Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF THE

2008 GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND POWER INC.

DECISION AND ORDER

OF THE BOARD

ORDER No. P. U. 32(2007)

BEFORE: **Mr. Robert Noseworthy**
Chair and Chief Executive Officer

Ms. Darlene Whalen, P.Eng.
Vice-Chair

ORDER NO. P. U. 32(2007)

IN THE MATTER OF
the *Public Utilities Act* RSNL 1990, Chapter P-47 (the *"Act"*) and
the *Electrical Power Control Act* RSNL 1994, Chapter E-5.1 (the *"EPCA"*) and
regulations thereunder;

AND IN THE MATTER OF
a general rate application by Newfoundland Power Inc. for approval of, *inter alia*, rates to be charged its customers (the "*Application*").

BEFORE:

Robert Noseworthy
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

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PART ONE. PROCEDURAL MATTERS AND BACKGROUND

I. APPLICATION AND PROCEEDING

1. The Application

Newfoundland Power Inc. ("NP") filed a general rate application (the "Application") with the Board of Commissioners of Public Utilities (the "Board") on May 10, 2007 for an Order of the Board approving, among other things, the rates to be charged as of January 1, 2008 for the supply of power and energy to its Customers.

In the Application NP proposed that the Board approve:

"1. the calculation of depreciation expense with effect from January 1, 2008 by:

(a) use of the depreciation rates as recommended in the Depreciation Study filed with the Application; and

(b) adjustment of depreciation expense to amortize over a four year period an accumulated reserve variance of approximately $700,000 identified in the Depreciation Study filed with the Application;

as set out in the evidence filed in support of the Application.

2. with effect from January 1, 2008:

(a) the adoption of the accrual method of accounting for other employee future benefits; and

(b) the adoption of the accrual method of accounting for income tax related to all employee future benefits;

as set out in the evidence filed in support of the Application.

3. the continued use of the Formula with changes to:

(a) use an equity risk premium of 5.25 percent at a risk free rate of 5 percent for 2008;

(b) revise the method for determining the risk free rate for the period subsequent to 2008; and

(c) reflect the adoption of the asset rate base method;

as set out in the evidence filed in support of the Application.

4. amortizations with effect from January 1, 2008 to:

(a) amortize as revenue over a five year period:

(i) $16,446,000 of 2005 unbilled revenue; and

(ii)$4,087,000 related to a timing difference in receipt and recognition of municipal taxes;

(b) amortize the recovery over a five year period of $12,733,000 in costs described in paragraph 7 of this Application;

(c) amortize the recovery over a five year period of $6,800,000 of the balance in the Weather Normalization Reserve;

(d) amortize over a five year period the balance of $1,342,000 in the Purchased Power Unit Cost Variance Reserve Account; and

(e) amortize the recovery over a three year period of an estimated $1,250,000 in Board and Consumer Advocate costs related to the Application;

as set out in the evidence filed in support of the Application.

5. *with effect from January 1, 2008:*
   (a) the discontinuance of the Purchased Power Unit Cost Variance Reserve Account; and
   (b) a Demand Management Incentive Account;

   as set out in the evidence filed in support of the Application.

6. *an overall average increase in customer rates of 5.3 percent with effect from January 1, 2008, based upon:*
   (a) a forecast average rate base for 2008 of $809,291,000 calculated in accordance with the asset rate base method;
   (b) a rate of return on average rate base for 2008 of 8.82 percent in a range of 8.64 percent to 9 percent; and
   (c) a forecast revenue requirement for 2008 of $502,486,000 to be recovered from electrical rates, following implementation of the proposals set out in the Application;

   as set out in the evidence filed in support of the Application.

7. *rates, tolls and charges effective for service provided on and after January 1, 2008, which result in average increases in customer rates by class as follows:*

Rate Class	***Average Increase***
Domestic	*6.4%*
General Service 0-10kW	*1.3%*
General Service 10-100 kW (110 kVA)	*2.3%*
General Service 110-1000 kVA	*4.3%*
General Service 1000 kVA and Over	*5.3%*
Street and Area Lighting	*5.3%*

as set out in Schedule A to the Application.

8. *amendments to the rules and regulations governing NP’s provision of electrical service to its customers to, in effect:*
   (a) provide for reasonable recovery of energy supply costs through the Rate Stabilization Account;
   (b) eliminate the requirement for payment in advance of fees for temporary connections, special facilities and relocations; and
   (c) allow a fee of $16 for each rejected payment;

   as set out in the evidence filed in support of the Application.”

2. Notice and Pre-Hearing Conference

Notice of the Application and Pre-hearing Conference was published in newspapers throughout the Province beginning on May 19, 2007. The Pre-hearing Conference was held on June 12, 2007 at the Board's hearing room in St. John's.

Following the Pre-hearing Conference the Board issued Procedural Order No. P. U. 17(2007) on June 22, 2007 which identified registered intervenors, established procedural rules and set the schedule for the proceeding.

Registered intervenors for the proceeding were the Government appointed Consumer Advocate, Mr. Thomas Johnson, and Newfoundland and Labrador Hydro ("Hydro"), represented by Mr. Geoff Young. NP was represented by Mr. Ian Kelly, Q.C. and Mr. Gerard Hayes.

The Board was assisted by Ms. Dwanda Newman, Board Counsel, Ms. Cheryl Blundon, Board Secretary, Ms. Barbara Thistle, Assistant Board Secretary, and Mr. Mark Kennedy, who was retained by the Board to facilitate the negotiated settlement process.

3. Information Requests/Reports

Pursuant to the Procedural Order No. P.U. 17(2007) a number of Requests for Information (RFIs) were exchanged among the parties. In total 628 RFIs were issued and answered.

On July 27, 2007 the Board's financial consultants, Grant Thornton LLP, filed a report entitled "Board of Commissioners of Public Utilities, Financial Consultants Report, Newfoundland Power Inc. 2008 General Rate Application", which presented Grant Thornton's findings and recommendations with respect to their financial analysis of the Application and evidence filed by NP in support of the Application.

Pre-filed evidence was also filed on behalf of the following experts for the Consumer Advocate:

(i) Dr. William T. Cannon (Queen's University School of Business) on August 6, 2007;
(ii) C. Douglas Bowman (Energy Consultant) on August 6, 2007; and
(iii) John D. Todd (Elenchus Research Associates Inc.) on August 14, 2007.

4. Negotiations and Settlement Process

As part of the Board's methodology in setting the schedule and procedures for a public hearing into a general rate application or other substantive applications the Board provides for a number of negotiation days in advance of the hearing. The purpose of these negotiation days is to enable and/or facilitate discussion between the applicant and registered intervenors to determine what, if any, agreement may be reached on the issues raised in the application. The specific objectives of such a forum, commonly referred to as a settlement conference, is to clarify and reduce the number of contested issues to be addressed in a formal public hearing and hence reduce regulatory costs associated with the application.

During the Pre-hearing Conference the Board set aside the period from August 20 to September 14, 2007 for negotiations, with the hearing scheduled to begin on October 16, 2007. The Board retained Mr. Mark Kennedy to act as facilitator to assist the parties with the negotiation process and the formalization of any resulting agreement. On September 20, 2007 Mr. Kennedy advised the Board by letter that the parties were still actively negotiating and were optimistic that an agreement would be concluded and filed with the Board on or before October 12, 2007. On October 5, 2007 the Board issued Order No. P. U. 28(2007) and set October 22, 2007 as the start date for the public hearing.

On October 11, 2007 NP filed an Amended Application, which incorporated the proposals set out in a Settlement Agreement between NP and the Consumer Advocate on a number of specific issues arising from the original Application. On October 17, 2007 Grant Thornton filed a Supplementary Report outlining a financial analysis of the Amended Application and the supporting evidence.

5. The Amended Application

The Amended Application incorporated the terms of the Settlement Agreement and updated 2008 test year customer, energy and demand forecast. Supplemental evidence and exhibits were also filed as part of the Amended Application.

In the Amended Application NP proposed that the Board approve:

"1. the calculation of depreciation expense with effect from January 1, 2008 by:
   (a) use of the depreciation rates as recommended in the Depreciation Study filed with the Application; and
   (b) adjustment of depreciation expense to amortize over a four year period an accumulated reserve variance of approximately $700,000 identified in the Depreciation Study filed with the Application;
   as set out in the evidence filed in support of the Application.

2. with effect from January 1, 2008 the adoption of the accrual method of accounting for income tax related to pension benefits as set out in the evidence filed in support of the Application and the Amended Application.

3. the continued use of the Formula with changes to:
   (a) use an equity risk premium of 4.35 percent at a risk free rate of 4.60 percent for 2008;
   (b) reflect the adoption of the asset rate base method;
   as set out in the evidence filed in support of the Application and the Amended Application.

4. amortizations with effect from January 1, 2008 to:

(a) amortize as revenue over a three year period:
(i) $16,446,000 of 2005 unbilled revenue; and
(ii)$4,087,000 related to a timing difference in receipt and recognition of municipal taxes;

(b) amortize the recovery over a three year period of $12,733,000 in costs described in paragraph 7 of the Amended Application;

(c) amortize the recovery over a three year period of $1,342,000 in the Purchased Power Unit Cost Variance Reserve Account;

(d) amortize the recovery over a three year period of an estimated $1,250,000 in Board and Consumer Advocate costs related to the Application; and

(e) amortize the recovery over a five year period of $6,800,000 of the balance in the Weather Normalization Reserve;

as set out in the evidence filed in support of the Application and the Amended Application.

5. *with effect from January 1, 2008:*
   (a) the discontinuance of the Purchased Power Unit Cost Variance Reserve Account; and
   (b) a Demand Management Incentive Account;

   as set out in the evidence filed in support of the Application and the Amended Application.

6. *an overall average increase in customer rates of 2.8 percent with effect from January 1, 2008, based upon:*
   (a) a forecast average rate base for 2008 of $812,212,000 calculated in accordance with the asset rate base method;
   (b) a rate of return on average rate base for 2008 of 8.37 percent in a range of 8.19 percent to 8.55 percent; and
   (c) a forecast revenue requirement for 2008 of $498,226,000 to be recovered from electrical rates, following implementation of the proposals set out in the Amended Application;

7. *rates, tolls and charges effective for service provided on and after January 1, 2008, which result in average increases in customer rates by class as follows:*

	Rate Class	***Percentage Change***
1.1	*Domestic*	*3.9%*
2.1	*General Service 0-10kW*	*(1.2)%*
2.2	*General Service 10-100 kW (110 kVA)*	*(0.2)%*
2.3	*General Service 110-1000 kVA*	*1.8%*
2.4	*General Service 1000 kVA and Over*	*2.8%*
4.1	*Street and Area Lighting*	*2.8%*

as set out in Schedule A to the Amended Application.

8. *amendments to the rules and regulations governing NP's provision of electrical service to its customers to, in effect:*
   (a) *provide for reasonable recovery of energy supply costs through the Rate Stabilization Account;*
   (b) *eliminate the requirement for payment in advance of fees for temporary connections, special facilities and relocations; and*
   (c) *allow a fee of $16 for each rejected payment;*

   as set out in the evidence filed in support of the Application and the Amended Application."

6. The Hearing

Pursuant to Order No. P. U. 28(2007) the public hearing began on October 22, 2007. Oral testimony was heard on October 22, 23, 24, 25 and 26, 2007. Written submissions were filed by NP and the Consumer Advocate on November 2, 2007. Final oral submissions were presented by NP and the Consumer Advocate on November 5, 2007. Hydro did not file a written submission or make an oral submissions as part of this proceeding.

During the hearing the following witnesses testified:

<u>On behalf of NP:</u>

Mr. Earl Ludlow	President and Chief Executive Officer
Ms. Jocelyn Perry	Vice President, Finance and Chief Financial Officer
Mr. Phonse Delaney	Vice-President, Engineering and Operations
Mr. Lorne Henderson	Director of Regulatory Affairs

<u>On behalf of the Consumer Advocate:</u>

Mr. C. Douglas Bowman	Energy Consultant
Mr. John D. Todd	Elenchus Research Associates Inc.

II. REGULATION OF NP 2003-2007

NP is an investor owned, fully regulated electrical utility which operates an integrated generation, transmission and distribution system throughout the island portion of the Province. All the common shares of NP are owned by Fortis Inc., a diversified holding company headquartered in St. John's. NP services approximately 230,000 residential and general service customers, or approximately 87% of all electrical consumers in the Province, with Hydro serving the remainder. NP's total energy sales in 2006 were 4,995 GWh. NP purchases in excess of 90% of its energy requirements from Hydro with the balance supplied by NP's own small hydro and thermal generation plants.

2003 General Rate Application

NP's last general rate application was filed on October 11, 2002. The Automatic Adjustment Formula used to set NP's annual rate of return on rate base was put in place in Order No. P. U. 36(1998-99) and expired in 2002. Because of the timing of the application, NP applied for an interim Order that established rates effective January 1, 2003. These interim rates were approved in Order No. P. U. 35(2002-2003). Order Nos. P. U. 19(2003) and. P. U. 23(2003) established final rates and resulted in, *inter alia*,

i) approval of a regulated return on common equity for ratemaking purposes of 9.75%;
ii) approval of a rate of return on rate base for 2003 of 8.96%, in a range of 8.78% to 9.14%; and for 2004 of 8.91%, in a range of 8.73% to 9.09%;
iii) a decrease of 0.15% in rates to become effective August 1, 2003; and
iv) the re-establishment of the Automatic Adjustment Formula for the years 2005, 2006 and 2007.

The operation of the Automatic Adjustment Formula resulted in an average decrease in rates of 0.49% in 2005 [Order No. P. U. 50(2004)]; no rate change in 2006 [Order No. P. U. 3(2006)] and an average increase of 0.07% in 2007 [Interim Order No. P. U. 42(2006) and Order No. P. U. 9(2007)]. In 2007, NP's purchased power costs from Hydro increased by 3.1% but were offset by a one time adjustment to Hydro's Rate Stabilization Historical Plan Balance.

2006 Revenue Recognition Policy Change Application

On September 29, 2005 NP applied to the Board requesting approval of certain proposed changes to its accounting policy for revenue recognition for regulatory purposes. These changes flowed from an outstanding tax case which concluded through a settlement with Revenue Canada in June 2005 and triggered issues in relation to NP's historical policy of using a cash basis for recording revenue. The application proposed the adoption of the accrual method for recording revenue beginning in 2006. This proposed change would require, *inter alia*, consideration of a balance sheet accrual of approximately $24.3 million as of December 31, 2005 (the "2005 Unbilled Revenue") and the application of $9.6 million of this amount in 2006 to offset an increase in depreciation expense and the income tax effects related to the tax settlement. NP proposed that the remaining balance would be considered by the Board at a future date and would be deducted from the rate base. NP also proposed that the Board approve the adoption of the Asset Rate Base Method for calculating rate base as of 2006 to be used in the next general rate application of the utility.

A public hearing into this application took place on December 7, 8 and 9, 2005, with participation from the utility, the Government appointed Consumer Advocate, Mr. Thomas Johnson, and the Board's financial consultants Grant Thornton. In Order No. P. U. 40(2005), issued on December 23, 2005, the Board approved, *inter alia*, the use of the accrual method of revenue recognition commencing in 2006, as well as the use of the book common equity instead of regulated common equity in the calculation of rate base. It also approved the use of $3,086,000 of the 2005 Unbilled Revenue in 2006 to account for income tax effects arising from the tax settlement, but ordered NP to defer recovery of an increase in the 2006 depreciation expense related to the amortization of the depreciation true-up approved in Order No. P. U. 19(2003). The Board also approved NP's proposal to deduct the average value of the unrecognized 2005 Unbilled Revenue from rate base, commencing in 2006.

The Consumer Advocate filed a Notice of Application for Leave to Appeal certain aspects of Order No. P. U. 19(2003) to the Newfoundland and Labrador Supreme Court, Court of Appeal. Leave to appeal was denied.

<u>2006 Amortization and Cost Deferral Application</u>

On September 13, 2006 the Board received an application from NP requesting, among other things, approval for the amortization of $2,714,000 of the 2005 Unbilled Revenue as revenue for regulatory purposes to offset the ongoing tax effects of the tax settlement of 2005. As well, NP requested approval to defer, until a further Order of the Board, the recovery of $5,793,000 related to the conclusion of the depreciation true-up in 2005. The Consumer Advocate, Mr. Thomas Johnson, filed a Notice of Intervention and, after the exchange of RFIs and responses and a report from the Board's financial consultants, written final submissions were filed. On December 5, 2006 the Board issued Order No. P. U. 39(2006) approving NP's application.

<u>Capital Budget Applications</u>

Pursuant to the *Act* NP filed annual capital budget applications with the Board during the period 2003-2007. The Board held public hearings to review NP's 2004 and 2005 Capital Budgets.

The Board established "Provisional Capital Budget Application Guidelines" in 2005 following a comprehensive consultation process with interested persons including the utilities and the Consumer Advocate. NP's 2006 Capital Budget application was filed on June 29, 2005 using these Provisional Capital Budget Application Guidelines. After publication of notice no intervenor submissions were received. NP answered a number of RFIs from the Board and the application was considered on the basis of the written record without a public hearing. Order No. P. U. 30(2005) was issued on November 14, 2005 approving the application as proposed.

NP's 2007 Capital Budget application was filed on April 28, 2006, again using the Provisional Capital Budget Application Guidelines. The Consumer Advocate, Mr. Thomas Johnson, was a registered intervenor and the process included exchange of a number of RFIs and related responses, a site visit and a technical conference related to the refurbishment of the

Rattling Brook hydroelectric plant, for which significant capital expenditures were being proposed, and written submissions by NP and the Consumer Advocate. The Board issued its Order No. P. U. 30(2006) on September 29, 2006 approving the application as proposed.

In each of NP's capital budget applications the Board approved the revised annual rate base and invested capital which would be used in the Automatic Adjustment Formula in determining the rates and the return on rate base for the subsequent year.

Rate Stabilization/Municipal Tax Adjustments

Hydro maintains a Retail Rate Stabilization Plan ("RSP") to smooth rate impacts for certain variations between actual results and Hydro's test year cost of service estimates for hydraulic production, fuel costs, customer load and rural rates. In conjunction with the RSP the Board has approved a Rate Stabilization Account ("RSA") for NP which includes a Rate Stabilization Adjustment in the rates charged by NP. Municipal taxes charged to NP by municipalities in the Province are collected through a Municipal Tax Adjustment ("MTA") factor included in its rates. The Rate Stabilization Adjustment is recalculated on July 1 of each year to reflect the accumulated balance in the RSA and any change in the mill rate charged to NP by Hydro as a result of the operation of the RSP. The MTA factor is also recalculated on July 1 of each year.

The annual Rate Stabilization and Municipal Tax Adjustments resulted in rate increases for NP of 2% in 2003, 4.5% in 2004, 5.2% in 2005 and 4.8% in 2006. On July 1, 2007, for the first time since 2002, there was a decrease in rates of 2.9%.

Other Applications

During the period 2003-2007 the Board also dealt with a number of additional applications from NP, including routine Contribution in Aid of Construction approvals, annual approval of balances in the Weather Normalization Account, and changes to NP's System of Accounts.

Other specific Orders issued by the Board in relation to NP during 2003-2007 included:

(i) Order No. P. U. 33(2003) – Approval of removal of certain of NP's diesel generating plants, St. John's Diesel Plant and Portable Diesel Units #1 and #2, from service;

(ii) Order No. P. U. 49(2004) – Approval of a variation from generally accepted accounting principles concerning the amortization of costs associated with a proposed Early Retirement Program;

(iii) Order No. P. U. 1(2005) – Approval to borrow up to $100,000,000 under the terms of a committed revolving term credit facility for the purposes of financing its working capital requirements and its capital expenditure requirements; and

(iv) Order No. P. U. 20(2005) – Approval of issuance of Series AK First Mortgage Sinking Fund Bonds up to $60,000,000.

