounts are most commonly used to ensure that actual (as opposed to forecast) costs (or revenues) incurred <u>during a GRA test year</u> are recovered from customers. Hence, variances from forecast costs (or revenues) are tracked so that they can be included in rates in a subsequent year. The rationale for using a deferral account in these cases is that the company should not be at risk for forecasting errors related to the costs included in the deferral account.

- Second, variance/deferral accounts can also be used, as an automated mechanism for recovering the year to year changes in costs in the absence of a GRA. In essence, when used in this way the deferral/variance account passes through to customers on a deferred basis variances between the actual costs incurred <u>during a non-GRA year</u> and the level of costs embedded in the base rates established by the GRA for a preceding year. The essential purpose of this mechanism is to avoid the costs of a GRA and embed a productivity incentive for the non-GRA years. While this use of variance/deferral accounts clearly overlaps with the first use noted above, the distinction between their use to capture forecast errors and their use to capture year over year cost changes is important both conceptually and practically. Most notable is the fact that some variance accounts that are appropriate within a multi-year regime may not be appropriate in the absence of a multi-year regime. That would be the case when the elimination of risk associated with the variance between forecast and actual costs in a test year is not warranted, while facilitating a multi-year regime is warranted.

- Third, deferral accounts are also used to defer known costs that are incurred in a particular year so that they are recovered in a future year.

An important benefit of the regulatory mechanisms that have been approved by the PUB over the years is that the frequency of GRAs has been reduced. While there is no mandatory period of time between GRAs, the discussion of regulatory mechanisms in the past appeared to have created a tacit understanding that the normal GRA cycle is three years. This perception is implicit in the following comment made by the Board in its last GRA decision.

> *The Board notes that, according to the Amended Application, the AAF is proposed to operate to set rates for three years following 2008. This means that the AAF would be used to establish rates for 2009, 2010 and 2011. However, six of seven of the amortization proposals for regulatory deferrals and reserves proposed in the Amended Application and approved by the Board in this Decision and Order are set to expire in 2010. As well, the Settlement Agreement proposed that the Energy Supply Cost Variance Clause to be added to the Rate Stabilization Clause would apply to energy supply costs incurred through to the end of 2010, unless a further application is made to the Board by either party for its extension, modification or non-renewal. In addition the evidence provided in relation to the proposal to continue to use the cash basis for recognizing expenses for OPEBs substantially related to the period ending in 2010. The uncertainty surrounding the IFRS issue is also a complicating factor. In light of these circumstances the Board does not feel it would be prudent to delay a GRA beyond 2010. On this basis, and in the absence of an application from NP requesting otherwise, NP will be required to file its next GRA in 2010 to set rates for a 2011 test year. (Order P.U. 32(2007), pp. 53-54)*

An inherent aspect of the multi-year regime is the inclusion of explicit and implicit incentive mechanisms. For example, the Demand Management Incentive Account includes a deadband that provides an incentive for the Company to manage peak demand so as to reduce the power costs that are passed through to its customers.

A further incentive that is inherent in the multi-year regime is the incentive for the Company to achieve productivity gains in the non-GRA years. NP's revenues for providing distribution services increase from year to year with customer growth and natural increases in use per customer. To the extent that it is able to control increases in costs that are not included in the variance/deferral account that make up the regulatory mechanisms, the company is able to increase its return on equity (subject to over-earning) in the non-GRA years. This incentive is similar to the productivity incentive that is integral to performance based regulation regimes that set rates over a multi-year period using a formula that decouples rates from costs.

It is appropriate that the multi-year regime that has been developed over time by the Board for NP does not include a mandatory period between GRA's. This feature of the regime recognizes that there may well be unanticipated factors beyond the Company's control that make it necessary to initiate a GRA earlier than the expected date. At the same time, however, the *quid pro quo* for approving the regulatory mechanisms that mitigate risk for the Company is that NP will not initiate a GRA prematurely unless there is a clear necessity for increasing rates. Presumably, necessity would relate to an increase in costs that is not addressed by any of the existing regulatory mechanisms and is beyond the control of management. It might also be expected that the discretionary reconsideration of a regulatory policy, such as the AAF, would not normally justify a premature GRA.