III. REGULATORY FRAMEWORK

Beginning with Order No. P. U. 7(2002-2003) the Board has, in subsequent GRA Orders, outlined the overall framework applied by the Board in the regulation of both NP and Hydro. This regulatory framework is referenced in Appendix A of this Decision and Order and incorporates the Board's statutory authorities and responsibilities, jurisprudence, established Board procedures and reporting/compliance requirements of utilities, along with a list of governing regulatory principles and a description of the rate setting process. The Board believes clarity, consistency, efficiency and transparency are essential cornerstones to sound and effective regulation. This framework remains a stable, useful and predictable roadmap for stakeholders participating in the regulatory processes of the Board. The Board will continue to rely on this regulatory framework but acknowledges revisions may be required from time to time to encompass legislative amendments and/or changes to Board policies, practices or procedures.

PART TWO. BOARD DECISIONS

I. CONSENSUS ISSUES

1. Use of Negotiated Settlements in General Rate Applications

In Hydro's 2006 GRA and now again in this Application, the parties have participated with considerable success in a Board facilitated negotiated settlement process in advance of the scheduled public hearing. The result of this Alternative Dispute Resolution (ADR) mechanism has, in each circumstance, resulted in an amended application from the utility and a signed settlement agreement addressing substantive issues arising from the original application. The amended application encompassing the settlement agreement and matters yet unresolved through the ADR process was then the subject of the public hearing and the resulting Decision and Order of the Board.

Order No. P. U. 8(2007) relative to Hydro's 2006 GRA highlighted the unanimous support of all parties respecting the negotiated settlement process, quantified some of the regulatory efficiencies achieved in terms of reduced hearing days, and hence lower costs, and pointed to several lessons learned in this the first such successful settlement negotiation of its kind facilitated by the Board. In that particular Decision and Order the Board stated:

> *"In conclusion, the Board is encouraged by the results of the negotiations and settlement process and believes it will serve as a valuable tool to be expanded and structured as required to meet the varying regulatory needs of the Board and its stakeholders. A number of useful lessons have been learned through the success experienced during this particular exercise, which will contribute to further enhancements to ensure the process becomes an integral part of the Board's regulatory framework."*

With respect to NP's current 2008 GRA, the participants again spoke favourably of the negotiated settlement process and the benefits flowing from the substantive agreement reached on many of the issues. These comments are outlined below:

<u>Newfoundland Power</u>

> (Mr. Kelly, Q.C.)…All parties were committed to constructive negotiation with a genuine desire to find solutions that fairly balance the interest of consumers and the interest of the utility. The result has been an agreement that resolves virtually all of the monetary issues and provides for a complete review of Newfoundland Power's rate structures over the next several years.
> (Transcript, Oct. 22, 2007, pg. 14/10-19)

> (Mr. Kelly, Q.C.) …The success of the negotiation process for Newfoundland Power's General Rate Application demonstrates the improved efficiency of the regulatory process in this jurisdiction.
> (Transcript, Oct. 22, 2007, pgs. 14/23-25; 15/1-2)

> (Mr. Kelly, Q.C.)…The efficiency of the hearing process, only five days of evidence was necessary, is a function of the Negotiated Settlement Agreement which was reached in this matter. As Mr. Ludlow indicated in his evidence, Newfoundland Power will continue to support and encourage the negotiated settlement process in the future.
> (Transcript, Nov. 5, 2007, pg. 2/12-19)

Consumer Advocate

(Mr. Johnson)…I should say that negotiations in such matters are never easy, but they were quite useful in this instance, as they provided a means for the Parties to get at the heart of several key issues after the file record was on the table so that they could be thoroughly discussed and where possible resolved on mutually acceptable terms in the context of an overall agreement.
(Transcript, Oct. 22, 2007, pgs. 41/20-25; 42/1-3)

(Mr. Johnson)…And I share my friend, Mr. Kelly's, observations that this has been certainly an efficient process.
(Transcript, Nov. 5, 2007, pg. 37/20-22)

Newfoundland and Labrador Hydro

(Mr. Young) …And I can also advise the Board that we are comfortable and assured that our participation was not necessary to further the progress of the negotiations. And we applaud the Parties for the success in that. It reminds me of the last hearing, we spent a considerable amount of time applauding ourselves on the success of the negotiations and it's become very business as usual, which I think is the way things ought to become here.
(Transcript, Oct. 22, 2007, pg. 61/11-21)

For the second time in successive GRAs the Board is encouraged by the collective achievements gained through the ADR process. These agreements reflect the process of negotiation and consensus building among the parties. This process is deemed more effective in relation to certain issues than the adversarial approach where each party advocates substantially different positions in a public hearing which must then be adjudicated by the Board. In addition, these agreements have resulted in proposals to reduce electricity rates initially applied for by the utility and as well assisted to resolve numerous other issues normally contested through a public hearing. As demonstrated with similar results in Hydro's 2006 GRA, the comparative length of the last two public hearings into NP's GRA's is in part illustrative of the regulatory efficiencies achieved in this particular settlement agreement. This comparison is shown below:

GRA	No. of Hearing Days
NP 2003	26
NP 2008	5.5

NP's 2003 GRA, without the benefit of a substantive settlement agreement, took 26 public hearing days to complete versus 5.5 days for this particular hearing. This suggests considerable regulatory savings with respect to NP's 2008 GRA which are ultimately passed on to electricity consumers.

NP and the Consumer Advocate are to be commended by the Board for the co-operative and responsible manner in which each participated in this negotiation process. Appreciation is also extended to Mr. Mark Kennedy who so ably facilitated the negotiation process.

Given the success of this initiative to date, the Board is committed to enshrining the negotiated settlement process into its regulatory policies and procedures. The Board views the negotiated settlement process as yet another opportunity to expand its existing regulatory processes and improve its regulatory efficiencies. While not ordering any specific action as part of this Order, the Board will be inviting all interested parties to assist in the formulation of appropriate policies, practices and procedural guidelines governing future negotiated settlement processes and their resulting agreements. The Board sees these discussions as consultative and iterative following much the same approach taken to develop the Provisional Capital Budget Application Guidelines.

2. Settlement Agreement Proposals

In the Settlement Agreement the parties set out a consensus position on the following matters:

- Cost of Capital;
- Cost of Service Study, Methodology and Rate Design;
- Asset Rate Base Matters;
- Automatic Adjustment Formula;
- Amortization of regulatory deferrals and reserves;
- Accounting treatment of Other Post Employment Benefits and Pension Costs;
- Depreciation Matters;
- Replacement of the Purchased Power Unit Cost Variance Reserve;
- Implementation of the Energy Supply Cost Variance Clause; and
- Rule Amendments.

NP's original proposals in relation to these matters above and the agreement of the parties with respect to each are set out below. The impact of the Settlement Agreement proposals are outlined in Section 3 - Amended Application.

i) Cost of Capital

In the original Application NP proposed a target rate of return on common equity for ratemaking purposes of 10.25%, requiring a $6,020,000 or a 1.9% increase in 2008 Test Year revenue requirement. The 2007 ratemaking return on equity established by the Automatic Adjustment Formula for 2007 was 8.6%. NP proposed a capital structure[1] consistent with previous Board Orders, with a 45% common equity component. According to NP, *"A common equity component of capital structure of 45 percent, together with a rate of return on common equity of 10.25 percent, will provide Newfoundland Power the opportunity to improve its credit metrics and maintain its investment grade credit rating."* (NP Application, pg. 57, lines 7/14)

The Settlement Agreement set out the following as being agreed to between the parties with respect to the capital structure and rate of return:

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[1] Capital structure is the mix of debt and equity invested in a company, with debt representing the investment of bondholders, or other long-term debt holders, and equity representing the investment of shareholders, in either common or preferred stock. (NP Application, pg. 56)

- *"The Parties agree that the risk free rate to be used for rate making purposes for NP's 2008 Test Year (i.e. the 30 Year Long Canada Bond Yield) should be 4.60%. The agreement reached by the Parties on the risk free rate is a reasoned consensus having regard to all available data, including the most current information from the financial markets and Consensus Forecasts.*

- *It is recognized that the Board's Decision and Order No. P.U. 19(2003) established an equity risk premium for NP of 4.15% at a risk free rate of 5.60%. Consistent with the adjustment mechanism in the Automatic Adjustment Formula, the equity risk premium for NP should be 4.35% at a risk free rate of 4.60% for the 2008 Test Year.*

- *The agreed upon rate of return on common equity for NP's 2008 Test Year should be calculated as follows:*

Risk Free Rate	*4.60%*
NP Equity Risk Premium	*4.35%*
Rate of Return on Common Equity	*8.95%*

- *The capital structure of NP as proposed in the Application should be approved."*

ii) Cost of Service Study, Methodology and Rate Design

In accordance with established regulatory practice and previous Board Orders, NP uses an embedded Cost of Service (COS) Study to assess fairness of cost recovery by customer class. The COS Study used in assessing customer rates in this Application is based on 2005 results, but reflects current rates and the current depreciation study. The COS Study also incorporates the results of the 2006 Load Research Study completed by NP, which was also filed with the Application. NP's proposed rate design also incorporates marginal cost considerations as determined by a Marginal Cost Study completed in January 2007. (NP Application, pgs. 113-115)

The Settlement Agreement set out the following as being agreed to between the parties with respect to the COS Study, methodology and rate design:

- *"The COS Study and Methodology as filed by NP in the Application is in keeping with previous Board Orders concerning the same and should be used to design NP's new rates.*

- *Excepting the Basic Customer Charges for NP's Domestic and GS 2.1 Customers, the Rate Design, including the relative rate changes by class, as filed by NP should be used by the Board to set Customer Rates.*

- *The Basic Customer Charge for Domestic customers remains a matter in issue to be determined by the Board.*

- *Instead of the rate design for GS 2.1 customers as proposed in the Application, the Basic Customer Charge for GS 2.1 customers should be maintained at current levels and the energy charge should be adjusted to recover any change in revenue allocation to this class.*

- *The Parties have agreed on a process for the review of NP's Domestic and General Service Rates (the "Rate Review"), as set out in Attachment A."*

iii) Calculation of Average Rate Base

In Order No. P.U. 19(2003) the Board found that the Asset Rate Base Method ("ARBM") should be used to calculate NP's rate base. As part of the Application NP filed a report entitled "A Report on the Implementation of the Asset Rate Base Method" detailing the remaining issues required to be addressed to adopt the ARBM. The outstanding matters include reconciling the remaining differences between NP's average rate base and its average invested capital, as well as removing unamortized deferred debt costs, which are currently included in rate base. NP proposed in the Application that the calculation of the rate base fully reflect the ARBM.

The Settlement Agreement states: *"The Parties agree with NP's implementation of the Asset Rate Base method as set forth in the Application."*

iv) Automatic Adjustment Formula

In the original Application NP proposed the following changes to the Automatic Adjustment Formula: (i) that the changes in the risk-free rate used in the calculation of the weighted average cost of capital ("WACC") be determined by reference to *Consensus Forecasts*; and (ii) that the arithmetic expression of the Formula be changed to reflect the transition to the ARBM to calculate rate base. NP proposed that the Formula be used to set rates for a further three-year period beyond 2008.

The Settlement Agreement states: *"The Automatic Adjustment Formula, reflecting the adoption of the Asset Rate Base Method as proposed in the Application, should operate in accordance with the existing methodology used by the Board to set rates for not more than three (3) years following the 2008 Test Year."*

v) Amortization of Regulatory Deferrals and Reserves

NP has a number of revenue deferrals and cost recovery deferrals related to previous Board Orders and accounting policy changes. The forecast regulatory deferrals as of December 31, 2007 are set out in NP's Pre-filed Evidence (pg. 82) and are shown below:

Regulatory Deferrals December 31, 2007 ($000s)		
Revenue Deferrals		
2005 Unbilled Revenue		16,446
Municipal Tax Liability		4,087
	Total:	**20,533**
Cost Recovery Deferrals		
Depreciation		11,586
Replacement Energy		1,147
	Total:	**12,733**

The 2005 Unbilled Revenue deferral results from NP's 2006 adoption of the accrual method of revenue recognition. The municipal tax liability of approximately $4.1 million arises as a result of the transition to the ARBM for calculation of rate base and the timing difference related to the recovery and payment of municipal taxes.

The cost recovery deferrals include deferrals related to depreciation in 2006 and 2007 and replacement energy costs in 2007. The depreciation cost deferrals represent approximately $5.8 million in each of 2006 and 2007 and effectively offset an increase in NP's depreciation expense in those years related to the conclusion in 2005 of the depreciation true-up as established in Order No. P.U. 19(2003). The replacement energy cost deferral was approved by the Board in Order No. P.U. 39(2006) and offsets an increase in NP's 2007 power supply costs related the refurbishment of the Rattling Brook Hydroelectric Plant. In the original Application NP proposed a five-year amortization of these regulatory deferrals. This proposed amortization will reduce pro-forma revenue requirements by approximately $5.1 million in 2008 and $1.1 million thereafter. (NP Application, pg. 85)

NP has also proposed that the current balances in the Degree Day component of the Weather Normalization Reserve and the Purchased Power Unit Cost Variance Reserve be amortized over five years. The proposed five-year amortization of these reserve balances would increase pro-forma revenue requirements by approximately $1.7 million per year through 2012. (NP Application, pg. 89)

NP also proposed that costs of the Board and the Consumer Advocate associated with the 2008 GRA, estimated at $1.2 million, be amortized evenly over a three-year period commencing in 2008.

As part of the Settlement Agreement the Parties agreed that the following regulatory deferrals and reserves should be amortized over three years commencing in 2008:

i. 2005 Unbilled Revenue (net of the 2008 one time tax effect);
ii. Municipal taxes;
iii. Deferred depreciation costs;
iv. Deferred replacement energy costs;
v. Balance in the Purchased Power Unit Cost Variance Reserve; and
vi. Application and Hearing Costs.

The Settlement Agreement proposed that the balance attributable to the Degree Day component of the Weather Normalization Reserve be amortized over five years, as proposed in the original Application.

vi) <u>Other Post Employment Benefits and Pension Costs</u>

NP provides two categories of benefits to its employees upon retirement: pension plans and other post employment benefits (OPEBs) such as retirement allowances and health, medical and life insurance for retirees and their dependants. Effective January 1, 2000 the Canadian

Institute of Chartered Accountants (CICA) recommended the adoption of the accrual method of accounting for OPEBs. NP currently accounts for pension plans on an accrual basis, while OPEBs are accounted for on a cash basis. Under the cash basis the amount of OPEBs costs recognized as an expense and included in revenue requirement is equal to the retirement allowance and insurance premiums actually paid in that year.

In Order No. P. U. 19(2003) the Board ordered NP to file a report with its next general rate application addressing the use of the accrual method of accounting for OPEBs expense as an alternative to the existing cash accounting treatment, including the impact on customers' rates. NP filed the report entitled "Employee Future Benefits Report" as part of its Application. In the original Application NP proposed to adopt the accrual method of accounting for OPEBs expense for regulatory purposes effective January 1, 2008. This change would result in an increase in 2008 test year expense of $6.4 million net of the associated income tax.

The transitional obligation associated with NP's proposed adoption of the accrual method of accounting for OPEBs in 2008 is $34.1 million. This transitional obligation arises from the difference between the use of the cash and accrual methods of accounting for OPEBs for the period 2000 to 2007. The Application proposed that the disposition of this transitional obligation be considered by the Board at NP's next general rate application. It was suggested that this would allow for an effective phasing in of the recovery of accrued OPEBs liabilities which, in turn, will help to moderate the immediate impact of the accounting change of customers' rates. (NP Application, pg. 78)

NP also proposed to adopt accrual accounting for the income tax expense related to OPEBs effective January 1, 2008 concurrent with its adoption of accrual accounting for OPEBs. (NP Application, pg. 80) This proposal would reduce NP's income tax expense, partially offsetting the impact on rates of the adoption of the accrual method of accounting for OPEBs. As well the calculation of NP's rate base would be affected with the subtraction from the rate base of the resulting average net accrued OPEBs liability, which is the cumulative amount by which recognized OPEBs expense has exceeded OPEBs payments.

The aggregate 2008 test year costs associated with the Application's proposals with respect to OPEBs is $7.2 million, which would require an increase of approximately 1.5% in revenue in 2008. These costs are shown below:

2008 Test Year Costs - OPEBs proposals ($000s)	
Accrual Accounting for OPEBs	6,400
Tax Accrual Accounting	(1,500)
Rate Base Effects	(200)
Income Tax Effects	2,500
2008 Cost Increase	**7,200**

(NP Application, pg. 81)

The Settlement Agreement set out the following as being agreed to between the parties with respect to the treatment of OPEBs:

- *"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.*

- *NP should commence to tax effect with respect to pension costs commencing in 2008 as set forth in the Application."*

vii) <u>Depreciation Matters</u>

NP filed a 2006 Depreciation Study with its Application. Based on this study the original Application proposed to implement new depreciation rates and to amortize an accumulated variance reserve of $0.7 million evenly over four years beginning in 2008. As indicated in the Application NP's revenues do not provide full recovery of depreciation costs, primarily as a result of the use of cost recovery deferrals to offset the impact of the 2005 conclusion of the depreciation true-up. The Application seeks to fully recover depreciation costs in customer rates commencing in 2008. These proposals would result in an increase in required revenue of $8,966,000 or approximately 1.9% in 2008.

As part of the Settlement Agreement the parties agreed that: *"NP's Depreciation Rates, Depreciation Expense for the Test Year and the amortization of the Depreciation Variance should be approved as filed in the Application."*

viii) <u>Replacement of Purchased Power Unit Cost Variance Reserve</u>

In Order No. P. U. 44(2004) the Board approved the establishment in 2005 of a Purchased Power Unit Cost Variance Reserve for NP in conjunction with the approval of a demand and energy rate structure for power purchased from Hydro. This Reserve was set up to provide NP with an incentive to influence demand conservation by its customers and provides a partial cost recovery within a pre-determined deadband, within which NP bears the risk of cost variations associated with its power purchases from Hydro. As of December 31, 2006 this reserve balance was $1,342,000, reflecting the after-tax benefit as a result of reduced demand requirement of NP's customers in 2006. Order No. P.U. 44(2004) requires NP to file an application with the Board no later than March 1st of each year for the disposition of the balance in the account. In Order No. P. U. 10(2007) the Board approved a request by NP to review the treatment of the reserve balance as part of the 2008 GRA.

The original Application proposed to amortize the balance in the Purchased Power Unit Cost Variance Reserve over five years, resulting in an annual amortization of $268,000. As well it proposed to replace this Unit Cost Variance Reserve with a Demand Management Incentive Account, which would be more explicitly related to demand management. (NP Application, pgs. 40-42 & Exhibit 4) The Purchased Power Unit Cost Variance Reserve is based on a combination of demand and energy costs, and the variance factor is based on forecasted amounts, which are updated each year. The proposed Demand Management Incentive Account is based solely on demand costs and the variance factor is based on the test year. NP will still be required to file an application with the Board no later than March 1st of each year for the disposition of the balance in the account.