The regulatory mechanisms and the multi-year regime are a package. If the benefits of a multi-year regime (i.e., reduced regulatory costs and the productivity incentive) are lost, questions must be asked about the merit of the overall design of the regulatory system. In particular, the rationale for not utilizing an explicit productivity adjustment in establishing allowed costs within a GRA (i.e., the multi-year regime provides a productivity incentive) is undermined. In addition, the context of the regulatory mechanisms is altered. The regulatory mechanisms benefit the customers by reducing regulatory costs and providing a productivity incentive within the multi-year regime. If the frequency of GRAs is increased, these customer benefits will be lost. The only benefit remaining for customers is that the risk adjusted cost of capital should be reduced to reflect the array of regulatory mechanisms that reduce the risk to which the company is exposed. Compromising the multi-year regime also creates a risk that the Company's decisions on the timing of GRAs will exhibit selection bias. That is, it will initiate a GRA when costs are rising more than revenue and will defer GRAs when costs are rising more slowly than revenues.

NP's current application raises questions about whether the multi-year regime, which is necessary to achieve the benefits of the regulatory mechanism, is currently viable. NP has initiated the current 2010 GRA after only two years although the normal three-year cycle would imply that the 2008 GRA would be followed by a 2011 GRA. Further, NP's proposal for the recovery of its application costs indicates that a 2011 GRA should also be expected, which would turn the multi-year regime into an annual GRA process despite the regulatory mechanisms that are in place. NP's comments on the recovery of its application costs (section 3.6.2) include the following footnote.

> *In the past, the Board has ordered recovery of Application costs over a 3 year period (see Order Nos. P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), and P.U. 32 (2007)). In each of these cases it was expected that the rates determined in the Applications would be in effect for multiple years. It is not currently expected that the rates set as a result of this Application will be in effect beyond 2010. (Pre-filed Evidence of NP, page 3-37, footnote 110)*

If the 2010 GRA and 2011 GRA were made necessary by cost increases that could only be addressed through a GRA then the break in the normal three-year cycle would be consistent with the underlying premise of the multi-year regime. However, a review of the components of the 2010 proposed rate changes which are conveniently summarized in the July 31, 209 Grant Thornton Report ("2009 GT Report) at page 29 raises questions about whether the factors contributing to the requested rate increase justify this break in the normal three-year cycle.

Certainly, there is no need to deal with the OPEBs issue at this time. In fact, as discussed in section 5 below, the Board had explicitly expected to revisit this issue as part of a 2011 GRA. In addition, the Energy Supply Cost Variance Adjustments would be addressed through the RSA in the absence of a 2010 GRA. These items account for

2.1% of the 6.1% requested rate increase (including elasticity). There would have been no financial impact on NP related to these matters in the absence of a 2010 GRA.

The increases in operating costs and depreciation (0.2% of the 6.1% proposed increase) are consistent with normal increases that are expected within the multi-year regime and are subject to the productivity incentive. The multi-year regime involves the expectation that NP will seek productivity gains that allow it to maintain its profitability by managing costs so that they can be accommodated by the normal growth in revenues due to customer growth and increased use per customer (pre-conservation).

It therefore appears that the need for a 2010 GRA hinges on NP's proposal to discontinue use of the Automatic Adjustment Formula ("AAF"). This proposal results in the increase in the return on rate base and the related increase in income taxes which together account for the remaining 3.7% of the 6.1% proposed rate increase. This issue is essentially a policy question that could have been addressed as easily within the context of a 2011 GRA as it is within the 2010 GRA.

It is clear that the proposal to terminate the AAF will have a significant financial impact on NP and its customers. What is not clear is whether, as a matter of principle, reconsideration of the AAF is an issue that in itself justifies the filing of a premature GRA. The Board needs to determine whether this matter warrants the filing of a GRA, particularly when it appears that other factors are going to make a 2011 GRA necessary in any case. Certainly, if the Board rejects NP's proposal to terminate the AAF, the benefits of less frequent GRAs and the multi-year productivity incentive will have been sacrificed for no purpose. In that event, the rationale for customers bearing the additional regulatory cost associated with the premature application would be weak, at best.

Given the Board's reliance on regulatory mechanisms and a multi-year regime to regulate NP, it is recommended that the Board defer consideration of all proposals contained in NPs application that would have an impact on rates. NP should be directed to address all issues raised in its 2011 GRA, which the Company has indicated will be required regardless of the outcome of the 2010 GRA.

3 PENSION EXPENSE VARIANCE DEFERRAL ACCOUNT

NP is proposing to introduce an additional regulatory mechanism, the Pension Expense Variance Deferral Account ("PEVDA"). In support of this proposal, the Company has provided a proposed definition (Exhibit 9) and discussion in section 3.4.2 of the risk associated with variances in pension costs. The primary factor of concern is the impact of changes in the discount rate. NP notes that "From 2006 to 2008, the discount rate increased by 2%." (Page 3-25, line 5) It therefore suggests that:

> *In these circumstances, the creation of a regulatory mechanism to ensure the reasonable recovery of actual pension expense is justified.*

This proposal would appear to be consistent with the established practice of the Board with respect to NP's regulatory mechanisms within the multi-year regime discussed in the preceding section. The PEVDA would ensure that pension costs are recovered in rates without the company being at risk for variances. In the context of the multi-year regime, year-over-year increases in pension expense would not trigger a GRA so that the company would be able to recover its prudently incurred costs. Conversely, a decline in pension costs would not result in a gain to the company that could be captured simply by deferring the next GRA.

It is less clear, however, that the proposed PEVDA is appropriate in the absence of a multi-year regime. As noted above, the use of variance/deferral accounts to ensure that actual test year costs are recovered from customers when they vary from forecast costs is distinct from their use to minimize the need for GRAs and thereby facilitate a multi-year regime. In the absence of a multi-year regime, the PEVDA will serve as nothing more than a mechanism to reduce NP's risk related to errors in forecasting its pension costs for the test year.

Assuming the Board reconfirms it commitment to maintaining a multi-year regulatory regime by accepting the recommendation contained in section 2 above, it would be consistent to accept NPs proposal to introduce the PEVDA. Since retroactive variances should not be included, however, the PEVDA should not come into force until 2011 at which time it would be used to recover variances in 2010 pension costs.

4 DEMAND MANAGEMENT INCENTIVE ACCOUNT

In evidence filed on behalf of the Consumer Advocate for the 2008 GRA, I discussed the Demand Management Incentive Account ("DMIA") which was proposed by NP in that application in a section of my evidence entitled *Proposed Changes to NP's Power Purchase Costs Risk Mitigation Mechanisms*. In supporting the introduction of the DMIA, I was concerned with the interplay between the risk mitigation features of the various power purchase cost regulatory mechanisms and their incentive effects.

The DMIA was one of the issues addressed in the 2008 GRA Settlement Agreement and accepted by the Board. In accepting the DMIA the Board stated:

> *The Board notes that, since this account is a new mechanism, it may be appropriate to review the operation of the account as part of NP's next GRA to implement changes if necessary.*
>
> ***The Board will approve the proposed Demand Management Incentive Account to replace the existing Purchased Power Unit Cost Variance Reserve. NP will be required to provide a report on the operation of this account with its next general rate application setting out any recommendations for changes if necessary.*** *(Order P.U. 32(2007), p. 27)*

NP has included in its pre-filed material for the 2010 GRA at Volume 2, Tab 8 a brief overview of the operation of the DMIA. This overview includes NP's Reserve Calculation Summary (Table 1) which reappears in NP's response to CA-NP-193 (h) at Table 3. These tables show the savings that have accrued to the company and customers for the years 2005 through 2008 related to the DMIA (for 2008) and the PPUCVR Account in preceding years. Detailed supporting calculations are also provided in the document at Volume 2, Tab 8.