In the Settlement Agreement the parties agreed that: *"The Purchased Power Unit Cost Variance Reserve should be replaced with the Demand Management Incentive Account as proposed in the Application."*

ix) Implementation of Energy Supply Cost Variance Clause

NP's rates are designed to recover the average test year cost of supplying energy to its customers. However, as load requirements on the system increase as a result of the addition of new customers, NP's supply costs from Hydro to serve these new customers increase due to the structure of Hydro's wholesale rate to NP. NP states that the current supply cost dynamics is such that the marginal supply cost exceeds the average supply cost recovered in rates by approximately 3.4¢ per kWh or approximately 50% for 2007 and 2008. (NP Application, pg. 91) The Application proposes that an Energy Supply Cost Variance Reserve be added to NP's Rate Stabilization Account (RSA) to account for the difference between NP's average energy supply cost and NP's marginal energy supply cost. This mechanism would permit NP to recover supply costs related to the cost of production at Holyrood and, according to NP, will avoid additional regulatory proceedings driven principally by NP's need to recover prudently incurred supply costs. (NP Application, pg. 93)

The Settlement Agreement sets out the following as being agreed to between the parties with respect to the implementation of the Energy Supply Cost Variance Clause:

- *"Subject to paragraphs 27 and 28, the Energy Supply Cost Variance Clause (the "ESCVC") should be added to the Rate Stabilization Clause as proposed in the Application.*

- *The ESCVC will apply to energy supply costs incurred through to the end of 2010.*

- *The agreement with respect to the ESCVC is without prejudice to either Party's position on the issue in any future hearing. For certainty, either Party may seek its extension, modification or non-renewal at either the next GRA or on application to the Board."*

x) Rule Amendments

The Application proposes two changes in NP's Schedule of Rates affecting Regulations 9(b) and 9(c) Requirement for Payment in Advance and Regulation 10(d) Rejected Payment Fee.

In the Settlement Agreement the parties agreed that:

"The Rules should be amended in accordance with the proposal in the Application:

a. To eliminate the requirement for advance payment of fees for temporary connections, special facilities and relocations; and
b. To increase and extend the application of the rejected payment fee."

3. Amended Application

In its Amended Application filed on October 11, 2007 NP incorporated revisions to reflect the impact of the Settlement Agreement as well as changes in 2008 forecasts of costs and sales since the filing of its original Application. These revisions resulted in changes to the proposed 2008 revenue requirement and the proposed rates. The impacts of these changes are described below.

i) Settlement Agreement Impacts

In the Amended Application NP set out the impact of the Settlement Agreement proposals on the 2008 test year revenue requirement filed with the original Application. The net impact of the Settlement Agreement proposals is to reduce the 2008 revenue requirement to be recovered in customer rates by $14,621,000, as shown below:

Impact of Settlement Agreement on 2008 Revenue Requirement ($000s)	
OPEBs	(6,327)
Cost of Capital	(7,251)
Regulatory Deferrals and Amortizations	(1,043)
Net Impact	**(14,621)**

(NP Amended Application, pg. 20)

The net impact of this decrease in 2008 revenue requirement of approximately $14,600,000 is to reduce the average customer rates proposed in the original Application by 3%.

ii) Updated 2008 Forecast of Costs and Sales

The forecast costs and sales revisions include the following revisions to the forecasts of 2008 operating costs, other revenue and finance charges:

- a reduction in 2008 test year forecast insurance costs of $190,000 to reflect insurance policy renewals which occurred after the original Application was filed;
- an increase in 2008 test year forecast of other revenue of $111,000 to reflect a change in revenue associated with wheeling charges paid by Hydro; and
- an increase in 2008 test year forecast finance charges of $900,000 to reflect the impact of Series AL First Mortgage Sinking Fund Bonds issued in August 2007 at a rate higher than anticipated in the original Application, as well as an increase in forecast short-term interest rates.

The impact of these revisions is an increase of $599,000 in the 2008 revenue requirement.

In addition NP also updated the 2008 Customer, Energy and Demand Forecast to incorporate the most recent key forecast assumptions. These updates are set out in detail in the Amended Application (pgs. 7-10) and result in an increase in the forecast number of customers, and higher energy sales and demand. The impact of this updated forecast on the 2008 revenue requirement is an increase of $876,000.

The overall impact of the updated costs and sales forecasts is to increase 2008 revenue requirement by $1,475,000 as shown below:

Impact of Updated 2008 Forecasts of Costs and Sales on 2008 Revenue Requirement ($000s)	
Forecast Cost Revisions	599
Customer, Energy and Demand Forecast Revisions	876
Net Impact	**1,475**

(NP Amended Application, pg. 10)

The net impact of this increase in 2008 revenue requirement is to increase the average customer rates proposed in the original Application by approximately 0.3%.

iii) Proposed 2008 Return on Rate Base

The 2008 return on rate base proposed in the Amended Application is shown below:

Proposed 2008 Return on Rate Base ($000s)	
Regulated return on common equity	32,700
Return on debt	34,680
Return on preferred equity	586
Return on rate base	**67,966**

(NP Amended Application, pg. 25)

The proposed 2008 return on rate base reflects a rate of return on average rate base of 8.37%, as shown below:

Proposed 2008 Rate of Return on Rate Base ($000s)	
Return on rate base ($000s)	67,966
Average rate base ($000s)	÷812,212
Rate of return on rate base	**8.37%**

(NP Amended Application, pg. 25)

As a result of the completion of the transition of the ARBM for calculating rate base NP's rate of return on rate base for ratemaking purposes will be the same as its weighted average cost of capital (WACC).

iv) Proposed 2008 Test Year Revenue Requirement

The Amended Application sets out the revised 2008 test year revenue requirement to be recovered from customer rates as follows:

Summary of 2008 Revised Revenue Requirement ($000s)	Original Application[1]	Amended Application[2]
Power Supply Cost	327,709	337,159
Operating Costs	47,890	47,700
Employee Future Benefits	9,718	3,348
Depreciation and Related Amortizations	42,524	44,070
Income Taxes	22,357	19,568
Return on Rate Base	71,370	67,966
Other Adjustments	92	92
Deductions:		
Other Revenue	(12,011)	(12,122)
Non-Regulated Expenses (Net of Tax)	(983)	(983)
Proposed 2008 Revenue Requirement	**508,666**	**506,798**
Revenue Deferral Amortization	(6,180)	(8,572)
Proposed 2008 Revenue Requirement from Rates	**502,486**	**498,226**

[1]NP Application, Table 41, pg. 99
[2]NP Amended Application, Table 15, pg. 22

The required revenue increase from existing rates is shown below:

Amended Application 2008 Required Revenue Increase ($000s)	Original Application[1]	Amended Application[2]
2008 Proposed Revenue Requirement	508,666	506,798
Revenue From Existing Rates	(478,535) [3]	(485,692) [4]
Amortization of Revenue Deferrals	(6,180)	(8,572)
Elasticity Impact	2,606	1,460
Required Increase in Revenue From Rates	26,557	13,994
Average Customer Rate Increase	**5.3%**	**2.8%**

[1]NP Application, Table 49, pg. 104
[2]NP Amended Application, Table 23, pg. 27
[3]Based on rates in effect as of the filing of the original Application.
[4]Based on rates in effect as of the filing of the Amended Application.

3. Board Findings – Consensus Issues

In considering the Settlement Agreement the Board must be satisfied that the proposals represent an equitable and practical balance between NP's requirement to deliver reasonable least cost electricity to customers and the ongoing financial integrity of NP, consistent with the province's regulatory policy framework. The Board recognizes that, through the negotiation process, compromises were made by each of the parties to arrive at the consensus outlined in the Settlement Agreement. Pursuant to the terms of the Settlement Agreement the individual agreements of the parties are not intended to be severable and the parties recommended that the Board make its determination on the agreed upon issues in accordance with the Settlement Agreement. The parties also agreed that the examination and cross-examination of any witness would be limited to questions necessary to explain or to clarify the provisions of this or any other agreement. Issues not agreed upon would be determined by the Board based on the full record of the hearing. The Board, therefore, in the context of its regulatory mandate has considered the Settlement Agreement proposals as a whole, non-severable proposal.

The Board notes that the negotiation process was comprehensive and involved the experts of both NP and the Consumer Advocate and followed the exchange of in excess of 600 requests for information. The Board's financial consultants Grant Thornton reviewed the calculations, methodologies and assumptions in both the original Application and the Amended Application to verify the accuracy and completeness of the proposals and to ensure compliance with Board orders. The Board is satisfied that the record is sufficient to enable a complete regulatory review of the Amended Application.

i) Cost of Capital

If the Settlement Agreement proposals are accepted by the Board, NP's forecast 2008 credit metrics are as follows (NP, Amended Application, pg. 17):

Pre-tax Interest Coverage (times)	2.5
Cash Flow Interest Coverage (times)	2.9
Cash Flow Debt Coverage (percent)	14.9

Ms. Perry, VP Finance and CFO, commented on the impact of the Amended Application proposals on NP's credit metrics during oral testimony:

> A. So you can see that the credit metrics resulting from the Amended Application are significantly improved over the 2007 forecasted credit metrics and the 2008 credit metrics under existing rates. These metrics will now be at or just slightly below the bottom of the range recommended by Moody's.
>
> I also believe the rating agencies' assessment of the Company's credit worthiness will be positively influenced by other proposals in the Amended Application. In particular, the Energy Supply Cost Variance Clause will ensure that the Company recovers its purchased power.
>
> (Transcript, Oct. 22, 2007, pgs 94/13-25; 95/1)

Moody's Investor Services credit opinion (Exhibit 6) states that a cash flow interest coverage of 3.0 times or higher and a cash flow debt coverage of 15 percent or higher is required to maintain its investment grade credit rating. The forecast 2008 credit metrics are marginally below the bottom of the range recommended by Moody's Investor Services. The Board notes the following comment issued in an October 12, 2007 press release by Moody's (Consent # 2):

> *"Moody's Investor Services believes that, if approved by the Newfoundland and Labrador Board of Commissioners (PUB), the revised GRA will not, in and of itself, result in a change in either the rating or outlook of NPI. Moody's currently rates NPI's senior secured debt Baa1 and has a stable outlook on the company's ratings."*

The Board also notes that the proposed capital structure of 45% equity, 54% debt and 1% preferred equity is consistent with Board Orders since 1990. As well the forecast 2008 cost of debt of 7.93% reflects NP's recent bond issue and an updated forecast of short-term interest rates.

The Board is satisfied that the proposals contained in the Amended Application with respect to NP's cost of capital, including a common equity component of 45% and regulated return on common equity of 8.95%, will provide NP with the opportunity to earn a just and reasonable return on rate base that will enable NP to maintain its creditworthiness, as required by legislation and consistent with the provision of least cost reliable power.

ii) Average Rate Base and Return on Rate Base

The impact of NP's proposal to complete the transition to the ARBM in the calculation of the average rate base was set out in detail in the original Application (pgs. 62-67). NP's forecast average rate base for 2008 is $812,212,000, which includes a reduction of $5,689,000 attributable to the transition to the ARBM. (NP, Written Submission, pg. 14) Grant Thornton's review confirmed that the forecast 2008 rate base is calculated in accordance with established practice and appropriately incorporates proposed changes related to the transition to the ARBM. The parties agreed as part of the Settlement Agreement that NP should implement the ARBM to calculate its rate base for the 2008 test year. The Board, however, sees value in requiring NP to continue to provide an annual report detailing changes in deferred charges, especially in view of the possible changes in accounting rules proposed by the AcSB.

The Board is satisfied that NP's forecast 2008 rate base of $812,212,000 has been calculated properly in accordance with established practice and appropriately incorporates proposed changes associated with the transition to the Asset Rate Base Method. The Board will require NP to continue to file, as part of its annual return, information relating to changes in deferred charges, including pension costs.

In the Amended Application NP is proposing a return on rate base for 2008 of $67,966,000, which reflects the capital structure and regulated return on common equity agreed to in the Settlement Agreement. This return on rate base equates into a rate of return on rate base of 8.37%. The Board has accepted the capital structure and regulated return on common equity agreed to in the Settlement Agreement and incorporated in the Amended Application. Grant

Thornton's review confirmed the forecast 2008 rate of return on rate base is calculated in accordance with established practice and appropriately incorporates the Settlement Agreement proposals.

The Board notes that no party raised any issue with respect to the current range of return on rate base for NP of ±18 basis points used by the Board when establishing the rate of return on rate base.

The Board will approve NP's proposed rate of return on rate base for 2008 of 8.37%, within a range of 8.19% to 8.55%.

iii) Proposed 2008 Test Year Revenue Requirement

With regards to the proposed 2008 test year revenue requirement, including power supply costs, operating costs, employee future benefits, depreciation, income taxes and return on rate base, the Board has reviewed the proposals contained in the Amended Application and the resulting impact on rates. The Board notes that the parties have substantially agreed on the revenue requirement to be recovered in rates, with the exception of outstanding issues related to the implementation of a productivity allowance and certain resources for other specific issues which are discussed in Part Two – Section II of this Decision and Order.

NP's forecast 2008 controllable operating costs represent approximately 9.5% of the forecast 2008 revenue requirement. [Exhibit 9 (1st Revision)] The Board notes that NP's operating costs have remained relatively stable at $49 million since 2002, and that the gross operating cost per customer is forecast to decrease by approximately 5.0% from 2002 to forecast 2008. [Exhibit 1 (1st Revision)] The Board accepts that this level of operating costs demonstrates that cost efficiencies have been achieved to the benefit of customers.

The Board notes the parties' agreement on the accounting treatment for OPEBs, which provides for continued recognition of OPEBs costs on a cash basis at this time. This proposal has been put forward in the context of achieving a balance between the principles of rate stability and intergenerational equity. The parties have proposed that the Board should give the principle of rate stability more weight at this time, recognizing that significant rate increases have been experienced by customers in recent years principally due to increased fuel costs at Hydro's Holyrood Thermal Generating Station. In the context of the non-severable Settlement Agreement considered as a whole, the Board is prepared to accept this proposal. In accepting this proposal the Board recognizes that the transitional obligation associated with delaying the adoption of the accrual method of accounting for OPEBs will increase by approximately $6.3 million per year. The Board will consider the rate impacts and the appropriate recovery of this transitional obligation as part of NP's next GRA. The Board also accepts the Settlement Agreement proposal related to the adoption of accrual accounting for income tax associated with pension costs.

In terms of the other components of the proposed revenue requirement, including the proposed amortizations for the regulatory deferrals and reserves and the test year depreciation expense and related amortizations, the Board is satisfied that these should also be approved as presented.

The Board is satisfied that, on an overall basis, the proposed 2008 test year revenue requirement as set out in the Amended Application incorporates a reasonable forecast of costs for the 2008 test year and is consistent with the provision of least cost service. The Board will also accept NP's proposal to undertake its next depreciation study in 2011 for plant in service as of December 31, 2010.

The Board accepts the 2008 test year revenue requirement, including the proposed amortizations for the regulatory deferrals and reserves, as proposed in the Amended Application. The Board will require NP to file a new depreciation study related to plant in service as of December 31, 2010.

iv) Automatic Adjustment Formula

The Automatic Adjustment Formula ("AAF") was established by the Board in Order Nos. P. U. 16(1998-99) and P. U. 36(1998-99) and was approved, with modifications, for continued use in Order No. P. U. 19(2003). In accordance with the Settlement Agreement the Amended Application proposes that the Board approve the continued use of the AAF with the existing methodology to set rates for not more than three years following the 2008 test year. The only proposed change is that the arithmetic expression of the AAF be changed to reflect the use of ARBM for calculating rate base. The revised arithmetic expression for the AAF is as follows:

Return on rate base = [rate base x weighted average cost of capital]

The Board agrees that the continued use of the AAF is appropriate both in terms of regulatory efficiency and greater regulatory predictability and certainty. The change in the arithmetic expression of the AAF is required to reflect the full adoption of the ARBM for calculating the rate base.

The Board will approve the proposed change to the Automatic Adjustment Formula to reflect the full adoption of the Asset Rate Base Method for calculating rate base and the continued use of the Automatic Adjustment Formula to set rates for not more than three (3) years following the 2008 test year.

v) Demand Management Incentive Account

The Demand Management Incentive Account proposed to replace the existing Purchased Power Unit Cost Variance Reserve will isolate the demand and energy cost variability and, according to NP, provide *"a meaningful incentive for Newfoundland Power to undertake reasonable initiatives to minimize peak demand."*

The Board is satisfied that the Demand Management Incentive Account should be accepted as proposed in the Settlement Agreement, and should replace the existing Purchased Power Unit Cost Variance Reserve. This Account will isolate the demand costs and, in conjunction with the Energy Supply Cost Variance discussed below, provide NP with the ability to recover its costs associated with variability in purchased power costs inherent in the demand and energy wholesale rate. The implementation of the Demand Management Incentive Account will provide for more transparency in monitoring variability in purchased power costs and allow for tracking of the impacts of any initiatives undertaken by NP to reduce peak demand. 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.

vi) Energy Supply Cost Variance

This mechanism is proposed to address the current supply cost dynamics that exist on the system and is intended to capture the change in energy supply costs related to the difference between purchasing energy at the 2nd block energy charge in the wholesale rate and the test year energy supply cost reflected in customer rates.

The Board is satisfied that the Energy Supply Cost Variance to be added to the Rate Stabilization Clause, as proposed in the Application and agreed to in the Settlement Agreement, should be approved. The recovery of variances in energy supply costs through the Rate Stabilization Account will allow NP to recover its prudently incurred energy supply costs without the necessity of filing a general rate application, which is consistent with the Board's goal of enhanced regulatory efficiency. The parties have proposed that this mechanism remain in place for the period 2008 up to and including 2010 with any renewal or extension requiring further consideration by the Board. The Board agrees with this proposal and will review the operation and impact of the Energy Supply Cost Variance in the Rate Stabilization Account as part of NP's next GRA.

The Board will approve the proposed change to the Rate Stabilization Clause to provide for the recovery of the Energy Supply Cost Variance through the Rate Stabilization Account for the period 2008 to 2010.

vii) Cost of Service Study, Methodology and Rate Design

The Settlement Agreement proposed that the COS Study and methodology proposed by NP is in keeping with previous Board Orders and should be used by NP to design new rates. The Board notes that NP completed an embedded COS Study for the 2008 test year as required by the Board and that the results of the recently completed Load Research Study were used to allocate demand costs to each class in the COS Study. As well the results of the Marginal Cost Study have been incorporated in the design of rates to reflect the high marginal cost of energy on the system.

The Board is satisfied that NP's COS Study and methodology and the Marginal Cost Study are appropriate to be used in establishing 2008 customer rates.

The parties also agreed that NP's rate design proposals should be approved, with the exception of the Basic Customer Charge for Domestic Customers, which is addressed in Part Two – Section II of this Decision and Order. NP's proposed rate design includes revenue to cost ratios ranging from 93.7% for Domestic Customers to 119.8% for General Service 0-10 kW Customers, reflecting the results of the Load Research Study. Revenue to cost ratios are higher than 110% for three of the General Service classes. (NP, Written Submission, pg. 41) NP states that it proposes to bring all customer classes to within its target revenue to cost ratio range[2] at its next general rate proceeding. NP states that *"The rate proposals in the Amended Application, if approved by the Board, will advance approximately half way to this goal."* The Board accepts this approach as being a reasonable manner to phase in changes to customer class recovery ratios and is consistent with rate design principles of fairness and stability.

With the exception of the Basic Customer Charge for Domestic Customers, which is specifically addressed as one of the contested issues in this Decision and Order, the Board will approve the rate design proposals set out by NP in the Amended Application.

viii) Amendments to Rules and Regulations

The Amended Application proposes changes to Regulations 9(b) and 9(c) to permit charges for temporary connections, special facilities and relocations to be included on customer bills, subject to credit approval. Regulation 10(d) is also proposed to be changed so that the fee be increased to $16.00 to better reflect costs. As well the Amended Application proposes to expand the application of the fee to include stopped payments and cheques rejected for reasons other than insufficient funds. NP advises that a comparable fee is applied by many other utilities to all returned payments.

These changes were agreed to by the Consumer Advocate as part of the Settlement Agreement. The Board is satisfied that these changes to the Rules and Regulations should be approved as proposed.

The Board will approve the proposed changes to Regulations 9(b) and 9(c) and to Regulation 10(d).

[2] In Order No. P. U. 7(1996-97) the Board stated: *"The Board agrees with the philosophy that it is not necessary to achieve a 100% revenue to cost ratio for all classes and takes no exception to a variance of up to 10%, i.e. to achieve between 90% and 110% of the cost of service to revenue."*

II CONTESTED ISSUES

1. Matters Unresolved – Settlement Agreement

In the Settlement Agreement the parties acknowledge that the following issues were unresolved and would be the subject of *vive voce* evidence at the hearing of the Amended Application by the Board:

"a) "Are the interests of NP's ratepayers being adequately protected in the charge out structure adopted by NP in relation to services performed by NP on behalf of or for Fortis-related companies? Without limiting the scope of the this issue, should a "stand-by" charge apply in respect of NP's executive and management which has provided and continues to provide a pool of talent for the use of Fortis Inc. and its affiliates?

b) What is the appropriate regulatory response to the issue of NP's executive management personnel receiving personal bonuses in respect of services rendered to Fortis Inc. or its affiliates?

c) Has it been adequately established that inter corporate transactions carried out since the Board's Order and Decision P.U. 19(2003) involving NP provided demonstrable benefit to NP and its ratepayers?

d) Is it appropriate for the Board to undertake a process aimed at codifying an Inter-Affiliate Code of Conduct for NP?

e) Should a Distribution Reliability Standard be developed for NP?

f) Should the Basic Customer Charge for Domestic customers be reduced from the level as proposed by NP in its Application?

g) Should NP provide a financial incentive to customers who opt to receive their bills by email?

h) Should the Board recognize an allowance for productivity for NP?

i) Given that NP does not have a tracking system for vacant positions, how should it be ensured that any savings related to vacancies which may occur are reflected in the rates of NP's customers?

j) Should the Board direct NP to undertake efforts to actively promote and coordinate with Newfoundland and Labrador Hydro on the development and implementation of communication programs related to utility safety issues, with such initiatives to include coordination of safety messages, sharing of media space, printing and production costs and to provide a record and report of the progress of these initiatives including the efficiencies achieved and cost savings realized, if any, at NP's next GRA?

k) Is NP's current practice of repurchasing its used poles at new pole prices ensuring the provision of least cost electricity to consumers?

l) *Should the Board direct NP to devote additional resources to develop and promote energy conservation communication for radio and television outreach to its consumers?*

m) *What are the changes to NP's Customer Energy and Demand Forecast for the Test Year since the Application?*

n) *What are the changes to NP's Revenue Requirement for the Test Year since the Application?"*

The following issues arising from the Application, considered by the parties to be non-issues, were set out as not being required to be raised in the hearing. These include: i) vehicle use and expenses; ii) review of NP's tax case; iii) vegetation management; iv) forecast methodology; and v) capitalization of costs for NP's rate design study.

The issues set out in (m) and (n) above were subsequently addressed in NP's Amended Application. The following sections set out the parties' position for each of the remaining contested issues identified above.

2. Board Findings – Contested Issues

i) Inter-Corporate Relationships and Transactions

Background

Issues surrounding inter-corporate relationships and transactions associated with NP and its affiliates have been considered by the Board in previous NP GRAs. Order Nos. P.U. 6(1991), P.U. 7(1996-97), P.U. 36(1998-99) and P.U. 19(2003) have all previously addressed inter-corporate issues in substantial detail. In Order No. P. U. 19(2003) the Board noted the increasing complexity of relationships between Fortis and its affiliates, including NP, and in this context decided it may prove useful to set out some guiding principles. Specifically the Board stated that NP was required to observe the following principles in all inter-corporate transactions:

"*(i) All inter-corporate transactions between a utility and its affiliates shall be fully transparent and are subject to scrutiny by the Board.*
(ii) A utility shall have the right to manage its affairs but it must demonstrate to the satisfaction of the Board that all affiliate transactions are prudent.
(iii) A utility shall ensure that inter-corporate transactions will not disadvantage the interests of ratepayers and furthermore that ratepayers and the utility will derive some demonstrable benefit from such transactions.
(iv) The onus is on the utility to show that it is in compliance with the guidelines and principles with respect to inter-corporate transactions."

Order No. P. U. 19(2003) required NP to file a detailed report in relation to its operating practice and procedures setting out details in relation to benefits and market rates. The Board notes while the level of inter-corporate activity has been high in the past, there has been a considerable reduction in this activity in recent years.

<u>Issues</u>

In the Settlement Agreement the following issues concerning inter-corporate relationships and transactions were identified as being unresolved:

i) whether the charge out structure for executive and senior management time adequately protects the interests of customers;
ii) bonuses paid to executives for inter-corporate services;
iii) whether inter-corporate transactions provide demonstrable benefits to customers; and
iv) codification of an inter-affiliate Code of Conduct.

With respect to inter-corporate transactions the Consumer Advocate points out:

"*Transactions between the utility and its affiliates present unique challenges, as they are non-arms-length transactions. Economically, it must be observed, there is no real incentive for NP to seek to maximize benefits to the advantage of its ratepayers. If NP charges more for the service it provides to its parent or affiliates, it will reduce the profits of its shareholders*." (Written Submission, Consumer Advocate, pg. 30/57)

On the issue of whether inter-corporate transactions provide demonstrative benefits to consumers, NP argued that these inter-corporate relationships clearly benefit customers by reducing operating costs and cited several examples including:

- economies of scale derived from managing all utility poles in NP's service territory;
- the centralized insurance program reducing NP's insurance program costs by 25% and saving over one percent of the Company's total 2008 operating costs forecast;
- negotiated volume discount of 5% on 2007 transformer purchases saving NP $230,000 in capital costs; and
- other not readily quantifiable benefits involving deployment of staff which assist in developing a skilled workforce. (NP, Written Submission, pg. 59)

During the hearing Mr. Ludlow described the value of inter-corporate relationships to his own personal development at NP:

> A. For me personally, I've had the privilege of working in operating roles in three regulated Fortis utilities other than Newfoundland Power. I have experience with different work methods, electrical system service standards, as well as a variety of approaches to customer service and the use of various technologies. I've seen things that work well and conversely, I've seen things that have worked not so well in a variety of circumstances. This experience informs my judgment at Newfoundland Power. I don't think it makes a lot of sense to waste time and effort trying to place a dollar value on an intangible like experience. As a person responsible for managing a utility, I do believe that there is real value in it for our customers.
>
> (Transcript, Oct. 22, 2007, pg. 80/7-24)

While the Consumer Advocate took no notable exception to any of the benefits outlined by NP, as noted previously he did observe that strict limits should be placed on how much time NP's executives and managers are permitted to spend on non-NP business. In addition, he felt the onus rests with NP to show that ratepayers receive some demonstrable benefit from inter-corporate transactions.

For its part, NP acknowledged the unique nature of inter-corporate transactions as well as the requirement for full transparency and has established accounting systems to ensure all costs are recorded and treated in accordance with Board Orders. With regard to the issue of transparency regarding inter-corporate transactions, Ms. Perry stated:

> A. …For this reason, we have accounting systems established which ensure we capture all of these costs and treat them in accordance with Board orders. We provide all the detail of these matters to the Board in the Company's quarterly regulatory reports and I observe that the Board's financial advisors review inter-corporate transactions each year to assess compliance with Board orders. Since our last general rate case in 2003, Grant Thornton has not identified any non-compliance with Board orders in any of its annual reviews. Mr. Chairman, Newfoundland Power's accounting for inter-corporate transactions is fully transparent.
> (Transcript, Oct. 22, 2007, pgs 109/12-25; 110/01)

The transparency of inter-corporate transactions was not a particularly contested issue in this proceeding.

Executives and Senior Management

With respect to the charge-out rate for management and executive time the Consumer Advocate questioned whether NP's ratepayers are being properly compensated for the use by other Fortis companies of NP's executives and managers. In particular the Consumer Advocate questioned whether NP's proposed 20% mark-up on executive and management time is an adequate proxy rate and whether it recognizes the value of the service being provided by NP to its affiliates. As an example the Consumer Advocate suggested that the legal services of Mr. Alteen, NP's VP Regulatory Affairs and General Counsel, were billed to Fortis Inc. at below-market prices for a lawyer with his experience. The Consumer Advocate argues:

> *"Though NP states that its proposed 20% mark-ups on executive and management time is as high as any other Canadian utility charges its affiliates the evidence is that NP did not take into account the extent to which NP provides and has provided management and executive services to affiliates as compared to the other utilities surveyed. This is, it is submitted, a material consideration given that this Board has stated that benefits should not only be transparent and demonstrable but also maximized to the advantage of ratepayers. If NP is a net seller of executive and management services relative to other utilities, it is not appropriate to fail to take that into account when the goal is to maximize the benefits to ratepayers. As the Board observed in P.U. 19(2003) using a charge out rate other than cost plus overhead basis "recognizes the value of the service being provided by NP." Proposing a proxy that does not take into account the fact that NP's management and executives have been frequently called upon on matters of great importance to Fortis Inc. cannot be said to truly recognize the value of the service being provided by NP to its affiliates."* (Consumer Advocate, Written Submission, pg. 35)

The Consumer Advocate notes that NP's executives are actually incented through personal bonuses paid as part of the Fortis Development Incentives plan which speaks to the value that Fortis Inc. places upon these services over and above what NP receives as compensation for these services. The Consumer Advocate encourages the Board to consider this as part of the determination as to whether consumers are being given maximum benefit.

In terms of other staff charges the Consumer Advocate submitted that such charges should be adjusted to reflect fair market value or an appropriate mark-up. According to NP's Policy on Inter-Corporate Transactions, inter-corporate charges for non-utility services will be based on fair market value. Where a market cannot be established the policy states that charges are to be based on fully distributed cost. The Consumer Advocate argues that in Order No. P. U. 19(2003) the Board *"effectively decided that it was not enough for NP to show that a transaction did not disadvantage the interests of ratepayers."* and that *"…the onus is on NP to show that ratepayers and the utility will derive some demonstrable benefit from such transactions."* He argues that the use of fully distributed cost has no place where consumers have the right to maximum benefits, as set out by the Board in Order No. P. U. 19(2003).

Based on NP's survey, conducted in compliance with Order No. P. U. 19(2003) and updated in 2007 in advance of the Amended Application, NP determined there is no observable market rate for inter-corporate services provided by utility executives and senior managers. The survey concluded that current Canadian utility practice is to charge senior management time related to affiliated business on a cost recovery basis. NP suggests that its charge out rate of fully distributed costs plus 20% mark-up *"fully protects the interests of consumers as it provides for full cost recovery and for the highest mark-up currently used by regulated utility in Canada for charges of this nature."* In addition, all bonuses paid to executives of NP for inter-corporate services are treated as non-regulated expenses hence the cost of such bonuses are not borne by customers of NP.

NP's stated intention is to reduce the level of inter-corporate activity between Fortis and NP. (NP, Written Submission, pg. 58) In recent years such decreases have reduced both the perceived complexity and integration of inter-corporate relationships on an operational level with charges to affiliates for senior management time in 2008 forecast at less than $100,000 or approximately 15% of 2001-2002 levels and 10% of the 2003 level.

The Consumer Advocate also submitted that the Board should require NP to charge a specific retainer fee in recognition of the pool of talent that NP has available to assist its affiliates. He states:

> *"Frankly, the Consumer Advocate believes that in the circumstances a retainer fee is the most practical solution together with strict limits concerning how much time NP's executives and managers can be permitted to spend on non-NP business. Otherwise, customers have no assurance that they will not see a repeat of the recent past when NP's executives and managers made themselves available to assist with Fortis' development to the extent shown in CA NP 401."*
> (Consumer Advocate, Written Submission, pg. 37)

NP disagrees with the Consumer Advocate's recommendation for a retainer fee, stating that this concept of a standby fee would not benefit customers because it implies the existence of an obligation on the part of NP to provide service to Fortis when requested. NP currently provides services to affiliates at its discretion, subject its own requirements.

Insurance program

Specifically, with regard to the central insurance program that NP administers on behalf of its affiliates, the Consumer Advocate takes issue with the charge-out structure for NP's staff time for the administration of the group insurance program. He points out that NP's Internal Guidelines for Pricing Inter-Corporate Transactions (CA-NP-156, Appendix C) state that a review of the market, where possible, is required to determine the market rate to be charged for services. However, while setting out the parameters for market rate determination for engineering services and executives and managers, the guidelines specifically state that staff time for the administration of the group insurance program is charged based on the recovery of fully distributed costs and not fair market value. The Consumer Advocate noted that the monies that NP receives for its internal insurance expertise has remained fairly flat over the past number of years, even though the number of affiliated companies that NP is providing these services for is growing.

According to the Consumer Advocate the services provided by NP's staff with respect to the group insurance program are valuable and should be charged out at fair market value. He argues that NP's current practices are not consistent with the requirement that NP should maximize benefit to ratepayers in these transactions. The Consumer Advocate requests that *"the Board order NP to undertake and file a fair market value determination for its staff associated with insurance and to commence charging that rate so determined as soon as possible."* If a market rate cannot be determined the Consumer Advocate suggests that NP should be required to charge a market proxy rate, which should be no less than the mark-up that NP effectively charges Persona and Aliant.

With respect to the centralized insurance program Ms. Perry indicated:

A. …the way to assess fair market value is looking at markets and to look at a Director of Risk Management and determine whether there's a market for a director of risk management, I would suggest that his salary is reflective of market, and we ensure that we track all time charged and we charge accordingly.
(Transcript, Oct. 23, 2007, pg. 95/13-20)

Codification of an inter-affiliate code of conduct.

The Consumer Advocate also submitted that NP should be required by the Board to undertake a process aimed at establishing a comprehensive inter-affiliate Code of Conduct. This Code of Conduct would deal with issues beyond pricing and include policy direction on matters such as governance and separation of utility businesses, confidentiality and compliance measures. The Consumer Advocate referred to the Fortis Alberta Code of Conduct released by the Alberta Energy and Utilities Board (AEUB) in January, 2005. (Information # 4) The Consumer Advocate argued that providing similar explicit regulatory policy direction with regard to NP's inter-corporate transactions is an example of an exercise of the Board's core regulatory function ensuring the interests of ratepayers are protected.

In terms of the proposal for an inter-affiliate Code of Conduct NP states that, while the current policies and guidelines are appropriate, NP is not opposed to formalizing current inter-corporate practices in a format that the Board directs. NP indicated the Fortis Alberta Code of Conduct was brought in at a time when restructuring of the electricity industry was occurring in that province and the Board should recognize this fact in considering the matter.

Board Findings

The Board concurs that inter-corporate relationships may prove beneficial to NP and ultimately its customers in terms of either financial advantage, operational support and efficiencies or exposure of employees to other electrical systems and business practices. The Board, however, reiterates its position stated in Order No. P. U. 19(2003) that such benefits should be transparent, prove beneficial to NP and provide demonstrable benefits to NP's ratepayers. Without these guiding principles NP's customers may not be fully compensated (stand to pay more for their electricity) while a disproportionate share of any benefits arising from these inter-corporate relationships may reside with the partner affiliate and its shareholders and/or customers.

With respect to demonstrating that benefits exists, the Board notes that some benefits such as the central insurance program have proven economic value while other initiatives such as staff deployment create less tangible qualitative advantages, particularly to the affiliate supplying the human resources. The Board recognizes that demonstrable benefits have a subjective dimension and, in these instances, the Board must rely on the utility's management to exercise sound judgment in inter-corporate relationships so as not to engage in transactions which will disadvantage NP's customers. The Board notes the stated intention of NP to reduce its level of inter-corporate activity in support of Fortis and to provide services to affiliates subject to its own requirements. Mr. Ludlow stated: *"…An obligation to serve Fortis on request is at variance with the stand-alone status of Newfoundland Power."* (Transcript, Oct. 22, 2007, pg. 29/16-18) The Board also notes Mr. Ludlow's comments that, with a new management team at NP, the sustainability of support in relation to Fortis requirements comparable to levels provided in 2001-2003 is not an active consideration and NP remains his No. 1 priority.

The Board accepts that inter-corporate transactions may present unique opportunities for NP from time to time but, in accordance with similar findings in Order No. P. U. 19(2003), such transactions should provide a net benefit to ratepayers and should only be entered into insofar as they do not compromise the operational or managerial integrity of the utility. The Board recognizes that the level of services supplied by NP to its affiliates has diminished considerably in recent years and the Board is not prepared to establish arbitrary limits on these transactions.

In relation to the insurance program, the Board agrees with the Consumer Advocate that distributing a fairly flat set of annual costs in recent years over an ever expanding group of affiliate customers may not adequately compensate NP for the valuable service of administering these insurance services. While the salary of Mr. Knight, the Director of Risk Management, may be reflective of a market determination, the allocation of fully distributed costs among client affiliates is not necessarily indicative of the intrinsic value of that insurance service to each client. The Board sees little distinction between establishing a market rate for these insurance services when compared to other technical and professional services supplied by NP and charged at market.

The Board will order NP to file a fair market value determination for insurance services provided by NP to its Fortis affiliates with an appropriate charge-out rate to be recommended.

With respect to inter-corporate transactions involving executives and senior management of NP, the Board is of the view that, despite the 20% mark-up applied to executive time, the bonus paid by Fortis suggests that it places a higher value on a fully functioning member of NP's executive team than the compensation NP receives. In this context the Board is not satisfied that NP is being appropriately compensated for the value of the services being provided to Fortis, or in the alternative, the value of executive services absent from NP.

The Board is not satisfied that the remedy proposed by the Consumer Advocate for a retainer fee to be paid by Fortis to NP is appropriate. Such a retainer fee is seen as arbitrary and indeed may suggest an obligation to Fortis not in the interests of NP ratepayers. There is no other evidence on the record, however, which would allow the Board to immediately implement an alternate determination to that currently applied by NP regarding inter-corporate transactions involving its executive and senior management.

The Board will not order a retainer fee be charged to Fortis for the availability of NP's executives and senior management, as proposed by the Consumer Advocate.

The Board is supportive of the development of a inter-affiliate Code of Conduct as proposed by the Consumer Advocate which, among other things, may appropriately resolve this question within a policy framework. The Board notes that inter-corporate relationships and resulting transactions have consistently presented significant and complex regulatory considerations involving NP, and to a lesser degree Hydro, dating back to the early 90's. These issues have evolved over the years through an expansion of inter-corporate relationships/transactions which have largely been dealt with by the Board in successive Orders addressing the particular problems raised during the hearing. Given the comparative low level of inter-corporate transactions forecast by NP over the next year or so and in advance of upcoming GRAs, the Board believes the opportunity exists to formulate a comprehensive inter-affiliate Code of Conduct which will satisfactorily address these recurring inter-corporate issues. The Board has reviewed the AEUB Decision document governing Fortis Alberta (Information # 4) and is not convinced that a Code of Conduct of this complexity or sophistication is needed to guide inter-affiliate relationships/transactions of utilities operating in this Province. The Board is persuaded, however, that a formal Code of Conduct developed in consultation with both the utilities will assist with regulatory accountability and oversight, provide proper guidance to the utilities in relation to these transactions, and protect the interests of ratepayers.

The utilities will be invited to participate in a process to be established by the Board in 2008 to formulate an appropriate inter affiliate Code or Codes of Conduct governing each utility.

The Consumer Advocate will be invited to participate in this process which is expected to address many of the recurrent issues in a consultative and co-operative format.

The Board accepts the Consumer Advocate's proposal with respect to the development of a formal inter-affiliate Code of Conduct for NP. To that end the utilities and the Consumer Advocate will be invited to participate in a process to be established by the Board to address this matter.

ii) Regulatory Reliability and Service Standards

The Consumer Advocate recommends that a Distribution and Reliability Service Standard be developed for NP. This standard would establish performance standards, and performance monitoring and reporting requirements. The Consumer Advocates states:

> *"The basic difference between a Board sanctioned Standard and the performance indicators that Newfoundland Power currently reports primarily consists of a) development and justification of the 'targets' and b) accountability in the event that the targets are not met. A Board sanctioned Standard would replace NP's internal targets with regulatory targets developed with input from the Consumer Advocate and the Board. In addition, depending upon the design or requirements of the standard, if performance were to fall below the regulatory targets in the Standard, there may be a regulatory requirement that Newfoundland Power file with the Board an action plan to address the problem."* (Consumer Advocate, Written Submission, pg. 12)

According to the Consumer Advocate's written submission (pg. 14) a Distribution Reliability and Service Standard may have multiple objectives, including:

- Enhancing transparency relating to distribution and supply service performance;
- Providing an audit trail for monitoring and analyzing performance during and between general rate applications;
- Providing a basis for determining the need and prudence of reliability and service related expenditures; and
- Promoting regulatory efficiency by enabling monitoring of performance relative to Board approved standards between general rate applications.