It may be noted that at the time Order P.U. 32(2007) was issued, the expectation was that the next GRA would be filed for 2011 rates; hence, the DMIA would have been in its third year of operation by the time the GRA was filed. With the filing of the 2010 GRA on May 28, 2009, however, there is only one full year of experience with the operation of the DMIA. This is a very limited basis on which "to review the operation of the account". It would be premature to draw any conclusions about the operation based on a single year; hence, it will be appropriate to respond to the Board's request for a review of the operation of the DMIA after more experience has been gained.

In evaluating the DMIA, it is my view that it is important to recognize that in the absence of an appropriate incentive mechanism, the regulatory mechanisms that pass through actual power purchase costs to customers would remove the financial incentive for NP to pursue strategies for reducing these costs. This is the reason that it is not only appropriate but also necessary to provide an incentive to reduce power purchase costs by sharing the benefits of cost reductions between customers and the Company.

Recognizing the importance of maintaining an effective incentive, it follows that an evaluation of the DMIA should encompass more than just a financial report on the transfers. The scope of the evaluation should examine the actual incentive effects of the DMIA as currently designed. In particular, it should address the following questions:

- Is there an incentive to reduce both the energy and demand components of power purchase costs?
- Does the operation of the incentive serve to reward the company at a level that is commensurate with the effort required to reduce power purchase costs?
- Does the incentive reward the company for all achievable levels of savings, or does the deadband design create an implicit cap on the level of savings that can produce a benefit that compensates the company for its efforts?

In my view, a comprehensive evaluation of NP's incentive with respect to its power purchase costs would address these questions by examining the operation of the DMIA and compare it to the way in which alternate mechanisms might operate.

For example, it would appear to be worthwhile to consider power purchase cost incentive mechanism designs that explicitly address both the energy and the demand components of energy costs. As the response to CA-NP-285 (Table 1) shows, the dollar impact of a 1% reduction in energy is roughly six times the dollar impact of a 1% reduction in demand.

In addition, the incentive effect relates to the marginal, not the absolute level of the reward. Hence, it is important to ensure that the incremental reward for incremental savings is appropriate in light of the incremental effort/cost needed to pursue reductions in power purchase costs.

I therefore recommend that the Board direct that NP include at the time of its next GRA an updated report on the operation of the DMIA that not only summarizes the amounts of the transfers and savings, but also examines the incentive effects of (i) the DMIA, (ii) all other existing regulatory mechanisms related to power purchase costs and (iii) possible alternative mechanisms, with respect to the effectiveness and efficiency of the incentive to reduce power purchase costs, which are ultimately borne by customers. This analysis should address both the energy and the demand components of power purchase costs.

It may also be appropriate to point out the following recommendation that was included in my evidence for the 2008 GRA

> *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:*
>
> 1. *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*
> 2. *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.*

Clearly, the Minimum Billing Demand has an important incentive effect since reducing peak demand below 99% of the forecast value can have no value to the Company or its customers.

5 REGULATORY TREATMENT OF OTHER POST EMPLOYMENT BENEFITS

The regulatory treatment of other post employment benefits ("OPEBs) has been an outstanding issue since the Board, in P.U. 19 (2003), ordered NP to submit as part of its next GRA a report addressing the use of the accrual method as an alternative to the cash method in accounting for other employee future benefits. In response to that directive, NP filed in its 2008 GRA entitled A Report on Employee Future Benefits (Volume II, Tab 4) along with a report prepared by Mercer Human Resources Consulting entitled Report on Non-Pension Post Retirement Benefit Expense for the Fiscal Year Ending December 31, 2006 Under CICA Section 3461.

In the 2008, the issue was addressed in the Settlement Agreement as follows:

- *"It is recognized that both cash and accrual accounting treatments are in accordance with GAAP and regulatory accounting principles.*
- *In applying regulatory rate making principles, the Parties agree that in considering the accounting treatment for OPEBs, it is appropriate at this time to give more weight to the rate impact on customers of increases in the cost of electricity than to the principle of intergenerational equity.*
- *NP should, therefore, maintain the cash accounting treatment for OPEBs until the next GRA at which time the matter will be further considered by the Board".*

The Board accepted the Settlement Agreement and directed the Company to continue using the cash basis for recognizing OPEBs expenses for regulatory purposes.

In the current GRA NP is again proposing "to adopt the accrual method of accounting for OPEBs costs for regulatory purposes effective January 1, 2010." (Pre-filed Evidence, page 3-27) In support of its proposal, NP has filed under Volume II, Tab 4 its Report on Other Post Employment Benefits dated May 2009 which updates the report It filed in the 2008 GRA. In addition, NP has filed an updated OPEBs valuation at Volume II, Tab 5 of its pre-filed evidence. Grant Thornton has reviewed this material and concludes with respect to the accrual basis for accounting for OPEBs:

> *Based upon our review of this issue we note that the Company's proposal of using the accrual method for accounting for other post employment benefits is in accordance with Canadian GAAP and is consistent with the Company's treatment*

> *of pension costs. In addition, as noted above, this treatment is consistent with Newfoundland and Labrador Hydro. (GT Report, p. 4)*

With respect to the Transitional Obligation, GT concludes that:

> *We have reviewed the Company's analysis and calculations and conclude that the forecast transitional balance of $46.2 million at January 1, 2010 agrees to calculations prepared by the Company's actuary. We also conclude that if the Board approves the Company's proposals to adopt the accrual method of accounting for OPEBs and defer consideration of the settlement of the transitional balance, the forecast balance of $46.2 million as at January 1, 2010 will not change in subsequent years. (GT Report, p. 6)*

NP's 2007 OPEBs Report proposed to transition from the Cash to the Accrual Method of accounting for OPEBs for regulatory purposes and outlined its proposal for transitioning to the Accrual Method for 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.*

As NP acknowledges in its response to CA-NP-185 (a), "Newfoundland Power's proposal for recognizing OPEBs using the Accrual Method contained in the Company's evidence for its 2010 GRA is consistent with the proposal contained in the Company's evidence for the 2008 GRA."

NP's proposal in the 2008 GRA was discussed at pages 7-11 of the 2008 GRA Grant Thornton Report to the Board ("2008 GT Report").[3] With respect to NP's proposal to adopt the accrual method of accounting for OPEBs costs for regulatory purposes in 2008, the 2008 GT Report stated:

> *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*

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

> *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.*[4]

It appears that there has been no significant change in NP's proposal or the comments of GT. My comments on this issue are also unchanged from my evidence that was filed on behalf of the CA in the 2008 GRA. In that evidence I stated:

> *While this summation [of GT] 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.*

It seems clear to me that based on the record of this issue, there is no need to deal with the OPEBs issue in the context of the 2010 GRA. Deferral of the issue to 2011 would be consistent with both Board Order P.U. 32(2007) and my recommendations in section 2.

In any case, it may be prudent to reconsider this OPEBs issue in the context of an examination of the overall implications of the anticipated introduction of International Financial Reporting Standards (IFRS) which will almost certainly have potential impacts for the timing and approach used for the recognition of costs and revenues. The Board's consideration of the rate impacts resulting from OPEBs and IFRS-related accounting changes and the possible need for mitigation of the rate impacts can be pursued on a more informed basis once the implications of the transition to IFRS are known.

It is therefore recommended that NP's proposal to move to the Accrual Method for recognizing OPEBs cost at this time be rejected by the Board.

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[4] GT Report, page 8.

6 OTHER REVENUE: KENMOUNT ROAD PROPERTY

NP's response to CA-NP-184 provides details pertaining to the gain on sale of property that is noted in its pre-filed evidence at footnote 11 on page 3-4. Further detail is provided in the response to CA-NP-281.