The Consumer Advocate has proposed to take the lead on development of the standard with data, information and review undertaken by NP, or in the alternative the Board would undertake this lead role. To assist in this process the Consumer Advocate provided as part of his written submission a "Data and Information Request", which would be used to gather the necessary information from NP to develop the standard.

NP opposes the development of such a standard as proposed by the Consumer Advocate. NP's principal concerns with the implementation of reliability and service standards as proposed by the Consumer Advocate were set out in its written submission (pg. 74):

> *" 1. the problem of how to deal with the difference between urban and rural reliability when setting benchmarks;*

2. *the cost associated with implementing the standards and their ongoing administration; and*
3. *the extent to which such standards will reduce management's flexibility."*

According to NP the evidence before the Board does not justify the adoption of a Distribution Reliability and Service Standard as proposed by the Consumer Advocate. NP states that there is no evidence of either a tangible customer benefit or the level of costs associated with the proposal. As well, while distribution and reliability service standards such as those proposed by the Consumer Advocate have been adopted in some jurisdictions in response to customer service issues created by industry restructuring or the adoption of performance based regulation (PBR), NP's position is that no justification exists for adoption of such a standard in this Province. NP argues:

> *"The Board's current regulatory oversight of Newfoundland Power is reasonably comprehensive and reasonably efficient. The efficiency results from the consistency between business reporting and regulatory reporting. Further formal standards are not necessary to ensure that Newfoundland Power provides safe and reliable electrical service to its customers at the lowest cost consistent with reliable service. The implementation of formal standards is only likely to increase the cost and complexity of regulatory oversight of Newfoundland Power."* (NP, Written Submission, pg. 76)

This is the second time in as many years that the Board has considered the issue of Distribution Reliability Policies and Standards. The Consumer Advocate put forward a similar proposal in Hydro's 2006 GRA. In its Order No. P.U. 8(2007) the Board did not direct Hydro to develop such a standard but rather acknowledged the efforts underway by Hydro to develop reliability parameters for each of its systems and to produce a comprehensive maintenance plan for all of its assets. The Board directed Hydro to include in its quarterly reports an update on the status of this initiative.

The Board again acknowledges in this proceeding the Consumer Advocate's submission with respect to the potential value for such a standard. The Board also accepts the evidence that the number one priority for customers is reliability, followed closely by price. The Board however is not persuaded that the establishment of a formal Distribution and Reliability Service Standard as proposed by the Consumer Advocate will provide incremental value to consumers, the utility or the Board at this time. While such standards or requirements appear to exist in Ontario and Alberta, it is noted that these standards were developed in response to a specific set of circumstances associated with the deregulation of the industry in the case of Alberta and as part of the implementation of PBR in Ontario. The applicability of the examples provided for Vermont and Delaware, while informative, is also questionable.

The Board is satisfied that its current regulatory framework has adequate processes and requirements in place to monitor reliability and service quality. The Consumer Advocate did not suggest that there are current reliability problems for certain customers or areas on NP's distribution system. The Board notes that the objectives cited by the Consumer Advocate appear to be related more to the transparency and accountability of the existing reporting and monitoring processes involving reliability and service quality tracking. The Consumer Advocate states in his written submission (pg. 12):

"Specifically, what is missing in the current reporting regime are targets that have been developed with input from the Consumer Advocate whose first priority is to represent the interests of consumers, versus targets that have been developed wholly by the Company whose first priority is to represent the interests of its shareholder. There would be no change in the current regulatory reporting requirement except that performance would be reported relative to targets that have been reviewed and approved by the Board, rather than Newfoundland Power internal targets which have no consumer or Board input."

The Board agrees that the input of the Consumer Advocate may be of value in the development of a formal reliability and service quality standard. As well the Board concurs that it may be useful to have the performance measures that are currently reported by NP to the Board benchmarked against some external standard. However the Board is not aware that such standards, either on an industry-wide basis or for other similar sized utilities operating in the same kind of environment, are available. The Board also has concerns about the lack of information relating to costs and other resources required to fully institute this approach, and the specific benefits to be gained from such a commitment of resources.

In reaching this conclusion the Board is also cognizant of Mr. Delaney's comments during direct testimony regarding the ongoing efforts by the Canadian Electrical Association to develop industry performance standards. He advised that the CEA has an on-going initiative to develop an appropriate set of industry standard performance indicators that can be used by utilities to report their performance to regulators. NP is participating in this initiative through CEA's Distribution and Customer Councils. According to Mr. Delaney: *"The goal of the CEA initiative is to propose a set of high level indicators for use in the regulatory setting by the end of 2007."* (Transcript, Oct. 24, 2007; pg. 45/2-8) In the Board's view these indicators, if accepted by the CEA for use, could provide a more uniform and consistent basis against which to measure utilities' performance in the areas of service and reliability. It is also noted that these indicators will have been developed in the context of the Canadian electricity environment.

Furthermore the Board acknowledges the unique and often harsh environment in which the utilities in this Province operate. The manner in which any externally developed standard or benchmark indicators are used to assess NP's reliability and service performance may be affected by this fact.

The Board does not accept that the establishment of distribution and reliability service standards as proposed by the Consumer Advocate is necessary at this time, given the existing regulatory oversight and the generally positive reliability measures reported for NP's system. However the Board is interested in exploring the possible application of the CEA standard performance indicators which are currently being developed to existing regulatory reporting requirements. To that end, once the CEA standards are finalized and accepted, the Board will require NP to report as to how these standards could be used in this Province. This may assist the Board in considering whether further action in relation to reliability and service quality standards is warranted.

The Board will not at this time require the establishment of a formal Distribution and Reliability Service Standard as proposed by the Consumer Advocate. When the CEA reliability and performance standards have been finalized and accepted for use in regulatory settings, NP will be required to report to the Board as to how these standards could be incorporated into the existing regulatory framework.

iii) Productivity Allowance

The Consumer Advocate raised the question of whether the Board should impose an allowance for productivity for the 2008 test year. It was suggested this could be achieved by ordering a reduction in NP's forecast 2008 costs to the level of NP's 2007 operating expense forecast, subject to the Consumer Advocate's request for additional expenditures in the areas of energy conservation/efficiency messaging and outreach. This productivity allowance would be imposed on a global basis with the decision left to NP as to where the productivity gains could be made.

In addressing this issue the Consumer Advocate highlighted the testimony of Mr. John Todd. Mr. Todd observed that from 2004 to 2007 NP was able to keep its operating costs flat. According to Mr. Todd this implies that NP's productivity gains during this period were sufficient to fully offset the upward cost pressure during those years. In 2008 operating costs are forecast to increase by $284,000. The Consumer Advocate notes that NP has expressly stated its intention to continue its efforts to achieve productivity, and that the evidence shows that there is no significant change in inflationary or wage pressures forecast for 2008.

Mr. Todd also observed that the issue goes beyond a single question of productivity gains in stating:

> A. …We also have to consider the costs that are being incurred to achieve these productivity gains. The relevant question is whether the benefits outweigh the costs, whether the gains being crystallized, being recognized in 2008 are sufficient to outweigh costs that are being incurred to generate productivity through time for the Company.
> (Transcript, Oct. 26, 2007; pg. 10/17-25)

Mr. Todd suggested that the nature of the multi-year regulatory regime in this jurisdiction provides NP with a much greater economic incentive to find productivity in the non-test years that in the test year. According to Mr. Todd, since revenue requirement is not adjusted between GRAs there is a strong incentive to achieve productivity gains and hence shareholder return early in the period and less so later. Productivity gains that are forecast and recognized in a test year generate no benefit to shareholders because they are already captured in rates and flow through to customers. Mr. Todd states:

> A. Hence, a productivity gain that is crystallized in the first year of the cycle flows to benefit shareholders in each year until it's rebased, that is until the next GRA test year.
> (Transcript, Oct. 26, 2007, pg. 12/13-14)

In discussing the purpose of imposing a productivity allowance in a test year Mr. Todd stated:

> A. The purpose of the productivity allowance is to provide some degree of sharing between the future productivity gains, between the company and its customers. This is not a penalty for poor performance. It is simply a mechanism that recognizes that there's an incentive that'll give rise to productivity gains and some portion of those gains should go to customers in the short run, as well as in the long run.
> (Transcript, Oct. 26, 2007; pg. 24/11-20)

In written submission (pg. 10) the Consumer Advocate argued:

> *"It may be punitive to set a productivity target above the level of past performance. But it is not punitive to implement a productivity adjustment which simply reflects an expectation of consistency between the test year (when there is no incentive) and the non-test years in which NP does have a greater incentive to achieve solid productivity improvements."*

The Consumer Advocate goes on to argue (pg. 11):

> *"Accordingly, having regard to the incentive-effect, to NP's productivity since the last GRA and the lack of demonstrated cost drivers on the operating expense side in 2008 relative to the previous years – if the Board believes that NP cannot prudently achieve any further gains, then it should not order a reduction in the forecast 2008 costs for NP. If the Board believes that NP is able to prudently hold operating costs level with 2007 forecast costs – then it should be so ordered."*

NP stated that despite bargaining unit salaries that are slated to increase by 4% or $1,002,000 in 2008, management has applied a productivity improvement of $531,000 to its forecast test year spending on labour of $28,671,000. This coupled with forecast expenditures on other (non-labour) operating costs of $20,712,000 shown in Exhibit 2 (1st Revision) of the Amended Application yields a combined total of $49,383,000 in forecast 2008 test year operating costs. The Board notes this figure represents an increase of $284,000 in forecast test year operating costs, which is the productivity allowance being sought by the Consumer Advocate. This productivity allowance would see a resulting reduction in these 2008 test year costs to the level forecast in 2007 of $49,099,000. NP argues no productivity adjustment or reduction in their 2008 operating forecast is justified.

In its written submission NP points out that productivity is clearly demonstrated in evidence indicating that its 2008 forecast total contribution to customer rates is 3.13¢/kWh compared to 3.19¢/kWh in 2002 on an actual basis. NP also argues that its 2008 forecast operating costs (exclusive of deferred regulatory costs, pension costs and transfers to general expenses capitalized) are consistent with 2003 costs on an actual basis. In its written submission (pg. 79) in reference to the Consumer Advocate's proposal for a productivity allowance NP submitted:

> *"The view that the Board ought to seek to capture efficiency gains in advance of their achievement may be consistent with performance based regulation, but not cost of service regulation. Cost of service regulation in this Province effectively provides that a utility is entitled to recover its reasonable and prudent forecast costs in addition to its return."*

In addition NP stated in oral submission:

> (Mr. Kelly, Q.C.) …Establishing an unrealistic productivity allowance has several potential negative consequences. First, it may deny Newfoundland Power the recovery of its just and reasonable operating expenses contrary to the Public Utilities Act. Second, it may create a disincentive or a penalty for good performance. And third, it may lead to more frequent rate hearings to recover necessary operating expenses.
> (Transcript, Nov. 5, 2007; pg. 11/10-19)

NP states that its 2008 forecast operating costs are reasonable and consistent with the provision of least cost service and that there is no justification in the evidence for the Board to recognize a productivity allowance for NP.

While the Board found the conceptual evidence of Mr. Todd to be informative and interesting, it was not determinative in addressing the particular question brought before the Board by the Consumer Advocate. Mr. Todd acknowledged that the concept concerning a relative benefits to cost ratio associated with productivity improvements cannot be determined from the evidence on the record. 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. The question posed by the Consumer Advocate is whether or not sufficient justification exists to hold the line on 2007 forecast operating costs into the 2008 test year having regard to the incentive effect it may produce. Assuming an affirmative answer as argued by the Consumer Advocate would mean a further reduction of $284,000 or 0.58% in NP's 2008 forecast operating costs of $49,383,000 as outlined in its Amended Application.

The Board notes the reduced revenue requirement proposed as a result of the Settlement Agreement contributes to a lower rate increase than originally proposed. This reduced revenue requirement includes a productivity improvement adjustment of $531,000 applied by NP to the increased labour component of $1,002,000 in the forecast 2008 test year operating costs. In striving to balance the interests of both consumers and the utility through its regulation, the Board acknowledges that this reduced revenue requirement represents tangible benefits to consumers.

While no explicit evidence was provided to guide the Board in linking performance based incentives which are used elsewhere to the mandated regulatory regime in this Province, Mr. Todd agreed that incentives are in place through the expanded ROE mechanism as well as the crystallization of efficiency gains in the GRA test year. NP's Early Retirement Program which was implemented following NP's 2003 GRA was cited as an example. It is recognized that these incentives are in contrast to other mechanisms which may potentially provide more immediate benefits for consumers in the intervening years between GRAs. The Board finds however that the kind of incentive mechanisms which may afford benefits to consumers in the non-GRA test years have not been demonstrated to be appropriate in the current regulatory regime in this Province.

The Board notes that the evidence of the Consumer Advocate for a reduction of $284,000 in NP's forecast 2008 test year operating costs contemplates a productivity adjustment centered on a global or envelope assessment of operating costs as opposed to reductions based on a single or particular set of operating costs combined with observations on their related impacts. NP, on the other hand, argues achieving its proposed $531,000 productivity improvement relating to labour costs will be a challenge considering the wage increases already committed for 2008 and the expanded apprenticeship and training programs. The Board is of the view that the evidence relative to global costs fails to provide sufficient justification to support a productivity allowance. Furthermore in the absence of any specific impacts other than those represented by NP, a productivity allowance reducing NP's 2008 forecast operating costs to a level equivalent with those of 2007 is deemed by the Board to be arbitrary.

The Board will not order a reduction in NP's forecast 2008 test year operating costs to the level forecast for 2007, as proposed by the Consumer Advocate.

iv) Basic Customer Charge for Domestic Customers

NP has proposed in its Application to maintain the Basic Customer Charge for Domestic customers (the "BCC") at its current level of $15.60 per month. The Consumer Advocate proposes that the BCC be reduced by $1.00 per month, to $14.60. According to the Consumer Advocate NP's proposed Domestic energy charge is less than the marginal cost of energy. The reduction in the BCC will increase the energy charge to a value closer to marginal costs. According to the Consumer Advocate: *"Owing to elasticity effects increasing the Domestic energy charge to levels closer to marginal energy costs leads to reduced energy consumption, and as a result, less production from Holyrood, thus reducing the average cost of power supply on the island interconnected system, and the attendant pollution associated with Holyrood production."* The Consumer Advocate submits that, in addition to improving the efficiency of the rate, a reduction in the BCC is also consistent with regulatory practice elsewhere in Canada and is consistent with the Government's Energy Plan and priorities/concerns expressed by NP. (Consumer Advocate, Written Submission, pg. 29)

A reduction in the BCC can also be implemented while maintaining acceptable customer impacts, argues the Consumer Advocate. He states that if the BCC is reduced by $1.00 a month Domestic customers consuming less than 1500 kWh per month, representing over 67% of the customers in the class, will see either reduced bills or bills that remain mostly indifferent, compared to NP's proposal to keep the BCC at current levels. If the BCC is reduced by $1.00 per month Domestic customers consuming more than 2000 kWh per month, representing less than 16% of the customers in the class, would see higher bills, ranging from 0.29% to 0.63% higher. Even with this impact the Consumer Advocate argues that customers will see bill impacts that are more than 2% less than originally proposed by NP. According to the Consumer Advocate the Board must decide if the benefits resulting from the efficiency gains justify the customer bill impacts. (Consumer Advocate, Written Submission, pg. 29)

In its written submission NP argues that maintaining the BCC at the current level will achieve a reasonable balance of fairness, efficiency and customer impacts in the 2008 Domestic customer rate. NP states that the evidence shows that decreasing the BCC by $1.00 per month will result in higher 2008 bill impacts for a significant number of customers than proposed in the Amended Application. According to NP the retail customer rate review proposed as part of the Settlement Agreement will comprehensively review existing and alternative rate designs with the objective to provide increased emphasis on energy efficiency and conservation. NP believes it is premature to decrease the BCC at this time to better reflect marginal energy costs. (NP, Written Submission, pg. 83)

The Board notes that as part of NP's 2003 GRA proposals arising from the mediation process the parties agreed that the BCC be reduced by $1.00. NP also agreed, among other things, that in its next general rate application the customer charge recovery of distribution costs allocated to customers will be capped at 50% of these allocated distribution costs for rate classes, with the remainder to be recovered through energy charges.[3] In Order No. P. U. 19(2003) the Board accepted the recommendation of the parties on this issue.

NP's evidence in this proceeding is that the existing BCC of $15.60 does not fully recover customer related costs[4]. In addressing NP's proposal to maintain the BCC at its current level Mr. Henderson pointed out that that there is justification for increasing the BCC as well as the energy charge:

> A. …the Company's Basic Customer Charge in addition to being below the embedded and marginal cost is also below the level of the cap agreed to at the last GRA. So, based strictly on a comparison of the level of the existing charge to customer-related cost, there is justification to increase the basic customer charge. However, the overall increase in the revenue requirement for the class and whether the level of the existing energy charge is appropriate are also relevant considerations.
> (Transcript, October 25, 2007; pg. 118/8-15)

NP states that its proposal to place the entire revenue increase required from the Domestic rate class on the energy charge is intended to promote the efficient use of electricity. According to Mr. Henderson "*…consumption charges are more important in promoting efficient use than fixed charges such as the Basic Customer Charges which do not vary with use.*" (Transcript, Oct. 25, 2007; pg. 119/10-13) Mr. Henderson also acknowledged that the Consumer Advocate's recommendation to reduce the BCC by $1.00 and increasing the energy charge would bring the energy charge closer to marginal costs, thus improving the efficiency of the price signal. However, he points out that:

> A. Mr. Bowmans' proposal would reduce …recovery of customer related costs below the current level. Currently Basic Customer Charge recovers only 75% of the embedded customer-related costs.
> (Transcript, Oct. 25, 2007, pg. 121/20-23)

The Board agrees with NP's position that the upcoming rate review process is the appropriate forum to review all rates, including the BCC. The fact that the existing BCC does not currently recover customer related costs is an important consideration for the Board. The

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[3] Distribution costs are network costs beyond the service drop and do not include customer specific costs such as meters, meter reading, billing and service drops.

[4] According to NP's Application (Rate Design Review, May 2007, pg. 5) embedded customer related costs are $20.88 and marginal customer related costs are $20.90. The maximum Basic Customer Charge for Domestic Customers calculated in accordance with the settlement reached at NP's 2003 GRA is $16.95.

Consumer Advocate's proposal to reduce the BCC by a $1.00 will result in an even lower recovery of these costs. On the question of whether or not the Consumer Advocate's proposed reduction will increase the efficiency of the rate, the Board is of the view that this determination should be made in the context of a comprehensive review of the rate design. The Board has been provided with little basis on which to judge the appropriateness of the $14.60 proposed other than an acknowledgement by both NP and the Consumer Advocate that the resulting higher energy charge will bring the rate closer to marginal costs. However it may be that the retail rate design review will show that the level of the BCC should be set at some other value when the totality of the rate is looked at in the context of pricing efficiency, cost recovery and customer impacts.

The Board will not direct NP to reduce the Basic Customer Charge for Domestic Customers by $1.00, as proposed by the Consumer Advocate.

v) <u>Coordination of Safety Communication</u>

The Consumer Advocate submits that there should be more formal coordination between NP and Hydro on safety messaging. He requests that the Board direct NP to *"undertake efforts to actively promote and coordinate with Newfoundland and Labrador Hydro on the development and implementation of communication programs related to utility safety issues, with such initiatives to include coordination of safety messages, sharing of media space, printing and production costs and to provide a record and report of these initiatives at NP's GRA."* (Consumer Advocate, Written Submission, pg. 42)

In its written submission NP advises that it actively coordinates with Hydro in utility safety issues, sharing information, including safety alerts and accident reports, and have cooperated in developing and delivering safety training programs. Both utilities have also coordinated on seasonal safety advertising initiatives and in public safety campaigns responding to identified problems. NP states that the objective of cooperation between the two utilities in safety communications is to maximize the effectiveness of the safety programs, including safety messages to employees, workers and the public. It is not intended to reduce safety related expenditures. NP submits that this issue, along with others, is one of managerial judgment and there is no evidence that justifies any action by the Board.

The Board is not persuaded that any specific direction to NP concerning the issue of formal coordination with Hydro on safety messaging is warranted. It is clear from the evidence that active coordination between Hydro and NP already exists and that resources and efforts are shared where possible and practical. The Board accepts that the purpose of this coordination is to maximize the effectiveness of the safety programs, and not necessarily to reduce expenditures. There is no evidence that the existing level of coordination is inadequate or that the communications related to utility safety issues is unacceptable so as to require any intervention or direction from the Board.

The Board will not direct NP at this time with respect to coordination with Hydro on safety communication, as proposed by the Consumer Advocate.

vi) Energy Efficiency Messaging to Customers

The Consumer Advocate recommends that the Board order NP to direct monies towards radio and television promotion of energy efficiency and conservation to its customers. NP is proposing to spend $90,000 on energy efficiency advertising in print media in 2008. According to the Consumer Advocate, while outreach to consumers by newspaper, bill inserts and trade shows are worthwhile, NP should buy paid radio and television outreach advertising for energy efficiency messaging. He points to the fact that NP's own surveys show that television was the second most preferred method of receiving information about energy efficiency from NP, ranking only behind NP's bill inserts. In the area of safety messaging NP proposes to spend $108,000 on television and $74,000 on radio in 2008. The Consumer Advocate recommends an equal amount for energy conservation messaging.

NP submits that this issue is one of managerial judgment and that there is no evidence that justifies any action by Board. NP argues that its decisions on the use of the various advertising media have been taken with a view to ensuring the messaging is effective with respect to both cost and impact. According to NP "*The decision not to focus on television advertising for the Company's energy efficiency communications with customers was influenced by the fact that there is already a considerable amount of energy efficiency messaging from various sources on television, and by the fact that television advertising is expensive*." (NP, Written Submission, pg. 92) As well, NP points out that further direction with respect to conservation messaging will be influenced by the Conservation and Demand Management Potential Study currently underway and the Energy Conservation and Efficiency Partnership announced in the Provincial Government's Energy Plan.

The Board is not persuaded that NP should be ordered to direct additional resources toward television and radio advertising on energy conservation and efficiency. The Board notes that NP is an active participant in the Energy Conservation and Efficiency Partnership recently announced by the Provincial Government as part of its Energy Plan. As well the results of the Conservation and Demand Management Potential Study may influence the nature and delivery of any future energy efficiency messaging. The Board accepts Mr. Delaney's explanation of how it approached the decision not to pursue television as a means of communicating to consumers with respect to energy efficiency:

> A. …Newfoundland Power looked at our approach to energy efficiency. We gave it considerable thought. Customer calls were increasing 94 percent. And we decided the best strategy for us in the whole scheme of things was the strategy we took. And we find ourselves now well positioned in the community in terms of energy efficiency. We have reorganized our people around the energy efficiency messages and getting out to the customer. We decided not to go to television. For one thing, the $100,000 is the amount paid to get the ad on TV. It's not the price to make the ad. And as we all know, in advertising, you know, the quality of the ad would say something about people's reaction to it. So the ad of still photography with not many bells and whistles that we have for safety cost us $30,000 to make, so additional costs with respect to making the ad and then for me drawing the cost benefits associated with that is another area that's, that it was a bit uncertain.
>
> (Transcript, Oct. 24, 2007, pgs. 72/10-25; 73/2-9)

In the Board's view the manner of how NP delivers its energy efficiency message to its customers is an area of managerial judgment and discretion and, in the absence of any evidence suggesting the unreasonable exercise of this judgment by NP, the Board sees no basis on which to intervene.

The Board will not direct NP with respect to the manner of its energy efficiency messaging to customers, as proposed by the Consumer Advocate.

vii) eBills Promotion

The question of whether NP should provide a financial incentive to customers who opt to receive their bills by e-mail was raised by the Consumer Advocate and identified as an unresolved issue in the Settlement Agreement. The savings of having customers receive an eBill as opposed to a traditional printed and mailed bill is approximately $7 per year per customer. (NP Application, pg. 35)

In addressing this issue on cross-examination by the Consumer Advocate, Mr. Delaney pointed out the challenges associated with providing such an incentive, including database modifications at a cost of $50,000 to NP's Customer Service System. (Transcript, October 24, 2007; pgs. 81 & 82) Mr. Delaney also pointed out that NP's participation rate of 7% of customers is the highest percentage among utilities responding to a recent 2007 survey about electronic billing and that none of the responding companies provide financial incentives to customers for their participation in eBills. In response to a question from NP counsel as to whether financial incentives to have customers use eBills is justified Mr. Delaney responded:

> A. "No I don't. Our current approach is working very well and we do not think that financial incentives are necessary. Furthermore, a system for providing financial incentives to customers who participate in eBills would be costly to implement and administer. Financial incentives could also be perceived as being unfair to customers who do not have the ability to receive bills via e-mail."
> (Transcript, Oct. 24, 2007; pg. 47/3-11)

The Consumer Advocate did not address this issue in his written submission.

The Board is not persuaded based on the evidence that NP should be directed to provide a financial incentive to customers who opt to receive their bills by e-mail. The Board notes that NP currently has a high participation rate in the electronic billing program in the absence of any such incentive. The potential costs associated with implementing an incentive program as well as the issue of perceived fairness to customers who do not have access to e-mail are also considered.

The Board will not direct NP to provide financial incentives to customers who opt to receive their bills electronically, as proposed by the Consumer Advocate.

viii) Vacancy Adjustment in Forecast Labour Costs

The question of how NP reflects labour cost savings related to anticipated vacancies was an unresolved issue in the proceeding. The Consumer Advocate stated in written submission (pg. 44):

> *"It would certainly appear that NP does attempt to take absences into account on a person by person basis when projecting its FTEs and labour cost forecast. But what is not clear from the record are the assumptions that are used and what those assumptions are based on. For instance what is the forecast FTE and labour forecast unadjusted for these assumptions of "vacancy" (whether by reason of LTD, Maternity, etc.) and how does that compare to the forecast FTE and labour expense forecast once these assumptions and/or adjustments have been incorporated."*

According to the Consumer Advocate NP's assertion that it does not support vacancy tracking by position does not remove the relevance of considering vacancies for regulatory purposes. The Consumer Advocate requested that, *"The Board order NP to file as part of its next GRA a detailed description of the method used to forecast its Test Year FTEs and labour expense forecasts with detailed explanation as to how assumptions as to employee vacancy(ies) were arrived at and incorporated into the Test Year forecasts."* (Consumer Advocate, Written Submission, pg. 45)

In its written submission (pg. 88) NP states that the company's forecast of FTEs includes specific information on expected vacancies, such as maternity leaves, absences due to disability and expected hire and retirement dates. According to NP: *"This ensures that labour cost savings related to vacancies are reflected in customer rates."*

The Board notes that this issue relates more to the lack of information on how variances are determined as opposed to the specific vacancy adjustment incorporated in NP's forecast of labour costs for 2008. The Consumer Advocate did not raise specific concerns regarding the accuracy of NP's forecast labour costs. The Board is satisfied the forecast of 2008 test year labour costs incorporates the anticipated vacancies for 2008. However the Board agrees with the Consumer Advocate that the process used by NP to make this determination lacks transparency. While NP's approach allows maximum flexibility for management it does not permit any sort of review or analysis of NP's proposals in this respect. To ensure completeness of the record in the next GRA the Board will direct NP to include, as part of its next general rate application filing, detailed information to the extent possible concerning the method used to forecast its test year FTEs and labour expense, as well as an explanation of the assumptions used to determine the expected vacancies.

The Board will direct NP to include, as part of its next general rate application, detailed information concerning the method used to forecast its test year FTEs and labour expense, as well as an explanation of the assumptions used to determine the forecast vacancies.

ix) Pole Management Practices

The question of whether NP's practice of purchasing used poles at new pole prices is consistent with the provision of least cost service was an issue that was identified as being unresolved in the Settlement Agreement. The Consumer Advocate questioned Mr. Delaney on this matter during cross-examination but did not address the issue in his written or oral submission.

In its written submission (pg. 90) NP states that the contracting associated with the outsourcing of its pole management function is designed to support the maintenance of a competitive market for pole contractors and to minimize administration costs. NP pays a blended rate to its contractors for both new and used poles. This practice is in place according to NP *"to reduce pole contract administration costs, and to encourage the re-use of used, serviceable poles…."*

The Board is satisfied that there is no basis on which to intervene in NP's pole management practices. According to the evidence the costs associated with NP's pole management practices have decreased by 11% on an inflation adjusted basis over the past 10 years. In the Board's view this result is consistent with the objective of least cost service.

The Board will not direct NP at this time with respect to its pole management practices.

III. OTHER MATTERS

1. Proposed Federal Corporate Tax Rate Reduction

On October 30, 2007 the Federal Government announced in an economic statement a proposed reduction in the general corporate tax rate of 1% in 2008. NP advises that the proposed tax reduction would reduce NP's 2008 tax expense by approximately $500,000. (Consent #5) However, the proposed tax reduction has not yet been made law and there is a possibility it will not be enacted.

NP has proposed, with the agreement of the Consumer Advocate, that an appropriate way for the Board to deal with this issue is to order the following:

> *"Upon the enactment of legislation enabling the Federal Government's economic statement, NP create a deferral account to true-up the income tax expense in its 2008 test year to reflect 2008 corporate tax changes contained in the legislation; and*
>
> *The disposition of any balance in the deferral account be subject to further Order of the Board."*

The Board agrees with this proposal as being the most appropriate means of dealing with this unexpected announcement. The proposal is fair to customers should the tax reduction materialize.

The Board will direct NP to create a deferral account to true-up the income tax expense for the 2008 test year and for subsequent years until its next general rate application to reflect proposed corporate tax changes announced by the Federal Government on October 30, 2007, with the disposition of the account balance, if any, to be subject to a further Board Order.

2. International Financial Reporting Standards

In its Supplementary report Grant Thornton addressed the issue of the proposed changes in financial reporting standards for reporting of external financial statements. This possible change is the result of the adoption by the Canadian Accounting Standards Board[5] (the "AcSB") of a strategic plan to transition Canadian GAAP to International Financial Reporting Standards ("IFRS") by 2011. Grant Thornton advises that this is a fundamental change in Canadian accounting standards and affects approximately 4,500 public reporting entities.

The move to IFRS may impact NP's ability to continue to recognize regulatory assets and liabilities in external financial statements as of 2011. NP currently has four principal types of regulatory assets: i) unrecorded future tax obligations; ii) OPEBs transitional obligations; iii) unrecovered reserve balances; and iv) cost recovery deferrals. According to NP these regulatory assets totaled over $120 million at the end of 2006. In addition NP has regulatory liabilities totaling approximately $22 million. (NP, Written Submission, pg. 61)

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[5] The Canadian Accounting Standards Board (AcSB) is the committee of the Canadian Institute of Chartered Accountants (CICA) responsible for establishing Generally Accepted Accounting Principles (GAAP).

In accordance with the AcSB strategic plan, recognition of these regulatory assets and liabilities in its external financial statements will be consistent with GAAP until at least 2011. Whether this transition to IFRS will impact the manner in which NP recognizes these regulatory assets following 2011 is still uncertain. It is possible that regulatory assets and liabilities will be able to continue to be recognized following 2011. NP also advises that the AcSB has indicated it will issue a progress report on IFRS transition in March 2008 and the possibility exists that dates for IFRS implementation may change. (Transcript, Oct. 22, 2007, pg. 125/14-17) Because of the uncertainty surrounding this issue, NP argues it is difficult to meaningfully assess the potential risk, if any, to NP's customers at this time. NP submits that:

> *"…the most appropriate regulatory response to this uncertainty is for the Board to ensure, as part of its powers of general supervision of the Company's operations, that it remains informed of developments associated with IFRS transition and Newfoundland Power's ongoing plans in respect of these developments. This approach will enable the Board to take timely action, if necessary, to deal with any hazard to Newfoundland Power's customers which may present itself as a result of IFRS transition."* (NP, Written Submission, pg. 63)

The Board is concerned about the potential substantive impacts of the changes being considered by the AcSB on both the utility and its customers. Such a change would appear to have the potential to significantly restrict the regulatory mechanisms currently available in the Board's oversight of this fully regulated industry. The Board notes that, until the AcSB further develops its position on this issue, there is little NP or the Board can do at this stage. In the interim NP will be required to report to the Board on a regular basis as to the status of the AcSB's considerations of this matter.

NP will be required to provide updates as part of its quarterly reports to the Board as to the status of the AcSB's considerations of the transition to IFRS.

3. Retail Customer Rate Review

The Settlement Agreement proposes that a retail customer rate review be undertaken following the 2008 GRA proceeding. The framework for this review of NP's rate design was set out in Attachment A to the Settlement Agreement. The purpose of the retail rate review is as follows:

1. to review existing retail rate designs;
2. to review potential alternative rate designs;
3. to consider whether the rate designs should be mandatory or optional; and
4. to develop a detailed time-bound action plan for implementation of the rate design recommendations.

The objective is to facilitate the exchange of information necessary to conduct a review of rate designs for NP's Domestic and General Service customers and to provide a mechanism for the participation of other interested parties in the process. If appropriate, new rate designs will be recommended for implementation by NP at its next GRA. The parties have agreed to a process that spans the period 2007-2009 with a technical conference to be hosted by the Board in mid-2009.

In its written submission (pg. 53) NP submits that the timing is appropriate for a retail rate review given the new information that is available from the Marginal Cost Study, the Provincial Energy Plan and the information that will be available when the Conservation and Demand Management Potential Study is completed later this year. Recent experience with rate designs in other jurisdictions will also be considered.

The Board agrees that it is an opportune time to commence a review of NP's retail rate designs. The proposed scope, objectives and processes will, in the Board's view, provide an open and transparent process to evaluate the rate designs in the context of current information and rate design practices. In particular the Board is interested in the ability of new rate designs to encourage increased energy conservation and efficiency. NP will be required to report on the progress of the review as part of NP's quarterly reporting to the Board.

NP will be required to provide updates as to the progress of the retail customer rate review as part of its quarterly reports to the Board.

4. Final Rates

NP proposes that the Board approve rates, tolls and charges effective for service provided on and after January 1, 2008, which are set out in Schedule A to the Amended Application. The average rate change resulting from these rate proposals are set out on page 5 of this Decision and Order and range from 3.9% for Domestic Customers to a decrease of 1.2% for 2.1 General Service 0-10 kW.

The Board has, in this Decision and Order, accepted the 2008 test year revenue requirement to be recovered in customer rates, and approved the forecast 2008 test year rate base and return on rate base, as proposed by NP in its Amended Application. The Board has also accepted NP's revenue to cost ratios which were determined based on the COS Study. On this basis the Board is satisfied that the final rates as proposed by NP should be approved.

The Board will approve the final rates for Domestic and General Service Customers and Street and Area Lighting as set out by NP in Schedule A of its Amended Application, to be effective January 1, 2008.

On December 11, 2007 NP filed an application for approval of interim rates based on the rates proposed in its Amended Application. This application was filed on the basis of the uncertainty associated with timing of the release of the Board's final Order on its Amended Application. Since the Board will, with this Decision and Order, approve the rates proposed in the Amended Application on a final basis, an Order of the Board in relation to the interim rate application is not required.

5. Timing of the Next General Rate Application

In its Supplementary Report (pg. 6) Grant Thornton noted the timing of a number of significant events arising out of the proposals in the Amended Application, and which may be of interest in the context of the Board's regulatory oversight. A number of deferral accounts expire in 2010, while others continue until 2012. It was noted that NP advises that it plans to file its next GRA in 2010 while the proposed AAF could continue to operate in 2010 to set rates for 2011. In Appendix B to its Supplementary Report Grant Thornton summarized the post hearing events and the associated timing:

January 1, 2008	Implementation of rates and other requirements subject to the 2008 GRA.
Jan-Dec 2010	NP advised it plans to file its next GRA in 2010 to establish customer rates for 2011.
December 31, 2010	End of period in which the Energy Supply Cost Variance Clause, included in the Rate Stabilization Clause, applies to energy supply costs.
Jan-Dec 2011	NP advised the next depreciation study is expected to be completed in 2011 based on plant in service as of December 31, 2010.
December 31, 2011	End of period subject to the AAF as proposed in the Settlement Agreement.
December 31, 2011	Proposed end of amortization period of the accumulated reserve variance identified in the Depreciation Study.
December 31, 2012	Proposed end of amortization period related to the Weather Normalization Reserve.

In addition it is noted that, according to the AcSB's May 2007 "Implementation Plan for Incorporating IFRSs in Canadian GAAP", the first year for reporting under the new IFRS-based standards is intended to be 2011.

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.

NP will be required to file its next general rate application by June 30, 2010 using a 2011 test year.

PART THREE. SUMMARY OF BOARD DECISIONS

I. Consensus Issues

Cost of Capital

1. The Board is satisfied that the proposals contained in the Amended Application with respect to NP's cost of capital, including a common equity component of 45% and regulated return on common equity of 8.95%, will provide NP with the opportunity to earn a just and reasonable return on rate base that will enable NP to maintain its creditworthiness, as required by legislation and consistent with the provision of least cost reliable power.

Average Rate Base and Return on Rate Base

2. The Board is satisfied that NP's forecast 2008 rate base of $812,212,000 has been calculated properly in accordance with established practice and appropriately incorporates proposed changes associated with the transition to the Asset Rate Base Method. The Board will require NP to continue to file, as part of its annual return, information relating to changes in deferred charges, including pension costs.

3. The Board will approve NP's proposed rate of return on rate base for 2008 of 8.37%, within a range of 8.19% to 8.55%.

Proposed 2008 Test Year Revenue Requirement

4. The Board accepts the 2008 test year revenue requirement, including the proposed amortizations for the regulatory deferrals and reserves, as proposed in the Amended Application. The Board will require NP to file a new depreciation study related to plant in service as of December 31, 2010.

Automatic Adjustment Formula

5. The Board will approve the proposed change to the Automatic Adjustment Formula to reflect the full adoption of the Asset Rate Base Method for calculating rate base and the continued use of the Automatic Adjustment Formula to set rates for not more than three (3) years following the 2008 test year.

Demand Management Incentive Account

6. 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.

Energy Supply Cost Variance

7. The Board will approve the proposed change to the Rate Stabilization Clause to provide for the recovery of the Energy Supply Cost Variance through the Rate Stabilization Account for the period 2008 to 2010.

Cost of Service Study, Methodology and Rate Design

8. The Board is satisfied that NP's COS Study and methodology and the Marginal Cost Study are appropriate to be used in establishing 2008 customer rates.

9. With the exception of the Basic Customer Charge for Domestic Customers, which is specifically addressed as one of the contested issues in this Decision and Order, the Board will approve the rate design proposals set out by NP in the Amended Application.

Amendments to Rules and Regulations

10. The Board will approve the proposed changes to Regulations 9(b) and 9(c) and to Regulation 10(d).

II. Contested Issues

Inter-Corporate Relationships and Transactions

11. The Board will order NP to file a fair market value determination for insurance services provided by NP to its Fortis affiliates with an appropriate charge-out rate to be recommended.