These responses indicate the following:

1. The property includes five separate parcels that were assembled from 1961 to 1989 for the Company's head office facilities at a total cost of $234,000 (including a 2009 survey). (CA-NP-281(b))
2. The value of the land was included in NP's rate base in prior years. (CA-NP-281 (a)) Hence, customer rates have included a carrying cost for this land. As land is not depreciated, they would not have borne any of the original purchase cost.
3. The sale price of the property was $618,000; hence the gain was $384,000. (CA-NP-184(a))
4. Under NP's proposal, customers receive no portion of this gain. (CA-NP-184(b))
5. This approach which involves the customers carrying the cost of an asset (which does not appear to have actually been used to provide service as it was assembled to accommodate the Company's head office and was ultimately not required) but receive no share in the benefit is, in the view of the company "consistent with past regulatory practice in this jurisdiction." (CA-NP-184(c))

Regardless of past practice, however, it may be appropriate for the Board to consider the treatment of this gain on the sale of this property given the specific circumstances and past regulatory treatment related to this property. Options that may merit consideration include:

- accepting NP's proposal that 100% of the gain accrue to the company;
- recognizing a portion of the gain as a credit to customers as on offset to the costs that were recovered in rates in past years (e.g., a credit equal to the present value of the past carrying costs)

- sharing the gain in a proportion that is deemed to be equitable at this time by the Board, recognizing the cost that were borne by the customers and approved by the Board on the basis that the land was used and useful, or was at least required for the on-going operations of the company.

It is recommended that the Board consider the appropriateness of recognizing a portion of the gain on sale of Kenmount Road property as other revenue in light of the specific facts surrounding the purchase and sale of this property, the inclusion of this property in rate base in past years. The resolution of this issue should be consistent with the regulatory principles espoused by the Board in Order No. P.U. 19 (2003), p. 15-16, in particular the sixth principle (End Result) which is:

> ***In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.***

7 SUMMARY OF RECOMMENDATIONS

The preceding sections of this report contain the following recommendations.

Pertaining to regulatory mechanisms and maintenance of the multi-year regime:

> ***Given the Board's reliance on regulatory mechanisms and a multi-year regime to regulate NP, it is recommended that the Board defer consideration of all proposals contained in NPs application that would have an impact on rates. NP should be directed to address all issues raised in its 2011 GRA, which the Company has indicated will be required regardless of the outcome of the 2010 GRA.***

Pertaining to the proposed Pension Expense Variance Deferral Account:

> ***Assuming the Board reconfirms it commitment to maintaining a multi-year regulatory regime by accepting the recommendation contained in section 2 above, it would be consistent to accept NPs proposal to introduce the PEVDA. Since retroactive variances should not be included, however, the PEVDA should not come into force until 2011 at which time it would be used to recover variances in 2010 pension costs.***

Pertaining to the Demand Management Incentive Account:

> ***I therefore recommend that the Board direct that NP include at the time of its next GRA an updated report on the operation of the DMIA that not only summarizes the amounts of the transfers and savings, but also examines the incentive effects of (i) the DMIA, (ii) all other existing regulatory mechanisms related to power purchase costs and (iii) possible alternative mechanisms, with respect to the effectiveness and efficiency of the incentive to reduce power purchase costs, which are ultimately borne by customers. This analysis should address both the energy and the demand components of power purchase costs.***

Pertaining to NP's proposal to move from the Cash Method to the Accrual Method of recognizing OPEBs for regulatory purposes:

> ***It is therefore recommended that NP's proposal to move to the Accrual Method for recognizing OPEBs cost at this time be rejected by the Board.***

With respect to Other Revenue related to the gain on sale of the Kenmount Road property:

> ***It is recommended that the Board consider the appropriateness of recognizing a portion of the gain on sale of Kenmount Road property as other revenue in light of the specific facts surrounding the purchase and sale of this property, the inclusion of this property in rate base in past years. The resolution of this issue should be consistent with the regulatory principles***

espoused by the Board in Order No. P.U. 19 (2003), p. 15-16, in particular the sixth principle (End Result) which is:

In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.