12. The Board will not order a retainer fee be charged to Fortis for the availability of NP executives and senior management, as proposed by the Consumer Advocate.

13. The Board accepts the Consumer Advocate's proposal with respect to the development of a formal inter-affiliate Code of Conduct for NP. To that end the utilities and the Consumer Advocate will be invited to participate in a process to be established by the Board to address this matter.

Regulatory Reliability and Service Standards

14. The Board will not at this time require the establishment of a formal Distribution and Reliability Service Standard as proposed by the Consumer Advocate. When the CEA reliability and performance standards have been finalized and accepted for use in regulatory settings, NP will be required to report to the Board as to how these standards could be incorporated into the existing regulatory framework.

Productivity Allowance

15. The Board will not order a reduction in NP's forecast 2008 test year operating costs to the level forecast for 2007, as proposed by the Consumer Advocate.

Basic Customer Charge for Domestic Customers

16. The Board will not direct NP to reduce the Basic Customer Charge for Domestic Customers by $1.00, as proposed by the Consumer Advocate.

Coordination of Safety Communications

17. The Board will not direct NP at this time with respect to coordination with Hydro on safety communication, as proposed by the Consumer Advocate.

Energy Efficiency Messaging to Customers

18. The Board will not direct NP with respect to the manner of its energy efficiency messaging to customers, as proposed by the Consumer Advocate.

eBills Promotion

19. The Board will not direct NP to provide financial incentives to customers who opt to receive their bills electronically, as proposed by the Consumer Advocate.

Vacancy Adjustment in Forecast Labour Costs

20. The Board will direct NP to include, as part of its next general rate application, detailed information concerning the method used to forecast its test year FTEs and labour expense, as well as an explanation of the assumptions used to determine the forecast vacancies.

Pole Management Practices

21. The Board will not direct NP at this time with respect to its pole management practices.

Proposed Federal Corporate Tax Rate Reduction

22. The Board will direct NP to create a deferral account to true-up the income tax expense for the 2008 test year and for subsequent years until its next general rate application to reflect proposed corporate tax changes announced by the Federal Government on October 30, 2007, with the disposition of account balance, if any, to be subject to a further Board Order.

International Financial Reporting Standards

23. NP will be directed to provide updates as part of its quarterly reports to the Board as to the status of the AcSB's considerations of this matter.

Retail Customer Rate Review

24. NP will be directed to provide updates as to the progress of the retail customer rate review as part of its quarterly reports to the Board.

Final Rates

25. The Board will approve the final rates for Domestic and General Service Customers and Street and Area Lighting as set out by NP in Schedule A of its Amended Application, to be effective January 1, 2008.

Next GRA/Reporting

26. NP will be required to file its next general rate application by June 30, 2010 using a 2011 test year.

III. COSTS

27. NP shall pay the expenses of the Board arising from this Application, including the expenses of the Consumer Advocate incurred by the Board, pursuant to Sections 90(2) and 111 of the *Act*.

PART FOUR. BOARD ORDER

IT IS THEREFORE ORDERED THAT:

RATE BASE AND RATE OF RETURN

1. NP's proposed forecast average rate base for the 2008 test year of $812,212,000, calculated in accordance with the Asset Rate Base Method, is approved.

2. NP's proposed rate of return on average rate base for the 2008 test year of 8.37% in a range of 8.19% to 8.55% is approved.

RATES, RULES AND REGULATIONS

3. The rates proposed by NP are approved as set out in Schedule A of this Decision and Order, effective for consumption on and after January 1, 2008.

4. The changes to the Rules and Regulations proposed by NP are approved and NP shall file with the Board, within 30 days of this Order, NP's Rules and Regulations revised to reflect changes to:

- **i. the Rate Stabilization Clause to provide for the recovery through the Rate Stabilization Account of the Energy Supply Cost Variance incurred through to the end of 2010, as set out in Schedule B of this Decision and Order;**
- **ii. Regulation 9(b) and 9(c) to permit charges for temporary connections, special facilities and relocations to be added to customer bills, as set out in Section C of this Decision and Order; and**
- **iii. Regulation 10(d) to increase the rejected payment fee, as set out in Schedule C of this Decision and Order.**

AUTOMATIC ADJUSTMENT FORMULA

5. NP's proposed use of the Automatic Adjustment Formula, changed to reflect the adoption of the Asset Rate Base Method for calculating rate base, to establish the rate of return on rate base for three years following the test year is approved, unless otherwise directed by the Board.

6. NP shall, unless otherwise directed by the Board, apply no later than November 30th in each year for the application of the Automatic Adjustment Formula to the rate of return on rate base and for a revised Schedule of Rates, Tolls and Charges effective January 1 in each year following.

7. NP shall, unless otherwise directed by the Board, file its next general rate application with the Board by June 30, 2010 with a 2011 test year.

ACCOUNTING TREATMENT AND POLICIES

8. NP's proposed amortizations are approved with effect from January 1, 2008 as follows:

i. Amortization over a three-year period of:

a) $16,446,000 of 2005 unbilled revenue;

b) $4,087,000 in revenue related to municipal tax timing reconciliation;

c) $11,586,000 in deferred 2006 and 2007 depreciation costs;

d) $1,147,000 in deferred 2007 replacement energy costs associated with the Rattling Brook Hydro Generating Plant refurbishment;

e) the $1,342,000 balance in the Purchased Power Unit Cost Variation Reserve Account; and

f) $1,250,000 in recovery of hearing costs.

ii. Amortization over a five-year period of the $6,800,000 balance in the Degree Day Component of the Weather Normalization Reserve.

9. NP's proposal to adjust the depreciation expense to amortize the accumulated reserve variance of $700,000 over the four-year period 2008-2011 is approved.

10. NP's proposal to use the depreciation rates as recommended in the 2006 Depreciation Study is approved.

11. NP's proposal to adopt the accrual method of accounting for income tax related to pension costs is approved.

12. NP's proposal to continue using the cash basis for recognizing expenses for other employee future benefits is approved.

13. NP's proposal to discontinue the Purchased Power Unit Cost Variation Reserve Account and establish the Demand Management Incentive Account is approved, as set out in Schedule D of this Decision and Order.

14. NP's proposal to create a deferral account to true-up the income tax expense for the 2008 test year and subsequent years until its next general rate application to reflect the proposed 2008 corporate tax changes announced by the Federal Government on October 30, 2007 is approved, with the disposition of the account balance, if any, to be subject to a further order of the Board.

15. NP shall file with the Board, no later than December 31, 2011 a new depreciation study related to plant in service as of December 31, 2010.

REPORTING

16. NP shall, unless otherwise directed by the Board, file with the Board, on or before March 31, 2008, a fair market value determination for insurance services recommending an appropriate charge-out rate.

17. NP shall, unless otherwise directed by the Board, report to the Board within 90 days of the finalization of the CEA reliability performance indicators as to the incorporation of these standards into the existing regulatory framework for NP.

18. NP shall, unless otherwise directed by the Board, as part of its next general rate application include detailed information concerning the method used to forecast its test year FTEs and labour expense, as well as an explanation of the assumptions used to determine the forecast vacancies.

19. NP shall, unless otherwise directed by the Board, as part of its next general rate application include a report on the operation of the Demand Management Incentive Account.

20. NP shall, unless otherwise directed by the Board, provide an update as part of its quarterly reporting to the Board on the status of the AcSB's considerations of the transition to IFRS.

21. NP shall, unless otherwise directed by the Board, provide an update as part of its quarterly reporting to the Board on the progress of NP's retail customer rate review.

22. NP shall, unless otherwise directed by the Board, file as a part of its annual return to the Board, information relating to changes in deferred charges, including pension costs.

23. NP shall, unless otherwise directed by the Board, file:

- **i. With its annual return, a modified schedule calculating the embedded cost of debt for the reporting year to identify specifically the causes of variations in the actual embedded cost of debt from the cost forecast for the test year; and**
- **ii. With its annual return, where in a year the actual rate of return on equity is greater than 50 basis points above the calculation of cost of equity for the same year, a report explaining the circumstances and facts contributing to the difference.**

HEARING COSTS

24. NP shall pay the expenses of the Board arising from this Application, including the expenses of the Consumer Advocate incurred by the Board.

Dated at St. John's, Newfoundland and Labrador this 19th day of December 2007.

____

Robert Noseworthy
Chair & Chief Executive Officer

____

Darlene Whalen, P.Eng.
Vice-Chair

____

Cheryl Blundon
Board Secretary

NEWFOUNDLAND POWER INC.
RATE #1.1
DOMESTIC SERVICE

Availability:

For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect July 1, 2007)

Basic Customer Charge: ....$15.60 per month

Energy Charge:
All kilowatt-hours ....@ 9.030¢ per kWh

Minimum Monthly Charge ....$15.60 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-10 kW

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect July 1, 2007)

Basic Customer Charge: .... $17.90 per month

Energy Charge:
All kilowatt-hours .... @ 11.015 ¢ per kWh

Minimum Monthly Charge, Single Phase .... $17.90 per month
Three Phase .... $35.80 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.2
GENERAL SERVICE 10-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect July 1, 2007)

Basic Customer Charge: .... $20.62 per month

Demand Charge:
$8.64 per kW of billing demand in the months of December, January, February and March and $7.14 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kW of billing demand.. @ 8.563 ¢ per kWh
All excess kilowatt-hours.. @ 6.255 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.3 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase .... $20.62 per month
Three Phase .... $35.80 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect July 1, 2007)

Basic Customer Charge: .... $92.81 per month

Demand Charge:
$7.46 per kVA of billing demand in the months of December, January, February and March and $5.96 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 30,000 kilowatt-hours .... @ 8.431 ¢ per kWh
All excess kilowatt-hours .... @ 6.106 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.3 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect July 1, 2007)

Basic Customer Charge: .... $185.64 per month

Demand Charge:
$7.05 per kVA of billing demand in the months of December, January, February and March and $5.55 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 100,000 kilowatt-hours .... @ 7.042 ¢ per kWh
All excess kilowatt-hours .... @ 5.980 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.3 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #4.1
STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service where the electricity is supplied by the Company and all fixtures, wiring and controls are provided, owned and maintained by the Company.

Monthly Rate: (Includes Municipal Tax and Rate Stabilization Adjustments in effect July 1, 2007)

	Sentinel/Standard	**Post Top**
High Pressure Sodium*		
100W (8,600 lumens)	$15.16	$15.98
150W (14,400 lumens)	19.09	-
250W (23,200 lumens)	25.25	-
400W (45,000 lumens)	34.47	-

* For all new installations and replacements.

Mercury Vapour		
175W (7,000 lumens)	$15.16	$15.98
250W (9,400 lumens)	19.09	-
400W (17,200 lumens)	25.25	-

Special poles used exclusively for lighting service**

Wood	$ 6.29
30' Concrete or Metal, direct buried	9.30
45' Concrete or Metal, direct buried	14.72
25' Concrete or Metal, Post Top, direct buried	7.39

Underground Wiring (per run)**

All sizes and types of fixtures	$12.39

** Where a pole or underground wiring run serves two fixtures paid for by different parties, the above rates for such poles and underground wiring may be shared equally between the two parties.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{\text{(Maximum Demand during Peak Period x 1573 hours)}}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced by 50% as a result of the first failure to Curtail during a Winter. For each additional failure to Curtail, the Curtailment Credit will be reduced by a further 25% of the Curtailment Credit. If the Customer fails to Curtail three times during a Winter, the Customer forfeits 100% of the Curtailment Credit and the Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

The Company shall include a rate stabilization adjustment in its rates. This adjustment shall reflect the accumulated balance in the Company's Rate Stabilization Account ("RSA") and any change in the rates charged to the Company by Newfoundland and Labrador Hydro ("Hydro") as a result of the operation of its Rate Stabilization Plan (“RSP”).

I. RATE STABILIZATION ADJUSTMENT ("A")

The Rate Stabilization Adjustment (“A”) shall be calculated as the total of the Recovery Adjustment Factor and the Fuel Rider Adjustment.

The Recovery Adjustment Factor shall be recalculated annually, effective the first day of July in each year, to amortize over the following twelve (12) month period the annual plan recovery amount designated to be billed by Hydro to the Company, and the balance in the Company's RSA.

The Recovery Adjustment Factor expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{B + C}{D}$$

Where:

B = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's RSP.

C = the balance in the Company's RSA as of March 31st of the current year.

D = the total kilowatt-hours sold by the Company for the 12 months ending March 31st of the current year.

The Fuel Rider Adjustment shall be recalculated annually, effective the first day of July in each year, to reflect changes in the RSP fuel rider applicable to Newfoundland Power. The Fuel Rider Adjustment expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{E}{D} \times F$$

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

I. RATE STABILIZATION ADJUSTMENT ("A") (Cont'd)

Where:

D = corresponds to the D above.

E = the total kilowatt-hours of energy (including secondary energy) sold to the Company by Hydro during the 12 months ending March 31 of the current year.

F = the fuel rider designated to be charged to Newfoundland Power through Hydro's RSP.

The Rate Stabilization Adjustment ("A") shall be recalculated and be applied as of the effective date of a new wholesale mill rate by Hydro, by resetting the Fuel Rider Adjustment included in the Rate Stabilization Adjustment to zero.

II. RATE STABILIZATION ACCOUNT ("RSA")

The Company shall maintain a RSA which shall be increased or reduced by the following amounts expressed in dollars:

1. At the end of each month the RSA shall be:

   (i) increased (reduced) by the amount actually charged (credited) to the Company by Hydro during the month as the result of the operation of its Rate Stabilization Plan.

   (ii) increased (reduced) by the excess cost of fuel used by the Company during the month calculated as follows:

$$\mathbf{(G/H - P) \quad x \quad H}$$

Where:

G = the cost in dollars of fuel and additives used during the month in the Company's thermal plants to generate electricity other than that generated at the request of Hydro.

H = the net kilowatt-hours generated in the month in the Company's thermal plants other than electricity generated at the request of Hydro.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

P = the 2nd block base rate in dollars per kilowatt-hour paid during the month by the Company to Hydro for firm energy.

(iii) reduced by the price differential of firmed-up secondary energy calculated as follows:

$$\mathbf{(P - J) \times K}$$

Where:

J = the price in dollars per kilowatt-hour paid by the Company to Hydro during the month for secondary energy supplied by Deer Lake Power and delivered as firm energy to the Company.

K = the kilowatt-hours of such secondary energy supplied to the Company during the month.

P = corresponds to P above.

(iv) reduced (increased) by the amount billed by the Company during the month as the result of the operation of the Rate Stabilization Clause calculated as follows:

$$\mathbf{\frac{L \times A}{100}}$$

Where:

L = the total kilowatt-hours sold by the Company during the month.

A = the Rate Stabilization Adjustment in effect during the month expressed in cents per kilowatt-hour.

(v) increased (reduced) by an interest charge (credit) on the balance in the RSA at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base.

2. On the 31st of December in each year, the RSA shall be increased (reduced) by the amount that the Company billed customers under the Municipal Tax Clause for the calendar year is less (or greater) than the amount of municipal taxes paid for that year.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly streetlighting rates are as follows:

	Fixture Size (watts)				
	100	150	175	250	400
Mercury Vapour	-	-	840	1,189	1,869
High Pressure Sodium	546	802	-	1,273	1,995

4. On December 31st, 2007, the RSA shall be reduced (increased) by the amount that the increase in the Company's revenue for the year resulting from the change in base rates attributable to the flow through of Hydro's wholesale rate change, effective January 1, 2007, is greater (or less) than the amount of the increase in the Company's purchased power expense for the year resulting from the change in the base rate charged by Hydro effective January 1, 2007.

The methodology to calculate the RSA adjustment at December 31, 2007 is as follows:

Calculation of increase in Revenue:	
2007 Revenue with Flow-through (Q)	$ -
2007 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2007 Purchased Power Expense with Hydro Increase (T)	$ -
2007 Purchased Power Expense without Hydro Increase (U)	$ -
Increase in Purchased Power Expense (V = T – U)	$ -
Adjustment to Rate Stabilization Account (W = S – V)	$ -

Where:

Q = Normalized revenue from base rates effective January 1, 2007.
R = Normalized revenue from base rates determined based on rates pursuant to the operation of the Automatic Adjustment Formula for 2007.
T = Normalized purchased power expense from Hydro's wholesale rate effective January 1, 2007 (not including RSP rate).
U = Normalized purchased power expense determined based on Hydro's wholesale rate effective January 1, 2006 (not including RSP rate).

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

5. On December 31st of each year from 2008 up to and including 2010, the Rate Stabilization Account (RSA) shall be increased (reduced) by the Energy Supply Cost Variance.

   This Energy Supply Cost Variance identifies the change in purchased power cost that is related to the difference between purchasing energy at the 2nd block energy charge in the wholesale rate and the test year energy supply cost reflected in customer rates.

   The Energy Supply Cost Variance expressed in dollars shall be calculated as follows:

$$\frac{(A - B) \times (C - D)}{100}$$

   Where:

   A = the wholesale rate 2nd block charge per kWh.

   B = the test year energy supply cost per kWh determined by applying the wholesale energy rate to the test year energy purchases and expressed in ¢ per kWh.

   C = the weather normalized annual purchases in kWh.

   D = the test year annual purchases in kWh.

III. RATE CHANGES

The energy charges in each rate classification (other than the energy charge in the "Maximum Monthly Charge" in classifications having a demand charge) shall be adjusted as required to reflect the changes in the Rate Stabilization Adjustment. The new energy charges shall be determined by subtracting the previous Rate Stabilization Adjustment from the previous energy charges and adding the new Rate Stabilization Adjustment. The new energy charges shall apply to all bills based on consumption on and after the effective date of the adjustment.

Newfoundland Power Inc.

Regulation Changes

Existing Regulation 9(b)

> *Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay the Company in advance a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material.*

Approved Regulation 9(b)

> *Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay the Company a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material. The payment may be required in advance or, subject to credit approval, billed to the Customer.*

Existing Regulation 9(c)

> *Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay the Company in advance the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment.*

Approved Regulation 9(c)

> *Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay the Company the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment. The payment may be required in advance or, subject to credit approval, billed to the Customer.*

Newfoundland Power Inc.

Regulation Change for Rejected Payment

Existing Regulation 10(d)

> *Where a Customer's cheque is not honoured for insufficient funds, a charge of $10.00 may be applied to the Customer's bill.*

Approved Regulation 10(d)

> *Where a Customer's cheque or automated payment is not honoured by their financial institution, a charge of $16.00 may be applied to the Customer's bill.*

Newfoundland Power Inc.

Demand Management Incentive Account

Approved Definition

Demand Management Incentive Account 278xx

This account shall be charged or credited with the amount by which the Demand Supply Cost Variance exceeds the Demand Management Incentive. The Demand Management Incentive equals ±1% of test year wholesale demand charges.

The Demand Supply Cost Variance expressed in dollars shall be calculated as follows:

$$(A - B) \times C$$

Where:

A = actual demand supply cost in dollars per kWh determined by dividing the wholesale demand charges in the calendar year by the weather normalized kWh purchases for that year (as will be reported in Return 13 of Newfoundland Power's Annual Report to the Board).

B = test year demand supply cost in dollars per kWh determined by dividing the test year wholesale demand charges by the test year kWh purchases.

C = the weather normalized annual purchases in kWh.

The amount charged or credited to this account shall be adjusted for applicable income taxes calculated at the statutory income tax rate.

Disposition of any Balance in this Account
Newfoundland Power shall file an Application with the Board no later than the 1st day of March each year for the disposition of any balance in this account.

REGULATORY FRAMEWORK

STATUTORY POWERS AND RESPONSIBILITIES

The statutory powers and responsibilities described below are consistent with those set out in Order No. P. U. 7(2002-2003) and are intended to communicate to the utilities and other stakeholders the fundamental regulatory framework used by the Board in issuing its decisions, findings and subsequent Orders.

The Board is an independent, quasi-judicial body established under Provincial legislation to regulate public utilities in the Province. Regulation is designed to ensure consumers receive safe and reliable electricity at rates that are reasonable while allowing the utility to earn a fair return on its investment in supplying the electrical service. Regulation strives to strike an equitable balance between the interests of consumers and the utility.

The regulatory framework of the Board consists of five cornerstones, as follows:

i. BOARD AUTHORITY sets out the legislative and legal powers and responsibilities of the Board.
ii. BOARD HEARING PROCEDURES govern the presentation of the evidentiary record on matters before the Board.
iii. REGULATORY PRINCIPLES which are commonly accepted in guiding sound public utility regulation.
iv. THE RATE SETTING PROCESS is founded in accounting, engineering and economic methodologies which are applied in combination with i), ii) and iii) and weighed by the Board in making decisions affecting rates.
v. REPORTING/COMPLIANCE provides appropriate regulatory monitoring of the utility's ongoing activities and compliance with Board Orders.

1. Board Authority

Mandate

The Board's authority is derived from its statutory powers and responsibilities as set out in the *Public Utilities Act* (the *"Act"*) and the *Electrical Power Control Act, 1994* (the *"EPCA"*).

The *Act* sets out the structure of the Board and defines its powers. The Board has responsibility for the general supervision of public utilities in the Province, which requires the Board to approve rates, capital expenditures and other aspects of the business of public utilities.

In addition to the provisions of the *Act*, the Board is also mandated through the *EPCA*, particularly Section 3, which states the power policy of the Province as follows:

"3. It is declared to be the policy of the province that

(a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province

(i) should be reasonable and not unjustly discriminatory;
(ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years;
(iii) should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world; and
(iv) should be such that after December 31, 1999 industrial customers shall not be required to subsidize the cost of power provided to rural customers in the province, and those subsidies being paid by industrial customers on the date this Act comes into force shall be gradually reduced during the period prior to December 31, 1999;

(b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner

(i) that would result in the most efficient production, transmission and distribution of power;
(ii) that would result in consumers in the province having equitable access to an adequate supply of power;
(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service…"

Section 4 of the *EPCA* states:

"4. In carrying out its duties and exercising its powers under this Act or under the Public Utilities Act, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice."

In summary, the *EPCA* mandates the Board to make rate decisions that are reasonable and not unjustly discriminatory. Rates are to be based on forecast costs for the supply of power for one (1) or more years. This timeframe in practice is generally referred to as the *"test year(s)"*. The legislation also ensures that the utilities are permitted to earn a just and reasonable financial return while maintaining a sound credit rating in the financial markets of the world. The legislation calls for the most efficient production, transmission and distribution of power that will afford consumers the lowest possible cost electricity consistent with equitable, safe and reliable service.

Form of Regulation

With regard to the form of regulation, Section 80(1) of the *Act* states:

"80. (1) A public utility is entitled to earn annually a just and reasonable return as determined by the Board on the rate base, as fixed and determined by the Board for each type or kind of service supplied by the public utility…"

This is commonly referred to as return on rate base regulation. Rate base consists largely of investment by the utility in plant and equipment and historically has constituted the statutory form of regulation used in the Province. Return on rate base regulation is more fully described in relation to the Rate Setting Process. Alternative forms of regulation in place elsewhere include Return on Equity (ROE) and/or an emerging trend toward Performance Based Regulation (PBR).

Statutory Limitations

The legislative authority of the Board is, nonetheless, subject to two limitations (Sections 5.1 and 5.2) in the *EPCA* as follows:

"5.1 Notwithstanding section 3 and section 4 of the Act and the provisions of the Public Utilities Act, the Lieutenant-Governor in Council may direct the public utilities board with respect to the policies and procedures to be implemented by the board with respect to the determination of rate structures of public utilities under the Public Utilities Act and, without limiting the generality of the foregoing, including direction on the setting and subsidization of rural rates, the fixing of a debt-equity ratio for Hydro and the phase in, over a period of years from the date of coming into force of this section, of a rate of return determination for Hydro and the board shall implement those policies and procedures.

5.2 The Lieutenant-Governor in Council may exempt a public utility from the application of all or a portion of this Act where the public utility is engaged in activities that in the opinion of the Lieutenant-Governor in Council as a matter of public convenience or general policy are in the best interest of the province, to the extent of its engagement in those activities."

Appeal Process

Section 99 (1) of the *Act* states the statutory authority embodied in an Order of the Board as follows:

"An appeal lies to the Court of Appeal from an order of the board upon a question as to its jurisdiction or upon a question of law, but the appeal can be taken only by leave of a judge of the court, given upon an application presented within 15 days after the making of the decision and upon the terms that the judge may determine."

An Order of the Board has the force of law and is binding on the parties and can only be appealed to the Court of Appeal on an issue of law or jurisdiction of the Board.

Stated Case

The most comprehensive judicial consideration of the authority of the Board comes from the comments of Mr. Justice Green in Newfoundland (Board of Commissioners of Public Utilities)(Re)(1998), 64 NFLD. & PEI R.60 (NFLD.C.A.) In 1998 the Board stated a case for the consideration of the Court of Appeal pursuant to Section 101 of the *Act*. Mr. Justice Green set out some general principles that apply to all decisions of the Board, which may be summarized as:

1. The *Act* should be given a liberal interpretation respecting the purpose of the legislation and the power policy of the province;
2. The Board has discretion in how it approaches its mandate;
3. The Board has all appropriate and necessary powers;
4. The Board must balance the interests of public utilities and electrical consumers;
5. The Board sets rates prospectively, after a full consideration of all available evidence; and
6. The Board has discretion to choose the approach to setting rates as long as it observes the legislation and sound utility practices.

The Court was clear in setting out that the Board must balance two sets of interests - the utility's right to a fair return and the consumer's right to reasonable access to power. Mr. Justice Green notes that the Board must be careful to balance both interests, when he says, at para. 144:

> *"It must always be remembered that, as has been emphasized throughout this opinion, the Board is charged with balancing the competing interests of the utility and the consumers of the service it provides. Neither set of interests can be emphasized in complete disregard of the interests of the other. Thus, in choosing to exercise a particular power within the Board's jurisdiction, the Board must always be mindful of whether, in so acting, it will be furthering the objectives and policies of the legislation and doing so in a manner that amounts to a reasonable balance between the competing interests involved."*

In conclusion, the Court found that the Board can be regulative and corrective but not managerial in its prospective regulation of a utility. The Board notes that the Court of Appeal suggested that the Board should observe a presumption of managerial good faith.

2. Board Procedures

The Board's procedures are governed by the relevant legislation and, as a quasi-judicial body, the principles of natural justice and procedural fairness apply. The *Act* and *Regulation 39/96* both set out procedures for the Board. In addition to prescribed regulations, Section 26 of the *Act* enables the Board to establish its own procedures. This permits the Board to exercise discretion to allow for a more informal and flexible treatment of issues.

The procedures of the Board address items such as the form of the application, public notice, submission by intervenors, information requests, document exchange along with rules and protocol surrounding public hearings. While the procedures in a hearing before the Board are less formal than a court, the principles of natural justice are still observed. Sufficient notice is given to all interested persons who are provided with the opportunity to participate. Witnesses are sworn, and their testimony is heard by way of both direct and cross-examination. Evidence is entered and documented and the Board maintains a full and complete record.

Hearing documentation is generally filed in electronic format with a paper copy maintained as the official Board record. The Board provides public access to all information through the Board's web site (**www.pub.nl.ca**). The web site is updated daily with transcripts and additional evidence filed during each day's proceedings posted in advance of the commencement of the hearing the following day. During the hearing the evidence can also be viewed simultaneously by the Board, parties and witnesses on monitors located in the Hearings Room.

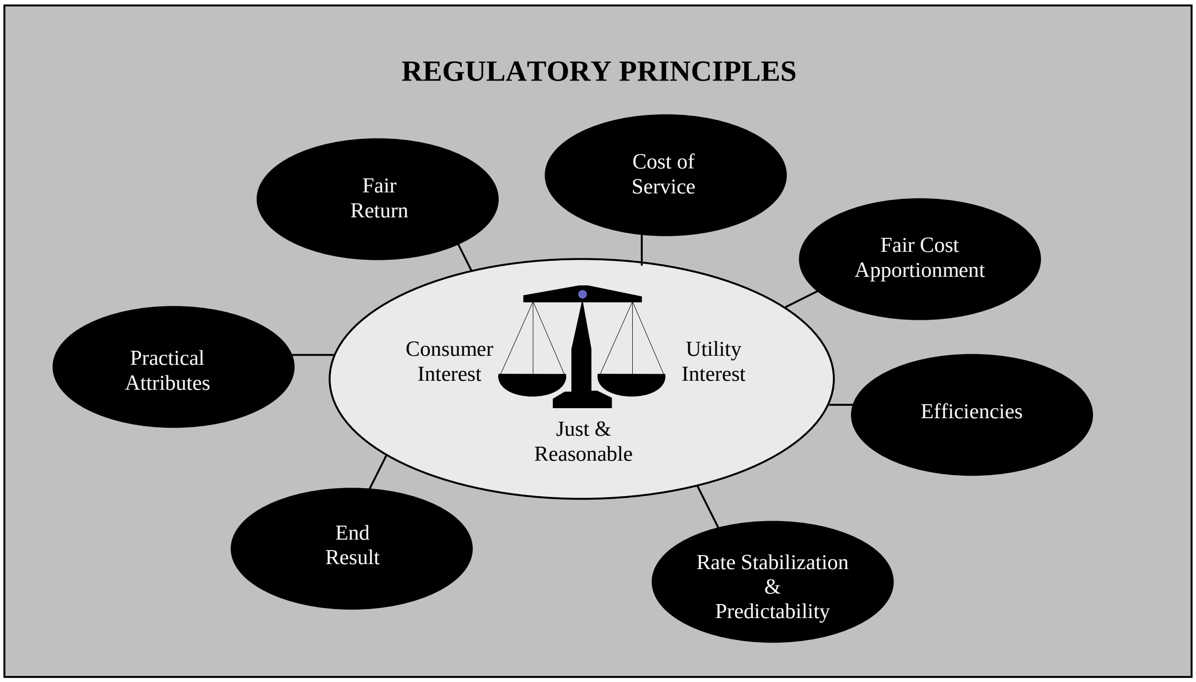
Through these procedures the Board ensures that the process is accessible and transparent for stakeholders, including the public. The Board may also travel throughout the province to hear from interested persons or organizations. Full and informed public debate and discussion on the issues is encouraged through the participation of the parties, the general public and, for major hearings, a government appointed consumer advocate.

After full consideration of all of the evidence the Board will issue a reasoned decision, usually in writing. A Decision and Order of the Board will be issued and, as noted previously, can only be appealed to the Court of Appeal.

3. Regulatory Principles

Sound regulatory practices encompass fundamental principles which are used by regulators as a guide or roadmap to rational decision-making. As stated in the Bonbright J. C., Danielsen A.L, Kamerscen D.R., Principles of Public Utility Rates (Arlington: Public Utilities Reports, Inc., 1988): "*We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.*" These are commonly referred to as Bonbright's principles.

Section 4 of the *EPCA* directs the Board to apply tests that are consistent with generally accepted sound public utility practice. The Board sets out the following principles for purposes of its regulatory framework:



1. Fair Return
   Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:

   - commensurate with return on investments of similar risk;
   - sufficient to assure financial integrity; and
   - sufficient to attract necessary capital.

   The fair return principle is consistent with both Section 80(1) of the *Act* and Section 3(a)(iii) of the *EPCA.*

2. Cost of Service

Under this principle a utility is permitted to set rates that allow the recovery of costs for regulated operations, including a fair return on its investment devoted to regulated operations - no more, no less. Costs should be:

- prudent;
- used and useful in providing the service;
- assigned based on cause (causality);
- incurred and recovered (matching costs and benefits) during the same period; and
- reflective of private/social costs and benefits occasioned by the service.

3. Fair Cost Apportionment

Fairness of specific rates in the apportionment of total costs of service among the different ratepayers should be such so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the *Act* which requires that *"all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …"*. Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the *EPCA* which declares it to be "…*the policy of the province that the rates to be charged ………should be reasonable and not unjustly discriminatory."*

4. Efficiencies

Rate classes and rate blocks should discourage wasteful use of service while promoting all types and amounts of use that are economically justified. Greater efficiency should also be encouraged in promoting innovation and responding economically to changing demand and supply patterns.

5. Rate Stability and Predictability

Rates and revenues should be stable and predictable from year to year with a minimum of unexpected changes seriously adverse to either ratepayers or utility companies. This principle may justify smoothing out increases to avoid sharp rate climbs or temporary fluctuations. The emphasis using this standard relates to the timing of rate implementation.

6. End Result

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

7. Practical Attributes

Rates should be simple, understandable and publicly acceptable with a minimum of controversy upon implementation.

While setting out these principles may be useful to ensure full consideration of all the issues, the Board notes that at times they may contain ambiguities, conflict with legislation, be inconsistent and/or hold different priorities. The real challenge for the Board, in keeping with its legislative mandate, is to balance ofttimes competing objectives within the regulatory environment to ensure a set of sound and reasoned decisions serving the interests of both consumer and utility alike.

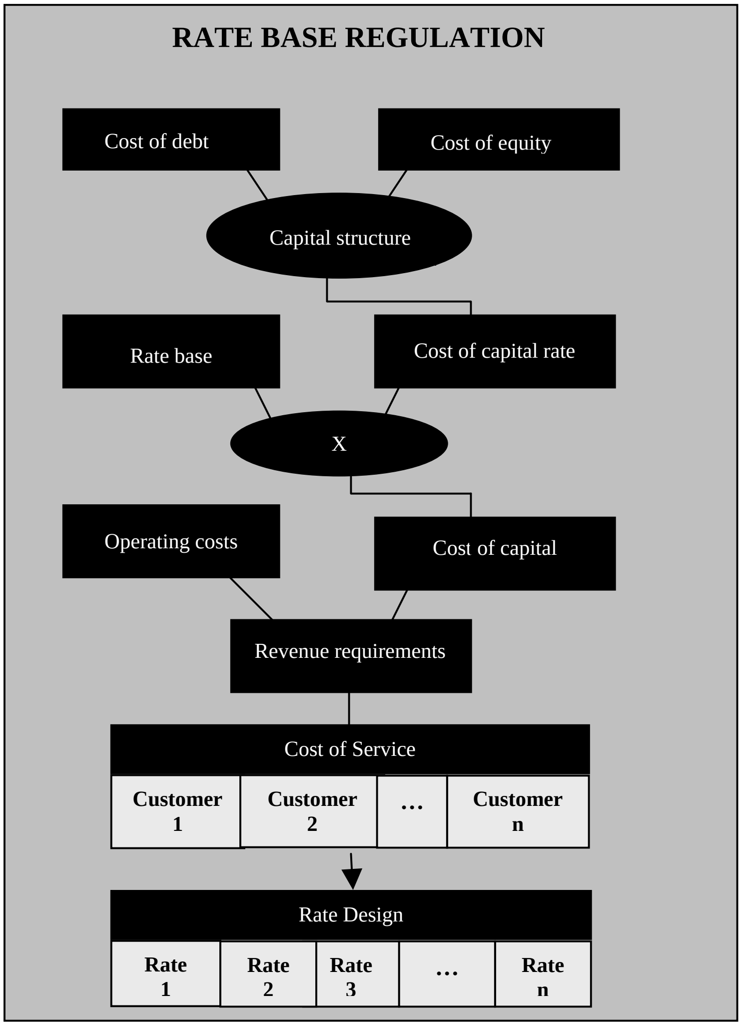
During rate proceedings the Board is often petitioned by intervenors and presenters to consider the customers' ability to pay when setting rates for various classes of customers and service. While cross subsidization of a group of customers contributing toward the cost of service assigned to another group of customers is a common regulatory practice, the ability of an individual customer to pay for the electrical service consumed is not considered by the Board in setting rates. Without compelling change in either legislation, public policy or structure of regulation, the Board will continue to pursue generally accepted regulatory principals as outlined above which does not incorporate ability to pay among its criteria for rate setting.

4. The Rate Setting Process

The rate setting process is founded in accounting, engineering and economic methodologies and is the proverbial glue that binds the regulatory framework. The Board's authority, the evidence and regulatory principles are combined by the Board through this process to make decisions affecting rates. The rate setting process is described below under the heading *"Rate Base Regulation"*.

Rate Base Regulation

As noted previously, pursuant to Section 80 of the *Act*, the regulatory framework of the Board is founded in rate base regulation. The elements of rate base regulation are illustrated as follows:



(As modified from *"Basics of Canadian Rate Regulation"*, pg. 13, by J. T. Browne and Charles Perron, Deloitte & Touche, 1997.)

The focus of return on rate base regulation is on earnings, in particular the allowed return per dollar of investment (rate base). Rates are set to give the regulated utility the opportunity to recover its revenue requirement consisting of its estimated operating costs and a fair return on its rate base. These costs are generally estimated for a test year(s) for which the rates are set.

Rate Base

Rate base is the amount of investment on which a regulated utility is allowed to earn a fair return. Rate base comprises primarily depreciated investment in plant and equipment plus working capital as well as certain deferred assets/costs attributable to future operations. Regulators tend to focus on whether additions to the rate base, looking at the asset, are needed and if the cost is reasonable.

Capital Structure

Capital structure is the relative amounts of equity and debt, commonly referred to as the debt to equity ratio, which comprises a company's total invested capital. The total invested capital represents the funds invested in the public utility by shareholders (equity) and by bondholders and other long-term debt holders (debt). The just and reasonable rate of return allowed on rate base is equivalent to the cost of capital representing the sum of the weighted costs of both debt and equity in the capital structure.

Revenue Requirement

Revenue requirement is the amount of revenue required by a utility to cover the sum of operating costs including debt service, depreciation, taxes and allowed return on rate base ($ rate base x cost of capital). The revenue requirement is the total amount of money a utility is eligible to collect from customers through rates:

Revenue Requirement = Operating Costs + (Rate Base x Rate of Return)

From a regulatory perspective, efficient operations, fully justified capital expenditures and a low cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers.

Cost of Service

Cost of service constitutes the basis on which the utility's revenue requirement is allocated to each class of customer served. The utility normally submits a study of the costs incurred in purchasing, producing, transmitting and distributing electricity to its customers, by customer class.

Rate Design

Once the cost of service or revenue requirement is allocated by customer class, specific rates are determined to recover the required costs/revenues from each customer within the class.

5. Reporting/Compliance

Reporting/Compliance is the mechanism used to monitor the ongoing activities of the utility from a regulatory perspective and is an important part of the regulatory framework. Section 16 of the *Act* states:

> *"The board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by public utilities with the law and shall have the right to obtain from a public utility all information necessary to enable the board to fulfil its duties."*

Consistent with the Court of Appeal's findings, the role of the Board is not to exercise managerial influence but to ensure appropriate reporting/compliance mechanisms are in place such that regulatory objectives are met. The objective of the Board is to focus on regulatory accountability of the utility rather than engage in detailed reviews and costly controls. In keeping with this approach, some examples of the Board's reporting/compliance requirements requested of the utilities include:

- Compliance with Board Orders;
- Annual financial review;
- Quarterly reports;
- Incident/Outage reports;
- Technical reports;
- Productivity, cost benefit and efficiency studies;
- CIAC audits; and
- Monitoring complaints.

6. Summary

A consistent and equitable regulatory framework is in the interests of both the regulated utilities and consumers. The framework as described above has been in place in one form or another since the Board was established in 1949. This framework has evolved to date through a series of legislative amendments and case law and will continue to form the basis of the Board's exercise of its regulatory authority under existing legislation, both in this Decision and Order and on a go forward basis.

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